THE BARBADOS LIGHT & POWER COMPANY LIMITED

APPLICATION

PURSUANT TO SECTION 16

OF

THE UTILITIES REGULATION ACT

CAP. 282 OF THE LAWS OF BARBADOS

FOR A REVIEW OF ELECTRICITY RATES

VOLUME 3

INDEX TO THE BARBADOS LIGHT & POWER COMPANY LIMITED APPLICATION FOR REVIEW OF ELECTRICITY RATES

A

GENERAL MEMORANDUM

INTRODUCTION

1. The Barbados Light & Power Company Limited ("BLPC" or "the Company") has worked diligently to provide safe, reliable and high-quality customer service, while maintaining basic electricity rates which are among the lowest in the Caribbean. For only the second time in nearly forty years, the Company is requesting a general tariff adjustment to enable the Company to continue its high quality of customer service and to continue the work to implement the changes to the electricity grid.

2. The only general tariff increase requested by the Company during this period of stable electricity prices was granted eleven years ago by the Fair Trading Commission (the "Commission" or the "FTC") on January 25th 2010[1], and raised base revenue by an average of 5.3%.

3. The Company's Rate Review Application ("Application") would raise base revenue by an average of 11.9%. This increase is less than the rate of inflation represented by the Consumer Price Index which increased by over 38% since 2010. Like every business, the Company must adjust its pricing to reflect the increased costs of doing business. In addition, the Company must implement new services to support the clean energy transition which will further increase costs. The increase in base revenue requested in this Application is substantially less than the general increase in prices within the economy.

4. The pace of change in the electricity sector has increased significantly over the past ten years. Three trends shaping the scale and pace of this change are decentralization, decarbonisation and digitalization. Decentralisation represents the shift in reliance on large centralized generating plants to dispersed generation across many smaller plants on the distribution network. Decarbonisation is the replacement of carbon-based fuels with renewable energy sources of electricity generation. The significant increase in intermittent renewable energy systems which characterise these two trends, requires more

[1] https://www.ftc.gov.bb/library/blip_app/2010-01-22_commission_decision_No2_of_09_rate_review_barbados_light_and_power_company_limited.pdf

complex grid management approaches and tools made possible by rapidly evolving digital or 'smart' technologies.

5. These trends are expected to accelerate in this decade, requiring major investments in grid modernisation. With this increasing pace in investment, the Company faces an increasing risk of delay between the time when the Company's costs increase and when the utility is allowed to recover those costs through rates. This is commonly referred to as regulatory lag. The sustainable implementation of these investments in grid modernisation will require additional rate relief that can be facilitated either through future rate reviews or other regulatory mechanisms such as the proposed Clean Energy Transition Rider currently being heard by the Commission.

6. Over the past eleven years, a significant portion of the Company's earnings have been reinvested in new plant and equipment required to replace older equipment to meet the increasing demands of customers, improve operating efficiency and transition to cleaner energy as recently prescribed under the Barbados National Energy Policy 2019 – 2030 (BNEP). A few years prior to the introduction of the BNEP, the Company began implementation of its own 100/100 vision for transitioning the Barbados energy market to 100% renewable energy and 100% electrification. Recent examples of investments in these areas include the installation of a 10 megawatt (MW) solar farm in 2016 at a cost of approximately $39M and the current installation of a 33 MW reciprocating generating plant (Clean Energy Bridge), scheduled for commissioning this year at a cost of approximately $133M. These projects play a crucial role in helping to stabilize fuel costs for customers by increasing fuel efficiency on the lowest grade residual fuel, heavy fuel oil (HFO), which is by far the least expensive fuel oil on the market, while displacing fuel with renewable energy sources. Savings in fuel costs are transparently passed through to customers through the regulated Fuel Clause Adjustment (FCA). These projects are also essential to implementing the Government of Barbados' (GoB) clean energy plan to transition to renewable energy generation sources.

7. Through careful cost management and process innovations, the Company has been able to defer a request for general rate relief for over eleven years since the Commission's Decision of January 25th 2010.

8. However, based on a review of our Company's recent financial performance and projections for 2021, the Company has determined it needs to urgently seek rate relief. This rate relief is necessary for the Company to continue meeting existing and new customers' needs while providing a safe, reliable, high quality service to customers.

9. The Company must also pursue a general rate review because of the need to have a rate structure which allows for timely recovery of the costs of the investments needed to facilitate our country's renewable energy transition under the BNEP while maintaining a safe, reliable and resilient electricity supply for our customers.

10. In summary, the primary factors driving the requirement for a rate review at this time are increased costs of operation (including depreciation), lower sales, clean energy transition investments, and meeting government's mandates for electricity sector restructuring.

COMPANY OVERVIEW

11. The Company strives to safely provide energy and energy services that are cost-effective, sustainable and reliable for our customers. Electricity customers in Barbados have been served by the Company and its predecessor, the Barbados Electric Supply Corporation since 1911.

12. Since it was founded in 1911, the Company has been a vertically integrated electric utility and presently operates under a franchise granted under Schedule 2 of the Barbados Light and Power Company (Extension of Franchise) Act 1982[2], to supply energy for all public and private purposes as defined by the Electric Light and Power Act[3] and for a period of forty-two years from August 1st 1986. Since the last rate review in 2009, the Company was acquired by

[2] Attached as Appendix I - Schedule 2 of the Barbados Light and Power Company (Extension of Franchise) Act 1982

[3] https://energy.gov.bb/download/electronic-light-power-act/

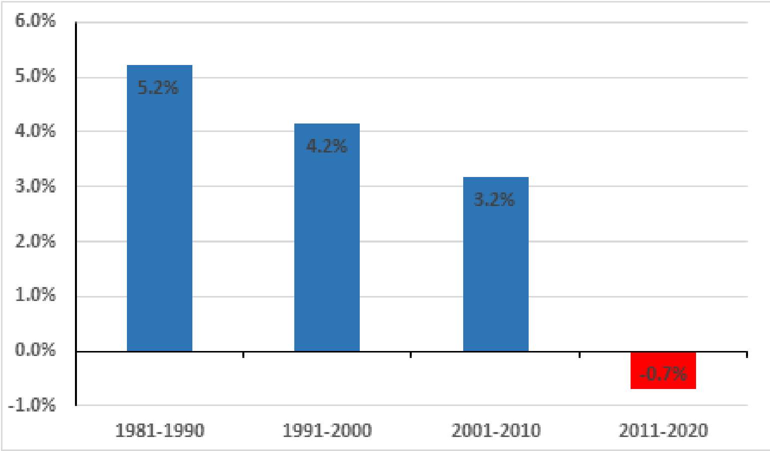
Emera Incorporated (“Emera”), a publicly traded multinational energy holding company based in Halifax, Nova Scotia. Emera’s strategic focus is to safely deliver cleaner, affordable and reliable energy to customers, which is consistent with the objectives of the BNEP.

13. The Company now faces a period of change in the electricity sector that is unprecedented in terms of scope and speed with the introduction of distributed energy technologies, reforms in the licensing and regulatory frameworks and new entrants to the energy market. These changes require the adoption of new technologies and business restructuring to meet customer needs and government clean energy transition policies and electricity market restructuring policies.

14. The Company is currently engaged in negotiations with GoB for the renewal of its licence and the Government has indicated it intends to replace the Company’s current single licence with a complex arrangement of five new licences, encompassed in three documents for: (a) Generation and Energy Storage, (b) Transmission, Distribution and Sales and (c) Dispatch. At December 31, 2020 the Company was serving a total of 131,522 customers through its island-wide distribution network, had a peak demand of 141 MW and recorded year-end sales of 889,943,723 kilowatt-hours.

15. Since the last rate review, the Company has made rigorous efforts to control costs in generating and distributing electricity. These efforts included a significant reengineering exercise to redesign business processes and associated organizational structures, in response to declining sales growth as shown in Figure A.1 and to strategically align the business to allow for the planned RE transition, the changes anticipated in the electricity market structure and increased efficiencies. The reengineering exercise also resulted in the emergence of two new Business Units (Customer Solutions and Asset Management), which increased focus on meeting customer needs and improving operational efficiencies.

Figure A.1: Sales Performance 1981 - 2020



16. Careful cost management improvements, like those resulting from the reengineering exercise, were key factors in enabling the Company to defer a request for general rate relief for over eleven years.

17. The Company has also embarked on building a strategy that encompasses four strategic pillars, namely Safety, Clean Energy, Customer Experience and Operational Excellence.

Safety

18. The Company, in its mission to achieve world-class safety, has built its safety culture based on a philosophy that all injuries are preventable. The Company has also been unrelenting in its commitment and investments to achieve safe work practices to ensure staff, contractors, and customers' safety and health.

19. For the Company, safety is a core value. It has a long history of engendering a positive safety culture complemented with a robust Safety Management System. In 2005, the Company took the progressive decision to join the pool of internationally recognized and certified companies. Led by a strong project team, intense planning, new policies and procedures, the Company met the ISO 9001 certification requirements. Following certification, the Company maintained and then enhanced the Safety Management System by introducing Job Hazard Analyses and Risk Assessments. The Company completed many of these for operational tasks, then used them to improve safe work practices and procedures.

Clean Energy & Energy Efficiency

20. The Company has a pivotal role in the transition towards a clean energy future. Around 2015, the Company developed its 100/100 vision of moving to 100% RE and 100% electrification over time.

21. The Company believes that moving to a future of increased renewable energy provides Barbados with an opportunity to eliminate the need for foreign oil and the resulting foreign currency dependence, strengthen the economy and create new jobs. The Company strongly supports and advocates for a renewable energy transition and has invested in a 10MW solar farm and 5MW battery Energy Storage Device (ESD). A cost-effective transition will deliver substantial benefits to our customers and the entire country.

22. With its application to the Commission in 2008 for a RE Rider pilot, the Company voluntarily opened the grid to solar. In 2010, with the FTC's approval, the Company implemented its RER, which facilitated households and businesses who wished to produce power using distributed solar PV and wind generation systems and sell such power back to the grid. The RER was grandfathered in September 2019 and is the predecessor to the new Feed In tariff (FIT) programs implemented by the Commission. Collectively, the RER and FIT have enabled over 1,500 customers, with a cumulative capacity of over 49MW, to interconnect into the grid to date.

23. Since 2007, the Company has invested significant resources pursuing the development of wind energy at Lamberts, St. Lucy. This has encountered many planning delays and challenges over the period and work is still in progress to acquire the necessary permissions for cost effective wind energy to be developed at the site.

24. In concert with the Company’s renewable energy initiatives and investments, the Company is also facilitating customer energy efficiency initiatives. In addition to its current customer education programme, the Company is currently seeking the Commission’s approval for a small-scale pilot programme to provide up-front financing for customers to install specific energy efficiency or solar PV projects with repayment through their monthly electric bill. This Integrated Utility Service (IUS) programme offers significant promise for

customers to access energy efficiency and renewable energy projects to lower their electricity bills with affordable repayment options.

25. The Company has also partnered with the GoB and the Inter-American Development Bank on an LED Streetlight replacement programme which is well advanced and is expected to be completed in 2021.

Customer Experience

26. The Company has always had a strong customer focus and has consistently engaged with various stakeholders and customers to understand their needs. This engagement has heavily influenced our investment decisions which have led to the incorporation of innovative solutions for our customers.

27. The Company has implemented an Advanced Metering Infrastructure (AMI) platform. The AMI project, an investment of over $$44M, represents one of the Company's most significant technology projects to date and will provide a foundation for smart-grid, customer focused energy management projects and other technology-based system improvements.

28. The Company has deployed AMI meters to over 95% of its customers, with project completion expected in 2021. AMI is an integrated system of meters, networks and data that enables 'two-way' communication between the utility and its customers. The system can provide near 'real-time' data on power consumption, which will assist the Company in its service management. The AMI roll out lays the foundation for future smart-grid applications which will be critical for supporting energy efficiency initiatives, potentially giving customers more data access and control over their demand.

29. AMI enables remote reading of meters, permitting accurate monthly billing of all customers based on their actual readings. For customers who have AMI meters, the Company has eliminated the need for interim and estimated bills.

30. As AMI and Smart Grid devices are rolled out onto the distribution network the Company will continue to maximize efficiency gains through the integration of Meter Data Management Systems (MDMS), Advanced Grid Analytics (AGA), Distribution Equipment Monitoring (DEM), Outage Management Systems (OMS), Distribution Management Systems (DMS) and Geographic Information Systems (GIS).

31. The Company has invested in a Customer Information System, which enabled the creation of a Web Self Service online portal. This system allows customers to view their bills and make payments online.

Operational Excellence

32. Over the last decade, the Company has continued to invest to ensure a high level of reliable service and grid resilience. The Company has been unwavering in its commitment to initiatives that help enhance reliability. Some of these include:

- Implementation of a robust Vegetation Management Programme to reduce outages caused by trees on lines;
- Installation of Distribution Automated switches to quickly isolate faults on distribution lines and automatically reconfigure the network to reduce outage times; and
- Deployment of a Geographic Information System (GIS) that provides the Company better visibility of its assets in the field and enhances its capability to predict when assets are likely to need replacement.

33. With the expectation of higher penetration of renewables interconnecting to the grid, the Company conducted Intermittent RE Penetration studies to understand the impact of renewables on the grid. Such studies identify mitigation measures the Company must implement to ensure continued grid stability.

34. These mitigation measures will require additional investments in upgraded conductors, transformers and other voltage regulating equipment. Some of these measures are described in the Capital Expansion Memorandum, however all of the measures and associated costs are subject to further analysis and investigation as intermittent RE penetration levels increase.

35. In November 2019, the Company experienced two highly unusual island-wide outages which were caused by a number of factors, some of which were outside of the reasonable control of the Company. Events of interruption occur periodically and the Company acts with urgency and diligence in such circumstances to repair and restore supply quickly as evidenced by our Standards of Service track-record. During the outages in November 2019, restoration was impeded due primarily to fuel quality issues being experienced at the time that affected multiple generating units. The Company nonetheless acted with expediency throughout and following these emergency events, and

took immediate corrective actions to prevent recurrence. Following a prudent review of timely and cost effective options, the Company added a further 27MW of generating capacity (12MW commissioned on December 21, 2019; 15MW commissioned on February 19, 2020) to provide a level of assurance against any further and protracted fuel issues. The Commission investigated the matter and issued its findings in December 2020.[4]

OUR STORY

36. Prior to 2008, the Company realized that a major change in the utility business model was occurring. Globally, electric utilities' business models were evolving to incorporate increasing levels of distributed grid-tied renewable energy production. In anticipation of this, without any policy or regulatory directives or legislative framework to support it, the Company, in its last rate review application, included a request to implement the RER.

37. The Company has always been a proactive and progressive company. Apart from introducing the RER, the Company later, in 2016, constructed a 10MW solar photovoltaic (PV) farm at Trents, St. Lucy, when it determined that utility-scale renewable energy plants were economically viable. This solar farm was the first utility-scale PV installation in the Eastern Caribbean. The solar plant's commissioning is estimated to save the country approximately $8-10M annually in foreign exchange based on fuel costs at an international oil price of US$60 per barrel.

38. At the Trents, St. Lucy site, the Company also installed a 5MW ESD to lower fuel costs and enhance grid reliability and resilience. The BNEP and the associated implementation plan includes a requirement for a potential 200 MW of battery storage.

39. To complement the RE transitional plan, the Company conducted a Demand-Side Management (DSM) Study in 2015 to assess the potential for DSM incentive-based programmes in Barbados. DSM aims to manage the demand for electricity through customer programmes, to contribute to a more efficient generation mix and improved system load management capabilities. However,

[4] https://www.ftc.gov.bb/library/2020-12-29_commission_summary_findings_report_outages_blandp_november_2019.pdf

the Company recognized that the largest barrier to customer uptake of equipment that facilitates DSM is customer knowledge and financing.

40. Recognizing the Company's desire to tailor a customer-driven DSM initiative, CARICOM and the German Agency for International Cooperation approached the Company to develop an innovative Integrated Utility Services (IUS) project. The project provides upfront financing for specific customer energy efficiency and renewable energy projects that can yield significant energy savings, enabling customers to lower their electricity bills. The Company hopes to implement a pilot programme later this year subject to the Commission's approval.[5] This programme will provide up-front financing for customers to install specific energy efficiency or solar PV projects with repayment through their monthly electric bill. It also offers significant promise for customers to access energy efficiency and renewable energy projects to lower their electricity bills with affordable repayment options.

41. The Company is on a path towards the national clean energy goals and supporting energy efficiency initiatives, but recognizes that fossil fuel will have a significant transitional role in the interim. Fossil fuels are purchased from the Barbados National Oil Company Limited (BNOCL) and other major oil companies to produce electricity, and the FCA is the mechanism that has been approved by the Commission for the Company to recover the cost of fuel used in electricity production. Fuel purchases are a "pass-through" cost applied equally to all customer groups through the FCA charge, which appears on all electricity bills. The fuel charge generally accounts for around 50% of customers' electricity bills. FCA changes result primarily from movements in the purchase price of fuel which is influenced by world oil prices. Fluctuations in fuel prices have been a major source of customer dissatisfaction in recent years, as they translate into significant volatility in the fuel portion of customers' bills.

42. In December 2014 the Company advised the Commission of its proposed fuel hedging strategy programme and sought approval to implement such an arrangement. The primary reason for wishing to implement the hedging programme was the Company's anticipation that the programme would be of

[5] https://www.ftc.gov.bb/library/blip_app/2021/2020-10-13_letter_to_ftc_ius_model_pilot_application.pdf

significant benefit to electricity customers. It would allow for better management of the FCA volatility and provide a more stable and predictable electricity price.

43. The Company has consistently been vigilant for opportunities to hedge over the years and believes that a fuel hedging programme can support fuel price stability during the transition period to 100% RE. Hedging would allow the Company to secure a fixed price for a percentage of fuel purchases, thereby mitigating volatile fuel prices and providing customers with the ability to better predict their electricity costs.

44. The Commission denied the Company's request to implement a fuel hedging programme on that occasion and subsequent requests. However, the Company believes that the implementation of a fuel hedging programme would financially benefit electricity customers. On March 20, 2020 during the 65th sitting of the House of Assembly, 2018-2023 Estimates, the Prime Minister indicated Government's support for the policy of hedging of energy products. On May 8, 2020, the Company made another Application to the Commission to implement a fuel hedging programme, including permission to apply the results and costs associated with a fuel hedging programme to calculate the FCA. A Decision by the Commission on this Application is pending. BLPC looks forward to working with stakeholders and the Commission on this matter to find a viable solution for hedging fuel prices.

45. The Commission implemented a Heat Rate Monitoring/Management programme on April 17, 2019 which is intended to create financial incentives for the Company to minimize the amount of fuel consumed by each plant in its production of a unit of electricity by active heat rate monitoring and management. Only fuel costs associated with the targeted heat rate are allowed to be passed on to customers, while the utility is allowed to benefit from any efficiency gains made. The Company's Application assumes compliance with the heat rate targets.

46. Besides stabilising fuel prices during the transition to 100% RE, the Company has continued to prudently invest in its existing plants, such as the steam units. The Company developed a life extension plan for the steam units to prolong their technical and economic lives in support of the transition to 100% RE.

Under ideal conditions, the Company would have retired the steam units as projected in the 2009 rate filing. However electricity market's economic and policy conditions began to change soon after that rate review and did not permit the steam units' retirement. Therefore, after extensive analysis and informing the FTC, the Company determined, based upon the information available at the time, that it was most prudent to extend the life of the steam plant.

47. The Company needed to modify its investment plan in response to the changing business environment. Between 2012 and 2014, the Company developed an Integrated Resource Plan, which considered the government's plan to introduce up to 60 MW of combined waste-to-energy and biomass generation between 2016 and 2018. The announcement of the government's plans, along with changes to the government's licensing regime, the new Electric Light and Power Act (ELPA) and anticipated reforms in the electricity market structure increased the level of uncertainty in Barbados' energy environment. As a result, the Company undertook reviews and adjustments to its investment plans over the period under discussion.

48. When the Company recognized that investor-driven plans to commission up to 60MW of firm renewable capacity were not likely to occur, the Company advanced plans to install new fossil fuel generating capacity. The Company had not installed any new fossil fuel capacity since 2005. Nonetheless, it recognized that to maintain adequate system reliability and resilience during the RE transition, and in the absence of any firm renewable energy capacity options, there was a need for additional fossil fuel generating capacity. The Company engineered, designed and after a significant period of planning and delays in obtaining permissions to replace firm capacity, was granted permission at the end of 2019 to proceed with the construction of a new 33MW CEB at Trents, St. Lucy. The CEB is expected to be commissioned by the end of 2021.

49. This highly efficient bridging solution will immediately reduce imported fossil fuel costs by over $30M annually (based on US$60/barrel oil prices) and reduce carbon emissions by displacing older, less efficient plants and, after 2030, can continue to provide back-up and balancing services to the grid.

50. Additionally, the Company, in its supporting actions towards the renewable energy goals has:

- With stakeholder engagement, drafted a Grid Code approved by the FTC and the Government Electrical and Engineering Department (GEED).
- Prepared drafts of Power Purchase Agreement (PPA) templates for Distributed Generators with systems less than or equal to 500kW as well as for Distributed Generators with systems over 500kW.
- Advised the Commission when fuel prices plummeted, affecting the credits the RER customers were receiving.
- Modelled indicative rates, as early as 2016, for potential Independent Power Producers (IPPs) and distributed suppliers. The Company also recommended a transition to 20-year contracts for RE suppliers and fixing the price for distributed RE suppliers, thereby delinking RE credits from fuel.
- Participated in consultation with the Ministry of Energy (MoE) over the development of the Barbados National Energy Policy.
- Become an early electric vehicle adopter. It currently has the largest privately owned EV fleet on the island.
- Assisted the Barbados Transport Board in strategically rolling out its first fleet of electric buses.
- Made strides to invest in grid modernization strategies.
- Upgraded its Customer Information System, which resulted in numerous process improvements and efficiencies in reducing the time taken to run critical jobs such as billing.
- Implemented a Geographical Information System (GIS), which allows the Company to have the ability to see its assets spatially. The GIS has also helped to facilitate several internal processes geared towards reliability such as damage assessment, vegetation management, asset planning and utilization of drones for line and transformer inspections.
- Deployed a Mobile Workforce Management System (MWMS), which has allowed the Company to move from paper-based processes to utilizing electronic devices in the field to facilitate real-time updates and reduce errors tied to data entry. The MWMS also significantly reduces the time taken for several field activities.

- Implemented an Information Security Programme, which focuses on improving the Company's cybersecurity approach and resilience to cyber-attacks.
- Implemented a VoIP (Voice over Internet Protocol) that brought significant cost savings, improved IVR (Interactive Voice Response), and self-service capabilities for customers.
- Systematically upgraded substations and Transmission & Distribution lines to strengthen the resilience and reliability of the network.

NEW MARKET STRUCTURE AND OPERATIONAL LICENCES

51. For the past several years the Company has also been pursuing the renewal of its operating licence which expires in 2028 with the GoB. It was not until 2019 that real progress began on licence renewal, culminating with a more complex arrangement of five new operational licences anticipated to be issued to the Company in 2021.

52. This new arrangement will require accounting separation of the business units and organisational restructuring, introducing new business risks and costs which are not fully identified and therefore not included in this Application.

53. The Company will require cost recovery mechanisms to accommodate the impact these new Licence obligations will have on the business. The MoE has presented to the Company its plans for a revised electricity market structure in addition to the new licence obligations. The new market structure will necessitate changes in the various roles and responsibilities of current parties and stakeholders in the sector. In anticipation of these changes, the Company has submitted an Application to the Commission for a Clean Energy Transition Rider (CETR) as a flexible supporting mechanism to facilitate timely cost recovery during this transition.

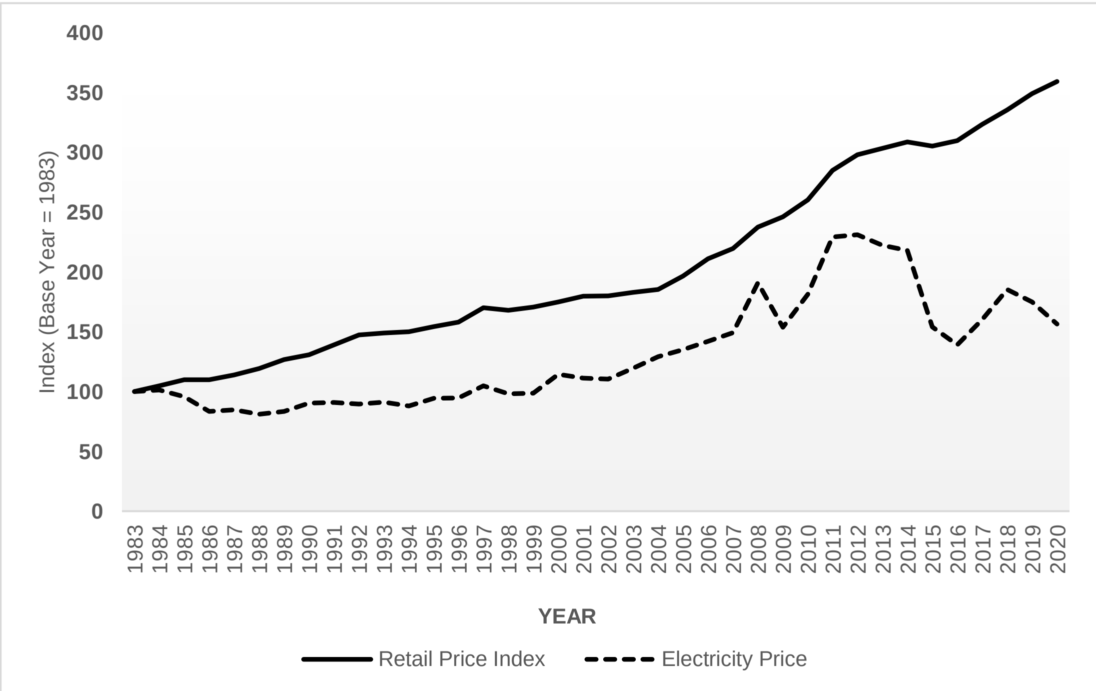
54. The Company is awaiting finalisation of the licences to determine what organisational structural changes will be required.

ELECTRICITY PRICES – 2010 TO 2020

55. The Company has sought only two base rate increases in the past 38 years, with one increase granted in 1983 and the second granted in 2010.

56. Since the last increase in electricity rates, gains in efficiency and load growth have allowed the Company to maintain the same basic rates for electricity. A comparison of electricity prices in 2020 compared with the Consumer Price Index (CPI) is shown in Figure A.2. This indicates that while the price of electricity has increased by about 72% including the fuel cost and VAT since 1983, the CPI by comparison has risen by approximately 259% over the same period.

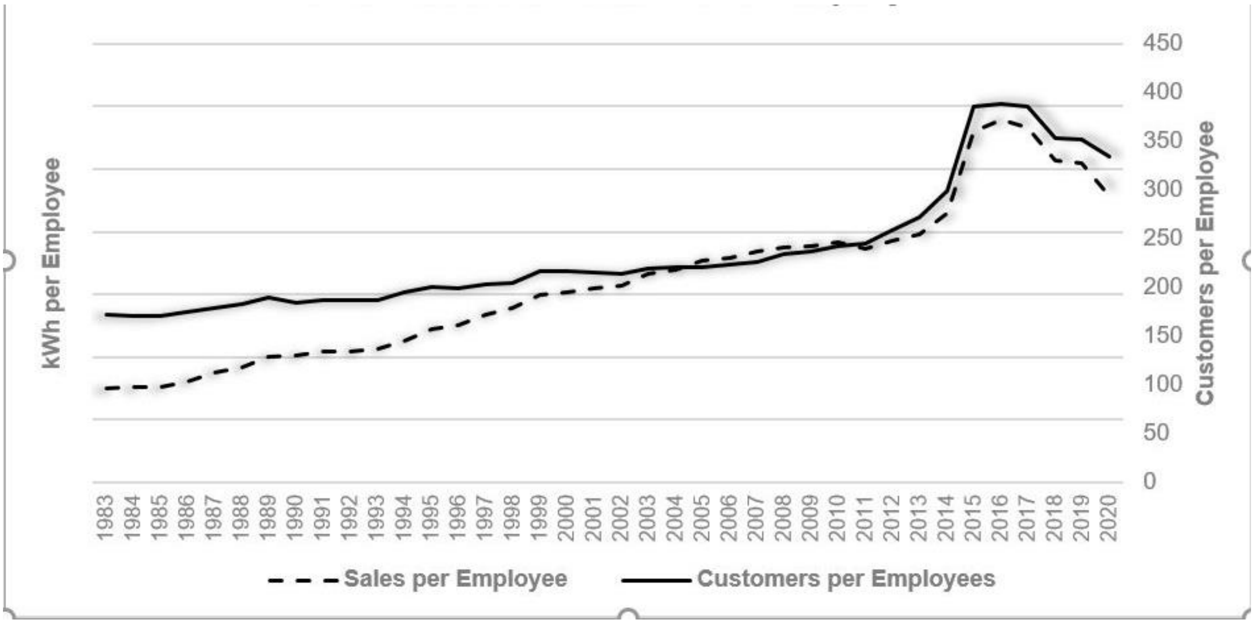
Figure A.2 – Evolution of Electricity Prices and Consumer Price Index



57. Aside from Trinidad and Tobago, which has an abundance of indigenous natural gas and oil, the Company's electricity cost per MWh has been one of the lowest in the Caribbean through the years 2014-2019 as attested by the Performance Benchmarking Study 2014-2019 carried out by Verlaan Consulting Inc, a copy of which accompanies the Company's Application as Appendix V.

58. Even though it has continued to make substantial investments in the electricity system and despite being impacted by higher domestic and international costs, the Company has been able to moderate the impact of these increases without compromising service to customers, by increases in productivity as illustrated by Figure A.3.

Figure A.3 – Labour Productivity



59. The Company can no longer defer a rate review due to:

- Increasing production, distribution and administrative costs;
- Significant network investment costs required to support reliability levels and the transition towards 100% renewable energy generation; and
- Requirements for new smart technologies essential for modernizing the grid.

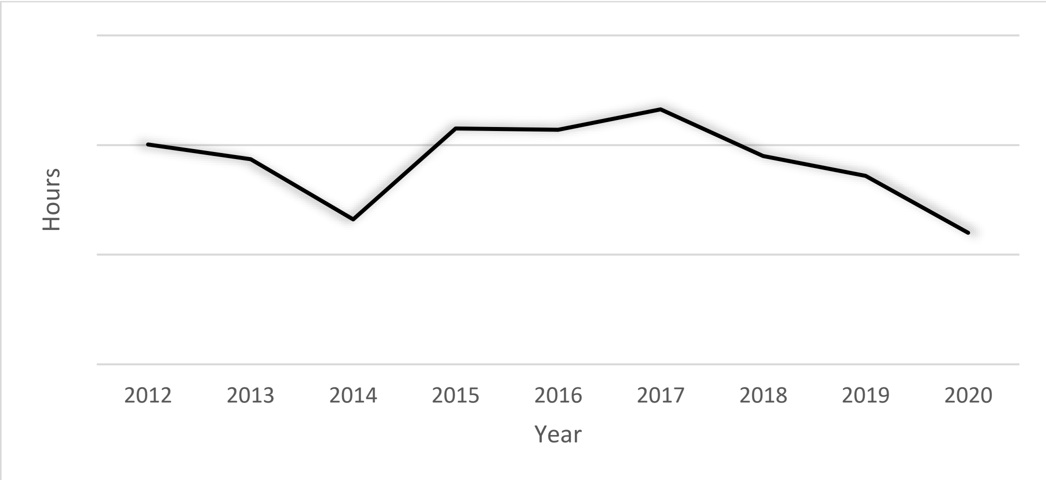
60. The issues above have been compounded by flat sales, which have averaged -0.1% over the period since 2010 to 2019. The recent economic disruptions caused by the Covid-19 pandemic have further aggravated the challenges related to low sales growth.

OPERATING PERFORMANCE

Service Reliability

61. The Company continues to strive for increasing levels of system reliability. The System Intensity, i.e. the product of the System Average Interruptions Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI) for the past few years, is shown below in Figure A.4.

Figure A.4: System Intensity



62. The 2020 SAIDI x SAIFI System Intensity result represents the Company's best performance over the last 16 years that these reliability indices have been consistently monitored.

63. Reliability improvements plans are developed annually for both the Generation and T&D business units.

64. On the T&D side of the business, implementation of a GIS system has laid the foundation for mapping key assets and leveraging data analytics for reliability. Targeted Vegetation Management programs allowed us to reduce the threat of trees to major T&D corridors and to reduce overall reliability threat levels to feeders on a more consistent basis. Additionally, integration of intelligent switches to the distribution network has allowed the Company to leverage Distribution Automation through isolating distribution related faults quickly after occurrence whilst maintaining supply to the non-faulted portion of the network.

65. Likewise, on the Generation side of the business, implementation of process improvements to the existing LSD station for improved low voltage ride-through has led to improved generator response during external system faults. This has provided commensurate benefits to both reliability and system stability. Further, installation of additional support systems such as redundant Uninterrupted Power Supplies (UPS) systems on Governor and Control Air Compressors on the LSD units has led to improved system response. Finally, modifications to the fuel valves settings for fuel curves of some Gas Turbine units (GT02 and GT03) have allowed these units to respond more quickly to increase their load in response to an external system disturbance without tripping on overload.

System Resilience

66. BLPC has implemented a number of measures aimed at increasing the ability of the power system to mitigate the impact of catastrophic events (e.g. storms, fires and cyberattacks). Examples of these include:

- Targeted Undergrounding - Major transmission lines have been placed underground (approximately 60%) with multiple redundant feeds to all substations. Additionally, underground distribution supplies are in place for critical national infrastructure (e.g. air and seaports, main hospital, Belle pumping station and government headquarters).
- Pole Hardening – Distribution pole specification upgraded for greater storm resistance.
- Indooring – 17 of 18 substations have been converted from outdoor to indoor designs, with the remaining outdoor substation scheduled for conversion in 2022. Indoor substations provide enhanced physical security and defence against extreme weather events.
- Cybersecurity – The Company views cyber resilience as a critical strategic objective, to enable our business to prevent, respond and recover from cyber threats which continue to increase at a significant rate throughout the world. The Company first introduced an Information Security program in 2008 and in 2019 developed an overall Cyber Security Framework consisting of 13 different standards (e.g. Governance, Asset Management, Data Protection and Classification, Human Resources, Supply Chain etc.) that will continuously be updated

and followed to ensure we can adapt to known and unknown crises, threats, adversaries and challenges within the cyber security realm.

- Emergency Preparedness and Response - The Company has a comprehensive hurricane preparedness and response plan which has been developed and refined by experience over the years. This plan is routinely reviewed and tested. The Company is also a member of the CARILEC Disaster Assistance Programme (CDAP), which has established a support and a mutual aid framework between the island states. Additionally, the Company can draw on the technical, supervisory and craft labour support from tits Emera affiliate companies in Canada and the US.

67. Complementing these resilience measures is a comprehensive Insurance and Loss Management program.

68. The Company maintains a commercial insurance program, underwritten by strong and financially stable third party insurers with financial rating of minimum AM Best ratings of A- or Standard and Poor's rating of BBB. Under the present program, the Company's assets are insured to a limit of US $100,000,000 per occurrence combined all coverage for Property, Business Interruption, and Extra Expense. With regards to Named Windstorm and Flood, the Company carries a limit of US $60,000,000 per occurrence and in the annual aggregate and with regards to damage by Earthquake, the Company carries a limit of US $85,000,000 per occurrence.

69. As is the case generally in the utility sector, third party commercial insurance is not available to insure loss or damage to installed transmission and distribution (T&D) property: poles, pole top transformers, conductors, overhead lines, streetlights and cables, except for:

- Any of the above items while they are not installed, or while they are in storage, or if they are located/installed within 1,000 feet of original insured's power generating sites.

- Meters on customers' premises; underground cables and equipment; substation buildings, equipment, plant or machinery (inside or outside); and Services (defined as cables running from nearest pole to the customers' meter).

70. Since the 1990’s, BLPC has maintained a Self-Insurance-Fund (SIF), to ensure that funds are available to pay the asset replacement costs associated with storms, primarily those assets for which insurance coverage is not commercially available, as described above.

71. The SIF was formally established in 1998, and was established for the purpose of self-insuring the transmission, distribution and generation assets of the Company against damage and consequential loss as a result of catastrophe. The initial language restricted the SIF to natural catastrophe; however this was subsequently amended in 2005 to permit the SIF to be used to fund losses which are ordinarily covered by commercially available third party insurance (e.g. machinery breakdown, fire). There is no restriction on the type of assets which can be paid for out of the accumulated SIF funds, however, for the past several years no claims have been made on the SIF.

72. At the end of 2020, the value of the SIF was US $32.4M. Periodically, the Company seeks expert advice on the adequacy of the fund. Experience in the Caribbean reinforces the prudence of maintaining the SIF.

73. There are no requests for contributions to the SIF included in the Company’s revenue requirements for this Application.

74. The Company has an ongoing comprehensive loss management program as part of its risk management measures. The Company conducts an annual operational risk evaluation of its facilities and generating assets from a property and machinery risk context under the guidance of its insurance broker. The insurance risk review involves a review of building construction, equipment, operations and infrastructure, associated risk mitigation systems, and exposures of the various facilities. On-site visits also include a review of risk management control programs such as inspection, testing, maintenance of fire protection systems and equipment; any impairments to these systems; management of hazards; managed maintenance programs; emergency response; spares strategy and other contingency programs.

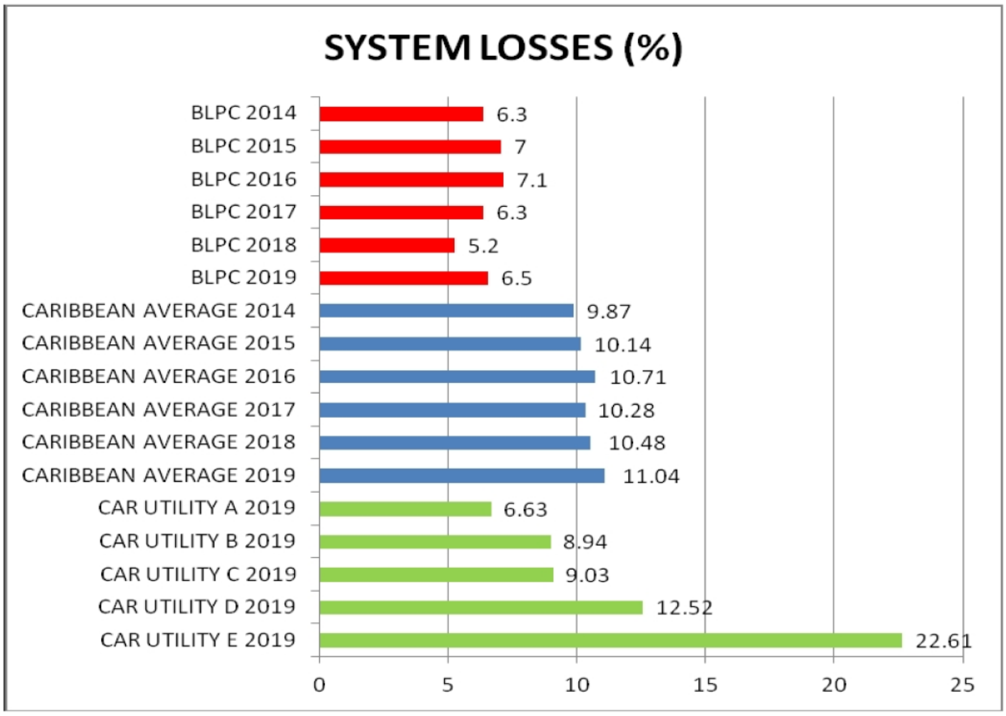
75. Assessments are also made based upon conditions and practices observed during the visits, discussions with senior management and information made

available to the insurers upon request during the time of evaluation. At the conclusion of each site survey, key findings are reviewed with senior management and engineering staff and an action plan developed for implementation to improve safety, drive continuous process improvement, and reduce exposure to loss.

System Efficiency

76. System losses are a measure of the efficiency of the transmission and distribution (T&D) network, and are inherent in the operation of an electricity system. The Company's electricity system losses continue to be among the lowest in the region and comparable to those of efficient utilities in North America and Europe as shown in Figure A.5.

Figure A.5: System Losses[6]



Standards of Service (SOS)

77. Effective January 1, 2018, the Commission established updated Guaranteed Standards of Service and Overall Standards of Service for the Company.

[6] Source Appendix V: Performance Benchmarking Study 2014 – 2019, April 2021

Results for the Standards of Service over the past 5 years are provided in the Memorandum on the Standards of Service attached at Schedule M.

78. Our company puts significant resources and effort into meeting the SOS targets. The work to meet the SOS targets is highly coordinated and planned, closely monitored and tracked on a monthly basis, and our teams are highly focused and dedicated to ensuring that they are met, as evidenced by our consistently high performance across all of the standards.

79. New Standards of Service are currently being developed for implementation in 2021. Increasing levels of distributed RE systems will create new challenges for voltage regulation, which will require the integration of mitigating solutions like energy storage and voltage regulating equipment.

80. The Company‘s current application is premised upon the current standards of service, with the financial and staff resources required to assure compliance with those standards. If the FTC issues new SOS that include significant changes which will affect the financial and staff resources needed to assure compliance, the Company reserves the right to file an amended application to address those changes.

FINANCIAL PERFORMANCE

81. To meet customer needs and to maintain a reliable system, the Company must:
    - Meet its expenses;
    - Keep the confidence of its investors by providing them with a fair and reasonable return; and
    - Satisfy lenders of the Company’s ability to repay the loans needed to run daily operations and to invest in new capital equipment required for the delivery of electricity service.

82. As stated earlier, the present basic electricity rates are now inadequate to allow the Company to meet these requirements. The Company is therefore seeking a review of its rates to:

- Provide the revenue required to meet its expenses involved in supplying a safe, adequate and reasonable service and to allow it to deliver a secure and reliable supply of electricity to all customers.
- Provide a reasonable rate of return, which is essential to convince lenders of Company's ability to repay loans and maintain the confidence of its investors in its ability to provide reasonable returns. This lender and investor confidence is essential to the Company's access to capital that is critical for investment in plant and equipment required to deliver service to customers.
- Bring the price of electricity to customers closer to the cost of supplying the service, thereby providing correct price signals to all customers and encouraging energy efficiency.
- Continue facilitating customer-owned renewable energy systems as well as IPPs who wish to connect to the grid.

83. The Company has submitted several memoranda in support of its Application for a review of electricity rates. In compiling these memoranda the Company has sought to comply with established regulatory practices, principles and policies.

Test Year

84. The Company's application is based on the audited financial results for the year ending December 31st, 2020 (the Test Year) adjusted for known and measurable changes. The term "Test Year" refers to a 12 month period, usually beginning on the first day of a calendar or fiscal year, for which operating data is available and reflects as closely as possible the conditions (such as sales and cost) a utility is expected to face when the rates being requested will come into effect.

85. The Company corresponded with the Commission in relation to the selection of the Test Year for the rate review Application and after providing its views on the factors to be taken into account to determine the Test Year it requested that it be allowed to use an audited 2020 Test Year to support its application. On March 8, 2021 the Commission accepted the Company's Test Year of January 1 to December 31, 2021 subject to review within the Rate Review Hearing.

Rate Base

86. Rate Base is the value of utility plant financed by the Company and investors that is prudently incurred and "used and useful" in public service. The "used and useful" concept is defined as only that plant currently that is providing or capable of providing utility service to the consuming public.

87. In its Application, the Company's proposes a Rate Base of $825,891,134, which is calculated for the Test Year on the audited financial statements for the year ended December 31, 2020 using original (historic) cost. The Company has included in the Rate Base only plant which it has determined to be "used and useful". This approach is consistent with the Commission's January 25th 2010 rate review decision approving the Company's use of historic valuation costs.

Depreciation Rates

88. The depreciation rates, capital balances and remaining lives being used in the Application are in accordance with the proposal in the current updated Depreciation Application submitted to the Commission in June 2020.

Income Statement

89. The Memorandum on Income Statement explains the income statement for the Test Year ended December 31, 2020.

90. The Income Statement is based on the audited financial statements for the year ended December 31, 2020 and records all electricity revenue (basic and fuel adjustment clause revenue) and miscellaneous income. From this, the expenses (fuel expenses, operating and maintenance expenses, depreciation, finance costs and taxation) incurred in those revenues are adjusted to arrive at the net income.

Rate of Return

91. The Company requests that the Commission adopt an overall Rate of Return on Rate Base of 8.79%, which is the Company's Weighted Average Cost of Capital (WACC) stated on a regulatory basis, including the weighted

combination of the Company's cost rates for debt and other sources of funds, and a fair rate of return on equity.

92. The Return on Equity ("ROE"), the cost of debt, and the WACC were determined by a Cost of Equity and WACC for BLPC Study prepared by the Company's consultants, The Brattle Group. The Rate of Return is made up of debt cost to the Company of 2.78% and a return on equity of 12.50% based on a Cost of Equity and WACC for BLPC Study using North American electric utilities, and other recognised sources.

93. The Study also references a number of risks faced by the Company, some of which can be mitigated by new regulatory mechanisms such as the proposed Clean Energy Transition Rider (CETR). If the CETR is approved, the rate of return recommended in the Study, is expected to enable the Company to fulfill its obligations to the public while providing the Company with an opportunity to meet its obligations to investors, including interest on its outstanding debt and a fair return on the capital committed by its equity investors. If the CETR is not approved, the rate of return requested would have to be higher due to the unmitigated risks.

94. The Company has used a capital structure of 35% Debt and 65% Equity in the calculation of the Weighted Average Cost of Capital in the preparation of the Application.

95. If approved, the rate of return recommended in the Study will enable the Company to fulfill its obligations to its customers while providing it with an opportunity to earn a fair and reasonable return.

Revenue Requirement

96. The revenue requirement is the total allowable cost of providing electricity service in the Test Year, including an 8.79% Rate of Return on Rate Base.

97. Details of the test year revenues on existing rates of $393,765,062 are set forth in Schedule D-1 of the Memorandum on Income Statement. The revenue requirement of $440,240,372 and the resulting revenue deficiency of $46,475,310 are both set out in Schedule G-1 of the Memorandum on Revenue

Requirement. Based on figures for the Test Year 2020, the Company requires an additional $46,475,310 in annual revenue to be collected from customers through rates and is seeking that the new rates become effective April 1st 2022 and interim rate relief effective November 1st, 2021 in order to achieve the required Rate of Return on Rate Base.

TARIFFS & TARIFF STRUCTURES

Existing Tariffs & Tariff Structure

98. The Commission approved rates effective March 1st, 2010 included six (6) tariff rate groups to serve electricity customers:

- Domestic Service (DS) – residential use
- General Service (GS) – small business, churches, temporary supplies.
- Secondary Voltage Power (SVP) – commercial customers who receive power from secondary side of a BLPC owned transformer.
- Large Power (LP): large commercial customers who receive power at high voltage and have their own transformer equipment.
- Employee – Company employees and retirees
- Street Lights (SL)

99. In March 2010, the Commission approved establishing of a Time-of-Use (TOU) tariff, an Interruptible Service Rider (ISR) and a Renewable Energy Rider (RER) on a pilot basis initially for a period of two years. The Commission granted extensions for the period of the Time-of-Use (TOU) tariff pilot and both the Interruptible Service Rider (ISR) and Renewable Energy Rider (RER) were subsequently approved permanently.

Proposed Tariffs & Tariff Structures

100. The Memorandum on Proposed Tariffs presents the electricity tariffs that are being proposed by the Company in its application to the Commission and the rationale for the rate design. The Company also proposes the establishment of a permanent Time-of-Use (TOU) tariff and the disaggregation of the current Fuel Clause Adjustment (FCA) to allow for the establishment of a Renewable Purchased Power Adjustment (RPPA) clause to recover the cost of renewable energy purchases.

101. BLPC analysed the results of the Allocated Class Cost of Service (COS) study as presented in the Affidavit of Dr. Philip Hanser of the Brattle Group to guide the revenue allocation and rate design process.

Existing Rates of Return by Tariff Group

102. The COS study identifies the current rates of return on rate base for each tariff group as shown in Table A-1.

Table A-1: Current Realized Rate of Return on Rate Base

Rate Class	Current Realized Rate of Return	Current Realized Rate of Return on Rate Base
Overall	**$27,300,331**	**3.31%**
Domestic Service	$7,344,704	2.48%
Employees	-$62,203	-4.39%
General Service	$2,572,675	4.71%
Large Power	$5,283,735	3.66%
Secondary Voltage Power	$12,451,959	4.70%
Time of Use	$1,377,010	7.04%
Street Lights	-$1,667,548	-3.69%

Proposed Rate of Return and Revenue Increase by Tariff Group

103. In designing the proposed tariffs and allocating revenues, the Company has taken into account the findings in the COS study. Table A-2 shows the rates of return and additional revenues that are expected to be provided by each tariff group.

Table A-2: Targeted Rate of Return and Revenue Increase

Rate Class	Targeted Rate of Return	Targeted Rate of Return on Rate Base	Targeted Revenue Increase
Overall	**$72,610,495**	**8.79%**	**$46,475,310**
Domestic Service	$23,386,160	7.91%	$16,458,556
Employees	$0	0.00%	$64,201
General Service	$5,556,552	10.18%	$3,060,891
Large Power	$14,711,720	10.18%	$9,631,891
Secondary Voltage Power	$26,966,118	10.18%	$14,887,911
Time of Use	$1,989,945	10.18%	$640,516
Street Lights	$0	0.00%	$1,731,345

Tariff Structures

104. As described in the Memorandum on Proposed Tariffs, the COS study also provided information on the following four main cost-sources that are relevant to the provision of electricity service.

a) **The Customer Charge:** This recovers the customer-related costs.
b) **The Demand Charge:** This recovers the demand-related costs.
c) **The Base Energy Charge:** This recovers the variable non-fuel energy-related costs. The demand-related costs are included in the energy charge for the Domestic Service, General Service, Street Lights and Employee tariffs since, as is common in the electric utility industry, the meters used for these tariffs do not register customer demand.
d) **The Fuel Charge:** This recovers the total cost of fuel, which varies with the amount of energy supplied to the customer. The Fuel Charge is comprised of an FCA charge and a Renewable Purchased Power Adjustment (RPPA) charge, discussed below.

105. The COS Report indicates that the fixed charge for all customers does not cover the fixed costs of providing the service.

Fuel Clause Adjustment and Renewable Power Purchase Adjustment

106. The current FCA recovers fossil fuel costs, renewable purchased power and battery storage costs. The Company proposes that the FCA be modified to only recover fossil fuel related costs.

107. The Company has presented in the Memorandum of Proposed Tariffs, a new Renewable Power Purchase Adjustment (RPPA) for the recovery of renewable purchased power.

Service Charges

108. The Application also contains proposals for other incidental charges, such as new service connection fees and reconnection fees. The proposed Service Charges are shown in Schedule K-10 of the Memorandum of Proposed Tariffs.

Street Lighting

109. The Company recognizes that street lighting provides a common amenity, keeping our community safe and lighting our streets for drivers and pedestrians. BLPC has replaced over 90% of its stock of High-Pressure Sodium (HPS) streetlights with Light Emitting Diode (LED) lights and anticipates that all of the streetlights would be LEDs in 2022.

110. The overall bill impact per light, using the FCA for September 2021 of 32.8251 cents/kWh, is a decrease of 6.0% for the 21 Watt LED light relative to the 50 Watt HPS light it replaced. The 49 Watt LED light bill will decrease by 12.3% relative to the 100-watt HPS light it replaced

Employee Tariff

111. The employee tariff has been established following the guidance of the Commission’s Decision of 2010 and adjusted to reflect the increased revenue requirement.

Time-of-Use Tariff

112. The Time-of-Use (TOU) tariff was approved on a pilot basis and implemented in 2010. A permanent tariff is proposed and available to all customers who receive electricity at primary voltage.

Impact of Proposed Tariffs

113. As part of the tariff design process, the Company gave careful consideration to the potential impact of its proposals on customers in the various tariff categories. The Company has used the COS Study as a guide in developing the new tariffs, but has not moved to full cost of service in order to reduce the affordability impact. The expected impact is discussed in more detail in the Memorandum on Proposed Tariffs.

114. The proposed rates are designed to recover the test year revenue increase of $46.475 million, as supported by the embedded cost of service study. The rate design proposed reduce the overreliance on volumetric charges such as energy charges for fixed cost recovery to facilitate the sustainable transition towards the nation's 100% renewable energy generation target. Bill increases in the rate design for Domestic Service customers with usage up to 150kWh have been limited to not exceed $6 per month based on the September 2021 FCA and taxes. This category of customers, who account for 35% of Domestic Service, is assumed to consist disproportionately of low-income customers.

115. The typical bill increase resulting from the proposed rates are estimated to range from 5% to 20% depending on the tariff on which customers receive their service. This increase is expected to be mitigated by lower fuel charges as a result of the commissioning of the Clean Energy Bridge in 2021.

116. Given prices within in the economy has risen by over 38% since 2010, the effective cost of electricity under the proposed rates represent a decline relative to the other costs in the economy.

SALES PROJECTIONS

117. The Company has prepared electricity sales projections over the period 2021 to 2025 as set out in the Memorandum on Sales Projections These projections serve as the Company's best estimate of future electricity sales and forms the basis by which total energy required to serve customers and the associated revenues and expenses is estimated.

118. The Company's expectation of future economic growth and its impact on electricity sales is conservative, and aligns with the Central Bank of Barbados' guidance that there is increased uncertainty regarding a post COVID-19 economic recovery.

119. The Company projects electricity sales will not return to pre-COVID-19 levels before 2023 for General Service customers, or even 2025 for the Secondary Voltage Power and Large Power customers, when the econometric models assume a return to typical tourism activities and stronger economic recovery. The forecast assumes an accelerated lifting of domestic and international travel restrictions in 2021. However, new waves and variants of the COVID-19 virus and the speed and actual efficacy of vaccinations are concerns to the Company's outlook for the growth of electricity sales. This is reinforced by the Company's actual sales over the period January to August, 2021 which declined by 1.1% when compared to the same period for 2020.

CAPITAL EXPANSION PROGRAMME

120. The Memorandum on Capital Expansion 2021 to 2025 sets out the Company's planned capital expenditures covering the purchase of new plant and equipment intended to allow it to maintain the reliability of the system.

121. This expansion programme also caters to the goals of the BNEP. However, new plant and equipment comes at a significant cost, and the Company has projected that in the absence of a rate adjustment there would be a significant shortfall in the revenue needed to fund this capital expansion.

122. The Company has kept abreast of emerging and disruptive technologies over the years to leverage innovative tools for enhanced customer benefits. The

Company is therefore seeking to recover costs for these efficiency improvements, technology enhancements and capital reinvestments prudently incurred that are geared towards managing costs and stabilizing rates for our customers.

FINANCIAL FORECAST

123. Two Five-year Financial Forecasts have been prepared for the years 2021 through 2025; the first based on the existing rates and the second based on the rates which the Company is proposing should take effect from 2021. These forecasts are explained in the Memorandum on Five Year Financial Forecasts and shows that the Company's revenues would be insufficient to allow it to:

    i. fund its planned investments to meet customer requirements;
    ii. have sufficient resources to attract capital and;
    iii. have sufficient financial resources to respond to financial, economic or environmental shock.

124. The Five Year Forecast, based on proposed rates, shows that the Company is being given the opportunity to improve its rate of return, but will fall short of the requested rate of return during the five year period due to capital investment required to maintain the existing plant and new investments required to support the transition to 100% RE sources. The forecast indicates that the Company will require additional rate relief within the five year period to maintain a reasonable rate of return.

MEETING CUSTOMER NEEDS OF THE FUTURE

125. The Company has demonstrated by its conduct that it has taken all prudent steps to avoid seeking an increase in rates over the last ten years. The Company has made every effort to minimize charges through increased productivity and better use of available resources. The Company has also financed capital investments expansion largely by reinvested earnings.

126. A secure, reliable, and affordable supply of electricity is vital to the economic prosperity of Barbados. Countries with unreliable electricity systems cannot expect to maintain a healthy and vibrant economy in this modern technological

era. The Company continues to strive for increasing levels of system reliability. The Company needs to continue to invest in its infrastructure to prevent degradation of reliability, and to support the country's transition to 100% RE. Maintaining the financial health of the utility is critical so that it can continue to provide a safe and reliable service to customers at affordable rates and achieve the objectives set out in the BNEP.

127. The Company is requesting that interim rate relief, at the proposed rates, come into effect from November 1, 2021 and shall be applied to all bills from November 1, 2021 and that this remains in place until the Commission issues its final Decision on the application. The Company is also requesting that the proposed tariffs come into effect from April 1, 2022.

128. The Company has avoided base rate increases for the past ten years while continuing to invest in many initiatives. This rate review application, seeking general rate relief, together with other rate regulatory mechanisms such as the proposed Clean Energy Transition Rider currently being heard by the Commission, will continue to facilitate those investments.

Dated the 30th day of September 2021

Paper prepared by:

Roger Blackman
Managing Director
The Barbados Light & Power Company Limited

B

MEMORANDUM ON TEST YEAR

TEST YEAR SELECTION

1. The Barbados Light & Power Company Limited ("the Company") corresponded with the Fair Trading Commission ("the Commission") on February 23, 2021 for approval to use the audited financial statements for 2020 with adjustments for known and measurable changes as the test year to support its Application. The Commission's correspondence of March 8, 2021, accepted the Company's request to use the twelve months of January 1 to December 31, 2020 as the test year to support its rate Application, subject to review within the Rate Review Hearing.

2. The Company has used the twelve months ending December 31, 2020, with adjustments for known and measurable changes, as the basis for its rate increase request. Given the main factors necessitating a base rate increase outlined in the Company's Application, the proposed 2020 historical test year with adjustments for known and measureable changes, will most accurately reflect the economic conditions during the first twelve months the Company anticipates new rates to become effective.

BACKGROUND

3. The Fair Trading Commission in its Decision and Order of January 25, 2010[1] stated that the test year usually reflects a 12-month period in which the Company's operating data is available and reflects as closely as possible the conditions that the utility expects to encounter after the imposition of new rates.

4. The Decision further highlighted that one of the following three data epochs serve to establish the test period:

    (1) historic data;
    (2) current data (partial historic and partial projected); or
    (3) projected data.

[1] https://www.ftc.gov.bb/library/blip_app/2010-01-22_commission_decision_No2_of_09_rate_review_barbados_light_and_power_company_limited.pdf

5. The Commission considered all three approaches, and ultimately determined that the historic data approach was the most appropriate, as it was the approach which would use historical financial statements for the entire period and be representative of the Company's expected normal operations, with adjustments to the financial statements for known and measurable changes.

6. The Commission approved that the use of 2008 audited financial statements would be appropriate. In so deciding, the Commission declined to use the projected data approach because the Company would be required to forecast revenue and expenses which would be challenging due to the world economic downturn.

7. In its current application, the Company has carefully considered all three data approaches for selecting a test period. The Company proposes to use the first approach and to select the historic twelve-month period ending December 31, 2020, with adjustments for known and measurable changes, as the appropriate test period for setting the Company's future rates.

8. This approach aligns with the Commission's 2010 Decision, allowing use of the most recent full 12 month period with audited financial statements herewith attached as Appendix III.

9. This approach also uses the period most reflective of the economic conditions that the Company is likely to face immediately after the Commission's Decision on the Application is issued.

10. The Covid-19 pandemic's impact on the Company's 2020 sales has been substantial due to the nationwide closure of non-essential businesses, schools and government agencies and the unprecedented impact on tourism-related activities.

11. The Company's experience at the end of August 2021 confirms that electricity demand remains below the comparative period for 2020 as highlighted in the Memorandum of Sales Projections. It is likely that sales would decline below that of 2020 if economic recovery is delayed further due to the continued Covid-19 pandemic impacts.

12. The projected data approach is not well suited for this period of great uncertainty. For the same reasons articulated by the Commission in its 2010 Decision, the Company faces significant uncertainty concerning the speed and size of the economic recovery due to the rapidly changing Covid-19 pandemic situation.

13. This uncertainty is highlighted in the Central Bank of Barbados' most recent "Review of the Barbados Economic Performance", attached as Schedule H-1 in the Memorandum on Sales Projections, which concluded that the economic outlook for 2021 is rendered more uncertain by the Covid-19 pandemic.

14. The third approach, using hybrid current data (partial historic and partial projected), is also not well suited to the uncertain economic conditions because it requires the same use of projected data.

15. In determining the test year, the choice must result in an outcome that balances the need to ensure rates are just and reasonable while allowing the Company the opportunity to earn its allowed rate of return. The Company submits that its proposal to use a historical test year, comprises of audited financial statements for 2020 with adjustments for known and measurable changes, balances these objectives.

16. The historic approach with the 2020 test year uses known costs and revenues as its starting point. The Company only adjusts its financial data for known and measurable changes to expenses and investments incurred during the first twelve months that the Company anticipates the new rates to become effective. The primary known and measurable adjustments to the 2020 audited financials relate to the new 33 MW medium speed diesel plant's operation as outlined in the Memorandum on Rate Base. The Company expects to commission the plant by the end of 2021.

17. The use of historical data as the basis for determining the test year is therefore more prudent than using a forecasted test year in the current environment given the unprecedented level of uncertainty that will limit the ability to make meaningful projections to inform a forecasted test year.

Dated this 30th day of September, 2021

Paper prepared by:

Roger Blackman
Managing Director
The Barbados Light & Power Co. Ltd.

C

MEMORANDUM ON RATE BASE

1. Rate Base is the value of utility plant financed by The Barbados Light & Power Company Limited ("the Company") and investors that is prudently incurred and "used and useful" in public service and is valued on the original or historic cost basis. The calculation of the Rate Base, as shown in Schedule C-1 is computed for the Test Year[1] based on the audited financial statements for the year ended December 31, 2020 with adjustments for known and measurable changes. According to *The Process of Rate Making* "An agency may, and often does, rely on projected or estimated costs to avoid the effects of administrative delay on the company's ability to attain the needed revenues. Such costs must be based on projections of actual-neither speculative nor contingent-costs. There must be evidence that the estimate is "known and measureable." The evidence must be sufficient for the agency to make a "fair guess" as to future conditions."[2] The Company has included in the Rate Base plant which it has determined to be "used and useful". The accumulated provision for depreciation is deducted from the historic cost to determine net total plant. There are also deductions from rate base for funding sources other than investors such as customer contributions for construction work not yet started and net accumulated deferred income taxes. The Company's proposed rate base of **$825,891,134** as shown in Schedule C-1 provides for the inclusion of cash working capital, materials, supplies, prepayments and an amount of construction work in progress (CWIP).

UTILITY PLANT IN SERVICE

2. The historic cost of utility plant of the Company is categorized as:

▪ Generating plant assets	-	$685,639,849
▪ Transmission and distribution assets	-	$650,035,195
▪ General property assets	-	$126,424,954
TOTAL	-	$1,462,099,998

3. Details of these categories of utility plant are shown in Schedule C-2.

[1] The test year is discussed in the document 'Memorandum on Test Year'
[2] "The Process of Ratemaking" by Leonard Saul Goodman, pages 284 and 285

Generating Plant - $685,639,849

4. Generating Plant comprises the equipment and facilities used in the production and storage of electricity. The Company requests the inclusion in its rate base of its 5 MW, Energy Storage Device (ESD) commissioned in 2018 as used and useful. The Memorandum on Capital Expansion 2021-2025 outlines the circumstances which led to its commissioning and justification based on fuel cost savings when co-optimized for energy shifting and reserve provisioning. At the time of its decision, regarding recovery of costs associated with this ESD, the Commission[3] required that after 3 years a review of the appropriateness and applicability of the recovery mechanism be completed. The Barbados National Energy Policy 2019 – 2030 (BNEP) and the associated implementation plan includes a requirement for a potential 200 MW of battery storage capacity by 2030. The Company is of the view that the cost of this ESD was prudently incurred, meets the criteria of "used and useful" in public service and is valued on the original or historic cost basis. The calculation of the Rate Base, as shown in Schedule C-1, therefore includes the unrecovered cost of the ESD.

Transmission and Distribution Assets - $650,035,195

5. Transmission and distribution assets are the facilities and equipment used to deliver the electricity produced from the generating stations to customers across the island.

General Property Assets - $126,424,954

6. General Property assets consist of vehicles, furniture, computers and other office equipment as well as lands and buildings not already included in generating plant or distribution substations. Assets costing $632,278 as described in Schedule C2-1 are deemed not "used and useful" and have been omitted from the rate base.

[3] Refer to Decision of the FAIR TRADING COMMISSION Re The Barbados Light & Power Company Limited Application to Recover the Costs of the 5MW Energy Storage Device through the Fuel Clause Adjustment FTCUR/DECESD/BL&P-2018-02

Valuation of utility plant

7. The Company bases its accounts on the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts. Utility plant is stated at historic cost. Cost represents expenditures that are directly attributable to the acquisition of the plant and includes the cost of materials, direct labour, project supervision, engineering services and interest during construction. Additions to utility plant are included in the asset's carrying value or recognized as a separate asset.

8. The Company has used the audited year-end balances for 2020 to arrive at the cost to be included in rate base.

Treatment of capital expenditure

9. In its application the Company has capitalized investment at December 31, 2020 for all plant in service as of that date. Contributions received from customers towards construction of utility plant are credited to the cost of construction or are shown as deferred credits in those cases where construction has not yet started. Interest charges are accrued during the period of construction of property, plant and equipment and are capitalized until the asset is brought into service, at which time capitalization of interest stops and depreciation starts.

ACCUMULATED DEPRECIATION - ($815,589,598)

10. Depreciation is the cost associated with the consumption or using up of physical capital, including generation and power delivery facilities. Depreciation policy shows up in two major dimensions of depreciation cost:
    (a) the rate of capital depletion, reflected as the annual charge for depreciation in the Statement of Income; and
    (b) the accrued level of capital depletion used to determine the net value of capital resources referred to as the accumulated depreciation in the rate base.

11. Land is not a depreciable asset. No depreciation is provided on CWIP until the assets involved have been put into service.

12. In keeping with good industry practice and to support the requirements of International Financial Reporting Standards, from time to time the Company performs studies to determine the appropriate book depreciation factors and rates to be applied to the property in service to enable recovery of the plant investment, adjusted for net salvage, over its remaining useful life. Such studies have been performed as of December 31, 2006, December 31, 2012, December 31, 2017 and most recently updated to December 31, 2019. Each of these have been submitted to the Commission and have been used to inform the annual depreciation charge and the resulting accumulated depreciation included in the annual audited financial statements.

13. The Company has used the audited year-end balances for 2020 to arrive at the accumulated depreciation to be included in rate base.

14. The accumulated depreciation applied to the 2020 Test Year has been calculated using rates and capital balances as included in the application made to the Commission pursuant to Section 16 of the Utilities Regulation Act, Cap 282 for approval of the depreciation policy of the Barbados Light & Power Company Limited Ref: FTCUR-0001/20.

CONSTRUCTION WORK IN PROGRESS - $143,004,791

15. CWIP represents new utility plant that is not yet in service.

16. CWIP can vary significantly as ‘lumpy’ investments are made in new plant, especially very costly generating plant. New plant can take two to three years to install and commission from the time that a contract is signed with the supplier until the time that it is put into commercial operation.

17. As accepted in the previous rate case, the Company requests that it be allowed a return on a reasonable amount of CWIP. In its application the Company is asking that those items of plant and equipment which are due to be in service within a 12 month period immediately following the end of the Test Year should be considered “used and useful” and be included in Rate Base.

18. Further, the company requests that known and measurable reasonable costs which were not incurred before the end of the test year, but are expected to be

incurred within the 12 months following and can be reliably estimated resulting from those items of plant and equipment which are due to be in service within a 12 month period immediately following the end of the Test Year, be considered "used and useful" and be included in Rate Base.

19. Since the rates that are being applied for are expected to be applicable in the year following the Test Year, allowing into Rate Base those items in CWIP which are to be in service in the 12 month period immediately following the end of the Test Year helps to mitigate regulatory lag.

20. Schedule C-3, Construction Work in Progress, details the projects under construction with an amount incurred before the end of the test year (December 31, 2020) of $134,772,528 of which $117,483,862 is scheduled to be in service in the 12 month period immediately following the end of the 2020 Test Year. Of the $117,483,862 scheduled to be in service in 2021, $107,707,261 is related to the Clean Energy Bridge[4] (CEB) a 33 MW plant being constructed in St. Lucy. The Company is nearing completion of the construction of the CEB which is expected to be in service and therefore used and useful by end of 2021, bringing significant benefits to customers. Among these benefits are enhanced reliability and better fuel efficiency, potentially leading to fuel cost savings depending on world fuel prices. The CEB is being constructed under contractually agreed terms and conditions including pricing. The known and measurable costs expected to be incurred in 2021 have been calculated as $25,520,929[5] and the Company requests that this be included in CWIP. Schedule C-3 therefore includes the CEB at a total value of $133,228,191. The total CWIP is therefore $143,004,791 and has been included in Rate Base.

RECONCILIATION OF FIXED ASSETS

21. Schedule C2-2 provides a reconciliation of fixed assets in the Rate Base with fixed assets used in financial reporting. The adjustment for General Property Assets is explained in paragraph 6 of this Memorandum and Schedule C2-1. The justification for inclusion of CWIP in the rate base is explained in paragraph

[4] Refer to The Memorandum On Capital Expansion 2021 – 2025
[5] Building work $7.5Million, Equipment $16.9Million and Other facilities $1.2Million

19 of this Memorandum and Schedule C-3. The adjustment for CWIP is explained in Schedule C-3.

CASH WORKING CAPITAL - $13,579,651

22. Cash working capital for the Company as shown in Schedule C-4 is the average amount of capital (in excess of that used to finance net utility plant and other separately identified rate base components) necessary to operate the business. Cash working capital included in the rate base provides return on the capital used to purchase inputs when the cost of such inputs cannot be recovered in revenue immediately. The Company needs money to operate between the time the Company must pay its suppliers and its employees for their work and the time the service is paid for by the customers. Essentially, cash working capital bridges the time gap between cash outflows to fund resource inputs, and cash inflows (revenues) for service provided to customers.

23. Across the regulated electric utility industry, a commonly applied guideline to determine the working capital amount is one-eighth of the utility's operations and maintenance (O&M) expenses. This methodology is often referred to as the '45-Day Rule' or formula approach. The 45-Day Rule has withstood the test of time and accordingly has been widely adopted by both utilities and regulatory agencies in the United States as a standard cost efficient approach.

24. The Commission accepted the 45-day rule in the previous rate case for the Company. The Company has continued to use the 45-day rule (1/8 O&M) to determine the cash working capital needs. The Company's cash working capital determination reflects known and measurable changes to the 2020 Test Year O&M expenses.

MATERIALS & SUPPLIES AND PREPAYMENTS - $29,323,147

25. Materials & Supplies as shown in Schedule C-5 include the cost of materials and supplies purchased for use in the utility business for construction, operation and maintenance purposes. All utilities maintain such supplies for use in their normal day-to-day operations. This is especially important in an island environment where replacement parts have to be acquired from overseas. Materials & Supplies include stocks of fuel, lubricants, generation plant spares,

substation equipment spares, poles and accessories etc. Materials and supplies when issued are charged to the appropriate construction or operating expense account on the basis of a unit price determined by the use of the average method of inventory accounting in conformity to accepted accounting standards consistently applied.

26. The level of Materials & Supplies changes daily. As with all inventory, different items may be needed at different times. It is thus possible that a level of Materials & Supplies at any given point in time would not be an accurate reflection of the ongoing inventory levels. The appropriate level included in rate base is generally an average level of thirteen months. This method has been chosen for inclusion in the rate base and is consistent with the decision of the Commission in the Company's previous rate case. Pending recovery of these costs from its customers, the Company is entitled to earn a return on the funds used to finance these inventories.

27. Materials & Supplies inventories are valued at cost, which is determined on an average cost basis. Certain Generation spares are carried at cost less provision for obsolescence.

28. Prepayments are also shown in Schedule C-5 and represent an investment of funds that is generally included in the rate base if that investment has not been recognized elsewhere, such as in cash working capital. Prepayments are not recognized in cash working capital under the "45-Day Rule" formula approach where there is no related O&M expense. Prepayments are made in advance of the period to which they apply and include items such as prepaid maintenance and plant and materials. The Company's prepayments to be included in rate base were computed based on an average level of thirteen months, consistent with the materials and supplies method as accepted in the previous rate case by the Company.

CUSTOMER CONTRIBUTIONS FOR CONSTRUCTION WORK NOT YET STARTED - ($3,171,092)

29. When a customer applies for service and the existing plant is unable to provide that service because of distance or load, then that customer may be asked to make a contribution towards the additional work required to effect service.

Contributions may also be required when customers request changes to existing plant e.g. realignment of poles. When the funds are paid into the Company they are credited against the cost of construction of the relevant plant. At the end of 2020 any contributions received, where work had not yet started, are deferred and shown as a deferred credit. Such customer provided funds are deducted from the Company's rate base.

ACCUMULATED DEFERRED INCOME TAX LIABILITY - ($3,355,763)

30. The major regulatory treatment of corporate income taxes is the normalization method of accounting for the benefits that arise from tax policy. The Company employs capital intensively, and tax policy in the form of accelerated depreciation can produce significant non-investor provided cash flow benefits. As a consequence, the manner in which these benefits are captured within the regulatory process is important. The general view in this respect is that accumulated deferred income tax liabilities represent a source of interest free funds or loans supplied by the government that the utility is free to use in support of rate base investment. Therefore, the rate base must be reduced by the accumulated deferred income tax liability, net of accumulated deferred income tax assets, to avoid the Company receiving a return on funds that are cost free. This is also referred to in the section on taxation in the "Memorandum on Income Statement." In December 2018, the Government of Barbados reduced the company's tax rate from 15% in 2018 to approximately 2.34% based on a sliding scale of 5.5% to 1%. This has also resulted in a corresponding reduction in the deferred tax liability. Schedule C-6 provides the calculation for Accumulated Deferred Income Tax Liability.

31. This Memorandum and the related Rate Base schedules may contain rounding differences.

Dated the 30th day of September 2021

Paper prepared by:

Ricaido Jennings

Ricaido Jennings
Director Finance
The Barbados Light & Power Company Limited

C-1

THE BARBADOS LIGHT & POWER COMPANY LIMITED

C-1 CALCULATION OF THE RATE BASE

	Sch.	$
A) Utility Plant In Service		
Cost of Plant		1,462,099,998
Accumulated Depreciation		(815,589,598)
	C-2	646,510,400
B) Construction work in progress (CWIP)	C-3	143,004,791
C) Total Net Plant	C-2-2	789,515,191
D) Current Asset and Liability Adjustment		
Cash Working Capital	C-4	13,579,651
Materials & Supplies and Prepayments	C-5	29,323,147
Customer Contributions for Work Not Yet Started		(3,171,092)
Accumulated Deferred Income Tax Liability	C-6	(3,355,763)
Total		36,375,943
Total Rate Base		825,891,134

C-2

THE BARBADOS LIGHT & POWER COMPANY LIMITED
FIXED ASSETS SUMMARY - HISTORIC COST 2020
C-2 UTILITY PLANT IN SERVICE

	DEPRN. RATE	HC VALUE 31:12:2019	TRANSFERS ADJUSTMENTS	ADDITIONS	RETIRALS	ADJUSTMENTS TO RATE BASE	HC VALUE 31:12:2020	ACCUM DEPR'N 31:12:2019	CHARGE 2,020	RETIRALS	RETIRAL EXPENSE	ACCUM DEPR'N 31:12:2020	WRITTEN DOWN VALUE 31:12:2020
GENERATION PLANT													
GARRISON													
Gas Turbine No. 2	33.33%	24,110,134	380,009	957,138	(570,956)		24,876,325	(23,826,198)	(552,414)	570,956		(23,807,656)	1,068,670
		-					-					-	-
SPRING GARDEN		-					-					-	-
Steam Building	25.00%	2163517	-	-	-		2,163,517	(2,163,517)	-	-		(2,163,517)	-
Steam Equipment	25.00%	58,305,041	-	7,444,037	(2,055,496)		63,693,582	(49,131,911)	(4,583,902)	2,055,496		(51,660,316)	12,033,266
Fuel Tank	2.83%	1,839,342	-	127,842	(39,683)		1,927,502	(1,309,840)	(54,452)	39,683		(1,324,609)	602,892
LSD D10 - D13 - Building	0.00%	24,568,990		-	-		24,568,990	(24,568,990)	-	-		(24,568,990)	-
LSD D10 - D13 - Equipment	2.22%	155,909,117	4,728,521	6,666,021	(5,289,901)		162,013,759	(131,123,217)	(3,601,977)	5,289,901		(129,435,293)	32,578,466
LSD D14 & D15 - Building	3.87%	23,321,244	129,831	774,942	(529,655)		23,696,361	(10,257,742)	(917,515)	529,655		(10,645,602)	13,050,759
LSD D14 & D15 - Equipment	3.94%	145,939,404	1,590,797	2,438,947	(1,852,319)		148,116,829	(61,133,814)	(5,839,639)	1,852,319		(65,121,134)	82,995,695
MSD CAT EQUIPMENT	10.00%		9,801,030	3,467,063	-		13,268,093	-	(1,326,809)	-		(1,326,809)	11,941,284
SEAWELL													
Gas Turbine No. 3 Building	3.02%	2,578,752	-	-	-		2,578,752	(1,838,092)	(77,907)	-		(1,915,999)	662,753
Gas Turbine No. 3	4.10%	30,164,783	246,822	1,188,445	(791,300)		30,808,749	(22,727,876)	(1,263,361)	791,300		(23,199,937)	7,608,812
Fuel Tank- other	3.18%	1,111,774	-	-	-		1,111,774	(907,004)	(35,384)	-		(942,388)	169,386
Gas Turbine No. 4	4.82%	33,509,265	-	129,229	(61,792)		33,576,701	(18,839,114)	(1,618,022)	61,792		(20,395,344)	13,181,358
Gas Turbine No. 5	4.87%	33,740,522	-	2,542,959	(1,132,372)		35,151,110	(17,178,007)	(1,710,282)	1,132,372		(17,755,918)	17,395,192
Gas Turbine No. 6	5.01%	29,009,635	1,341,177	4,784,985	(2,755,473)		32,380,324	(14,340,025)	(1,621,115)	2,755,473		(13,205,667)	19,174,657
Trents													
Solar	5.14%	38,920,953	-	-	-		38,920,953	(6,715,422)	(1,999,027)	-		(8,714,449)	30,206,504
BATTERY	9.41%	16,447,572	-	-	-		16,447,572	(3,289,514)	(1,548,007)			(4,837,521)	11,610,051
							-					-	-
LSD A Spares	1.25%	17,108,078	(1,124,814)	1,586,299	(516,506)		17,053,058	(15,291,641)	(195,713)			(15,487,354)	1,565,704
LSD B Spares	4.31%	13,371,144	(1,517,337)	2,362,589	(930,499)		13,285,897	(4,442,172)	(552,511)			(4,994,683)	8,291,215
TOTAL GENERATION		**652,119,267**	**15,576,037**	**34,470,496**	**(16,525,951)**	**-**	**685,639,849**	**(409,084,097)**	**(27,498,036)**	**15,078,947**	**-**	**(421,503,186)**	**264,136,663**
TRANSMISSION AND DISTRIBUTION													
Substation Buildings	2.06%	20,687,772	935,352	475,392	0		22,098,517	(8,707,545)	(455,196)	-	-	(9,162,741)	12,935,776
Substation Equipment	2.29%	89,628,380	3,354,771	2,716,886	(1,006,659)		94,693,378	(55,566,129)	(2,239,911)	1,006,659	-	(56,799,380)	37,893,998
Poles & Accessories	3.40%	105,682,415	-	4,399,245	(898,341)		109,183,319	(69,832,199)	(3,713,519)	898,341	69,996	(72,577,381)	36,605,938
Overhead Conductors	2.93%	42,497,913	-	1,030,802	(56,997)		43,471,718	(25,743,440)	(1,273,386)	56,997	(19,804)	(26,979,632)	16,492,086
Underground Cables	3.00%	207,127,784	-	2,569,735	(89,375)		209,608,144	(65,791,993)	(6,292,490)	89,375	-	(71,995,108)	137,613,036
Transformers	2.98%	57,528,882	(2,011,805)	1,954,903	(940,783)		56,531,197	(36,914,198)	(1,585,264)	940,783	868	(37,557,812)	18,973,386
Services	2.92%	41,704,296	-	1,519,689	(130,348)		43,093,637	(27,006,268)	(1,258,053)	130,348	16	(28,133,957)	14,959,680
Street Lights	2.33%	6,506,964	-	-	(2,687,849)		3,819,115	(5,619,079)	(89,158)	2,687,849	19785	(3,000,603)	818,512
Meters	1.86%	5,497,927	-	347,961	(83,029)		5,762,859	(3,980,373)	(106,972)	83,029	800	(4,003,516)	1,759,343
AMI Meters	5.37%	41,581,021	-	2,818,818	0		44,399,839	(5,844,419)	(2,384,951)	-	0	(8,229,370)	36,170,469
LED Street lights	5.06%	10,741,638	-	6,631,834	-		17,373,473	(735,905)	(879,643)		-	(1,615,548)	15,757,925
TOTAL DISTRIBUTION		**629,184,992**	**2,278,318**	**24,465,267**	**(5,893,382)**	**-**	**650,035,195**	**(305,741,547)**	**(20,278,544)**	**5,893,382**	**71,661**	**(320,055,048)**	**329,980,147**
GENERAL PROPERTY													
Build - H/Hall & SP. GDN	2.46%	6,185,238	-	-	0		6,185,238	(3,542,003)	(152,098)	-	-	(3,694,101)	2,491,137
Build - Other	2.46%	19,835,742	53,934	1,164,036	0		21,053,712	(8,154,484)	(517,719)	-	0	(8,672,203)	12,381,509
Transport - Heavy	6.33%	9,748,953	-	349,999	0		10,098,953	(6,600,511)	(335,590)	-	-	(6,936,101)	3,162,852
Transport - Light	9.20%	2,917,553	-	369,300	(148,259)		3,138,593	(1,947,264)	(199,232)	148,259	0	(1,998,237)	1,140,357
Furniture & Equipment	4.83%	15,491,032	279,643	1,677,102	(9,582)		17,438,195	(10,475,311)	(842,713)	9,582	- 1,500	(11,309,942)	6,128,254
Computer Equipment	16.67%	6,552,623	-	680,457	(21,942)		7,211,139	(4,021,946)	(892,047)	21,942	- 600	(4,892,651)	2,318,488
Computer Software	11.11%	40,199,514	541,364	698,045	0		41,438,922	(34,181,171)	(1,334,492)	-	-	(35,515,663)	5,923,259
AMI Software	10.00%	2,298,249	-	199,493	0		2,497,742	(762,693)	(249,774)	-	-	(1,012,467)	1,485,275
Land	0.00%	17,994,737	-	-		(632,278)	17,362,459	-		-	-	-	17,362,459
TOTAL GEN PROPERTY		**121,223,642**	**874,941**	**5,138,432**	**(179,783)**	**(632,278)**	**126,424,954**	**(69,685,383)**	**(4,523,665)**	**179,783**	**- 2,100**	**(74,031,364)**	**52,393,590**
TOTAL ASSETS		**1,402,527,902**	**18,729,296**	**64,074,195**	**(22,599,116)**	**(632,278)**	**1,462,099,998**	**(784,511,027)**	**(52,300,244)**	**21,152,112**	**69,561**	**(815,589,598)**	**646,510,400**
						C-2-1	C-1		D-5			C-1	C-1

C-2-1

THE BARBADOS LIGHT & POWER COMPANY LIMITED
C2-1 UTILITY PLANT NOT USED AND USEFUL

Description	Ref	Cost at 31 Dec 2020 $
Land at Bellavista - St Joseph	Note 1	260
Land at Cleavers Hill - St Joseph	Note 1	120
Land at Checker Hall - St Lucy	Note 2	631,898
	C2-2	632,278

Note 1:Land is no longer being used in the course of business

Note 2:Land to be used for future developments

C-2-2

THE BARBADOS LIGHT & POWER COMPANY LIMITED
RECONCILIATION WITH FINANCIAL STATEMENTS
C-2-2 RECONCILIATION WITH FIXED ASSETS

Plant in Service:	**2020 Actual** $	**Adjustment** $	**Sch.**	**Rate Base** $
Generation Plant	685,639,849			685,639,849
Transmission and Distribution Plant	650,035,195			650,035,195
General Property	127,057,232	(632,278)		126,424,954
Total Plant in Service	1,462,732,276	(632,278)	C-2-1	1,462,099,998
Construction Work in Progress				
Generation	117,479,765	21,111,871		138,591,637
Transmission & Distribution	16,653,463	(12,728,222)		3,925,241
General Property	639,300	(151,386)		487,914
Total Construction Work in Progress	134,772,528	8,232,263	C-3	143,004,791
Total Gross Assets	1,597,504,804	7,599,985		1,605,104,789
Less: Accumulated Depreciation				
Generation Plant	(421,503,186)			(421,503,186)
Transmission and Distribution Plant	(320,055,048)			(320,055,048)
General Property	(74,031,364)			(74,031,364)
Total Accumulated Depreciation	(815,589,598)	-		(815,589,598)
Net Fixed Assets	**781,915,206**	**7,599,985**		**789,515,191**

C-3

THE BARBADOS LIGHT & POWER COMPANY LIMITED
C3 CONSTRUCTION WORK IN PROGRESS

DESCRIPTION	BALANCE 31 Dec 2020	ADJUSTMENT	Ref	RATE BASE 31 Dec 2020
GENERATION				
Clean Energy Bridge	107,707,261	25,520,929	Note 4	133,228,191
Wind Turbine Project - Lamberts	3,950,690	(3,950,690)		-
Raw Water Filtration System LS	239,141	(239,141)		-
Fuel Pipeline (Checker H-Trents)	210,821	(210,821)		-
D13 Generator Rewind	801,716		Note 3	801,716
Installation of Generator Lube	14,763		Note 3	14,763
LSD B Oil-Fired Boiler Tube Stack	247,148		Note 3	247,148
D14 Generator Re-wedge	168,608		Note 3	168,608
Spring Garden HFO Tank Inspections	337,346		Note 3	337,346
New Solar PV Site Devpt - L. Grove	8,406	(8,406)		-
Camera System Upgrade	205,533		Note 3	205,533
Replacement Economizer - Exhaust gas boiler - D14	250,134		Note 3	250,134
Online Chemistry Monitoring System	1,243,031		Note 3	1,243,031
Replacement of Garrison Diesel Tanks	9,410		Note 3	9,410
HFO Purifer Upgrade	240,613		Note 3	240,613
Fire System for LSDA HFO Tanks	367,566		Note 3	367,566
Welding Room– Generation SG	235,816		Note 3	235,816
Padmount Transfr re: Seawell	79,517		Note 3	79,517
Old stores Building Renovation	84,449		Note 3	84,449
LSD A Sludge System	112,365		Note 3	112,365
Automate D12 Boiler Sootblower	702,928		Note 3	702,928
Fuel Redundancy LSD HFO Tanks	74,772		Note 3	74,772
Passive Dryer for Transformers	107,528		Note 3	107,528
Upgrade LSDA Protection Relay	80,203		Note 3	80,203
Total Generation Construction Work in Progress	**117,479,765**	**21,111,871**		**138,591,637**
DISTRIBUTION				
St. Lawrence Phase 2 Underground Cable	96,845	(96,845)		-
Carlton Sub -24 & 11 kV UG Connection	167,849	(167,849)		-
Northern Underground 132kV & 24kV Cables	9,256,897	(9,256,897)		-
Marhill Street / Belmont 24kV Underground Cable	1,529,587	(1,529,587)		-
South Coast 11kV U/G Feeder	920,917	(920,917)		-
Purchase of 15/20 MVA Tx	1,231,378		Note 3	1,231,378
Spring Garden - 69kV Switch	444,902	(444,902)		-
Lamberts to Trents O/H line	174,309	(174,309)		-
Hampton Indoor Subst - Civil	136,916	(136,916)		-
Wotton-24 kV & 11kV Sw/gear GL	1,066,087		Note 3	1,066,087
Capacitors	7,770		Note 3	7,770
Electric Vehicle Man. & Charge	100,798		Note 3	100,798
Surge Protection Servs-R Base	11,836		Note 3	11,836
Motor Transport - Vehicles	1,507,371		Note 3	1,507,371
Total Construction Distribution Work in Progress	**16,653,463**	**(12,728,222)**	**-**	**3,925,241**
GENERAL				
PeopleSoft HCM Upgrade	151,386	(151,386)		-
Christie Building Renovations	37,825		Note 3	37,825
Cyber Risk Assess. Remediation	199,589		Note 3	199,589
MDMS Upgrade	250,499		Note 3	250,499
Total Construction General Work in Progress	**639,300**	**(151,386)**	**-**	**487,914**
Total Construction Work in Progress	**134,772,528**	**8,232,263**		**143,004,791**
		C2-2		C1

Note 3: Projects will be in service by December 31, 2021

Note 4: Adjustments made for known and measurable changes for Clean Enegy Bridge Project to be in service by December 31, 2021

C-4

THE BARBADOS LIGHT & POWER COMPANY LIMITED
C-4 CASH WORKING CAPITAL

	Sch		2020 Actual	Adjustments	Test Year 2020
			$		$
Cash Working Capital			**12.5%**	**12.5%**	**12.5%**
Operating & Maintenance					
Generation			44,620,745	(4,616,890)	40,003,855
Distribution			10,746,662		10,746,662
Insurance			8,198,082	4,150,559	12,348,641
General					-
Customer Care		6,587,138		-	6,587,138
Finance		5,019,910		358,911	5,378,821
Information & Comm. Technology		6,170,450			6,170,450
Human Resources		4,954,266			4,954,266
Facilities		1,969,584			1,969,584
Administration		3,889,577		-	3,889,577
Resource Centre		2,368,436			2,368,436
Communications		1,205,906		-	1,205,906
HSEQ		1,153,865			1,153,865
Customer Solutions		3,962,842			3,962,842
Asset Management		1,762,194			1,762,194
Taxes other than on income		4,934,971		1,200,000	6,134,971
			43,979,139		
Cashflow expenses			107,544,628	1,092,580	108,637,207
Cash Working Capital (12.5%)	C-1		**13,443,078**	**136,572**	**13,579,651**
			-	-	-

C-5

THE BARBADOS LIGHT & POWER COMPANY LIMITED
C-5 MATERIALS & SUPPLIES AND PREPAYMENTS

Month	Sch	Test Year 2020
		$
Dec-19		31,476,909
Jan-20		29,240,026
Feb-20		29,294,350
Mar-20		29,039,058
Apr-20		29,505,734
May-20		29,303,144
Jun-20		27,248,119
Jul-20		27,154,637
Aug-20		27,715,761
Sep-20		29,726,360
Oct-20		29,795,848
Nov-20		29,542,321
Dec-20		32,158,642
Calculated using a thirteen (13) month average	C-1	29,323,147

C-6

THE BARBADOS LIGHT & POWER COMPANY LIMITED

C-6 CALCULATION OF ACCUMULATED DEFERRED TAXES

		Accum Deferred tax as per Financials 31/12/2020		Adjustment	Sch.	Accum. Deferred Tax Test Year 2020
Written down value of tax depreciable assets (including WIP) at 31/12/20		727,047,179		20,191,802		747,238,980
Less tax written down values on depreciable assets 31/12/20		529,873,161		8,867,406		538,740,567
		197,174,018		11,324,396		208,498,414
Tax on assets timing difference 31/12/2020	Tax rate 2.3359%		4,605,743	264,524		4,870,267
Other timing differences at 31/12/2020		(26,573,662)		(38,262,971)		(64,836,633)
Tax on timing differences	Tax rate 2.3359%		(620,728)	(893,776)		(1,514,504)
Accumulated deferred tax balance at 31/12/20			**3,985,015**	**(629,252)**	D-3	**3,355,763**
Accumulated Deferred tax balance						
Accumulated deferred tax balance at 31/12/19			3,823,258	-		3,823,258
Deferred tax charge for the year			161,757	(629,252)	D-3	(467,495)
Accumulated deferred tax balance at 31/12/20			**3,985,015**	**(629,252)**	D-3	**3,355,763**

D

MEMORANDUM ON INCOME STATEMENT

1. The Memorandum on Income Statement explains the Income Statement for the Test Year ended December 31, 2020. The Income Statement provided in Schedule D-1 records all electricity revenue (basic and fuel adjustment clause revenue) and miscellaneous income, and from this the expenses (fuel expenses, operating and maintenance expenses, depreciation, finance costs and taxation) incurred in generating those revenues are deducted to arrive at the net income.

2. The Income Statement is based on the audited financial statements for the year ended December 31, 2020.

OPERATING REVENUE

3. The Operating Revenue consists of:

Basic revenue	-	$ 186,038,177
Fuel revenue	-	$ 202,978,824
Miscellaneous revenue	-	$ 4,700,692
Investment income	-	$ 326,939
Other income	-	$ 1,412,333
TOTAL	-	$ 395,456,966

Basic Revenue - $186,038,177

4. The Company derives electricity sales revenue from commercial and residential tariffs and street lights.

5. This electricity sales revenue is recognized on the accruals basis. It records revenue, other than fuel clause revenue, as billed to its customers, net of value-added tax and discounts and does not recognize any unbilled portion, which exists at year-end unless it is material.

Fuel revenue **- $ 202,978,824**

6. Fuel revenue represents amounts approved by the Fair Trading Commission ("the Commission") for recovery through the Fuel Clause Adjustment (FCA), which includes costs associated with fuel and renewable purchased power. The cost of fuel and purchased power is recognized on the basis of the amount actually recoverable for the financial year. Fuel cost recovered from the customers through the Fuel Clause Adjustment in 2020 was approximately $181.5 Million and purchased power under the renewable energy rider and the Feed in Tariff recovered through the FCA was $21.4 Million in 2020.

7. The unbilled portion of fuel revenue between meter reading and the end of the year is normally not material on a year-to-year basis.

Miscellaneous Revenue **- $ 4,700,692**

8. Miscellaneous revenue primarily consists of pole rental fees, reconnection fees, new service connection fees and revenue from the 5MW Energy Storage Device (ESD). The revenue from the ESD is calculated in accordance with the Commission's Decision of April 23, 2019[1]. The Memorandum on Rate Base outlines the request to include the ESD in Rate Base. The Barbados National Energy Policy 2019 – 2030 (BNEP) and the associated implementation plan includes a requirement for a potential 200 MW of battery storage by 2030. The Company therefore requests to recover the unrecovered cost of the ESD through base rates. The revenue from the ESD has therefore been removed from miscellaneous revenue and included in the basic revenue requirement in the test year in Schedule D-1. This adjustment is detailed in Schedule D-7.

Investment Income **- $326,939**

9. Investment income consists of earnings on short-term deposits and miscellaneous rental income.

1 https://www.ftc.gov.bb/library/2019-04-17_commission_decision_blandp_motion_esd_decision.pdf

<u>Other income</u> **- $1,412,333**

10. Other income represents efficiency incentives related to heat rate targets on certain generating plant set out by the Commission in their Decision of April 23, 2019. This Decision penalizes the Company by limiting the amount of fuel costs that can be recovered from customers by the Company when operating certain of its base load plant less efficiently than pre-set performance targets and conversely allows the Company to earn an incentive related to the cost of the fuel saved by performing better than the set targets. This mechanism fluctuates from time to time based on performance and is not expected to form part of the Company's revenue requirement. It has therefore been excluded and the adjustment is detailed in Schedule D-7.

OPERATING & MAINTENANCE EXPENSES

11. The Company is currently organised by the following business units: generation, distribution, customer care, finance, information and communication technology, human resources, facilities, administration, resource management centre, communications, health and safety, customer solutions and asset management. Operating and maintenance (O&M) costs are the costs incurred by these business units and are recorded on an accruals basis. The accruals basis represents costs incurred in the year whether paid or not. The expenses have been adjusted for unusual amounts incurred in the test year and for known and measurable changes to develop the test year in Schedule D-1. According to *The Process of Rate Making* "An agency may, and often does, rely on projected or estimated costs to avoid the effects of administrative delay on the company's ability to attain the needed revenues. Such costs must be based on projections of actual-neither speculative nor contingent-costs. There must be evidence that the estimate is "known and measureable." The evidence must be sufficient for the agency to make a "fair guess" as to future conditions."[2] The adjustments are detailed in Schedule D-7.

[2] "The Process of Ratemaking" by Leonard Saul Goodman, pages 284 and 285

12. Operating expenses consist of:

Fuel Expense	-	$202,978,824
Insurance	-	$ 8,198,082
Depreciation	-	$ 52,300,344
Lease Amortisation	-	$ 406,353
Generation Expenses	-	$ 44,620,745
Distribution Expense	-	$ 10,746,662
General Expenses	-	$ 43,979,139
TOTAL	-	$363,230,050

13. Schedule D-2 provides a statement of the Operating & Maintenance expenses by business unit.

Fuel expense - $202,978,824

14. Fuel expense represents the cost of fuel, additives consumed by the generators in producing electricity and purchased power during the financial year. Fuel cost in 2020 was approximately $181.5 Million and purchased power under the renewable energy rider and the Feed in Tariff was approximately $21.4 Million in 2020.

Insurance - $8,198,082

15. Insurance expense includes the cost of general property insurance. The cost of insurance in 2020 is not expected to be sufficient to cover the cost in the coming years due to general price increases for insurance. The cost of insurance incurred in 2017 was $4.7 Million, $5.2 Million in 2018, $5.8 Million in 2019 and $8.2 Million in 2020. A reasonable estimate of the cost of insurance is approximately $12.3 Million, significantly more than the amount included in the 2020 test year. The Company requests a reasonable amount to cover known and measurable increases in the cost of insurance be included in determining the revenue requirement. As such insurance expense has been adjusted to include an additional amount of approximately $4.2 Million based on 2021 insurance premiums, bringing the cost of insurance included in the test year for purposes of calculating the revenue requirement to $12.3 Million. Indications are that these increases are not expected to reverse for the foreseeable future, rather further increases are possible due to developments

that affect the global insurance market. This adjustment to Insurance expense is detailed at Schedule D-7.

Depreciation - **$52,300,244**

16. The Company uses the remaining life method, which is a generally accepted straight-line method. This method recovers the original cost of the plant, adjusted for net salvage, over the remaining life of the plant. In keeping with good industry practice and to support the requirements of International Financial Reporting Standards, from time to time the Company performs studies to determine the appropriate book depreciation factors and rates to be applied to the property in service to enable recovery of the plant investment, adjusted for net salvage, over its remaining useful life. Such studies have been performed as of December 31, 2006, December 31, 2012, December 31, 2017 and most recently updated to December 31, 2019. Each of these has been submitted to the Commission and have been used to inform the annual depreciation charge and the resulting accumulated depreciation included in the annual audited financial statements. The rates and methodology used are those included in the Application by The Barbados Light & Power Company Limited for approval of the Depreciation Policy of the Barbados Light & Power Company Limited (Ref: FTCUR-0001/20) currently being heard by the Commission and applied to the 2020 Test Year. The Commission had indicated that they would issue a Decision in the matter by end of May – therefore the matter was expected to be determined before this rate application was heard, consistent with the practice followed during the previous rate hearing. The Company is nearing completion of the construction of the Clean Energy Bridge (CEB) which is expected to be used and useful by end of 2021, bringing significant benefits to customers, among them enhanced reliability and better fuel efficiency, potentially leading to fuel cost savings depending on world fuel prices. The Company requests the known and measurable depreciation charge associated with the CEB be included in determining the revenue requirement. As such the depreciation expense has been adjusted to include an additional amount of approximately $5.3 Million based on 12 months depreciation charge of the forecasted completion cost of the CEB bringing the depreciation charge included in the test year for purposes of calculating the revenue requirement to $57.6 Million. Schedule D-5 provides the Statement of Depreciation Expense and the relevant adjustment is listed in Schedule D-7.

<u>Amortisation of Lease</u> **-** **$406,353**

17. The Company has leased land at Lamberts St. Lucy for the purposes of constructing a wind farm. The lease has been accounted for as a right of use asset, amortised on a straight-line basis from the lease commencement date to the earlier of the end of the useful life of the right-of-use asset or the end of the lease term. This amortization has been excluded in determining the revenue requirement and this adjustment to amortization of lease expense is detailed at Schedule D-7.

<u>Generation expenses</u> **-** **$44,620,745**

18. The Generation business unit is responsible for the supply of electricity to the grid and ensures that peak demands are met. It operates and maintains the generation units at the Company's four generating locations. The costs incurred are for labour, materials and supplies on the generation units.

19. Consistent with the previous rate application, costs associated with the fully depreciated unit GT01 of approximately $ 0.7 Million have been excluded.

20. During 2020 the Company incurred generation rental costs of approximately $ 9.6 Million. These costs have been excluded in determining the revenue requirement, as they are not expected to be annually recurring costs.

21. The cost incurred in 2020 for Lubricants for unit D15 was lower than normal as the unit was not available for a significant part of the year and is therefore inadequate to cover expected lubricant use in that unit in a normal year. Unit D15 uses far more lubricant than the other generating units, which were utilized to satisfy customer demand while unit D15 was unavailable. Unit D15 is one of the most fuel efficient units and is therefore normally utilized once available. It is expected in a year with higher unit availability the cost of lubricant would be significantly higher. The Company requests a reasonable amount to cover the cost of lubricants be included in determining the revenue requirement. As such, the amount of generation expenses has been adjusted to include an additional known and measurable amount of approximately $1.7 Million based on typical lubricant costs in the test year for purposes of calculating the revenue requirement.

22. The Company is nearing completion of the construction of the CEB which is expected to be used and useful by end of 2021, bringing significant benefits to customers, among them enhanced reliability and better fuel efficiency, potentially leading to fuel cost savings depending on world fuel prices. The Company requests the annual operating and maintenance expenses associated with the CEB be included in determining the revenue requirement. As such the generating expenses has been adjusted to include an additional known and measurable amount of approximately $4.8 Million based on 12 months of materials and labour associated with the CEB be included in the test year for purposes of calculating the revenue requirement.

23. The adjustments to Generation Expenses have the impact of reducing the generation expenses by approximately $4.6 Million for the purposes of calculating the revenue requirement in the test year and are listed at Schedule D-7.

Distribution expenses - $10,746,662

24. The Distribution business unit ensures that there is a safe, efficient and reliable supply of electricity from the substations linked with the generating stations to the customer. Its responsibilities include maintenance of power lines, the Supervisory Control & Data Acquisition (SCADA) system, substations, transformers, meters, streetlights and tree trimming. The business unit also responds to emergency calls from customers. The cost incurred is for labour, materials and supplies.

General expenses - $43,979,139

25. General expenses consist of the following:

Customer Care	-	$ 6,587,138
Finance	-	$ 5,019,910
Information & Communication Technology	-	$ 6,170,450
Human Resources	-	$ 4,954,266
Facilities	-	$ 1,969,584
Administration	-	$ 3,889,577
Resource Management Centre	-	$ 2,368,436
Communications	-	$ 1,205,906

Health Safety and Environment	-	$ 1,153,865
Customer Solutions	-	$ 3,962,842
Asset Management	-	$ 1,762,194
Taxes other than on income	-	$ 4,934,971
TOTAL	-	$43,979,139

Customer Care business unit - $6,587,138

26. This business unit is responsible for the service application, meter reading, billing, uncollectible bills, revenue collection, disconnections, reconnections and the call center. The cost incurred is primarily for labour and services.

Finance business unit - $5,019,910

27. This business unit is responsible for all financial planning, reporting and analysis, treasury functions and supply chain management in the Company. It does all financial and tax preparation and reporting. The cost incurred is primarily for labour and services. The adjustments to Finance business unit's expenses are detailed at Schedule D-7.

Information & Communication Technology business unit - $6,170,450

28. This business unit provides for the maintenance on all the application systems, maintenance of the website and other intranet-related applications, network support on all internal and external communications and maintenance to all hardware connected on the corporate network. The cost incurred is primarily for labour, materials and services.

Human Resources business unit - $4,954,266

29. This business unit coordinates the human resource function in the Company including training, development and employee relations. The cost incurred is primarily for labour and services.

Facilities business unit - $1,969,584

30. This business unit coordinates the maintenance of administrative offices and buildings for the Company. The cost incurred is primarily for labour, materials and services.

Administration business unit - $3,889,577

31. This business unit coordinates the corporate support of the Company. It provides legal support and costs associated with corporate governance. The cost incurred is primarily for labour and services.

Resource Management Centre business unit - $2,368,436

32. This business unit plans, schedules and inspects work of the distribution department. The cost incurred is primarily for labour, material and services.

Communications business unit - $1,205,906

33. This business unit is responsible for communicating with internal and external customers and stakeholders.

Health Safety and Environment business unit - $1,153,865

34. This business unit is responsible for managing and reporting on the health safety and environmental programmes of the entire Company.

Customer Solutions business unit - $3,962,842

35. This business unit is responsible for regulatory affairs, key accounts programme and business solutions.

Asset Management business unit - $1,762,194

36. This business unit is responsible for system planning, monitoring performance, transmission and distribution asset management and generation asset management.

Taxes other than on income - $4,934,971

37. This includes property taxes paid to the Land Tax Department as well as the license fee paid to the Accountant General. The Company is nearing completion of the construction of the CEB, which is expected to be used and useful by the end of 2021 bringing significant benefits to customers, among them enhanced reliability and better fuel efficiency, potentially leading to fuel cost savings depending on world fuel prices. The Company requests the Taxes other than on income associated with the CEB be included in determining the revenue requirement. As such this expense has been adjusted to include an additional known and measurable amount of approximately $1.2 Million based on the increased cost to be levied on the improved value bringing the taxes

other than on income included in the test year for purposes of calculating the revenue requirement to $6.1 Million. The adjustment to Taxes other than on income is listed at Schedule D-7.

Finance Costs - **$5,872,467**

38. Finance cost consists of interest on borrowings, finance charges on the borrowings, interest on customer deposits, less interest during construction.

Finance costs consist of:

Interest on long-term loans	-	$5,304,721
Interest on customer deposits	-	$1,582,354
Interest during construction	-	($1,088,362)
Finance charges	-	$ 130,493
Bank Charges	-	($ 56,739)
TOTAL	-	$5,872,467

39. Interest costs are the cost incurred on the Company's borrowings and are computed based on the repayment schedule of the respective borrowings. Finance charges incurred on these borrowings are amortised over their lives. Schedule D-6 provides the Statement of Interest Expenses. During 2020 a full year of interest costs related to debt to fund the CEB was not incurred due to amounts being drawn in tranches during the year and an amount of $33.1 Million committed but undrawn at the end of 2020. Further during 2020 an amount of approximately $1.1 Million was capitalized as interest during construction which is not expected to recur. The Company has therefore included an adjustment of $2.1 Million representing known and measurable interest costs expected during the test year. The adjustment to Interest cost is listed at Schedule D-7.

40. All customers, except Barbadian citizens categorised under the Domestic Service tariff, are required to provide security for payment. However, Barbadian residents under this tariff may be asked to provide security if they are delinquent in paying their bills. Interest accrues on customer deposits at 3.5%.

41. Interest incurred during construction is capitalized on qualifying capital projects. The adjustment to Interest incurred during construction is explained at Schedule D-7.

Taxation **-** **($2,368,793)**

42. Taxation expense in the statement of income comprises:

Current tax	-	($ 490,927)
Deferred tax	-	$ 161,757
Deferred investment tax credit	-	($1,377,331)
Deferred manufacturing tax credit	-	($ 662,292)
TOTAL	-	($2,368,793)

43. Schedule D-3 details the deferred taxes, investment tax credit, manufacturing tax credit and related adjustments.

Current Tax - ($490,927)

44. Current tax is the expected tax payable to the Commissioner of Inland Revenue on the taxable income for the period using tax rates enacted. The current tax is negative due to an adjustment related to 2019 not recorded in 2019 and only recorded in 2020. Consequently this has been excluded from the test year. This adjustment is shown in Schedule D-7.

45. As of December 31, 2020, the Company had tax losses of $8,316,956.67 available to be carried forward and applied against future taxable income.

Deferred income tax - $161,757

46. For the purposes of determining tax liability, government has allowed accelerated depreciation, where the rates are higher in the earlier years of the life of the asset and lower in the later years. Accelerated depreciation alters the timing, but does not eliminate corporation tax liabilities over the life of an asset.

47. For each financial reporting period, the corporation taxes reported reflect straight line depreciation on booked depreciation rates, whereas the actual corporation taxes payable are based on accelerated depreciation as required by the tax laws. The difference between the corporation tax provision and

actual taxes payable is recorded as a deferred expense in the Income Statement and on the Company's Balance Sheet as a deferred income tax liability. In December 2018, the Government of Barbados reduced the company's tax rate from 15% to approximately 2.34% using a sliding scale of 5.5% to 1%.

48. The Public Utilities Board ("the PUB") in its 1983 Decision[3] stated that "*the issue of deferred taxes and the deferred investment tax credit must be settled once and for all. The matter has arisen in the last four rate cases, and considerable time has been spent during the course of those hearings debating the issue whether deferred taxes are to be allowed as a proper cost of service. It is a matter of record that in the 1980 Review decision the Board permitted the company to include as an operating expense a sum which represented the deferred portion of income taxes, and the Board went to great lengths to deal with the conceptual basis of deferred taxes in that decision."*

49. The PUB further stated in its 1983 decision[4] that, *"applying the principles enunciated above to the evidence in this case, the Board finds that the Company has demonstrated that there are in fact temporary timing differences in the circumstances of this case and exhibits D/S8 and D/S9 clearly demonstrate the fact of such temporary timing differences. The Board therefore permits the Company to recover $4,288,000 for deferred income taxes as claimed in D S/1 as an operating expense."*

50. Deferred income tax assets are recognized to the extent that it is probable that future taxable profits will be available against which the assets can be utilised. The Company's deferred income assets primarily related to unutilised tax losses resulting from manufacturing tax credit discussed below. The adjustment to deferred income tax as a result of the adjustments to the test year is shown in Schedule D-7.

Deferred investment tax credit - ($1,377,331)

51. The investment tax credit (ITC) was a 20% investment allowance associated with the acquisition of plant and equipment acquired prior to financial year

3 PUB Decision Dated 12th May 1983 - Page 16

4 PUB Decision dated 12th May 1983 - Page 21

2018. The ITC effectively reduced the cost of the related asset and, for that reason, it is deferred and amortized over the productive life of the related asset. From a rate regulation perspective the deferral method is much fairer to all customers receiving utility service over the productive life of the asset, which generated the ITC, as opposed to only the current customers of the year of allowance generation.

52. Consistent with the Company's last rate application associated with the Commission's 2010 Decision, the Company, in this Application, has utilised amortization of accumulated deferred ITC as a reduction in the cost of service, to the benefit of customers. The accumulated deferred ITC is included in the capital structure for determining the utility's allowed rate of return.

Deferred manufacturing tax credit - ($662,292)

53. The manufacturing tax credit is a 50% allowance associated with the construction of plant and equipment, which is earned ratably over the related income tax life. Although the amount of the credit is different, the manufacturing tax credit is conceptually the same as the ITC. The Company has accounted for it in the same deferral manner as for the ITC for financial reporting purposes and proposes that the manufacturing tax credit be accorded the same regulatory treatment.

54. This Memorandum and related Statement of Income schedules may contain rounding differences.

Dated this 30th day of September, 2021

Paper prepared by: Ricaido Jennings

Ricaido Jennings
Director Finance
The Barbados Light & Power Company Limited

D-1

THE BARBADOS LIGHT & POWER COMPANY LIMITED

D-1 INCOME STATEMENT FOR YEAR ENDING 31 DECEMBER 2020

		Balance as per Financial statements Dec 31, 2020	Adjustments	Sch	Test Year at existing rates	Rate Increase	Test Year at proposed rates 2020
Revenues							
Basic revenue		186,038,177			186,038,177	46,475,310	232,513,487
Fuel Revenue		202,978,824			202,978,824		202,978,824
Misc Revenue		4,700,692	(279,571)	D-7-1	4,421,121		4,421,121
Investment Income		326,939			326,939		326,939
Heat Rate (Penalties)/Incentives		1,412,333	(1,412,333)	D-7-2	-		-
Total Revenues		395,456,966	(1,691,903)		393,765,062	46,475,310	440,240,372
Operating and maintenance expenses							
Fuel		202,978,824			202,978,824		202,978,824
Insurance		8,198,082	4,150,559	D-7-3	12,348,641		12,348,641
Depreciation		52,300,244	5,329,128	D-7-4	57,629,372		57,629,372
Amortization of Lease		406,353	(406,353)	D-7-5	-		-
Generation		44,620,745	(4,616,890)	D-7-6	40,003,855		40,003,855
Distribution		10,746,662			10,746,662		10,746,662
General							
....Customer Care	6,587,138				6,587,138		6,587,138
....Finance	5,019,910		358,911	D-7-7	5,378,821		5,378,821
....Information & Communication Technology	6,170,450				6,170,450		6,170,450
....Human Resources	4,954,266				4,954,266		4,954,266
....Facilities	1,969,584				1,969,584		1,969,584
....Administration	3,889,577				3,889,577		3,889,577
....Resource Centre	2,368,436				2,368,436		2,368,436
....Communications	1,205,906				1,205,906		1,205,906
....HSEQ	1,153,865				1,153,865		1,153,865
....Customer Solutions	3,962,842				3,962,842		3,962,842
....Asset Management	1,762,194				1,762,194		1,762,194
....Taxes other than on income	4,934,971		1,200,000	D-7-8	6,134,971		6,134,971
		43,979,139					
Operating expenses before taxes		363,230,050	6,015,354		369,245,404	-	369,245,404
Taxes							
Corporation tax expense		(490,927)	490,927	D-7-9	0	271,370	271,370
Deferred taxes		161,757	(629,252)	D-7-10	(467,495)	893,776	426,281
Deferred investment tax credit		(1,377,331)	-		(1,377,331)		(1,377,331)
Deferred manufacturers tax credit		(662,292)	(273,554)	D-7-11	(935,847)		(935,847)
Total taxes		(2,368,793)	(411,879)		(2,780,672)	1,165,146	(1,615,526)
Total expenses		360,861,256	5,603,475		366,464,731	1,165,146	367,629,877
Operating income		**34,595,709**	**(7,295,378)**		**27,300,331**	**45,310,164**	**72,610,496**
Finance costs		5,872,467	2,181,245	D-7-12	8,053,712	-	8,053,712
Net income for the year		**28,723,243**	**(9,476,623)**		**19,246,619**	**45,310,164**	**64,556,784**

D-2

THE BARBADOS LIGHT & POWER COMPANY LIMITED
D-2 STATEMENT OF OPERATING & MAINTENANCE EXPENSES BY DEPARTMENT

	Balance as Per Financial statements Dec 31, 2020	ADJUSTMENT	Sch.	Balance after Ist Adjustment	ADJUSTMENT	Sch.	Test Year 2020
	$			$			$
FUEL EXPENSES							
Bunker C (fuel) HFO	83,258,691			83,258,691			83,258,691
Natural Gas	-			-			-
Diesel Fuel	24,962,388			24,962,388			24,962,388
Av-Jet fuel	73,235,620			73,235,620			73,235,620
Heavy Vacuum Gas Oil	100,113			100,113			100,113
Fuel - Purchased Power	21,422,013			21,422,013			21,422,013
Total Fuel	**202,978,824**			**202,978,824**			**202,978,824**
GENERATION EXPENSES							
Generation Supervision	4,721,745	(63,110)		4,658,635	967,371		5,626,007
Operators wages	6,296,422	(497,156)		5,799,266	1,412,400		7,211,666
Water	1,280,157			1,280,157	142,898		1,423,055
Lubricants	4,084,561	1,586,203		5,670,764	720,000		6,390,764
Production Supplies	19,497			19,497	3,600		23,097
Common Facilities - Station cleaning	335,507	(1,820)		333,687	180,000		513,687
Provision for Obsolete Stock	277,658	1,575		279,233			279,233
Ash Handling	52,258			52,258			52,258
Maint. of Common Facilities	975,020			975,020			975,020
Maintenance of Lands/Buildings	748,084	(3,989)		744,095	80,000		824,095
Maintenance of Boiler Plant	507,245			507,245			507,245
Maintenance of Prime movers	11,768,254	(767,229)		11,001,025	945,570		11,946,596
Maintenance of Generators	94,214			94,214			94,214
Maintenance of Electrical Plant	2,119,560	(66,736)		2,052,825	301,560		2,354,384
Maintenance Auxilaries Power Plant	1,403,828	10,000		1,413,828	33,320		1,447,148
Maintenance of Instrumentation	11,285			11,285			11,285
Rental of Generation	9,601,349	(9,601,349)		-			-
Safety	203,824			203,824			203,824
Security	56,115			56,115			56,115
Generation Welfare	(375)			(375)			(375)
Training	64,537			64,537			64,537
Generation Tools	-			-			-
Total Generation O&M	**44,620,745**	**(9,403,610)**	D-1	**35,217,135**	**4,786,719**	D-1	**40,003,855**
DISTRIBUTION EXPENSES							
Distribution Supervision	1,407,843			1,407,843			1,407,843
Maintenance of Substation Buildings	360,592			360,592			360,592
Maintenance Substation Equipment	911,222			911,222			911,222
Maintenance of Overhead Lines	2,681,379			2,681,379			2,681,379
System Control - SCADA	1,129,940			1,129,940			1,129,940
Maintenance of Street Lighting	547			547			547
Maintenance of Underground System	216,943			216,943			216,943
Trouble Calls	1,907,600			1,907,600			1,907,600
Maintenance of Transformers	193,987			193,987			193,987
Maintenance of Meters	948,772			948,772			948,772
Damage to Customer premises	69,199			69,199			69,199
Distribution Welfare	-			-			-
Motor Transport	1,834			1,834			1,834
Distribution Tools	-			-			-
Power Quality Assurance	421,303			421,303			421,303
Training	495,501			495,501			495,501
Total Distribution Expenses	**10,746,662**			**10,746,662**			**10,746,662**

THE BARBADOS LIGHT & POWER COMPANY LIMITED
D-2 STATEMENT OF OPERATING & MAINTENANCE EXPENSES BY DEPARTMENT

	Balance as Per Financial statements Dec 31, 2020	ADJUSTMENT	Sch.	Balance after Ist Adjustment	ADJUSTMENT	Sch.	Test Year 2020
	$			$			$
CUSTOMER CARE EXPENSES							
Customer Care Supervision	1,006,703			1,006,703			1,006,703
Meter Reading	419,128			419,128			419,128
Uncollectible bills	362,520			362,520			362,520
Billings	1,263,659			1,263,659			1,263,659
Service Centre	1,274,444			1,274,444			1,274,444
Customer Accounts	483,124			483,124			483,124
Contact Centre	988,852			988,852			988,852
Studies	12,000			12,000			12,000
Credit Collections	419,736			419,736			419,736
Training	1,493			1,493			1,493
Customer Experience	(5,975)			(5,975)			(5,975)
Service Standard Penalties	15,491			15,491			15,491
Damage to Customer premises	251,995			251,995			251,995
Quality & Compliance	93,968			93,968			93,968
Total Customer Care Expenses	**6,587,138**			**6,587,138**			**6,587,138**
FINANCE EXPENSES							
Finance & Accounting Supervision	2,158,382			2,158,382			2,158,382
Financial Services	638,395	358,911		997,306			997,306
Internal Audit	-			-			-
Audit Fee	97,353			97,353			97,353
Supply Chain - Purchasing	1,031,925			1,031,925			1,031,925
Supply Chain - Stores	1,078,137			1,078,137			1,078,137
Training	15,718			15,718			15,718
Total Finance Expenses & Finance charges	**5,019,910**	**358,911**	D-1	**5,378,821**			**5,378,821**
INFORMATION & COMMUNICATION TECHNOLOGY							
ICT Supervision	954,936			954,936			954,936
ICT System Maintenance	647,573			647,573			647,573
ICT System Operations	1,069,419			1,069,419			1,069,419
Training	13,537			13,537			13,537
ICT Software Licenses	2,502,462			2,502,462			2,502,462
ICT Hardware Maintenance	898,956			898,956			898,956
ICT Supplies	83,568			83,568			83,568
Total Information & Communication Technology	**6,170,450**			**6,170,450**			**6,170,450**
HUMAN RESOURCES EXPENSES							
Human Resources Supervision	2,138,372			2,138,372			2,138,372
Legal Fees	18,543			18,543			18,543
Advertising	79,835			79,835			79,835
Employee Benefits	2,703,132			2,703,132			2,703,132
Training	14,861			14,861			14,861
Retirees Association	(478)			(478)			(478)
Total Human Resources Expenses	**4,954,266**			**4,954,266**			**4,954,266**
FACILITIES							
Admin Office Expenses	38,414			38,414			38,414
Admin Building Maintenance	908,409			908,409			908,409
Security	1,022,761			1,022,761			1,022,761
Total Facilities Expenses	**1,969,584**			**1,969,584**			**1,969,584**

THE BARBADOS LIGHT & POWER COMPANY LIMITED
D-2 STATEMENT OF OPERATING & MAINTENANCE EXPENSES BY DEPARTMENT

		Balance as Per Financial statements Dec 31, 2020	ADJUSTMENT	Sch.	Balance after Ist Adjustment	ADJUSTMENT	Sch.	Test Year 2020
		$			$			$
ADMINISTRATION EXPENSES								
Admin Supervision		1,501,846			1,501,846			1,501,846
Head Office Expenses		936,070			936,070			936,070
Legal fees		954,123			954,123			954,123
Tourism Promotion Expenses		250,008			250,008			250,008
Directors Fees		228,442			228,442			228,442
Training		1,508			1,508			1,508
Hurricane Assistance		-			-			-
Studies		-			-			-
Carilec		17,580			17,580			17,580
Total Administration Expenses		**3,889,577**			**3,889,577**			**3,889,577**
RESOURCE CENTRE								
Resource Centre Supervision		426,824			426,824			426,824
Resource Centre Benefits		11,581			11,581			11,581
Resource Centre Tools		39,173			39,173			39,173
Technical Planning		445,295			445,295			445,295
Resource Dispatch		772,887			772,887			772,887
Maintenance of Plant Records		218,570			218,570			218,570
Maintenance of Overhead Lines		315,033			315,033			315,033
Inspections		33,755			33,755			33,755
Training		15,355			15,355			15,355
Maintenance of Street Lighting		89,963			89,963			89,963
Total Resource Centre Expenses		**2,368,436**	**-**		**2,368,436**	**-**		**2,368,436**
COMMUNICATIONS								
Communications		504,595			504,595			504,595
Cust Comm. & Public Relations		701,149			701,149			701,149
Government Relations		-			-			-
Training		163			163			163
Total Communications Expenses		**1,205,906**	**-**	D-1	**1,205,906**	**-**	D-1	**1,205,906**
HEALTH, SAFETY, EVIRONMENT & QUALITY								
Health Safety Environment Quality (HSEQ)		1,150,111			1,150,111			1,150,111
Training		3,754			3,754			3,754
TOTAL HSEQ Expenses		**1,153,865**	**-**		**1,153,865**	**-**		**1,153,865**
CUSTOMER SOLUTIONS								
Customer Solutions Supervision		1,715,985			1,715,985			1,715,985
Key Accounts		5,265			5,265			5,265
Business Solutions		18,347			18,347			18,347
Regulatory Fees		1,531,395			1,531,395			1,531,395
Studies		685,642			685,642			685,642
Training		6,207			6,207			6,207
Total Customer Solutions Expenses		**3,962,842**	**0**	**0**	**3,962,842**	**0**	**0**	**3,962,842**
ASSET MANAGEMENT EXPENSES								
System Plannning		166,550			166,550			166,550
T & D Asset Management		254,693			254,693			254,693
Generation Asset Management		211,442			211,442			211,442
Performance		447,870			447,870			447,870
Maintenance of Overhead lines		57,683			57,683			57,683
Training		18,524			18,524			18,524
Studies		605,432			605,432			605,432
Total Asset Management Expenses		**1,762,194**	**0**	**0**	**1,762,194**	**0**	**0**	**1,762,194**
OTHER EXPENSES								
Taxes other than on income		4,934,971			4,934,971	1,200,000		6,134,971
Insurance								
- Insurance - General	8,198,082					4,150,559		
- Insurance - Self								
		8,198,082			8,198,082	4,150,559		12,348,641
Total Other Expenses		13,133,053	-	D-1	13,133,053	5,350,559	D-1	18,483,612

D-3

THE BARBADOS LIGHT & POWER COMPANY LIMITED
D-3 DEFERRED TAXES, INVESTMENT TAX CREDIT &
MANUFACTURING TAX CREDIT

CALCULATION OF DEFERRED TAXES

		Deferred tax as per financial statements 31/12/2020	Adjustment	Sch	Adjusted Deferred Tax Test year 2020
Asset timing differences					
Written down value of tax depreciable assets (including WIP) 31/12/19	637,306,923				637,306,923
Less tax written down values 31/12/19	447,162,050				447,162,050
		190,144,874	-		190,144,874
Written down value of tax depreciable assets (including WIP) at 31/12/20	727,047,179		20,191,802		747,238,980
Less tax written down values 31/12/20	529,873,161		8,867,406		538,740,567
		197,174,018	11,324,396		208,498,414
Timing difference on asset timing differences 31/12/20		7,029,144	11,324,396		18,353,540
Deferred tax charge - tax rate 2.3359%		**164,192**	**264,524**		**428,716**
Other timing differences					
At December 31, 2019		(25,996,004)	-		(25,996,004)
At December 31, 2020		(26,573,662)	(38,262,971)		(64,836,633)
Net change		(577,658)	(38,262,971)		(38,840,629)
Deferred tax charge on other timing differences - tax rate 2.3359%		**(13,493)**	(893,776)		**(907,269)**
Adjustment resulting from prior year		11,058			11,058
		11,058			11,058
Deferred tax charge for the year		**161,757**	**(629,252)**	D-1	**(467,495)**

CALCULATION OF DEFERRED INVESTMENT TAX CREDIT (ITC)

	Deferred ITC Allowance as per financial statements 2020 $	Adjustment	Sch	Deferred ITC Allowance Test Year 2020 $
Net additions at December 2020	-	-		-
0% Investment tax allowance on net additions for the year 2020	-	-		-
Annual allowance for 2020 @ tax rate	-			-
Annual allowance over average asset lives	1,377,331			1,377,331
Deferred investment tax credit at December 31, 2020	1,377,331	-	D1	1,377,331

CALCULATION OF DEFERRED MANUFACTURING TAX CREDIT (MTC)

		MTC Allowance as per financial statements $	Adjustment	Sch	Deferred MTC Allowance Test Year 2020 $
Deferred Manufacturing tax credit at December 31, 2019		19,740,452			19,740,452
Manufacturing allowance 2019 tax adjustment (50%) @ Depreciation tax rate		460,279			460,279
Manufacturing allowance 2020 (50%) @ Depreciation tax rate	28,441,205	522,430			522,430
Manufacturing allowance 2020 (50%) @ Depreciation tax rate - CEB	8,326,762		194,505		194,505
		(1,645,002)	(7,780)		(1,652,782)
Deferred Manufacturing tax credit at December 31, 2020	36,767,967	19,078,160	186,725		19,264,884
Manufacturing allowance 2019 tax adjustment (50%) @ Depreciation tax rate		460,279	(460,279)		0
Manufacturing allowance 2020 (50%) @ Depreciation tax rate		522,430	194,505		716,935
Amortization of Deferred Manufacturing Credits @ Depreciation book rates		(1,645,002)	(7,780)		(1,652,782)
Deferred Manufacturing tax credit at December 31, 2020		(662,292)	(273,554)	D-1	(935,847)

D-4

THE BARBADOS LIGHT & POWER COMPANY LIMITED
D-4 CORPORATION TAX COMPUTATION

INCOME YEAR		**2020**		**2020**	
ASSESSMENT YEAR		**2021**		**2021**	
			Balance as Per Financial Statements		**Adjusted Balance**
			$		**$**
Profit before taxes as per Financial Statements			**28,394,073**		**18,779,124**
ADD:	Depreciation	52,706,598		57,629,372	
	Balancing charge	55,657		55,657	
	Provision not allowable:			-	
	- Increase in bad debt provision	300,000		300,000	
	- Increase in Obsolete Stock Provision	277,658		277,658	
	-Interest on Lease	(285,156)		(285,156)	
	(Gain)/ Loss on sale of fixed assets	(16,255)		(16,255)	
	- Deferred Investment tax credit	(1,377,331)		(1,377,331)	
	- Deferred Manufacturing tax credit	(662,292)		(935,847)	
			50,998,878		**55,648,098**
LESS:	Capital Allowances				
	- Annual	58,598,536		75,252,059	
	- Manufacturing	28,942,909		37,269,671	
	Balancing allowance	108,963		108,963	
	Lease Payment	59,500		59,500	
			(87,709,907)		**(112,690,193)**
	ADJUSTED TAXABLE (LOSS)/PROFIT		**(8,316,958)**		**(38,262,971)**
LESS:	**LOSSES B/FWD**		**-**		**-**
	TAXABLE PROFIT		**(8,316,958)**		**(38,262,971)**

D-5

THE BARBADOS LIGHT & POWER COMPANY LIMITED
D-5 STATEMENT OF DEPRECIATION EXPENSE

	Balance Per Financial Statements 2020 $	ADJUSTMENTS	Sch	TEST YEAR EXPENSE 2020 $
GENERATION				
GARRISON				
GAS TURBINE No. 2	552,414			552,414
SPRING GARDEN				
Steam Building	-			
Steam Equipment	4,583,902			4,583,902
Fuel Tank	54,452			54,452
LSD D10 - D13 - Building	-			
LSD D10 - D13 - Equipment	3,601,977			3,601,977
LSD D14 & D15 - Building	917,515			917,515
LSD D14 & D15 - Equipment	5,839,639			5,839,639
MSD CAT EQUIPMENT	1,326,809			1,326,809
SEAWELL				
Gas Turbine No. 3 Building	77,907			77,907
Gas Turbine No. 3	1,263,361			1,263,361
Fuel Tank- other	35,384			35,384
Gas Turbine No. 4	1,618,022			1,618,022
Gas Turbine No. 5	1,710,282			1,710,282
Gas Turbine No. 6	1,621,115			1,621,115
Trents				
Solar	1,999,027			1,999,027
BATTERY	1,548,007			1,548,007
Clean Energy Bridge	-	5,329,128		5,329,128
LSD A Spares	195,713			195,713
LSD B Spares	552,511			552,511
TOTAL GENERATION	**27,498,036**	**5,329,128**		**32,827,164**
SUBSTATION BUILDINGS	455,196			455,196
SUBSTATION EQUIPMENT	2,239,911			2,239,911
POLES & ACCESSORIES	3,713,519			3,713,519
OVERHEAD CONDUCTORS	1,273,386			1,273,386
UNDERGROUND CABLES	6,292,490			6,292,490
TRANSFORMERS	1,585,264			1,585,264
SERVICES	1,258,053			1,258,053
STREET LIGHTS	89,158			89,158
METERS	106,972			106,972
AMI Meters	2,384,951			2,384,951
LED Street lights	879,643			879,643
TOTAL DISTRIBUTION	**20,278,544**	**-**		**20,278,544**
BUILD - H/HALL & SP. GDN	152,098			152,098
BUILD - OTHER	517,719			517,719
TRANSPORT - HEAVY	335,590			335,590
TRANSPORT - LIGHT	199,232			199,232
FURNITURE & EQUIPMENT	842,713			842,713
COMPUTER EQUIPMENT	892,047			892,047
COMPUTER SOFTWARE	1,334,492			1,334,492
AMI Software	249,774			249,774
LAND	-			
TOTAL GENERAL PROPERTY	**4,523,665**	**-**		**4,523,665**
TOTAL	**52,300,244**	**5,329,128**	**D1**	**57,629,372**

D-6

THE BARBADOS LIGHT & POWER COMPANY LIMITED
D-6 STATEMENT OF INTEREST EXPENSES

	31-Dec-20	Adjustment	Ref	Test Year 2020
Finance costs				
Finance Charges	130,493	(130,494)	D-7-12	-
Bank Charges	(56,739)	56,739	D-7-12	-
Interest on customers' deposits	1,582,353			1,582,353
Interest on loans				
Scotia Bank USD Loan 4.5% repayable 2025	957,989			957,989
National Insurance Board - Debenture Stock Certificates 5.875% repayable 2025	1,171,156			1,171,156
Royal Bank of Canada 4.00% repayable 2022	195,167			195,167
Scotia Bank BBD Loan 2.25% repayable 2024	1,115,743			1,115,743
National Insurance Board - Debenture Stock Certificates 3.5% repayable 2040	776,304			776,304
Scotia Bank BBD Loan 2.05% repayable 2025	1,088,362	1,166,638	D-7-12	2,255,000
Subtotal	6,960,829	1,092,883	D-7-12	8,053,712
Interest during Construction	(1,088,362)	1,088,362		-
Total	**5,872,467**	**2,181,245**	**D-7-12**	**8,053,712**

D-7

EXPLANATIONS AND COMMENTS ON ADJUSTMENTS

The below information provides an explanation for the adjustments made by the Company to operating income.

REVENUE

	Miscellaneous revenue		**(279,571)**
1	Adjustment to exclude Battery Revenue		
	Heat Rate (Penalties)/Incentives		**(1,412,333)**
2	Adjustment to exclude Heat Rate (Penalties)/Incentives.		

OPERATING AND MAINTENANCE EXPENSES

	Insurance		**4,150,559**
3	Adjustment to increase in insurance cost due to increased premium		
	Depreciation		**5,329,128**
4	Adjustment to include annual depreciation charge related to the Clean Energy Bridge station.		
	Amortization of Lease		**(406,353)**
5	Adjustment to exclude the lease expense relating to the lease of land at Lamberts which is not included in rate base.		
	Generation Department		**(4,616,890)**
6	The Company recognizes certain costs incurred during the year as unusual and therefore not likely to recur in the foreseeable future. Accordingly, a series of adjustments have been made with the net impact of reducing generation expenses. These adjustments are detailed below –		
	a) Cost of generation rental	$	(9,601,349)
	b) GT01 expenses	$	(693,185)
	c) Other Aggreko expenses	$	(809,076)
	d) Normal usage of lubricants for LSB D15	$	1,700,000
	e) CEB Annual operating and maintenance expenses	$	4,786,719
	Total	**$**	**(4,616,890)**
	Finance Expense		**358,911**
7	Adjustment to transfer finance charges relating to amortizing debt issuance costs and bank charges to Finance expenses.		
	Taxes other than on income		**1,200,000**
8	Adjustment to include Land tax increase as a result of the improved value of the Land due to construction of the Clean Energy Bridge station and related substation.		
	Corporation Tax Expense		**490,927**
9	Adjustment to exclude amount relating to prior year taxes		
	Deferred Taxes		**(629,252)**
10	Adjustment to deferred Taxes resulting from the expected timing differences relating to the Clean Energy Bridge		
	Deferred Tax Manufacturing credit		**(273,554)**
11	Adjustment to exclude amount relating to prior year taxes		(460,279)
	Adjustment to include Clean Energy Bridge deferral		186,725
	Finance costs		**2,181,245**
12	Adjustment to include interest expense re CEB		2,255,000
	Adjustment to transfer finance charges relating to amortizing debt issuance costs		(130,494)
	Adjustment to transfer finance charges to Finance expenses		56,739

F

MEMORANDUM ON RATE OF RETURN

INTRODUCTION

Purpose of Fair & Reasonable Rate of Return

1. In order to maintain a high level of service, safety and reliability during the transition to energy from 100% renewable sources and a new electricity market structure, continued investment by The Barbados Light & Power Company Limited ("the Company") is required. This investment requires significant amounts of funding and one of the main objectives of this application is to ensure that customers receive the reliable supply of electricity they are accustomed to at reasonable rates. To achieve this objective the Company must 1) meet its expenses, 2) keep the confidence of its investors by providing them with a fair and reasonable return, and 3) satisfy lenders of its ability to repay the loans needed to run daily operations and to invest in new capital equipment required for the delivery of electricity service.

2. The rate of return serves to compensate investors for capital used to finance plant, equipment, supplies and other functions necessary to provide utility services. A utility's rate of return is considered as a measure of the utility's profitability and can be estimated by determining the utility's cost of capital.

Principles of a Fair Rate of Return

3. The rate of return is an essential element in the process of rate regulation. The overall return to be earned on a company's rate base is an important part of overall revenue requirement.

4. Two US Supreme Court decisions are today accepted by regulatory authorities as having provided the main standards and principles to be used for rate of return determination. The first decision is **Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia** 262 U.S. 679 (1923). In this decision the Court stated:

   "What annual rate will constitute just compensation depends upon many circumstances and must be determined by exercise of fair and enlightened judgment, having regard to all relevant facts. A public utility

> *is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public… The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties."*

5. The **Bluefield** case is accepted as having established the following general standards for a rate of return, namely, that (a) the return should be sufficient for maintaining financial integrity and capital attraction and (b) a public utility is entitled to a return equal to that of investments of comparable risks.

6. In the second case, that of **Federal Power Commission v. Hope Natural Gas Company** 320 U.S. 591 (1942), the Court stated that:

> *"The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks"*

The Court thus re-affirmed the earlier **Bluefield** standards.

7. Returns that adhere to these principles and standards accord with the fairness criterion that balances consumer and investor needs, and provide the means for the Company to fulfill its duties to the public. Good utility regulation recognizes that inadequate authorized return levels violate these criteria and essentially constitute the confiscation of the capital committed by investors.

<u>Realized Return on Rate Base for Test Year 2020 (Existing Rates)</u>

8. The Rate of Return on Rate Base realized by the Company under existing rates for the Financial Year 2020 using the audited financial statements prepared in accordance with International Financial Reporting Standards (IFRS), before adjustments was 4.23% and 3.31% after adjustments for known and measureable changes in the Test Year 2020, well below the allowed 10% determined in the 2010 decision.[1]

[1] https://www.ftc.gov.bb/library/blip_app/2010-01-22_commission_decision_No2_of_09_rate_review_barbados_light_and_power_company_limited.pdf

Requested Rate of Return on Rate Base

9. As part of its preparation for the filing of the Application the Company retained the services of and sought advice from its consultants, The Brattle Group (Brattle) to enable the Company to determine the overall Rate of Return on Rate Base for which it should seek the Commission's approval. Dr. Bente Villadsen of Brattle led the team which undertook the "Cost of Equity and WACC for BLPC" ("the Study") dated September 20, 2021. A copy of the Study is attached to the Affidavit of Bente Villadsen as Exhibit "BV2". Brattle analyzed and reviewed the relevant data and recommended conservatively that the Company should be permitted to earn an overall Rate of Return on Rate Base of 8.79%. This represents the Company's Weighted Average Cost of Capital (WACC) stated on a regulatory basis, including the weighted combination of the Company's cost rates for debt and other sources of funds, and a fair rate of return on equity (ROE).

10. The Company has, through its efforts to renegotiate existing loans and secure new debt, been able to achieve a Cost of Debt included in this WACC significantly lower than the Cost used in setting the existing Tariff which will benefit the customer. The Study provides a range and point estimate for the ROE and after-tax WACC for the Company. The Study evaluated the cost of capital for companies of comparable business risk by choosing a proxy group of publicly traded regulated electric utilities and adjusting for differences in financial risk. The Study also references a number of risks as detailed in paragraphs 13 and 14 of this memorandum faced by the Company, some of which can be mitigated by other regulatory mechanisms such as the proposed Clean Energy Transition Rider (CETR)[2]. If the CETR is approved, the rate of return recommended in the Study, is expected to enable the Company to fulfill its obligations to the public while providing the Company with an opportunity to meet its obligations to investors, including interest on its outstanding debt and a fair return on the capital committed by its equity investors. If the CETR is not approved, the rate of return requested would be higher due to the unmitigated risks.

[2] https://www.ftc.gov.bb/library/blip_app/cetr/2020-09-23_blanp_CETR_application.pdf

11. The Company's financial technical and other data were made available to Brattle to enable them to undertake the assignment. The Company is relying on Dr. Villadsen's evidence as the main expert witness on this aspect of the Company's application and the views expressed in this Memorandum have taken into account the matters discussed in the Study and the analyses, opinions, findings and conclusions therein. It is also relying on the knowledge and experience of the Company's management in the conduct of the Company's business.

12. The existing rate of return on rate base of 3.31% constitutes a significant shortfall for the Company when compared to the rate of return of 8.79% recommended as fair and reasonable in the Study. This shortfall is primarily driven by the growth in rate base over the last 2 years and the decline in electricity load in the last year.

Maintaining Shareholder Investment and Financial Risk Factors

13. Increasing globalization of capital flows means that investors can place capital worldwide. Investors benchmark various investment opportunities of comparable risks with respect to the expected returns obtainable elsewhere. The Company is operating within this investment environment and has to compete for funds accordingly. Unless investors are provided with reasonable, risk appropriate rates of return for the use of their capital, they are likely to invest elsewhere leaving the Company with fewer and more costly alternatives in its efforts to raise the required capital.

14. The Company's unique collection of risks that it faces both in normal operations and in emerging circumstances is important because it heavily influences the degree of financial strength and flexibility that it requires. It is therefore an important determinant of the appropriate capital structure to employ and the level of ROE required in providing adequate financial strength and a fair return to investors. The main financial risks facing the Company can be grouped into the following broad categories:

    (a) Capital expenditures and future revenues - As demonstrated in the Memorandum on Five Year Financial Forecast and The Memorandum on Capital Expansion 2021 – 2025 submitted with this application, significant reinvestment and in some instances, new investment in plant is required to support the transition to generation from RE sources and other policy objectives over the period 2021 to 2025. Investments of this size, while from a customer and policy perspective are valuable, increase the risk profile from an investors' perspective as recovery is dependent on increased future revenues. It is assumed that the risk of untimely rate adjustments causing under recovery of a fair and reasonable return is mitigated through the approval and implementation of the CETR;

(b) Island grid system and infrastructure including generation mix, fuel supply and access to energy markets – The Company operates on the island of Barbados, a relatively small island system isolated from any other grid, largely dependent on imported fossil fuels for firm capacity and imported supplies of parts and certain services to maintain its plant. This island reality and small size constrains its access to sources of fuel, other materials and certain labour in meeting its critical reliability requirements given no access to electricity from any other market, which translates into increased risk from an investor perspective. The Fuel Clause Adjustment (FCA) moderates without eliminating risk to investors. The FCA is most useful in mitigating fuel price risk, however the Company retains the risks associated with access to the appropriate fuels in sufficient quantities, quality, timing, storage and associated liquidity risk with the fuel. While the Company has a strong track record of managing these risks, the high cost of fuel and other materials and the liquidity required, highlights the importance of the need for financial strength;

(c) Climate and weather such as tropical storms - As an island in the Caribbean, Barbados is highly susceptible to damage from a Tropical Storm or other weather related event with potentially devastating impacts to load and assets. The Company must maintain sufficient liquidity or access to credit to fund initial storm response and survive the effects of reduced load during restoration. The Company has taken several steps over the years to harden its network in key areas which is expected to help mitigate any potential storm damage. The Company has also developed other risk mitigation strategies such as purchasing insurance from rated institutions and where not available, establishing a self-insurance reserve to cover those assets not otherwise insured;

(d) Increased penetration of Independent Power Producers - The Barbados National Energy Policy 2019 – 2030 (BNEP) and supporting legislation create an obligation for The Company to be the off taker from all Power Purchase Agreements. This creates significant credit risk and working capital risk for the Company;

(e) New energy market structure - The Company is currently a vertically integrated utility operating under one licence which expires in 2028 and grants a franchise to generate, transmit and distribute electricity on the island. In 2019, the Government of Barbados passed legislation amending the number of licenses required for the supply of electricity from a single integrated license which currently exists to multiple licenses for Generation, Storage, Transmission and Distribution, Sales and Dispatch. The terms of the draft licences introduce significantly more risk to the investor than the single licence under which the Company currently operates. Changes of this nature have the unintended consequence of destabilizing the confidence of the investors and causing them to require a higher return due to higher risk;

(f) Dependence and access to foreign currency – The Company is heavily dependent on access to foreign currency to pay for imports of non-fuel materials and certain labour as many of the Company's suppliers will not accept Barbados currency to pay for goods and services. The Company does not earn any currency other than Barbados currency which creates an additional risk to its operations. The Company is only able to access foreign currency with the permission of the Central Bank of Barbados. The Company's access to foreign currency is limited to the levels available in the Barbados economy. Should the levels not be sufficient at the time, the Company's ability to meet its obligations would be challenged. In the recent past, several commentators have expressed concerns about the adequacy of foreign currency in the Barbados economy and certain financial institutions have declined to offer the Company debt financing denominated in US currency.

Revenue Requirements

15. The Company's revenue for the 2020 Test Year, adjusted for known and measureable changes, is calculated at $393,765,062.[3] The Company is requesting an increase of $46,475,310 in base revenue. If this request is granted it will provide the Company with the opportunity to earn the requested rate of return of 8.79%, which the Study has concluded is a fair and reasonable return on rate base.

SOURCES OF FUNDS

16. As approved in the FTC's 2010 Decision, the Company's present sources of funds, used in the Cost-of-Capital computation, include debt, customer security deposits, shareholder equity and 'non-traditional' elements of Deferred Tax Credits. The Deferred Tax Credits include Deferred Investment Tax Credit and Deferred Manufacturers' Allowance. These funds have been "costed" in the Study at the calculated WACC, stated on a traditional basis before the inclusion of these regulatory capital elements.

COST OF DEBT

Company's Cost of Debt

17. The Company's application is based on a cost of 2.78% for the Company's outstanding long-term debt as calculated in the Study. This cost is significantly lower than the cost of debt used in determining the existing tariffs. It was derived from the actual interest on the Company's long-term debt, which carried a balance at the end of 2020 of $228.8 million ($195.7 million drawn at end of 2020 and a further $33.1 million committed but not yet drawn at end of 2020 expected to be drawn in 2021 related to the construction of the Clean Energy Bridge) as shown in the Study.

[3] Income Statement for Year Ending December 31, 2020 - Schedule D-1

RETURN ON EQUITY

Determination of the Equity Capital

18. The application for a review of electricity rates is made against the background of the accepted regulatory principle that investors should be allowed the opportunity to earn a ROE comparable to what they could earn on other investments of similar risk.[4] While the cost rate for debt can be directly observed, the ROE cannot be so easily discerned, and must therefore be estimated. The Study applies capital valuation methods as set forth by and defined within the longstanding principles of financial economics.

Cost of Capital Methodologies

19. Formal cost of capital models are most useful when applied to capital markets that satisfy standards of transaction and information efficiency, and liquidity depth. Accordingly, the Study draws upon the experience of publically traded regulated electric utilities with comparable business risk (sample or proxy group). Due to insufficient data on Caribbean utilities, data from US electric utilities was used and a group of U.S. natural gas local distribution companies was used as a sensitivity to check the reasonableness of the US electric utility sample. The Study applies three models to analyze the cost of equity for the Company: (1) the Capital Asset Pricing Model (CAPM) as well as an Empirical version hereof, the ECAPM, (2) Discounted Cash Flow (DCF) models, and (3) Risk Premium. The models use data from the sample, where such returns serve as a basis for the expected level of future earnings performance. Model results obtained from the sample are then adjusted for factors that account for differences in risk between the cost of equity capital for the Company and the sample, such as to reflect the effect of capital structure on the cost of equity and other risks.

Cost of Capital - Results of Analysis

20. The cost of equity estimates resulting from the Study range from 10.0% to 14.5%. The Study further recommends that, given the unique business risk

[4] Federal Power Commission v. Hope Natural Gas Company (320 U.S. 591, 1944)

factors faced by the Company it should be placed in the upper half of the range of 12.25% to 13.25%.

Recommended Cost of Equity

21. The Study recommends an ROE of 12.5%. Assuming the CETR application is successful and it is used to contain some of the existing business risks, this ROE level is considered reasonable for the capital committed by equity investors in the Company given the other risks and is incorporated in the Company's WACC of 8.79%.

DIVIDEND PAYOUT

Dividend Payout Ratio

22. The existing tariff was determined based on a capital structure of Debt 35% and Equity 65%[5]. This capital structure differed from the actual capital structure of the Company, at that time, of approximately Debt 20% and Equity 80%. The Company has made efforts to transition its capital structure closer to the approved structure by raising debt to fund new investments and making reasonable dividend payments over the period. The dividend payout ratio has varied through the years, with an average of about 86% since 2009.

Dividend – 2020 Test Year

23. As shown in Schedule O, Statement of Dividends, the Company did not pay a dividend for the 2020 Test Year. This was due to the prevailing economic circumstances.

CAPITAL STRUCTURE

Debt / Equity Ratio

24. The Debt / Equity (D/E) ratio of the Company has varied over the years, and at the end of 2020 the Company's capital structure was made up of 26% debt and 74% equity with committed but undrawn debt of $33.1 million related to the

[5] Paragraph 2 of part 5 of the 2010 order

Clean Energy Bridge. After taking account of the committed but undrawn debt of $33.1 million related to the Clean Energy Bridge this moves to 29% debt and 71% equity. As discussed below, the Study and the WACC proposed in the Company's filing incorporates lower equity participation of 65% for regulatory purposes, which adjusted to include other 'non-traditional' sources of capital, works out to be 58.72%.

Future Borrowing Needs

25. The Company is entering a period during which significant investment in plant will be required to facilitate the transition to electricity from 100% RE sources and to maintain a safe reliable supply of electricity for customers. It is anticipated that the Company's debt will increase during the period covered in the Financial Forecast[6]. The present capital structure would not be appropriate in calculating the WACC and the Company has therefore used a capital structure that better matches the Debt / Equity ratio for the period during which the proposed new tariffs will apply.

Proposed Capital Structure for Ratemaking Purposes

26. In the 2010 Decision, the Commission approved the use of a capital structure for rate making purposes of 35% debt and 65% equity. The Company considers this to still be reasonable and has therefore used a capital structure of 35% Debt and 65% Equity in the calculation of the Weighted Average Cost of Capital. This results in an effective lower overall cost of capital than if the 2020 actual capital structure is used. This will be of benefit to ratepayers. The Company therefore seeks the approval of the Commission for the proposed capital structure to be used in the determination of the Rate of Return.

WEIGHTED AVERAGE COST OF CAPITAL - RETURN ON RATE BASE

Weighted Average Cost of Capital

27. The WACC is calculated using the cost of debt, the expected ROE, and the proportion in which these sources of funds are used in the overall capital structure of the Company. For a regulated electric utility this is equivalent to

[6] Financial Forecast based on Proposed Rates - Schedule L2

the Rate of Return on Rate Base that the utility should be achieving to meet its obligations to its lenders and shareholders.

Weighted Cost of Capital – Existing Capital Structure

28. Using strictly long-term debt and equity and the Company's actual capital structure for 2020 would result in a WACC of 9.66%, as shown in **Table F.1**.

Table F.1

WEIGHTED AVERAGE COST OF CAPITAL FOR ACTUAL CAPITAL STRUCTURE Based on 2020 Balances

Capital Component	Balances ($ 000)	Cap Share	Cost Rate	Weighted Cost
Long Term Debt	228,825	29%	2.78%	0.81%
Common equity	553,985	71%	12.50%	8.85%
	782,810	100%		9.66%

Revised Capital Structure

29. However, since the Company's request is based on a 35% / 65% Debt to Equity ratio this capital structure is used in place of the capital structure based on 2020 balances. As can be seen below, reducing equity participation from 71% to 65% lowers the WACC by approximately 0.56%, as shown in **Table F.2**. This effectively reduces the requested revenue requirement by approximately $4.6 million.

Table F.2

WEIGHTED AVERAGE COST OF CAPITAL FOR ADJUSTED CAPITAL STRUCTURE Based on 2020 Balances

Capital Component	Balances ($ 000)	Cap Share	Cost Rate	Weighted Cost
Long Term Debt	273,983	35%	2.78%	0.97%
Common equity	508,827	65%	12.50%	8.13%
	782,810	100%		9.10%

Other Adjustments

30. An adjustment has also been made for other sources of capital. Customer deposits held to secure electricity accounts are included at cost. The cost of

customer deposits was reduced from 8% to 3.5% with approval from the Commission. The inclusion of non-traditional elements such as the manufacturers' allowance, when "costed" at the debt/equity-based WACC level, results in a slightly lower overall WACC of 8.79% as shown in **Table F.3** which is taken from the Study.

Table F.3

RATE OF RETURN RECOMMENDATION FOR 2020
WEIGHTED AVERAGE COST OF CAPITAL FOR
PROPOSED REGULATORY CAPITAL STRUCTURE
Based on Total 2020 Balances

	Amount (BDS$)	Share (%)	Cost Rate	Weighted Cost Rate
Equity	508,826,918	59%	12.50%	7.34%
LT Debt	273,983,725	32%	2.78%	0.88%
Customer Deposits	47,401,616	5%	3.50%	0.19%
Deferred Investment Tax Credits	17,232,462	2%	9.10%	0.18%
Deferred Manufacturing Tax Credits	19,078,160	2%	9.10%	0.20%
Total	866,522,880			8.79%

`

CONCLUSION

31. The WACC for the Company as determined by and recommended in the Study is 8.79%. The Company is requesting that this be used as the Rate of Return on Rate Base for the purpose of setting electricity prices.

Dated this 30th day of September, 2021

Paper prepared by: Ricaido Jennings

Ricaido Jennings
Director Finance
The Barbados Light & Power Company Limited

G

MEMORANDUM ON REVENUE REQUIREMENT

1. The revenue requirement is the total amount which must be billed and collected in rates from utility customers for the utility to recover its costs and earn a fair and reasonable return. The formula applied to determine the Company's revenue requirement is the same formula that was applied in the Fair Trading Commission's ("Commission") 2010 rate decision. Consistent with the last rate review, the Company's revenue requirement has been developed with the intent to provide an opportunity to recover its prudently incurred costs for providing utility services and to earn an appropriate return on invested capital, including a fair return on equity. The revenue requirement has been determined based on the following rate-making formula and its components:

   Rate Base
   x Allowed Rate of Return
   = Operating Income (Required Return)
   \+ Operating Expenses, Depreciation and Taxes
   = Revenue Requirement

2. The Company's determination of its revenue requirement, based on the 2020 test year, is set forth in Schedule G-1.
   - Rate base is calculated as shown in Schedule C-1 and is discussed and described in the "Memorandum on Rate Base." The proposed rate base is $ 825,891,134.
   - The Company's requested overall rate of return of 8.79% is calculated as shown in Schedule F. An overview of its components is given in the "Memorandum on Rate of Return," and also addressed in the affidavit of Dr. Bente Villadsen in support of this application.
   - Operating income of $72,610,495 is calculated as shown in Schedule G-1, and corresponds with the amount of operating income set forth in Schedule D-1, in the adjusted test year income statement column for the revenue requirement increase.
   - Test year operating expenses, depreciation and taxes total $367,629,877, an overview of which is given in the "Memorandum on Income Statement" and shown in Schedule D-1.

3. Adjustments to the test year income statement to reflect the increase in revenue requirement and related charge in income taxes are set forth in Schedule G-1.

4. Test year revenues on existing rates of $393,765,062 are set forth in Schedule D-1. The revenue requirement of $440,240,372, required to support a rate base of $825,891,134 and the resulting revenue requirement deficiency, which is $46,475,310, are both set forth in Schedule G-1.

5. This Memorandum and related revenue requirement schedule may contain rounding differences.

Dated this 30th day of September, 2021

Paper prepared by:

Ricaido Jennings

Ricaido Jennings
Director Finance
The Barbados Light & Power Company Limited

G–1

THE BARBADOS LIGHT & POWER COMPANY LIMITED
G-1 Statement of Revenue Requirements

	Ref	$
Proposed Rate Base	C-1	825,891,134
Proposed Rate of Return (ROR)	F-1	8.79%
Operating Income required		72,610,495
Proposed Operating Expenses, Depreciation & Taxes	D-1	367,629,877
Total Revenue Required	D-1	440,240,372
Current revenue	D-1	393,765,062
Requirement deficiency grossed up for taxes	D-1	46,475,310
Current rate of return		
Rate Base		825,891,134
Current operating income		27,300,331
Current rate of return		3.31%
Current Operating Income	D-1	27,300,331
Required Operating Income	D-1	72,610,495
Additional revenue required before tax		45,310,164
Proof		$
Additional revenue required		46,475,310
Less Income Tax		271,370
Less Deferred Income Tax		893,776
Net operating Income Deficiency		45,310,164
% Increase in Revenue Requirement		11.80%

H

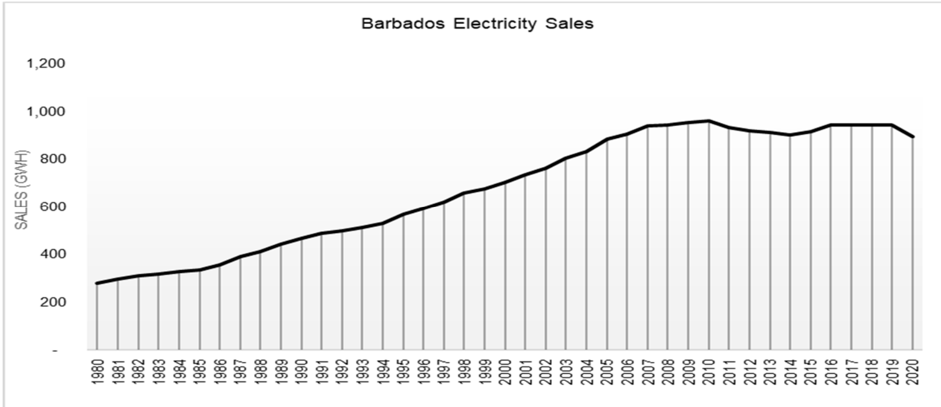
MEMORANDUM ON SALES PROJECTIONS

1. The Barbados Light & Power Company Limited ("the Company") has prepared electricity sales projections over the period 2021 to 2025. These projections serve as the Company's best estimate of future electricity sales and forms the basis by which total energy required to serve customers and the associated revenues and expenses are estimated.

2. The outcome of electricity sales is largely influenced by growth in output within the general economy. The growth in economic output is combined with other variables known to drive electricity sales over the short and long run, namely population growth, average temperatures and fuel prices. The historical relationships between sales growth and these variables are quantified using regression analysis. These estimated relationships are then used to project sales into the future based on the expected future evolution of the key sales drivers. The statistical approach is also complemented by analysis of historical sales growth trends, such as the growth in renewables and utilization of more energy efficient solutions. The analysis assumes the current Buy All/Sell All billing arrangement for customer owned renewables and takes into account any known and anticipated future trends expected to impact sales growth, but not captured in the aforementioned variables.

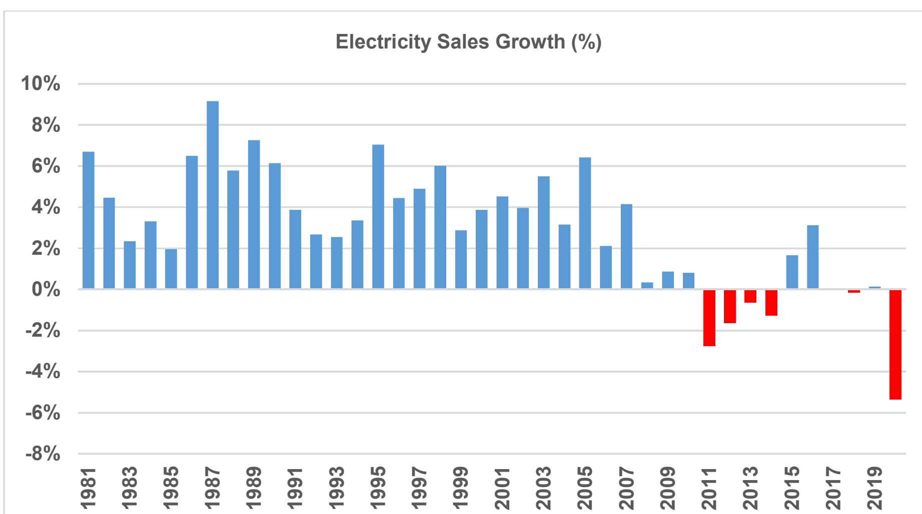
3. The historical growth of electricity sales in the last four decades is characterized by two distinct periods, 1980 to 2010 and 2011 to 2020. During 1980 to 2010, sales growth was steady and sustained, reaching a high of 960 Gigawatt hours (GWh) in 2010. In contrast, there has been no consistent growth since 2010. This outcome followed from prolonged recessionary conditions caused by the global financial crisis in 2009. After declining in 2011, 2012, 2013 and 2014, sales began to recover in 2015 and 2016; however, by the end of 2019 sales had not recovered to the highs recorded in 2010. Moreover, sales at the end of 2020 were 7% lower compared to 2010 due to the impact of the COVID-19 national lockdown and the subsequent recession in 2020. Figure H.1 shows electricity sales in GWh for each year since 1980.

Figure H.1



4. In Figure H.2, the percentage growth rates of electricity sales over the period 1980 to 2020 are presented. The evolution of sales over the last ten years is evident when viewed through the lens of growth rates. Sales increased every year prior to 2010 but have only shown growth in two out of the last ten years. This pattern is consistent with economic growth trends in the country. Following a brief recovery in 2015 and 2016, economic growth stagnated in the next two years following the Government's introduction of additional fiscal adjustment measures in 2017 and the implementation of the International Monetary Fund's Extended Arrangement in 2018. In 2020, sales declined by 6.1% following the negative economic impact of the COVID-19 pandemic.

Figure H.2



5. The steady growth of electricity sales observed over the period 1980 to 2010 was reflected across each of the major customer tariff groups. The decline of sales since 2010 was driven by declines in the General Service, Secondary Voltage Power and Large Power tariff groups. Electricity sales to the Domestic Service customers was the only major tariff group to increase on average after 2010, albeit at a reduced rate compared to pre-2010. Table H.1 shows the ten-year annual-average percentage growth rate of total sales and sales by major tariff group over the review period 1980 to 2020.

Table H.1:

Period	Domestic Service	General Service	Secondary Voltage Power	Large Power	Street Lighting	Total
1981-1990	5.7%	0.3%	7.8%	3.9%	3.9%	**5.2%**
1991-2000	4.9%	4.3%	5.8%	1.7%	3.7%	**4.2%**
2001-2010	2.8%	6.7%	3.6%	2.3%	2.2%	**3.2%**
2011-2020	1.2%	-1.9%	-1.7%	-3.1%	-1.9%	**-0.7%**

6. The data shows the Company experienced weak sales growth over the last decade, which was further compounded by the ongoing COVID-19 pandemic. The Company's expectation of future economic growth and its impact on electricity sales is conservative, and aligns with the Central Bank of Barbados' guidance that there is increased uncertainty regarding a post COVID-19 economic recovery. The Central Bank of Barbados, in its recent [1]Review of the Barbados' Economic Performance, January to June 2021, provided the following economic outlook:

> ***"Given the uncertainty associated with global developments, the Bank has left its economic growth forecast unchanged at between 1.0 percent and 3.0 percent for 2021.***
>
> ***This outlook hinges on the speed of the recovery in tourism and the reports of planned increased airlift over the next six months to cope with pent-up demand for travel bodes well for energising a strong but gradual recovery. However, the environment remains hostile with new virus mutations and the continued uneven distribution of vaccines across the world. There are other downside risks that have to be managed. For example, Barbados has recently been placed on the "green list" of our largest source market for tourists, the United Kingdom, thus exempting***

[1] Schedule H.1 "Review of Barbados' Economic Performance – January to June 2021"

visitors from having to quarantine after they return from Barbados. Retaining this status requires us to continue to manage the virus through careful observance of the health protocols, thus minimising risk to ourselves while providing confidence to potential visitors that the exempt status will not be subject to a sudden change."

7. The future growth in electricity sales over the period 2021 to 2025 was estimated by econometric models. The models provide statistical estimates of the historical relationship between electricity sales and key predictors of sales growth. The estimates of electricity sales are projected into the future by making assumptions about the future evolution of these predictors.

8. The predictors of sales growth comprised of economic trends as measured by Gross Domestic Product (GDP), total population, temperature and fuel prices. Assumptions on the future growth of GDP and total population for 2021 to 2025 are obtained from the International Monetary Fund's World Economic Outlook Database. The evolution of the average temperature over the forecast period is based on a 30-year moving average of past temperature readings for Barbados obtained from the Barbados Meteorology Department. Future fuel prices are tied to the long-term Energy Information Administration (EIA) projections of international fuel prices.

9. The relationship between electricity sales and the predictors is modelled for the individual customer tariff categories and aggregated to provide a forecast of total electricity sales.

10. The econometric models used to project electricity sales are variants of the following equation:

$$\Delta S_{it} = \alpha_{it} + \beta_{ij}\Delta S_{i,t-j} + \gamma_{ij}\Delta GDP_{i,t-j} + \delta_{ij}\Delta TEMP_{i,t-j} + \varphi_{ij}\Delta FPRICE_{i,t-j} + \rho_{ij}\Delta POP_{i,t-j} + v_{ij}$$

where Δ is the first difference operator, i is the individual tariff group, j is the number of lags, v is the error associated with the model and α, $\beta, \gamma, \delta, \varphi$ and ρ are the regression coefficients from a time series regression of sales on a constant, past sales, real GDP, average temperature, fuel price and population growth.

11. A growth assumption employed in the modeling over the forecast period are summarized in Table H.2.

Table H.2. Key Forecast Assumptions

Variables	Average Annual Values 2021-2025
Temperature ……………………………….……….	0.1%
Economic Growth …………………………….…..……	4.3%
Fuel Prices ……………………………………….….	10.0%
Population Growth ………......................……..........	0.3%

12. In Table H.3 the results from the econometric models that formed the basis of the forecast of electricity sales for the period 2021 to 2025 are shown as well as the actual electricity sales for 2019 and 2020.

13. The statistical analysis is also complemented by analysis of historical sales growth trends, such as the steady growth in use of renewable energy in response to Government of Barbados policies, the electrification of transport and the steady utilization of more energy efficient solutions.

14. Electricity sales are forecasted to remain flat during 2021 as the COVID-19 pandemic continues to have a major impact on tourism and its related economic activities in the economy. Gradual recovery is projected during 2022 as travel restrictions ease and travelers regain confidence once vaccinated, but the projected growth is expected to be uneven among customer categories.

15. The Company projects that electricity sales will not return to pre-COVID-19 levels before 2023 for General Service customers, or even 2025 for the Secondary Voltage Power and Large Power customers, when the econometric models assume a return to typical tourism activities and stronger economic recovery. The forecast assumes an accelerated lifting of domestic and international travel restrictions in 2021. However, new waves and variants of the COVID-19 virus and the speed and actual efficacy of vaccinations are concerns to the Company's outlook for the growth of electricity sales. This is reinforced by the Company's actual sales over the period January to August, 2021 which declined by 1.1% when compared to the same period for 2020.

Table H.3 Sales Projections

	2019 Actual	*2020 Actual*	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast
			Electricity Sales (GWh)				
Domestic service	327.2	345.2	350.5	350.1	352.4	355.8	360.7
General service	53.9	50.0	48.9	50.5	51.7	52.9	54.0
Secondary Voltage Power	325.2	286.3	284.6	306.4	313.9	317.2	321.9
Large power	203.7	166.2	167.0	178.6	180.3	181.6	184.6
Time of use	26.3	32.6	33.4	35.7	36.1	36.1	36.5
Employees	1.7	1.9	1.9	1.9	1.9	1.9	1.9
Streetlights	9.7	7.8	7.9	7.9	7.9	7.9	8.0
Total Electricity Sales	**947.7**	**889.9**	**894.3**	**931.1**	**944.1**	**953.4**	**967.6**
			Growth Rate (%)				
Domestic service	2.9%	5.5%	1.5%	-0.1%	0.6%	1.0%	1.4%
General service	-1.6%	-7.3%	-2.2%	3.3%	2.4%	2.2%	2.2%
Secondary Voltage Power	-0.3%	-12.0%	-0.6%	7.7%	2.4%	1.1%	1.5%
Large power	-0.1%	-18.4%	0.5%	6.9%	0.9%	0.7%	1.7%
Time of use	-5.5%	24.2%	2.4%	6.8%	1.1%	0.1%	1.0%
Employees	-0.1%	8.1%	1.9%	-1.1%	-0.4%	0.7%	1.1%
Streetlights	-3.3%	-18.9%	1.2%	0.1%	0.1%	0.0%	0.7%
Overall Sales Growth	**0.5%**	**-6.1%**	**0.5%**	**4.1%**	**1.4%**	**1.0%**	**1.5%**

16. In summary, electricity sales were 947.7 GWh in 2019 and 889.9 GWh in 2020 and the Company projects sales to be 894.3 GWh in 2021, 931.1 in 2022, 944.1 in 2023, 953.4 in 2024 and 967.6 in 2025.

Dated this 30th day of September, 2021

Paper prepared by:

Adrian Carter
Manager, Regulatory Affairs
The Barbados Light & Power Co. Ltd.

H-1

000760

Press Release

Review of Barbados' Economic Performance

January to June 2021

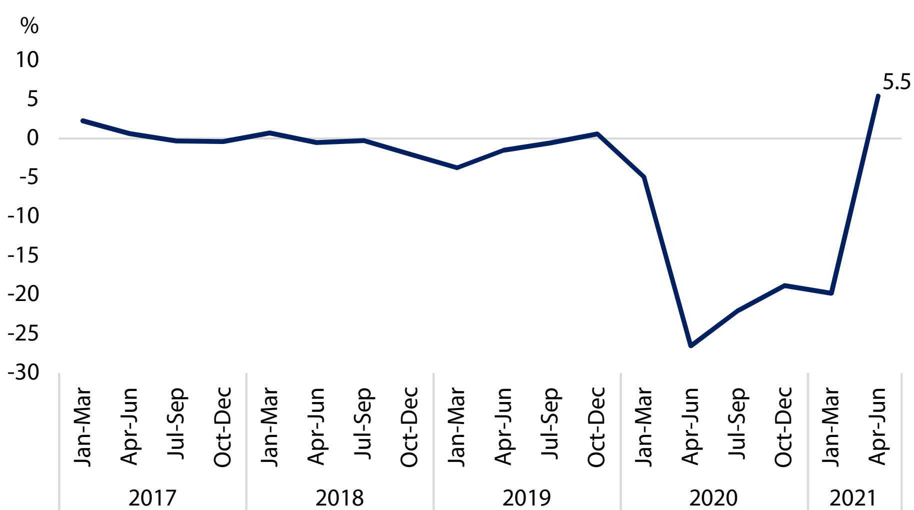
Overview

The performance of Barbados' economy continues to be restrained by the protracted global presence of the COVID-19 pandemic. The uncertainty created by the high incidence of COVID-19 cases at home and in our key source markets for tourism, international travel restrictions, and the "National Pause" in February have dampened economic activity.

However, following the sharp decline during the preceding twelve months, preliminary data suggests that the economic recovery has started. With the on-going weakness of the tourism industry, the non-traded sectors which were particularly hard-hit in the corresponding quarter a year ago served as the principal source of modest growth during the second quarter. Despite these gains, private spending remains well below pre-COVID levels.

The recent ash-fall from the eruption of La Soufrière volcano and the passage of Hurricane Elsa have further demonstrated our vulnerability to external shocks and resulted in unplanned fiscal costs. Government has relaxed its fiscal policy stance to cushion the adverse economic effects of the pandemic by supporting efforts to safeguard lives and livelihoods but it will need to adapt its programme so as to cope with these emerging challenges.

Figure 1: Quarterly Real GDP Growth



Sources: Barbados Statistical Service and Central Bank of Barbados

Economic Activity

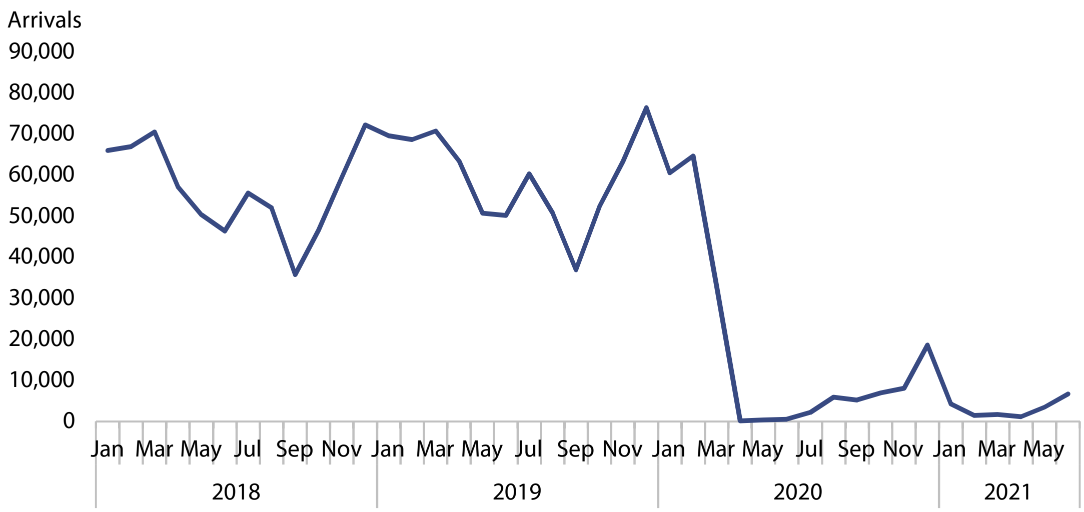
The economy grew by an estimated 5.5 percent during the second quarter, indicative of an emerging mild recovery. The improved performance between April and June reflects the gradual easing of travel restrictions and higher domestic private sector spending relative to last year when the economy was under lockdown for much of the quarter. However, the moderate growth was not enough to offset the very weak performance of the tourism sector in the first quarter and preliminary indicators suggest that activity for the first half of the year was 9.0 percent lower than for the same period in 2020.

Tourism

Activity in the tourism sector remains subdued. In the second quarter, a partial resumption of airlift facilitated 11,289 long stay tourist arrivals compared to only 980 tourists for the corresponding period a year earlier. Prolonged travel restrictions, especially in the UK, due to the rising cases of the highly contagious Delta variant of COVID-19, coupled with on-going uncertainty as it relates to travel protocols, served to temper the budding recovery. The modest increase in arrivals were not sufficient to offset the virtual absence of visitors in the first quarter, however, and arrivals for the first half of the year were 88 percent lower than for the same period of 2020.

The Welcome Stamp programme continued to attract new remote workers, contributing to economic activity through real estate rentals and spending on other ancillary services. With the low influx of tourists, the hotel sector suffered from low occupancy and revenues, but some properties benefitted from their use as quarantine facilities and from the local demand for staycation packages. Some hotels and restaurants took the opportunity to effect renovations during the down period, in preparation for offering enhanced service as tourism returns.

Figure 2: Monthly Tourist Arrivals as at June 2021



Sources: Barbados Statistical Service and Barbados Tourism Marketing Inc.

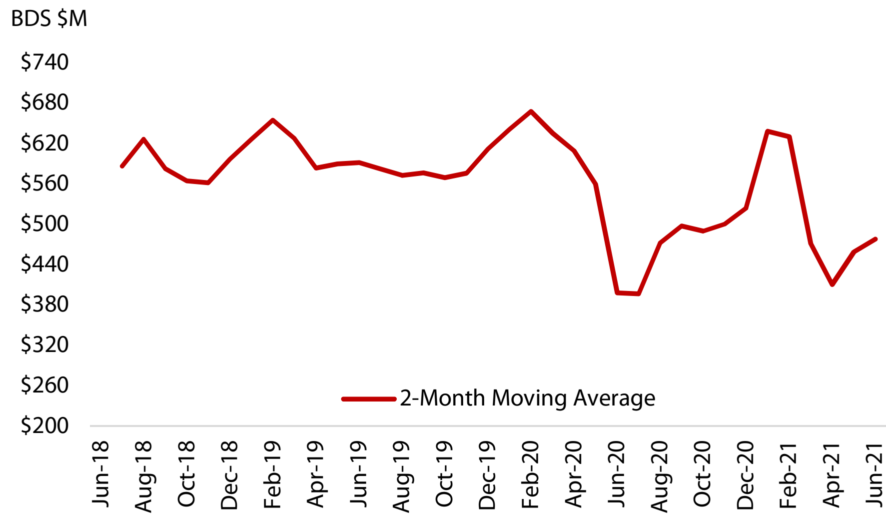
Other Traded Activity

Other traded activity expanded on the strength of improved manufacturing output. The higher production partly reflects better export penetration by the rum, other beverages, and electronic components subsectors. Agricultural output was lower for the six-month period, the result of reduced demand for chicken, particularly from the tourism industry. In addition, food crop production, which was hindered by the ashfall and interruptions from the "National Pause" also suffered a small decline. Milk production increased over the period, as output benefitted from the importation of cows during the last half of 2020. The sugar cane harvest registered better yields, but the shift towards the production of better-quality molasses led to lower sugar production.

Non-Traded Activity

The non-traded sector registered a partial recovery during the second quarter, reflecting an upturn in the retail and general business services sectors that were hard-hit by the lockdown in 2020. The "National Pause" in the first quarter slowed construction activity, but the continuation of projects related to the upgrade of the hotel infrastructure, road works, the Grantley Adams International Airport runway repaving project, the Sagicor Retirement Village and other small-scale projects boosted the sector between April and June.

Figure 3: Sales by VAT Registrants – Wholesale and Retail



Source: Barbados Revenue Authority

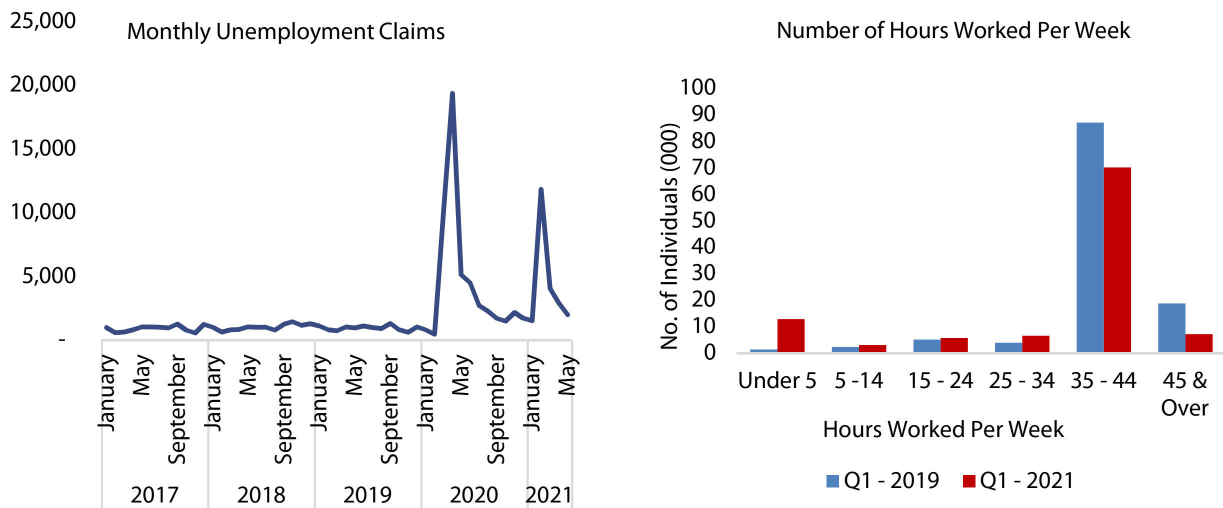
Labour Market

The weak economic activity continued to place pressure on employment levels. The most recent estimate of the Barbados Statistical Service is that during the first quarter when the economy was under the "National Pause", 105,700 persons were employed and the unemployment rate was 17.2 percent compared to 13.6 percent at the end of 2020. Some displaced workers have returned to work but, given the level of activity over the past year, there has been increased incidence of part time work.

The NIS continues to play a central role in helping to stabilise the situation. During the first 12 months of the crisis, claimants for NIS unemployment benefits received payments estimated at almost 14 weeks on average. New unemployment claims for 2021 spiked in February, but for the first six months of 2021 they were over 10,000 fewer claims than for the same period in 2020. The greater share of applicants was in the tourism sector as the renewed restrictions early in the year dampened the prospects of a robust recovery for the sector.

The continued implementation of the Barbados Employment and Sustainable Transformation (BEST) programme for workers in the tourism sector contained new claims from that sector. In the circumstances, wage rates have been frozen, but low-income workers received a boost to their incomes when government introduced an economy-wide minimum wage rate of $8.50 per hour.

Figure 4: Monthly Unemployment Claims[1] and Individuals' Number of Hours Worked Per Week



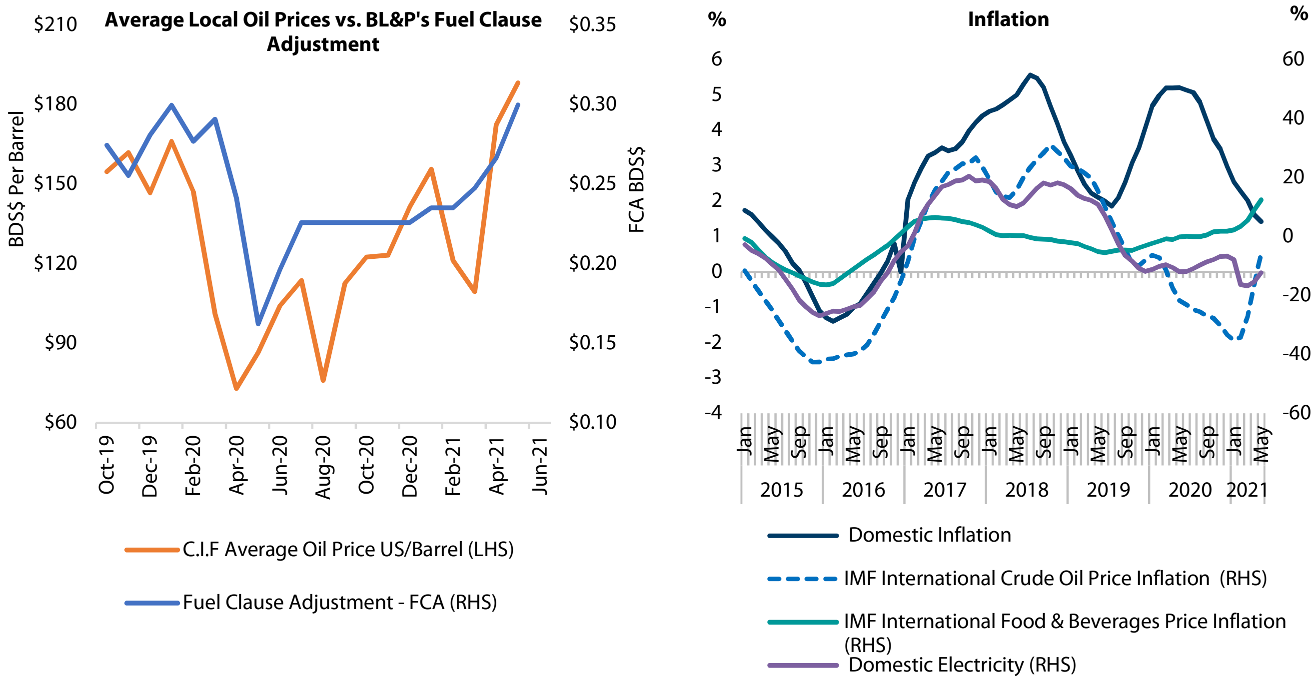
Sources: National Insurance Scheme and Barbados Statistical Service

Prices

As at May 2021, the 12-month moving average inflation rate was estimated at 1.5 percent. Food prices, especially for vegetables, were responsible for an upward trend in inflation over the last half of 2020. However, this direction has slowed during the first half of 2021. In addition, over the past twelve months, on average there have been price declines for other categories of non-food spending, including clothing, household furnishings, electricity and transportation costs which together represent almost 47 percent of the retail price index. Some of these lower prices can be linked to increased discounting by businesses as they adapted to the COVID-19 environment.

[1] Monthly unemployment claims reflect data up to May 2021.

Figure 5: Average Local Oil Prices vs. BL&P's Fuel Clause Adjustment and Inflation

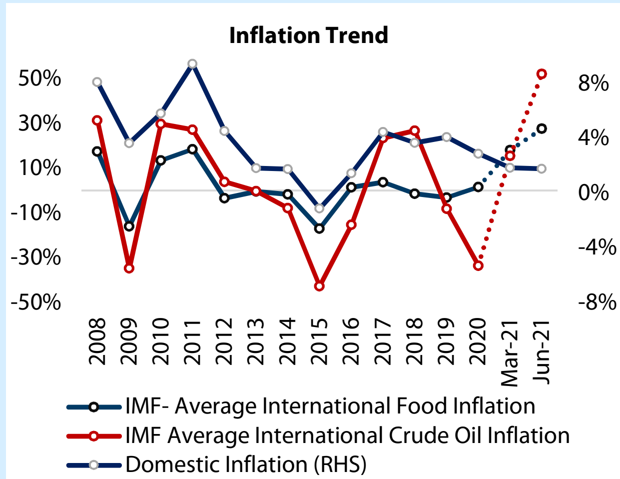


Sources: Barbados National Oil Company (BNOC), Barbados Light and Power Company, Barbados Statistical Service and International Monetary Fund Primary Commodity Prices

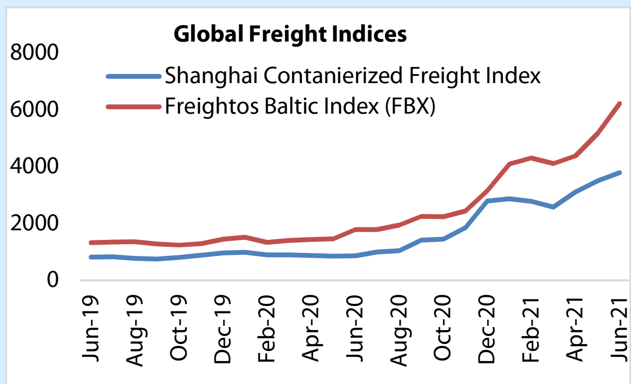
In addition, the sharp fall in oil prices in 2020 lowered electricity and transportation costs. However, in recent months, a resurgence of prices for imported oil has started to reverse this trend and prices are now returning to the pre-COVID level. The increase in fuel prices will likely impact energy intensive enterprises in the transportation sector but the Transport Board's transitioning to electric buses is expected to mitigate the impact on that entity.

Trends in International Commodity Prices

According to the World Bank[2], the impact of COVID-19 on commodity markets was felt acutely on energy prices, reflecting the pandemic's effect on global economic activity, including the demand for tourism and travel. Crude oil prices declined dramatically in 2020, falling by 33.4 percent, the largest decline in such prices since 2015. This sharp fall occurred despite the supply cuts announced by OPEC and reduced drilling activity in the United States.



In contrast, international food prices increased by 2.0 percent despite weakened demand for commodities such as vegetable oil, sugar, wheat, maize and rice. In most cases, labour shortages[3], export restrictions and logistical bottlenecks were responsible for the relative stability of food commodity prices during 2020.



However, in 2021, promising global growth prospects resulted in rising commodity prices during the first half of the year, with international food prices up by 27.6 percent and crude oil prices increasing by 52.0 percent. These developments have resulted in oil prices returning to 2019 levels, while food prices are their highest since 2014. According to the World Bank[4], the likelihood of prices remaining close to current levels for the remainder of the year hinges on the successful containment of the virus and production decisions of major commodity producers.

Rising freight costs have also contributed to increased import prices during 2021. Global freight indices increased by over 200 percent at the end of June 2021, the result of a lack of transport capacity to match the surge in global demand. Additionally, persistent lockdowns as a result of the COVID-19 outbreak in some markets have negatively impacted supply and export volumes and contributed to higher freight costs to producers and higher prices of goods to consumers.

The EIA[5] acknowledges the heightened uncertainty related to the ongoing economic recovery, but forecasts that global oil production will outpace the growth in oil consumption and contribute to declining oil prices in 2022. Given the high level of dependence that Barbados has on international oil, global energy market developments will directly impact domestic prices such as diesel and gasoline prices at the pump and the electricity bill via the Fuel Clause Adjustment.

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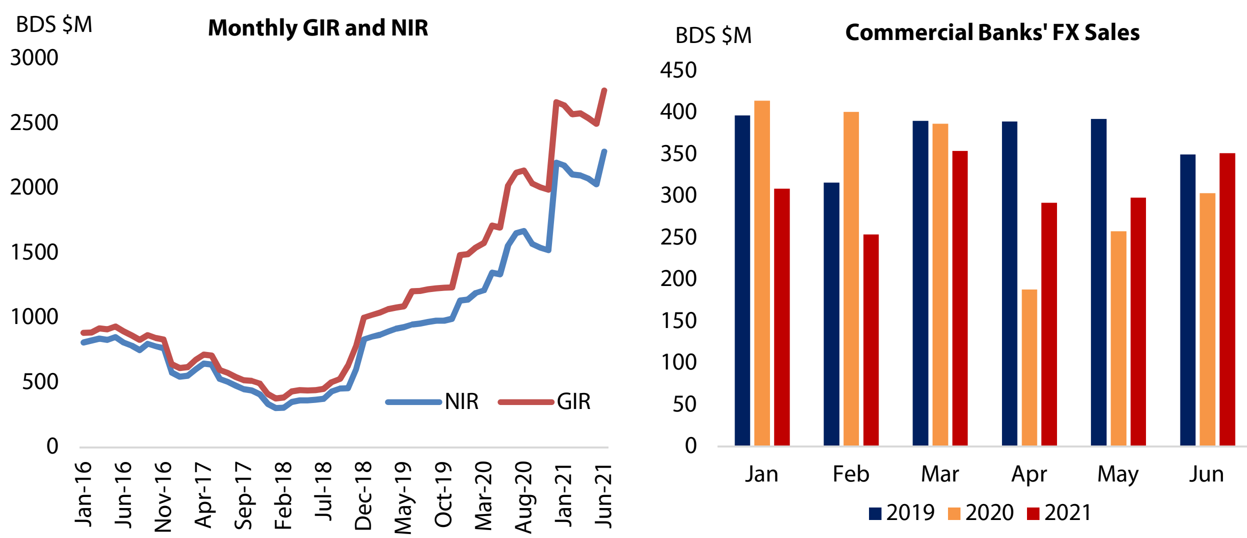
[2] Impact of COVID-19 on Commodity Markets Heaviest on Energy Prices; Lower Oil Demand Likely to Persist Beyond 2021 (worldbank.org)
[3] COVID-19 and the food and agriculture sector: Issues and policy responses (oecd.org)
[4] Commodity Prices to Stabilize after Early 2021 Gains, World Bank
[5] Short-Term Energy Outlook - U.S. Energy Information Administration (EIA)

International Reserves

The country's foreign exchange buffer remained elevated, as evidenced by an import cover equivalent to almost 44 weeks of imports. Gross International Reserves (GIR) ended the period at $2.7 billion, an increase of $88 million for the six-month period. Inflows from the World Bank ($200 million), the IMF ($48 million) and tax revenue from the international business sector reversed the first quarter reserve losses, offset outflows associated with central government debt service payments and other government expenses and boosted reserves in the second quarter.

With the decline in tourism earnings, the supply of foreign exchange to the banking sector fell. Purchases of foreign currencies rose in the April to June quarter, but falling imports contained the demands on the Central Bank to sell foreign exchange into the banking system. Reduced import volumes dampened the impact of rising oil prices on the balance of payments, resulting in lower fuel import costs. However, non-oil imports, remained relatively flat in comparison to last year.

Figure 6: Gross International Reserves (GIR), Net International Reserves (NIR) and Commercial Banks' Foreign Exchange (FX) Sales

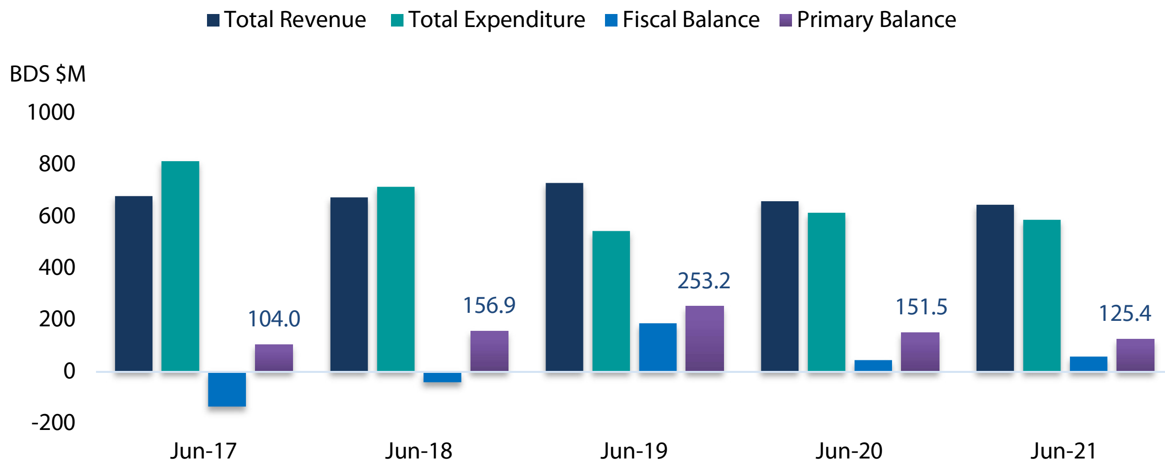


Source: Central Bank of Barbados

Fiscal Operations

COVID-19 continued to adversely impact the public finances, reducing revenue and raising public sector spending. Government incurred a primary deficit of one percent in FY 2020-21 and a balanced budget is targeted for the current financial year. During the quarter, the primary surplus contracted to $125 million, less than half the surplus achieved for the same period of FY 2019-20.

Figure 7: Fiscal Indicators



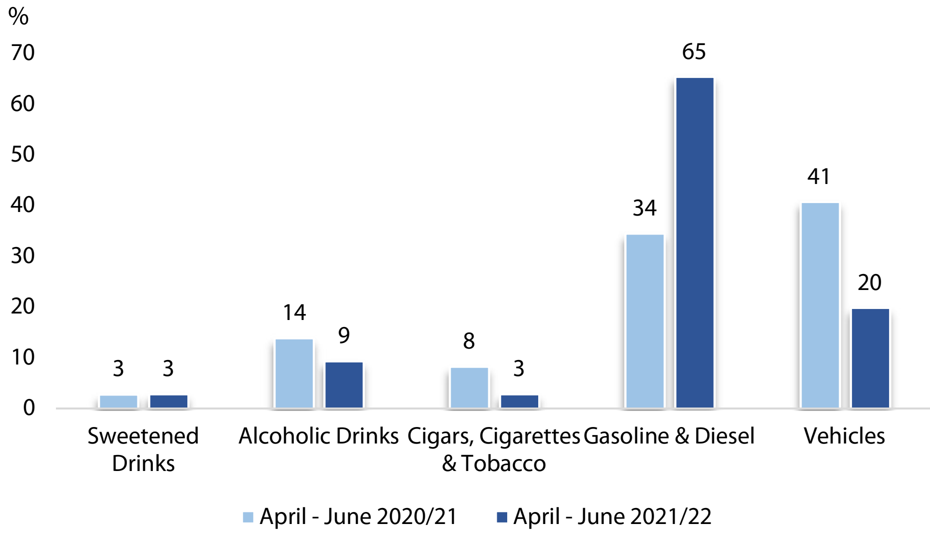
Source: Ministry of Finance

Revenue

There were broad-based increases in revenues but overall, total revenue declined by 2 percent, the result of lower collections of corporate taxes which contributed 41 percent of revenue in April to June 2020. The decline ($122 million) was anticipated, given the absence of the special one-off factors that boosted revenue the previous year. Other direct taxes partially recovered, rising by 22 percent, with moderate gains in personal income taxes, property tax receipts, withholding taxes, and the training levy.

Transaction based taxes also registered a partial recovery, reflecting the pick-up in economic activity. Value Added Tax (VAT) receipts were up $29 million, while excises and import duties rose by $23 million and $12 million, respectively. A reduction in rebates improved the performance of excises, while a general pickup in economic activity and, the clearing of back-logged items at the port added to revenue for other taxes on imports. Additionally, there was a pick-up in non-tax revenues, partly the result of the foreign exchange fee.

Figure 8: Percentage Share of Net Excise Categories



Source: Customs and Excise Department

Expenditure

Current non-interest expenditures rose by $27 million, the result of increased spending on welfare and the household survival programme, as well as larger transfers to the Queen Elizabeth Hospital, partly to cover additional COVID related spending. Wages and salaries also expanded modestly but expenditure on goods and services contracted despite payments to cover the ashfall clean-up.

Spending on capital works fell by $15 million, the result of lower transfers to Barbados Water Authority (down $31 million), which had received large disbursements in the corresponding period of the previous fiscal year to finance the water supply network project. However, this decline was partly offset by higher transfers to other projects, including outlays to small and medium sized enterprises impacted by the national pause as well as improvements for road works.

Debt and Financing

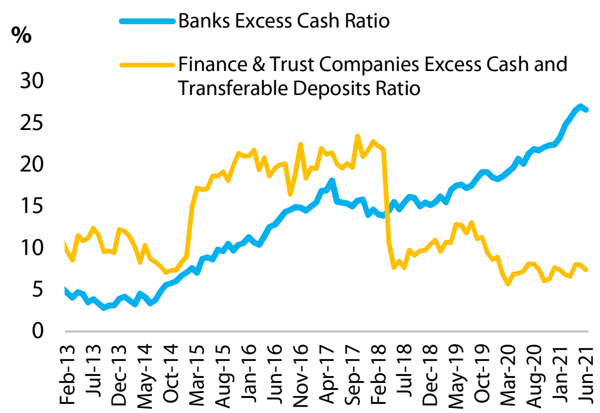
The debt stock at the end of June 2021 was equivalent to $13 billion (150 percent of GDP). This elevated debt ratio continues to be driven by the contraction in GDP which was responsible for 78 percent of the increase in the pre-COVID debt ratio. Since June last year, international financial institutions, recognising the severity of the shock caused by the pandemic on public finances, have assisted government in covering its financing needs. During the April to June quarter, funding from external creditors was $264 million.

Financial Sector Developments

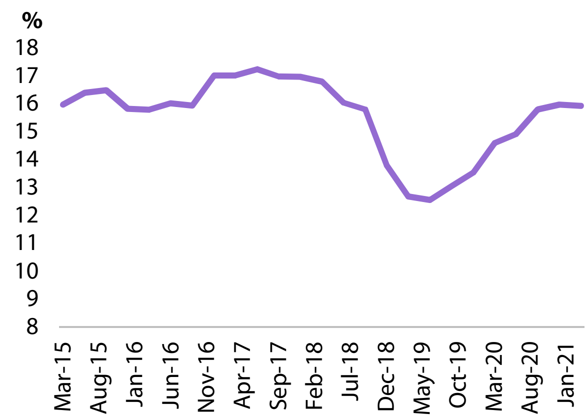
The financial system remains stable despite the elevation of credit risks induced by the prolonged impact of the pandemic. During the first six months of 2021, deposit-taking institutions (DTIs) remained highly liquid and well capitalised, with buffers well in excess of the statutory requirements. In addition, profitability for banks improved mainly as a result of lower provision expenses compared to the prior year when financial institutions raised provisions as a precaution against COVID-19 related credit losses. Interest rates remained at historically low levels.

Figure 9: Liquidity and Capital Ratios

Banks' and Finance & Trust Companies Excess Liquidity Ratios



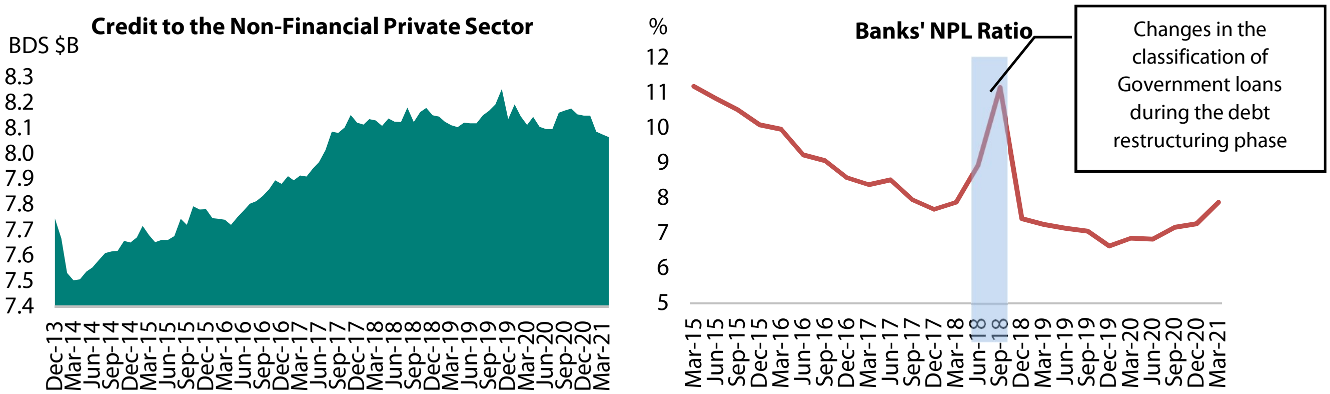
Banks' Capital Adequacy Ratio



Source: Central Bank of Barbados

Activity in the credit market remained weak as financial institutions, which were confronted by uncertain economic conditions, tightened their lending criteria and focussed new lending on supporting their existing clients. The moratoria programmes that dominated 2020 have largely come to an end, but some borrowers, mainly in the hotel and restaurant sectors, continue to benefit from extended moratoria arrangements. Generally, all institutions are offering their customers a menu of assistance via restructuring, debt consolidation, refinancing of loans and case-by-case extensions of moratoria. Several borrowers have consolidated and restructured their outstanding loans to make repayment plans more manageable in the face of lower income.

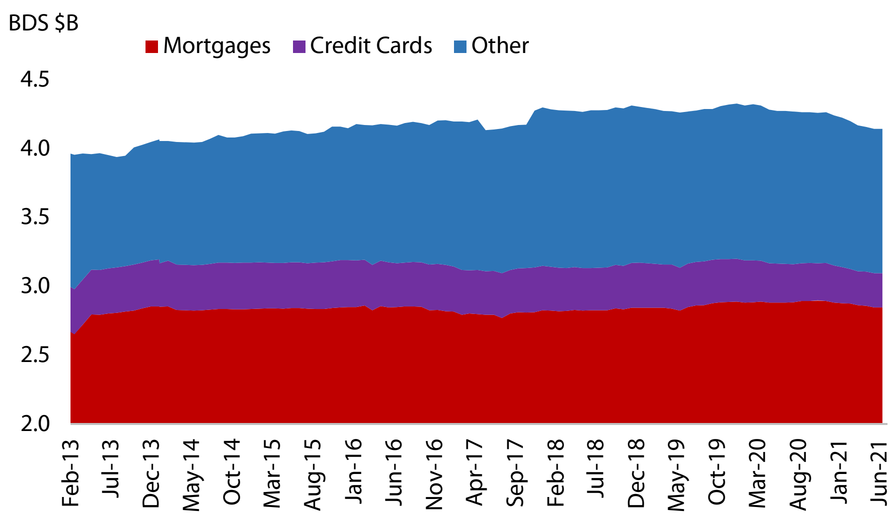
Figure 10: Credit to the Non-Financial Private Sector by DTIs & Commercial Banks' Non-Performing Loans



Source: Central Bank of Barbados

Non-performing loans as a percentage of total loans trended upwards, largely due to the increased classification of loans to the tourism, real estate and personal sectors. Mortgage related non-performing loans registered a modest increase during the period, driven by personal mortgages. However, this outturn was below the levels for the corresponding period of 2020 partly due to recoveries.

Figure 11: Household Debt from Commercial Banks and the Finance & Trusts Companies



Source: Central Bank of Barbados

Credit to the non-financial private sector by deposit-taking institutions[6] contracted by 1.1 percent during the first half of the year. The decline was driven largely by a reduction in loan balances of individuals which outweighed loan growth to utilities and other sectors. The decline in lending to the

[6] These include commercial banks, finance and trust companies and credit unions.

personal sector was driven by mortgages and credit cards, which accounted for more than half of the overall reduction for the sector.

Domestic-currency deposits expanded by 1.7 percent for the first half of 2021, the combined effect of government's fiscal stimulus and higher personal savings by individuals. Foreign currency balances grew by 2.9 percent, reflecting growth in balances of the personal and non-financial business sector. The expansion of foreign currency deposits of these corporations was driven by activity in the legal services and purchases of luxury properties in the real estate sector.

Outlook

The immediate challenge facing the Barbados economy is to build on the green shoots of growth experienced during the second quarter. The global economy remains on track for recovery as countries ease the restrictions that have been introduced to manage the virus. Barbados expects to benefit from the resumption of global activity and our relative success in managing the virus so far encourages optimism that we will register a mild recovery during 2021 and create a platform for sustainable growth over the medium term. Given the uncertainty associated with global developments, the Bank has left its economic growth forecast unchanged at between 1.0 percent and 3.0 percent for 2021.

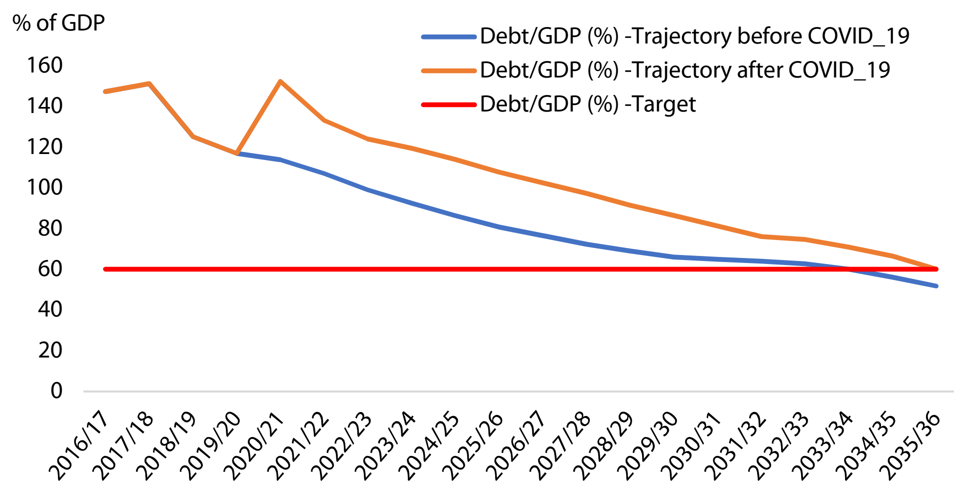
This outlook hinges on the speed of the recovery in tourism and the reports of planned increased airlift over the next six months to cope with pent-up demand for travel bodes well for energising a strong but gradual recovery. However, the environment remains hostile with new virus mutations and the continued uneven distribution of vaccines across the world. There are other downside risks that have to be managed. For example, Barbados has recently been placed on the "green list" of our largest source market for tourists, the United Kingdom, thus exempting visitors from having to quarantine after they return from Barbados. Retaining this status requires us to continue to manage the virus through careful observance of the health protocols, thus minimising risk to ourselves while providing confidence to potential visitors that the exempt status will not be subject to a sudden change.

In addition, COVID has slowed the pace of planned investment which is critical for building capacity, enhancing competitiveness and creating opportunities to ease labour market pressures. Repairs to the housing stock damaged by recent climatic events should boost construction activity in the short-term, but implementing a programme of private sector investments, including for renewable energy, embracing technology, innovation and process improvements will influence how quickly the recovery accelerates over the medium-term. The uptick in global inflation is a source of concern but as the pandemic-driven demand and supply shocks subside, international prices are likely to normalise over the medium-term.

The recent passage of Hurricane Elsa has further exacerbated the already stressed economic conditions. With damage assessments still being tallied, government will be challenged to assist in strengthening the housing infrastructure, making it more resilient to withstand future climatic events. In addition, the persistence of the pandemic will place pressure on Government to maintain its efforts to alleviate the economic and social consequences of the virus by providing temporary welfare assistance, strengthening the public health infrastructure and the accelerating implementation of public sector projects.

Government has relaxed its fiscal stance and the primary balance FY 2021-22 is targeted for a balanced budget. Over the past year, Government borrowed to facilitate the policy adjustment. While the sharp contraction in GDP has temporarily raised the debt-to-GDP ratio, Government remains committed to fiscal and debt sustainability and to attaining its debt-to-GDP anchor of 60 percent. A new timeline of FY 2035-36 has been established, as achieving debt sustainability over the medium and long-term requires a strengthening of economic growth and higher primary surpluses. Achieving these objectives underscores the importance of maintaining public enterprise reform efforts to ease demands on central government while strengthening Barbados' competitive position to generate growth.

Figure 12: Debt-to-GDP Ratio Trajectory



Sources: Ministry of Finance and Central Bank of Barbados

The front-loading of external borrowing has enabled the build-up of the international reserve cover. As the economy recovers, the demand for foreign exchange to support imports will rise, but the International Monetary Fund's (IMF) planned increase in the Special Drawing Rights[7] (SDR) allocation of its members is expected to further boost the country's foreign reserve buffer during the third quarter.

[7] An SDR is a foreign reserve asset which is created and issued by the IMF, in order to supplement the international reserves position of its member countries.

Table 1 - Economic Indicators

	2017	2018	2019	2020	Jun 2018	Jun 2019	Jun 2020	Jun 2021[(e)]
Nominal GDP ($ Million)[1]	9,971.9	10,245.8	10,595.9	8,974.9	5,140.3	5,272.5	4,628.6	4,285.2
Real Growth (%)	0.6	(0.5)	(1.3)	(18.0)	0.1	(2.6)	(15.5)	(9.0)
Inflation (%)[2]	4.5	3.7	4.1	2.9	5.3	2.0	5.1	1.5*
Avg. Unemployment (%)[3]	10.0	10.1	10.1	13.6	10.2	9.2	n.a.	n.a.
Gross International Reserves ($ Million)	411.3	999.6	1,481.0	2,660.7	440.0	1,204.0	2,017.2	2,749.1
Gross International Reserves Cover, Weeks	5.3	12.8	18.6	40.7	5.6	15.3	27.1	43.6
BoP Current Account (% of GDP)	(3.8)	(4.4)	(2.9)	(6.2)	(3.3)	(1.8)	(3.3)	(14.8)
Total Imports of Goods (% of GDP)	30.5	29.3	29.3	31.6	28.8	28.5	30.5	32.0
Travel Credits (% of GDP)	21.7	21.8	24.2	12.7	23.9	26.5	18.0	5.2
Financial Account ($ Millions)	86.4	887.6	792.7	1,652.1	157.4	288.8	770.2	679.0
Gross Public Sector Debt[4] (% of GDP)	148.4	125.4	118.0	142.3	144.6	123.1	126.9	150.3
External Debt Service to Curr. Acct. Cred.	8.3	4.9	3.6	9.0	7.1	3.4	5.8	7.4
Treasury-Bill Rate	3.2	0.5	0.5	0.5	3.1	0.5	0.5	0.5
Implicit Deposit Rate	0.10	0.09	0.07	0.04	0.10	0.08	0.07	0.04
Implicit Loan Rate	7.4	7.1	6.2	5.7	6.4	6.5	6.2	5.6
Excess Cash Ratio	14.2	16.1	18.5	22.4	14.3	17.0	19.1	25.6
Private Sector Credit Growth (%)[5]	3.2	0.4	0.9	(1.2)	(0.2)	(0.7)	(1.8)	(1.1)
Private Sector Credit (% of GDP)[5]	81.7	79.8	77.9	90.8	82.3	79.1	76.6	94.8
Domestic Currency Deposits (% of GDP)[5]	112.6	110.9	109.8	136.8	96.4	95.4	112.4	146.9
Fiscal Year	**2017/18**	**2018/19**	**2019/20**	**2020/21**	**Apr -Jun 2018**	**Apr -Jun 2019**	**Apr -Jun 2020**	**Apr -Jun 2021[(p)]**
Fiscal Balance (% of GDP)	(4.6)	(0.3)	3.6	(5.1)	(0.4)	1.8	0.4	0.7
Primary Balance (% of GDP)	3.2	3.5	6.0	(1.0)	1.6	2.5	1.4	1.5
Interest (% of GDP)	7.7	3.7	2.4	4.0	2.0	0.7	1.0	0.8
Fiscal Current Account (% of GDP)	(2.8)	1.6	5.4	(1.8)	(0.2)	1.9	0.8	1.0
Revenue (% of GDP)	28.8	29.2	28.2	30.1	6.8	7.1	6.2	7.6
Expenditure (% of GDP)	33.3	29.5	24.6	35.2	7.2	5.3	5.8	6.9
Non-interest Expenditure (% of GDP)	25.6	25.7	22.2	31.2	5.2	4.6	4.8	6.1
Capital Expenditure (% of GDP)	1.7	1.9	1.8	3.2	0.2	0.1	0.4	0.3
Gov't Interest Payments (% of Revenue)	26.9	12.9	8.4	13.4	29.5	9.2	16.3	10.5

[(p)] - Provisional

[(e)] – Estimate

[1] - Central Bank of Barbados and Barbados Statistical Service

[2] - Twelve Month Moving Average

[3] - Four Quarter Moving Average

[4] - Gross Public Sector Debt = Gross Central Government Debt + Other Public Sector Debt

[5] - Based on consolidated data for deposit-taking institutions (Commercial Banks, Finance & Trust Companies and Credit Unions)

* - Data as at May 2021

n.a.- Not Available

Sources: Barbados Statistical Service, Accountant General, Ministry of Finance and Central Bank of Barbados

Table 2 - GDP by Sector and Activity (BDS $Millions, Constant Prices[1])

	2017	2018	2019	2020	Jun-18	Jun-19	Jun-20(p)	Jun-21(e)
Tradeables	**1,908.1**	**1,940.7**	**1,963.7**	**984.2**	**1,013.0**	**1,008.6**	**608.5**	**321.1**
Tourism	**1,314.9**	**1,342.7**	**1,379.8**	**409.1**	**711.8**	**711.1**	**325.4**	**31.4**
Agriculture	**105.5**	**121.1**	**115.5**	**121.5**	**63.7**	**57.7**	**59.8**	**52.2**
Sugar	5.4	6.0	4.0	4.2	5.3	4.0	4.2	4.2
Non-Sugar Agriculture	100.1	115.1	111.6	117.3	58.3	53.7	55.6	48.0
Manufacturing	**487.8**	**476.9**	**468.4**	**453.6**	**237.5**	**239.9**	**223.3**	**237.5**
of which:								
Rum & Other Beverages	*94.7*	*92.6*	*90.9*	*88.0*	*46.1*	*46.6*	*43.4*	*46.1*
Food	*124.0*	*121.2*	*119.1*	*115.3*	*60.4*	*61.0*	*56.8*	*60.4*
Furniture	*13.4*	*13.1*	*12.9*	*12.5*	*6.5*	*6.6*	*6.1*	*6.5*
Chemicals	*29.4*	*28.7*	*28.2*	*27.3*	*14.3*	*14.4*	*13.4*	*14.3*
Electronics	*36.9*	*36.1*	*35.4*	*34.3*	*18.0*	*18.1*	*16.9*	*18.0*
Other Manufacturing	*189.4*	*185.2*	*181.9*	*176.1*	*92.2*	*93.1*	*86.7*	*92.2*
Non-tradeables	**6,193.4**	**6,119.3**	**5,991.0**	**5,542.6**	**3,049.0**	**2,946.0**	**2,733.4**	**2,718.9**
Mining & Quarrying	40.7	42.2	49.6	47.9	22.1	21.5	20.9	21.5
Electricity, Gas & Water	214.8	214.1	213.5	202.3	107.1	104.5	99.8	98.6
Construction	492.9	461.6	452.3	434.4	228.7	221.3	217.4	212.8
Distribution	759.2	747.7	736.8	666.2	369.4	369.5	322.0	314.1
Transport, etc	1,046.7	1,027.7	1,007.4	937.9	511.3	505.9	467.6	467.5
Finance and Other Services	2,783.5	2,784.2	2,740.4	2,462.8	1,397.2	1,341.2	1,223.8	1,222.5
Government	855.6	841.8	791.0	791.1	413.3	382.2	381.9	382.0
Total	**8,101.6**	**8,060.1**	**7,954.8**	**6,526.8**	**4,062.0**	**3,954.6**	**3,341.9**	**3,040.0**
Nominal GDP	**9,971.9**	**10,245.8**	**10,595.9**	**8,974.9**	**5,140.3**	**5,272.5**	**4,628.6**	**4,285.2**
Real Growth Rates	**0.6**	**(0.5)**	**(1.3)**	**(18.0)**	**0.1**	**(2.6)**	**(15.5)**	**(9.0)**
Tradeables	3.1	1.7	1.2	(49.9)	4.2	(0.4)	(39.7)	(47.2)
Non-tradeables	(0.2)	(1.2)	(2.1)	(7.5)	(1.1)	(3.4)	(7.2)	(0.5)

(p) - Provisional

(e) - Estimate

1 - BSS' 2010 Base Year Series

Sources: Barbados Statistical Service and Central Bank of Barbados

Table 3- Balance of Payments (BDS $Million)

	2017	2018	2019	2020(p)	Jun 2018	Jun 2019	Jun 2020(p)	Jun 2021(e)
Current Account	**(380.6)**	**(453.2)**	**(311.1)**	**(561.8)**	**(168.6)**	**(93.2)**	**(151.0)**	**(632.5)**
Inflows	**4,832.0**	**4,855.0**	**5,142.4**	**3,519.0**	**2,476.3**	**2,676.7**	**2,137.9**	**1,415.8**
Travel	2,161.4	2,230.7	2,482.5	1,148.2	1,228.7	1,397.4	833.7	224.4
Other Services	429.9	444.7	458.5	397.4	174.0	178.7	173.0	157.0
Domestic Exports	509.7	510.2	507.4	449.4	252.0	265.2	219.9	220.5
Rum	83.9	79.8	76.8	75.9	42.4	42.1	34.7	42.6
Food	64.6	65.3	66.4	61.3	32.1	31.5	32.1	30.5
Sugar	13.5	0.4	0.6	0.9	0.2	0.1	0.2	0.3
Chemicals	72.5	80.3	77.8	84.7	38.8	41.6	38.5	30.0
Printed Paper Labels	22.7	26.6	15.3	23.5	12.7	11.8	9.8	12.8
Construction Materials	42.1	51.7	59.1	38.2	25.4	31.5	20.4	19.0
Other	210.3	206.1	211.4	164.9	100.4	106.6	84.2	85.3
Re-exported Goods	461.1	385.7	380.8	241.0	213.1	214.2	154.2	100.2
Net Export of Goods under Merchanting	635.4	633.8	637.6	547.6	316.9	318.8	311.8	296.4
Income	529.8	543.0	565.4	338.7	252.9	263.6	205.5	209.2
Transfers	104.7	107.0	110.1	396.6	38.8	38.8	239.8	208.0
Outflows	**5,212.6**	**5,308.2**	**5,453.5**	**4,080.8**	**2,644.9**	**2,769.9**	**2,288.9**	**2,048.3**
Total Imports of Goods	3,040.3	2,997.7	3,003.7	2,843.9	1,479.2	1,505.0	1,412.1	1,370.4
Fuel Imports	626.2	712.2	728.0	510.6	388.9	384.6	297.7	255.9
Other Merchandise Imports	2,414.1	2,285.5	2,275.7	2,333.3	1,090.2	1,120.4	1,114.4	1,114.6
Services	1,014.0	1,073.9	1,148.9	553.3	584.3	596.6	409.3	333.4
Income	977.6	1,042.6	1,099.2	473.7	473.5	556.1	350.9	223.1
General Government	167.4	183.2	150.0	139.3	94.6	119.0	71.2	35.4
Other Sectors	810.2	859.5	949.1	334.3	378.9	437.1	279.7	187.8
Transfers	180.6	194.0	201.7	209.8	107.9	112.2	116.7	121.4
Capital Account	(2.4)	50.9	(5.3)	(4.5)	53.5	(3.9)	(3.3)	(3.5)
Financial Account	86.4	887.6	792.7	1,652.1	157.4	288.8	770.2	679.0
Net Foreign Direct Investment	468.2	464.8	375.3	509.2	181.8	227.7	214.3	196.0
All Other Investment Flows	(381.8)	422.8	417.3	1,142.9	(24.4)	61.1	555.9	483.0
Net Long-term Public	(134.9)	451.0	387.8	968.2	(81.9)	138.8	394.0	184.7
Net Long-term Private	(156.8)	(3.8)	113.0	251.3	49.1	(32.8)	183.6	325.3
Net Short-term	(90.1)	(24.4)	(83.5)	(76.7)	8.5	(44.8)	(21.7)	(27.0)
Net Errors & Omissions	68.0	102.9	5.0	93.9	(13.8)	12.7	(79.7)	45.3
Overall Balance	(228.5)	588.3	481.4	1,179.7	28.6	204.4	536.3	88.4
Change in GIR: - increase/+ decrease	228.5	(588.3)	(481.4)	(1,179.7)	(28.6)	(204.4)	(536.3)	(88.4)

(p) - Provisional

(e) - Estimate

Source: Central Bank of Barbados

Table 4 - Summary of Government Operations (BDS $Millions)

	2017/18	2018/19	2019/20	2020/21	Apr -Jun 2018	Apr -Jun 2019	Apr -Jun 2020	Apr -Jun 2021[(p)]
Total Revenue	**2,845.4**	**2,993.6**	**2,984.2**	**2,563.3**	**672.4**	**728.8**	**657.7**	**643.6**
Tax Revenue	**2,656.3**	**2,812.4**	**2,771.2**	**2,387.8**	**625.5**	**690.2**	**637.8**	**612.3**
i) Direct Taxes	**968.9**	**1,126.9**	**1,084.7**	**1,202.9**	**247.0**	**303.0**	**392.4**	**298.3**
Personal	462.6	482.1	454.7	308.1	113.8	153.3	98.7	107.5
Corporate	275.1	355.5	309.0	612.9	89.8	79.9	269.3	147.7
Property	137.6	161.3	214.7	181.6	10.2	41.0	6.0	21.0
Financial Institutions Asset Tax	48.7	44.6	47.4	45.6	15.5	9.5	11.0	12.0
Other	44.9	83.4	58.9	54.7	17.8	19.4	7.4	10.1
ii) Indirect Taxes	**1,687.4**	1,685.6	**1,686.5**	**1,185.0**	**378.4**	**387.2**	**245.4**	**314.0**
Stamp	10.5	10.9	11.4	7.6	2.3	3.1	0.9	2.0
VAT	887.3	940.9	966.9	706.3	212.8	229.7	152.9	181.8
Excises	303.1	271.2	250.9	154.1	53.8	51.2	22.6	45.7
Import Duties	218.6	213.8	231.6	191.9	44.0	55.8	37.9	49.6
Hotel & Restaurant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Social Responsibility Levy	152.0	49.4	0.1	0.0	40.3	0.0	0.0	0.0
Other of which:	115.9	199.4	225.6	124.9	25.3	47.3	31.1	35.0
Fuel Tax		68.6	82.1	63.8		14.7	9.1	14.9
Room Rate/Shared Accommodation		10.1	28.1	9.5		6.1	2.8	1.7
Non-Tax Revenue & Grants	**189.1**	**181.2**	**213.0**	**175.4**	**46.9**	**38.6**	**19.9**	**31.2**
Non-Tax Revenue	149.0	161.5	201.3	169.5	46.9	35.5	19.9	31.2
Grants	22.0	0.1	11.8	0.0	0.0	3.2	0.0	0.0
Post Office - Revenue	18.1	19.6	0.0	5.9	0.0	0.0	0.0	0.0
Current Expenditure	**3,123.8**	**2,826.4**	**2,407.9**	**2,716.8**	**693.4**	**529.3**	**570.7**	**558.0**
Wages & Salaries	782.3	811.9	807.4	808.0	182.7	197.9	197.9	202.2
Goods & Services	364.3	356.3	375.5	399.8	70.4	62.5	65.2	51.5
Interest	764.7	384.9	249.7	342.6	198.0	67.1	107.5	67.6
External	168.0	48.0	62.7	144.1	11.2	20.4	59.9	17.6
Domestic	596.7	336.9	187.0	198.5	186.9	46.7	47.6	50.0
Transfers & Subsidies	1,212.5	1,273.3	975.3	1,166.3	242.2	201.8	200.0	236.7
Grants to Individuals	358.3	362.8	389.2	423.7	70.8	73.4	81.7	95.2
Grants to Public Institutions	761.2	814.8	517.6	657.3	155.5	108.5	107.9	121.5
Subsidies	51.9	51.8	31.8	49.7	6.8	12.5	4.4	4.0
Subscriptions & Contributions	22.1	25.7	20.3	20.3	4.8	4.4	3.5	12.1
Non-Profit Agencies	19.0	18.3	16.4	15.3	4.4	3.0	2.4	3.8
Capital Expenditure & Net Lending	**171.8**	**197.8**	**191.8**	**276.1**	**20.1**	**13.4**	**43.1**	**27.8**
Capital Expenditure	149.1	184.9	185.1	278.3	15.0	11.6	43.6	28.4
Net Lending	22.7	12.9	6.7	(2.2)	5.1	1.8	(0.5)	(0.6)
Fiscal Balance	**(450.2)**	**(30.6)**	**384.5**	**(429.6)**	**(41.2)**	**186.1**	**44.0**	**57.8**
Primary Balance	**314.5**	**354.3**	**634.2**	**(87.0)**	**156.9**	**253.2**	**151.5**	**125.4**
Fiscal Balance to GDP (%)	**(4.6)**	**(0.3)**	**3.6**	**(5.1)**	**(0.4)**	**1.8**	**0.4**	**0.7**

[(p)] Provisional

Sources: Ministry of Finance and Central Bank of Barbados

Table 5 - Government Financing (BDS $Millions)

	2017/18	2018/19	2019/20	2020/21	Apr-Jun 2018	Apr-Jun 2019	Apr-Jun 2020	Apr-Jun 2021[(p)]
Total Financing	**450.2**	**30.6**	**(384.5)**	**429.6**	**41.2**	**(186.1)**	**(44.0)**	**(57.8)**
Domestic Financing (Net)	**629.3**	**(315.5)**	**(491.1)**	**(432.6)**	**55.1**	**(157.6)**	**(355.7)**	**(286.7)**
Central Bank	92.8	(166.4)	164.7	(66.6)	85.2	99.3	(212.2)	(10.3)
Commercial Banks	257.9	82.8	(86.3)	106.6	57.5	10.5	33.1	(21.3)
National Insurance Board	3.1	8.9	(85.2)	(207.9)	7.3	(21.3)	(21.3)	(0.7)
Private Non-Bank	(57.2)	(119.6)	(217.7)	(34.9)	(35.5)	0.8	(20.2)	(28.0)
Other	332.8	(111.2)	(58.3)	(167.9)	(59.4)	(222.4)	(73.2)	(196.6)
Arrears Payments	n.a.	(10.0)	(208.3)	(61.9)	0.0	(24.5)	(61.9)	(29.9)
Foreign Financing (Net)	**(179.1)**	**346.2**	**106.6**	**862.2**	**(13.9)**	**(28.5)**	**311.7**	**228.9**
Capital Markets	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Project Funds	113.8	87.9	72.0	81.8	13.2	3.9	5.0	22.0
Policy Loans	0.0	350.0	150.0	968.1	0.0	0.0	341.3	249.1
Amortisation	(292.8)	(91.7)	(115.4)	(187.7)	(27.1)	(32.4)	(34.6)	(42.2)

[(p)]-Provisional

Source: Central Bank of Barbados

Table 6 – Public Debt Outstanding (BDS $Millions)

	2017	2018	2019	2020	Jun-18	Jun-19	Jun-20	Jun-21(p)
Gross Central Government Debt[1]	**13,666.0**	**12,755.8**	**12,426.6**	**12,761.3**	**14,127.5**	**12,726.4**	**12,383.0**	**12,971.6**
Domestic Debt	10,840.1	9,556.9	9,336.6	8,786.7	11,194.2	9,482.8	8,987.5	8,796.3
Central Bank[2]	2,227.7	703.8	814.1	757.0	2,282.3	734.4	715.3	794.8
Commercial Banks	2,144.9	2,340.2	2,355.2	2,340.4	2,137.5	2,333.1	2,347.7	2,334.8
National Insurance	3,518.9	2,938.4	2,880.0	2,690.6	3,532.1	2,922.5	2,837.4	2,649.5
Insurance Companies	527.2	1,114.6	807.5	816.3	824.3	1,193.7	815.7	817.2
PPP	241.8	-	-	-	240.6	-	-	-
Other	2,179.7	2,150.3	2,312.9	2,140.9	2,177.3	2,020.1	2,189.4	2,128.0
Domestic Arrears	-	309.5	167.0	41.5	1,200.0	279.0	82.0	72.1
External Debt	2,825.8	3,198.9	3,090.0	3,974.5	2,933.3	3,243.5	3,395.5	4,175.3
International Financial Institutions	1,043.7	1,379.5	1,445.5	2,407.8	916.1	1,283.3	1,763.0	2,615.7
Bonds	1,452.8	1,142.8	1,126.2	1,067.3	1,409.0	1,135.7	1,127.3	1,062.3
PPP	243.1	237.0	228.8	255.0	237.0	228.8	269.5	240.5
Bilateral	86.1	211.5	222.6	244.4	83.8	197.3	235.8	256.8
External Arrears	-	228.1	67.0	-	101.2	398.4	-	-
Other Public Sector Debt	**1,144.0**	**94.3**	**72.3**	**53.5**	**976.8**	**98.1**	**56.5**	**50.5**
Domestic Debt	884.6	-	-	-	765.7	-	-	-
Foreign Debt	259.4	94.3	66.4	53.5	211.1	91.4	56.5	50.5
Other Public Sector Arrears	-	-	6.0	-	-	6.7	-	-
Gross Public Sector Debt[3]	**14,810.0**	**12,850.1**	**12,499.0**	**12,814.8**	**15,104.3**	**12,824.5**	**12,439.5**	**13,022.1**
Central Government Financial Assets	**715.1**	**795.0**	**739.6**	**912.3**	**685.7**	**583.8**	**674.8**	**306.6**
Central Bank	20.3	389.4	311.4	801.9	2.2	254.5	482.3	186.3
Commercial Banks	96.0	174.6	248.4	95.5	103.4	139.7	177.6	105.3
Sinking Funds	598.8	231.0	179.7	14.9	580.2	189.6	14.9	14.9
Other Public Sector Financial Assets	**189.0**	**221.6**	**392.6**	**426.0**	**192.2**	**246.4**	**400.6**	**493.6**
Public Corporations' Deposits	189.0	221.6	392.6	426.0	192.2	246.4	400.6	493.6
Gross Public Sector Debt/GDP (%)	148.4	125.4	118.0	142.3	144.6	123.1	126.9	150.3
Gross Central Government Debt/GDP (%)	136.9	124.5	117.3	141.7	135.1	122.1	126.3	149.7
External Debt/GDP (%)	28.3	33.4	29.8	44.1	27.6	32.0	34.6	48.2
Net Central Government[4]/GDP (%)	129.8	116.7	110.3	131.5	128.5	116.5	119.4	141.0

(p) – Provisional

[1] Gross Central Government Debt = Domestic Debt + External Debt+ Domestic and External Arrears

[2] Comprises Treasury Bills, Debentures and Ways & Means Account Balance

[3] Gross Public Sector Debt = Gross Central Government Debt + Other Public Sector Debt +Arrears

[4] Net Central Government Debt = Gross Central Government Debt - Central Government Financial Assets

Source: Accountant General, Ministry of Finance and Central Bank of Barbados

Table 7 - Select Monetary Aggregates and financial Stability Indicators for the Banking Systems (BDS $Million)

	2017	2018	2019	2020	Jun 2018	Jun 2019	Jun 2020	Jun 2021[p]
Monetary Authorities								
Net International Reserves	334.7	832.5	1,130.8	2,195.0	364.8	941.3	1,554.6	2,279.3
Monetary Base	2,375.9	2,659.0	2,938.8	3,551.8	2,524.7	2,845.0	3,210.3	4,063.8
Net Domestic Assets	1,996.9	1,788.8	1,761.6	1,296.2	2,117.0	1,860.8	1,598.1	1,719.4
Deposit-taking Institutions[1]								
Credit to Public Sector[2]								
Central Government (net)	2,164.5	1,896.4	1,886.7	2,056.5	2,172.7	1,931.5	1,964.8	2,056.3
Rest of the Public Sector	344.8	107.9	65.0	85.3	321.7	110.4	43.1	82.0
Credit to Rest of Financial System	248.7	274.5	255.7	262.8	281.8	265.1	261.3	257.1
Credit to the Non-Financial Private Sector[3]	8,151.3	8,179.1	8,254.4	8,153.7	8,137.7	8,121.3	8,105.4	8,064.5
Total Deposits	11,978.7	11,967.1	12,284.6	12,976.2	11,939.6	12,269.2	12,660.6	13,207.3
Transferable Deposits[4]	9,667.6	9,844.5	10,394.3	11,178.9	9,750.7	10,197.0	10,858.5	11,424.5
Non-Transferable Deposits	2,311.1	2,122.6	1,890.3	1,797.3	2,188.9	2,072.2	1,802.1	1,782.8
Memo Items								
Domestic Currency Deposits	11,223.9	11,365.1	11,631.0	12,283.2	9,527.7	9,797.4	11,886.0	12,494.2
Foreign Currency Deposits	754.8	602.0	653.6	693.0	731.3	643.9	774.7	713.1
Banking System Financial Stability Indicators[5]								
Capital Adequacy Ratio (CAR)	17.0	13.8	13.5	16.0	16.1	12.6	14.9	16.3
Loan to Deposit Ratio	64.4	63.0	61.7	57.1	65.8	60.7	58.0	53.9
Liquid Assets to Total Assets	29.7	21.8	23.1	25.2	32.9	23.7	24.8	29.2
Non-Performing Loans Ratio	7.7	7.4	6.6	7.3	7.7	7.1	6.8	8.0
Provisions to Non-Performing Loans	80.4	67.3	59.4	62.0	67.5	56.4	69.1	59.3
Return on Average Assets (12-month)	1.3	(0.2)	0.6	0.8	1.2	(1.1)	0.9	1.1

[p] - Provisional

[1] Comprises Commercial Banks, deposit-taking Finance & Trust Companies and Credit Unions

[2] Reflects both security holdings and loans.

[3] Does not include credit to the non-resident sector

[4] These comprise of call deposits, demand deposits and savings deposits with unrestricted withdrawal privileges

[5] Data on commercial banking sector

Source: Central Bank of Barbados

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MEMORANDUM ON CAPITAL EXPANSION 2021 - 2025

OVERVIEW OF CURRENT SITUATION

1. The Barbados Light & Power Company Limited ("BLPC" or "the Company") as at December 31, 2020 served a total of 131,522 customers with a peak demand of 141 MW, and had an installed capacity of 256.1MW of generating plant. Additionally, customer owned distributed solar photovoltaic systems account for around 49MW of generating capacity as of September 2021. A historic peak of 167 MW was experienced during 2007. Power is transmitted from the generating stations at 69,000 volts and 24,000 volts to 18 substations across the island as shown in Schedule I-4.

Existing Generating Plant

2. Since 2010 the Company has focused on meeting the island's demand for safe, clean and affordable energy by adopting a 100/100 vision for transitioning to 100% renewable energy and 100% electrification. This vision finds alignment with the national goal of 100% renewable energy by 2030 as outlined in the Barbados National Energy Policy (BNEP) 2019 - 2030[1]. While the Company continues to operate and maintain its fleet of traditional fossil fuel generating assets, including a steam turbine, low speed diesel engines and gas turbines located at its three generating stations (Spring Garden, Seawell and Garrison), the process of transitioning fuel away from a high carbon future to a low carbon future is already underway,

3. In an effort to reduce the country's dependence on imported fossil fuel use, reduce foreign exchange pressure and increase price stability as well as maintain high levels of reliability for customers, the Company invested in its first large scale solar PV farm at Trents in St. Lucy. This 10 MW solar PV plant was commissioned in 2016 at this site also called the St. Lucy Energy Gateway (SLEG). Shortly thereafter, during 2018, the Company also commissioned a 5 MW Energy Storage Device (ESD) which was predicated on fuel arbitrage and the savings this device would bring to customers over the 10 year operational life of the battery.

[1] https://energy.gov.bb/publications/barbados-national-energy-policy-bnep.

4. Following the outages of November 2019, the Company took several additional measures to ensure continued security of supply including the procurement of rental generating units from Aggreko. These units were deployed within one month of arrival by December of 2019 and provided an additional 12 MW of generating capacity. The availability of these units has allowed maintenance to proceed on some of the larger generating units in light of delays experienced as a result of Covid 19 impacts. Having these units on island prior to this period has mitigated some of the challenges associated with sourcing both personnel and equipment in a timely manner which was exacerbated by the Covid situation.

5. During December 2019 the Company procured an additional 15 MW of diesel generating capacity as part of a short-term measure to boost reserves while the 33MW Clean Energy Bridge (CEB) was being fast tracked. This 15 MW diesel plant consists of 12x1.5MW previously owned Caterpillar XQ2000 containerized diesel units and associated Balance of Plant (BOP). This plant was sited at Spring Garden due to this location being already permitted for industrial use, the ready availability of fuel storage facilities and the ability to rapidly deploy BOP for reduced costs to the overall implementation. Ten (10) of these units were commissioned by February of 2020 while the additional two (2) units are kept as spares in the event of any failures.

   Expenditure - $13.3M.

6. It was previously recognised that in the absence of any firm renewable energy capacity options, there was a need for additional fossil fuel generating capacity in order to maintain adequate system reliability and resilience during the transition to 100% RE. The Company therefore engineered, designed and sought to procure additional capacity but after a significant period of planning and delays in obtaining permissions to replace firm capacity, permission was granted towards the end of 2019 to proceed with the construction of a new 33MW CEB at Trents, St. Lucy. The CEB is expected to be commissioned by the end of 2021.

Retirement of Generating Plant

7. Since the year 2000, addition of new generating capacity was predicated on sales growth driving demand and the retirement of existing assets. During 2005 the Company made a significant capital investment in two 30 MW low speed diesel (LSD) generators. Installation of these fuel efficient LSD units in 2005 was able to mitigate some of the effects of oil price volatility which reached an all-time high during 2008.

8. With the onset of the recession during 2009, sales growth was stymied and the need to add or retire existing plant, including the Steam Station, slowed during the period. The electricity industry's economic and policy conditions began to change soon after the last rate review as outlined by the Sustainable Energy Framework for Barbados during 2010 and so the Company thought it not prudent at the time to retire the steam units as planned.

9. The steam turbine generators installed in 1976 were previously scheduled for retirement during 2012. However, the lack of sales growth and the transition to renewable energy, particularly the growth in distributed renewable energy, tempered demand. Between 2012 and 2014, BLPC developed an Integrated Resource Plan which considered the government's plan to introduce up to 60 MW of combined waste-to-energy and biomass generation between 2016 and 2018. The announcement of the government's plans, along with changes to the government's licensing regime, the new Electric Light and Power Act (ELPA) and anticipated reforms in the electricity market structure caused Barbados' energy environment to become more dynamic and uncertain. As a result, the BLPC undertook systematic reviews and adjustments to its investment plans.

10. Given that the 60 MW of waste-to-energy and biomass generation did not materialize as anticipated, the Company deemed it prudent to invest in life extension of the Steam Station over a 10 year period through the application of various asset management strategies rather than replacing them with fossil

fueled generation assets. This included investment in major system components such as the turbine rotor, alternator, high pressure super heater steam assembly, electromatic valves, nozzle valve actuators and replacement of sections of the boiler tube assemblies to ensure continued reliable operation of the steam station until its eventual retirement.

11. Unit S2 was repurposed during 2020 to provide spares for unit S1 while Unit S1 is scheduled for retirement during 2023.

12. To facilitate the orderly transition to renewable energy and retirement of existing plant, whilst maintaining high levels of reliability, the Company is currently constructing a 33 MW CEB plant at Trents, St. Lucy. This facility consists of 4 modular 8.32 MW Wartsila Power Cube engines which have the capability to rapidly ramp up and down in response to variable RE which is expected to accelerate over the next decade. These units, while designed to operate on Heavy Fuel Oil (HFO), have the capability to be converted to natural gas operation in the event that this cleaner fuel becomes available at an economic price.

13. The CEB, because of its high efficiency, is projected to save $30M annually at US$60 per barrel international oil price. These savings, in addition to reducing the drain on much needed foreign exchange, will also help to stabilize electricity rates with savings being passed directly to customers through the Fuel Clause Adjustment (FCA) mechanism. Even after the 2030 goal is achieved, the plant will continue to provide both reliability and resiliency to counteract reduced availability of renewables on any given day. This ability to provide back-up services to the grid is critical to mitigate against the need for excessive battery storage. The CEB is scheduled to be commissioned by the end of 2021 and will facilitate the ultimate retirement of the Steam Station. Investment in the CEB is expected to be in excess of $133M.

Table I-1. Installed Generating Capacity - 2020

General Plant Information	Max. Countinuous Rating (MW)	Totals (MW)	Year Installed	Retirement Date	Fuel Type
Steam Station					
Unit S1	20		1976	2023	HFO
Unit S2 - Note 1			1976	2020	HFO
Sub-total		**20**			
Low Speed Diesels (Spring Garden)					
Unit D10	12.5		1982	2028	HFO
Unit D11	12.5		1982	2028	HFO
Unit D12	12.5		1987	2028	HFO
Unit D13	12.5		1990	2028	HFO
Unit CG01	1.5		Upgraded in 1993	2028	
Unit D14	30		2005	2032	HFO
Unit D15	30		2005	2032	HFO
Unit CG02	2		2005	2032	
Small Diesels (Spring Garden)	15.0		2020	2030	Diesel
Sub-total		**128.5**			
Gas Turbines (Garrison)					
Unit GT02	13.0		1990	2022	Diesel
Sub-total		**13.0**			
Gas Turbines (Seawell)					
Unit GT03	13.0		1996	2026	Diesel
Unit GT04	20.0		1999	2029	Diesel
Unit GT05	20.0		2001	2030	Diesel
Unit GT06	20.0		2002	2030	Diesel
Sub-total		**73.0**			
Trents Solar & Battery					
Trents Solar PV	10.0		2016	2036	
Trents Battery	5.0		2018	2028	
Sub-total		**15.0**			
Total		**249.5**			

Note 1: Unit S2 repurposed in 2020 as critical spares for unit S1.

Renewable Energy

Lamberts 10 MW Windfarm Project

14. The Company, as part of its longer-term commitment to wind energy development, started resource wind measurements in the mid-1990s. In December 1998, an application was made for wind farm development at Lamberts East and the site was subsequently included in the amended 2003 Barbados National Physical Development Plan as one of the sites with the best wind regimes. Permission was granted during December 2010 to install a 10 MW windfarm at the Lamberts St. Lucy site consisting of 11 turbines for an operational period of 24 years. Since that time, there was a change in ownership of the land associated with the windfarm. This along with delays in receiving the planning permissions coupled with obsolescence of the original

turbine has led to a redesign using more efficient wind turbine units. The Company subsequently executed an Engineering Procurement and Construction (EPC) contract with Enercon Ltd. for the supply of five (5) turbines rated at 2.05 MW each.

15. Subsequent to the Environmental Impact Assessment (EIA) completed by AMEC consultants in 2007 and updated in 2010, an Environmental and Social Impact Assessment (ESIA) was submitted to Town & Country Development Planning Office (TCDPO) during November 2019 to evaluate possible changes to any of the Valued Ecosystem Components (VECs) given the changes in technology. This application is currently being assessed prior to windfarm construction. More recently, on October 22, 2020 the Company successfully completed a Public Information Consultation (PIC) process as part of the Town Planning requirement for stakeholder engagement prior to project implementation.

16. In compliance with the new licensing regime, an application for a generation license to operate the windfarm was submitted during January 2020, to the Ministry of Energy, Small Business and Entrepreneurship (MESBE) pursuant to the ELPA 2013, CAP. 278. The Lamberts windfarm is projected to produce 32 GWh annually with the ability to power over 9900 homes. Given the length of time and impacts of the recent licensing regime, the Company is once again exploring a redesign of this project to maximize customer benefits.

Lower Estate Solar PV Project

17. In keeping with its 100/100 vision for Barbados, the Company is in the process of expanding its renewable generation portfolio through the development of a 7.5 MW Solar Photovoltaic Plant on 29 acres of land at Lower Estate, St. Michael. Solar PV has proven to be an easily permitted and acceptable technology in the local landscape with one 10 MW utility scale plant already in service and more than 49 MW of distributed PV systems grid tied since introduction of the Renewable Energy Rider (RER) program in 2010. Annual energy production from this plant is anticipated to be, on average, 14 GWh/year resulting in projected foreign exchange savings annually.

18. Given the restructuring of the energy market place as the island transitions to 100% renewables both the Lamberts and Lower Estate projects are expected to be subject to the new licensing regime.

Existing Transmission & Distribution (T&D) Network

19. The Company continues to operate a transmission network that is highly efficient with losses which are among the lowest in the region and comparable to that in North America. At the end of 2020, overall system losses stood at 5.91%. With the advent of Automatic Metering Infrastructure (AMI), non-technical losses have also been demonstrated to be among the lowest in the region and is a testimony to the robust design of the BLPC system.

20. The development of the Barbados transmission network over the next 20 years, specifically in the north of the island where there is a significant development of generation proposed, high potential for new load growth and tourism related projects are contemplated, is critical. To cater for such capacity expansion the Northern Underground Transmission project was established to provide a reliable and redundant high capacity link from the generating plant in Trents St. Lucy to the St. Thomas substation. Additionally, it was envisaged that the link from St. Thomas to Warrens will provide improved reliability by extending this link into the existing 69kV transmission network between Spring Garden and Central substations via a proposed intertie at Warrens substation.

21. Work on the 132, 000 volts double circuit transmission cables between St. Thomas and Trents commenced in 2006 and was completed by 2009. Originally, these cables were designed with the capability to carry up to 240 MW of power from the Trents generating site. This higher design voltage was selected for ease of transitioning to increased capacity without having to disrupt the underground cable system in the long term. In keeping with the Company's vision for the St. Lucy site as a clean energy gateway in line with the 100/100 vision, these cables were initially energized at 24,000 volts to facilitate dispatch of renewable energy from its 10 MW solar PV farm which was commissioned during 2016.

22. In addition to the double circuit underground cable transmission link from Trents to St. Thomas, BLPC will seek to enhance the transmission network to improve

reliability to cater to future system expansion. This expansion will take into account resiliency of the network to cater to interconnection of Independent Power Producers (IPPs) seeking to advance projects in the north of the island particularly around the Trents, North and St. Thomas substations. Linking the three major generating stations comprising of Trents, Spring Garden and Seawell, via major underground transmission in the near future, provides network reliability and the flexibility of network re-configuration for future security of supply.

Supervisory Control And Data Acquisition (SCADA) & Geographical Information System (GIS)

23. Efficient network operation in the power industry relies on the ability to make processes faster, more flexible, efficient and, above all, more cost effective. The Company, in implementing its SCADA system over 36 years ago, sought to achieve this with a system that has the capability to remotely monitor and control key assets on the T&D network. Significant strides were made over the years from a reliability and safety perspective as the SCADA system underwent various stages of its evolution.

24. During 2017 the Company started preparations for upgrade to its long-standing SCADA PRISM software which entailed an upgrade to the core PRISM platform to deliver real-time information and automate processes 10 times faster than the previous application. The most recent upgrade to the SCADA system sought to provide significant enhancements to both features and performance across the spectrum of PRISM applications by targeting resilience and backup recovery as key strategic business priorities.

25. The evolution of the smart grid along with proliferation of Intelligent Electronic Devices (IEDs) and other automated devices and sensors being deployed as part of its Distribution Automation program on the T&D network requires significant SCADA expansion capability. The upgraded PRISM platform is scalable with the capability to respond to future needs through the provision of additional SCADA stations and data endpoints.

26. Expansion of the SCADA system facilitates ease of integration to the Company's Geographical Information System (GIS), which serves as the

system of record for both overhead and underground T&D assets along with its electrical connectivity model. In an era where the growth of renewables will increase exponentially, the combination of these two enterprise systems will allow the Company to deliver increasing value as it seeks to monitor, control and maintain its key assets geospatially for reliability and safety. Investment in SCADA equipment and software to date is $3.8M.

Disaster Recovery Site

27. During a system crisis, the ability to quickly recover without loss of any mission critical information is paramount. Therefore, in addition to an upgrade to the core SCADA application, the Company also implemented a Disaster Recovery Site (DRS) with capability to house the required hardware and engineering to back up its existing primary SCADA system. The DRS is connected via fibre to a secure remote backup location to allow the system to continue to deliver mission-critical performance in the event of a major storm or other outage event.

28. During the Covid 19 pandemic, the Company was able to successfully test the remote servers, software and hardware at the DRS as part of its business continuity plans in the event that activation of the site became necessary should the main control room become compromised in any way.

<u>Substation Infrastructure</u>

29. Over the years the Company has sought to upgrade its existing substation assets by replacing outdoor substation structures, which were exposed to the elements and flying debris, with modern indoor substations. These substations incorporate a resilient design constructed to withstand up to a Category 3 storm.

30. Modern switchgear design also includes several safety components with switchgear designed for internal arc rating to reduce the incidence of faults and exposure of personnel to incident arc energy. These key features enhance both the reliability and resiliency of these assets which are pivotal to the distribution of electricity to the various load centres. Since the last rate case indoor substations were constructed at Carlton, North, Trents and Belmont.

Hampton is the only remaining outdoor substation and construction of a modern indoor facility at this location is in progress.

SUBSTATION INVESTMENTS

31. In keeping with its mandate to provide a safe, affordable and reliable electricity supply, BLPC enhanced the reliability and resiliency of its substation infrastructure by completing construction of indoor substations at its Carlton, North and Trents Substation sites. More recent upgrades were completed at Belmont and Wotton along with a further upgrade to the Trents substation in St. Lucy to facilitate new switchgear installation at these substations.

Belmont Substation, St. Michael

32. Belmont substation provides a critical interconnection between the major substations in the City such as Whitepark, Marhill Street and Temple Yard. It also allows for the rapid dispatch of the Gas Turbine (GT02) at Garrison into the network when this unit is called into service. While an outdoor substation design is cost effective and allows for easy identification and rectification of faults, an outdoor structure presents higher exposure to the elements and incidence of lightning strikes during storms. Additional land was acquired adjacent to the existing substation to allow for the construction of a modern indoor facility thereby improving the reliability and resiliency of this critical infrastructure. Work commenced during 2010 on an eight (8) panel 24, 000 volt switchgear facility which was subsequently commissioned in 2012 whilst the 11,000 volt switchgear was commissioned in 2015.

Total Expenditure – Belmont Substation:$ 4.6M

Wotton Substation, Christ Church

33. Wotton substation was commissioned in 1984 and was among the early vintages of switchgear which utilized SF6 gas insulation technology. Subsequent improvements in design rendered this switchgear obsolete. Wotton substation, because of its location, provides supply to vital industrial and commercial loads including the hotel sector along the south coast. This

substation was therefore fully upgraded during 2018 to facilitate installation of both 24,000 volt and 11, 000 volt switchgear along with commissioning of a new 20 MVA power transformer. The 11, 000 volt switchgear along with the power transformer was commissioned during 2019 and the 24,000 volt switchgear was commissioned by August, 2021.

Total Expenditure – Wotton Substation: $ 3.1M

Trents Substation, St. Lucy

34. In line with its clean energy vision the Company started its transition to utility scale renewable energy projects with the commissioning of the 10 MW solar PV farm at the St. Lucy Energy Gateway during 2016. This necessitated the construction of a 24, 000 volt substation to allow for interconnection of the solar farm to the network via the 132,000 volt cables previously terminated at the site. These cables are initially being operated at 24, 000 volts and allow for dispatch of clean energy into the grid via the undergrown cable system installed between Trents and St. Thomas. This first phase of switchgear installation also catered for future connection of the proposed Lamberts windfarm via a 24,000 volt overhead transmission line. The Trents substation was further upgraded starting in 2018 to allow for commissioning of the ESD, future commissioning of the 33 MW Clean Energy Bridge (CEB) as well as to allow for future interconnection of any IPP that emerges during the transition to 100% RE.

Total Expenditure – Trents Substation: $3.7M.

<u>Substation Transformers</u>

35. Substation transformers are integral devices which transform bulk power that was transmitted between substations at either 69, 000 volts or 24, 000 volts to lower distribution voltages of 11,000 volts before such power is distributed to residential and commercial enterprises for consumption. The Company employs a number of asset management strategies to ensure the health of these assets including an assessment of end of life along with periodic oil testing using Dissolved Gas Analysis (DGA) techniques.

36. To facilitate increased penetration of distributed renewables a key consideration is incorporation of a tap-changer that is easily maintained given the increased duty on this asset as a result of having to constantly adjust to voltage variations. In the 2020 Barbados Generation and Transmission Masterplan by Mott MacDonald Limited, transformers were identified as required at North, Trents, White Park, Temple Yard and Regency for the high demand case scenario while additional transformers are required at Spring Garden, Seawell, St Thomas and Old Works due to projected 11, 000 volt feeder load growth.

37. Increased penetration of RE impacts the voltage profile on distribution networks and has the potential to cause reverse power flow at various distribution transformers. In addition to voltage regulation via tap changing transformers at the substation level, to help manage voltage impacts, the Company has employed various Volt-Var optimization strategies. These include investments in smart capacitors for distribution lines as well as equipment monitoring through smart metering devices. As renewables proliferate, further analysis is required through Advanced Grid Analytics (AGA) and management of distribution equipment aimed at limiting impacts to power quality and to continue operation of the network within prescribed voltage limits.

Projected Expenditure in Substation Transformers: $4.5M

<u>Grid Modernization</u>

Automatic Metering Infrastructure (AMI)

38. The ever-increasing expectations and demands of customers, have moved utilities to adapt the way they do business in order to meet these evolving requirements. Implementation of AMI as part of the new utility business model allows utilities to be flexible and responsive to such demands in an effort to deliver world-class service. In keeping with this trend, during 2016 the Company initiated and invested $47.3M in the deployment of its AMI program as the foundation of a Smart Grid initiative with targeted project conclusion by end of 2021.

39. An AMI system comprises a combination of software coupled with state-of-the art electronic and digital hardware devices which leverages communication

infrastructure to measure and monitor interval meter data. AMI empowers the utility and its customers to make intelligent decisions about consumption and demand. In addition to the roll out of its AMI program, which replaces its fleet of legacy meters with smart meters, the Company also redesigned its internal processes to further drive technology enhancements and efficiencies.

40. AMI also serves to facilitate grid enhancements including the ability to read meters remotely, disconnect meters on demand and potentially allow for prepaid service by customers desiring that service. Since AMI leverages the telecommunications component of the infrastructure, it also helps to facilitate future distribution communications technologies and outage notification.

41. As AMI and Smart Grid devices are rolled out onto the distribution network the Company will continue to maximize efficiency gains by integrating existing legacy software systems such as SCADA and Customer Information Systems (CIS) with future enterprise systems. This includes integration to its Meter Data Management Systems (MDMS), Advanced Grid Analytics (AGA), Distribution Equipment Monitoring (DEM), Outage Management Systems (OMS), Distribution Management Systems (DMS) and Geographic Information Systems (GIS). To date the Company has changed over 120,000 meters and is on schedule to complete the full change out by end of year 2021.

Projected Expenditure in AMI: 2021- $1M

Distribution Automation

42. In 2017, BLPC sought to enhance its existing Distribution Automation (DA) program by embarking on a multiyear plan to establish full automation on a number of its distribution feeders. Distribution automation includes integration of both Information Communication and Operational Technologies (ICT & OT) and therefore required a phased approach to optimise placement of DA switches for both safety and reliability. Enhanced performance results were achieved through utilization of a combination of intelligent DA devices integrated to a robust communications network along with sensors and fault indicators.

43. The deployment strategy initially targeted ten (10) distribution feeders, which already had extensive AMI deployment and electrical connectivity in place to

facilitate feeder automation over a three year period. Through monitoring of the DA feeder performance, reliability improvements were assessed through a pilot program which comprised of three rural circuits (Dukes, Belleplaine, and Woodland) with initial expenditure of $1.3M as part of a 3-year investment plan. It was anticipated that reduced impacts to both SAIDI[2] and SAIFI[3] for these rural feeders would translate to an approximate 50% improvement in reliability overall for the targeted feeder and would drive further investments.

Projected Expenditure: Distribution Automation- $6.2M

System Protection

44. Protection relays and circuit breakers are the key components of electricity network system protection. The main function of this system protection is to cause the prompt removal from service of any element of a power system that has experienced a short circuit or is operating in an abnormal manner and which, if allowed to continue, would cause damage or otherwise interfere with the normal operation of the system.

45. During 2013 the Company commissioned Parsons Brinkerhoff (PB) Limited to perform a system protection study to enhance existing protection schemes and to minimize the impact that faults on the system have on customers. The study took into consideration recent upgrades and investment plans for the generation and T&D system facilities as well as recent developments in protection systems technology.

46. The Company has upgraded its system protection with the introduction of modern high-speed digital relays and fiber optic communication technology on major transmission lines. The introduction of this technology has enhanced the protection currently in use on ‘ringed’ feeds or dual sources of power to major substations. The introduction of Unit protection and accelerated tripping schemes has facilitated the removal of single contingency outages on ringed networks with no impact on customer supply once the faulted transmission line feeding the substation has been de-energized.

[2] SAIDI- System Average Interruption Duration Index
[3] SAIFI- System Average Interruption Frequency Index

Battery Storage

47. The Company commissioned GE Consulting during 2015 to conduct an updated Wind and Solar Penetration Study to assess the technical and economic impact of variable renewable energy (RE) resources on the generation, transmission, and distribution system and to evaluate the benefits of operating the grid with increasing penetrations of RE. GE Consulting in its analysis identified Battery Energy Storage Devices (ESD) and Synchronous Condensers (SCOs) as mitigation strategies to facilitate integration of higher penetrations of wind and solar into the system. ESDs were identified as having fast response, frequency regulation and load following capability whilst the SCO was identified for its contribution to improved system inertia capability.

48. During 2017, the Company in partnership with Tesla Inc. undertook the implementation of an innovative ESD application at its St. Lucy Energy Gateway. This first application of battery storage technology in Barbados, while it had the capability to provide both grid and ancillary services, was evaluated on the basis of the value creation afforded customers in terms of fuel savings. In its application to the FTC the Company through its modelling of the ESD quantified such fuel savings to be in excess of $26 M when co-optimized for energy shifting and reserve provisioning over the 10-year life of the asset.

49. Battery storage technology is integral to the realization of the 100/100 vision and achieving the 2030 targets. The BNEP 2019-2030 in its goal to achieve 100% RE generation by 2030 calls for a potential 200 MW of battery storage. Independent studies have identified battery storage for its ease of installation and relatively high efficiency for electricity storage compared to other technologies such as pumped storage, the latter of which has a substantial initial capital outlay due to the major construction required.

50. During 2018, BLPC successfully commissioned its first ESD with resultant benefits to customers both in terms of fuel savings as well as the ancillary services the battery provides in terms of smoothing solar PV output and frequency response. Net fuel savings from operation of the ESD was projected to be $26.7 million over the lifetime of the battery.

51. BLPC proposed modifications be made to the existing FCA formula to account for cost recovery and this was approved by the FTC to allow for recovery of the asset including the proposed customer benefits.

52. To help meet the 2030 target the Company intends to invest in a portfolio of storage assets either through partnerships or competitive procurement as prescribed by the new licensing regime geared towards realizing the 100% RE goal.

Synchronous Condensers (SCO)[4]

53. With the proposal to retire the Steam Station and ultimately other rotating assets, there will be a concomitant reduction in system inertia. To reverse this trend and to achieve appropriate inertial response, the introduction of synchronous condensers is required to support system stability. SCOs help stabilize the grid when running under non-synchronous generation conditions, i.e. when the system demand is fully met by solar and wind sources alone. SCOs do not provide generation capacity but are reactive power devices used for grid stability and to enable very high penetration levels of variable renewable generation.

54. Mott MacDonald in the Barbados Generation and Transmission Masterplan (the 2020 study) indicated that large increments of batteries are required in 2025 and later in 2030 together with the SCOs to provide the necessary fast megawatt (MW) response from batteries and reactive power from SCO devices. For those occasions where there is zero synchronous generation, grid-forming inverters will be required along with ESDs to mitigate against decreased levels of system inertia.

55. Synchronous Condensers are proposed to be located at various substations including Spring Garden, Garrison, Central, White Park and Temple Yard based on voltage studies. The initial investment plan for 2021-2023 proposes

[4]Synchronous condensers (SCOs) are essentially generators with no prime mover or turbine or where the prime mover has been removed from service and the electric alternator is converted to serve as a SCO.

the installation of 3 x 10MVA SCOs comprising 20 MVA at Spring Garden and 10 MVA at Temple Yard or Whitepark Substations.

Projected expenditure in SCOs: $40.8M

Automatic Generation Control (AGC):

56. With the advent of increased penetration of renewables the requirement for Automatic Generation Control (AGC) software, associated telecommunications infrastructure and power plant interface controls to manage the generators in the Barbados network becomes paramount as the power system becomes increasingly complex. As an increasing penetration of renewables is added to the system, AGC will assist in balancing generation with interchange of load whilst supporting frequency regulation and control of the Area Control Error (ACE) when interacting across multiple Control Areas.

57. The Company is currently conducting an AGC study for future implementation with the opportunity to integrate to the existing SCADA system and generation Distributed Control Systems (DCS) associated with various legacy generation. Benefits of AGC include automatic regulation of system frequency, system time deviation and interchange of power. Implementation of AGC software and hardware is intended to support multiple telecommunication protocols for the monitoring and control of generating units from multiple sources including RE sources as this portfolio is built out and proliferates.

Projected Expenditure in AGC: $2.5M

PLANNING CRITERIA

58. The goal of the Company's expansion plan is to determine the least-cost solution required to provide electricity service which meets the specified levels of reliability. The Company's aim is to achieve the right balance between cost and system reliability. A more reliable system can be achieved with more plant but at increased cost. The Company uses a loss-of-load probability (LoLP) as its main planning criteria for generation reliability.

59. The need for new generating plant is based on maintaining an acceptable level of reliability and doing so at the least cost to the consumer. The following input data was used to determine the need for and type of new plant to be purchased:

- Target levels of system reliability.
- Electricity sales projections.
- Expected growth in peak demand.
- System load factor.
- The existing generating plant types and the options available for new plant (candidate plant).
- Proposed retirement schedule for existing plant.
- Availability, reliability, fuel type and efficiency of existing and candidate plant.
- Estimated capital cost of candidate plant.
- Operating and Maintenance (O&M) cost of existing and candidate plant.
- Fuel price projections.

60. A measure of the reliability of a transmission system is its ability to satisfy the N– 1 criterion (that is, the system remains stable, and within continuous rating notwithstanding the outage of any one circuit).

61. As part of its planning process, the Company in 2018 retained Mott McDonald, to prepare the 2020 Study which took into account the island's goal of 100% renewable energy by 2030.

62. For the purposes of the 2020 Study, the key planning criteria were:

- A study horizon of 20 years with detailed investment plan for the first 5 years (2021 - 2025),
- A generation reliability criteria of 1 day/year LoLP.
- A maximum allowable individual generating unit size of 20% of the projected peak demand,
- N-1 planning criteria for the transmission network to ensure full system operation following a loss of a cable or transformer,
- Electricity sales growth scenarios of 0.67%, 1.38% and 3.27%.

Sales and Peak Demand Growth 1981–2020

63. The demand for electricity over the period has declined. The average annual growth rates in sales and peak demand over the last 5 years were -0.5 % and -1.9 % respectively as shown in the following Table I-2.

Table I-2 Historical Sales and Peak Demand

5-Year Period	Sales		Peak Demand	
	Average GWh	Average Annual Growth	Average MW	Average Annual Growth
1981-1985	317.3	3.8%	59.9	3.6%
1986-1990	413.0	7.0%	77.8	6.4%
1991-1995	518.5	3.9%	95.4	3.6%
1996-2000	649.9	4.4%	117.8	3.7%
2001-2005	804.1	4.7%	140.8	4.3%
2006-2010	940.1	1.7%	163.3	1.7%
2011-2015	915.8	-0.9%	156.9	-1.5%
2016-2020	933.4	-0.5%	152.0	-1.9%

Sales Growth Projections

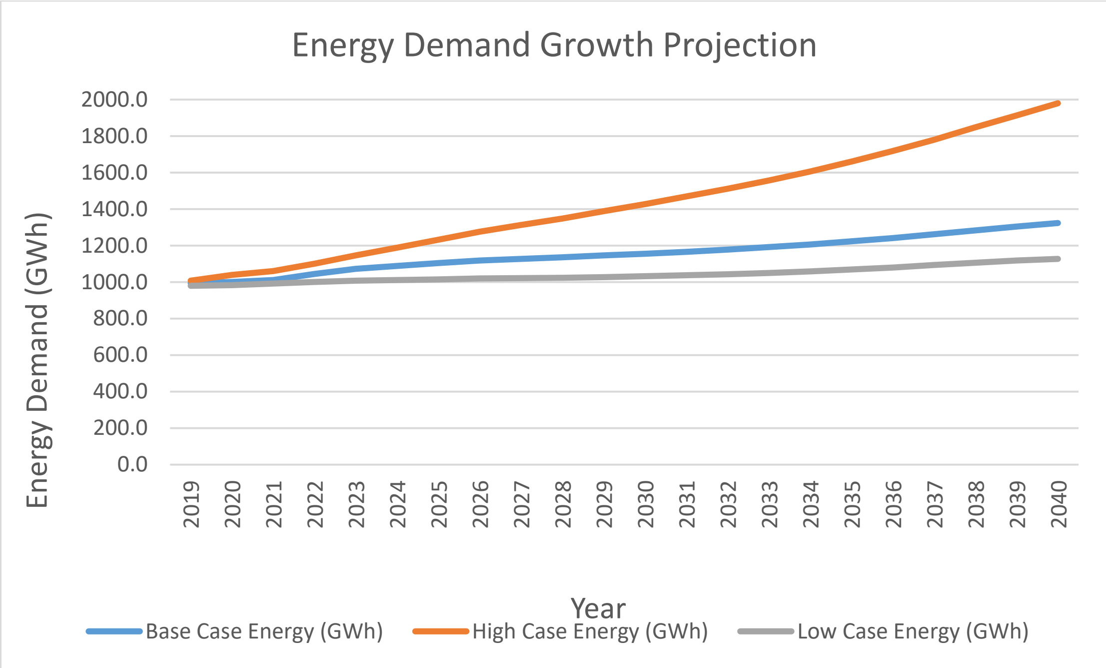
64. For the purposes of the expansion study the Company selected three (3) sales growth scenarios, namely:

a) A base case scenario;
b) High growth scenario;
c) Low growth scenario.

At the time it was projected that both the system and peak loads would steadily increase from 2019 with an average growth of around 1.3 % per year, however this was tempered by the world situation.

65. These scenarios are shown in Figure I-1 below:

Figure I-1. Comparison of Growth Scenarios



66. Uncertainty over the future of oil prices, the COVID situation and the projected slowdown in world economies suggest that the most likely near term scenario is one of low load growth. Further analysis as detailed in the Memorandum on Sales Projection at Schedule H also supports this lower projected growth. The five year investment plan presented herein is therefore based on the low load growth scenario.

Energy Options

67. During 2018 the Company commissioned Mott MacDonald Limited to conduct twenty (20) year generation expansion planning studies to meet defined reliability criteria taking into consideration the following:

I. the Barbados National Energy Policy 2019 – 2030;
II. the accelerated RE Policy of the Government of Barbados; and
III. the BLPC 100/100 Clean Energy strategy.

68. In addition, it was anticipated that the generation expansion plans would consider the following technologies/projects without being necessarily constrained by the following opportunities:

- Centralised Waste to Energy / Biomass impacts
- Distributed Biomass
- DSM and Energy Efficiency measures
- Electrification of the transportation sector (Electric vehicles, electric buses)
- Residential grid-tied battery system penetration /behind the meter applications

Ocean Technologies

69. The Company is keeping abreast of developing technologies e.g. wave, ocean current technologies and Ocean Thermal Energy Conversion (OTEC), which are now being tested for the production of electricity, but they are, so far, not yet commercially viable.

GENERATION INVESTMENT PLAN: 2021 - 2025

70. The 2020 Study identified the 5 year investment plan for a 1.3% growth under the scenario where the energy mix allowed for forced IPPs, along with imported bio-fuels allowed as shown in Schedule I-5.

71. Due to the impacts of the COVID -19 pandemic beginning in Q1 2020, a number of the projects that were under development and construction have been delayed. These included the CEB plant, the 10 MW Lamberts windfarm and solar developments. The CEB plant is scheduled to be completed at the end of 2021.

72. The changes in the energy sector has also required the Company to review the recommended five year investment plan which varies from the 2020 Study due to reasons outlined in paragraph 71.

73. The Company's five-year capital investment plan for the recommended scenario described in Table I-3 is as follows:

Table I-3 – New Generation and Retirement Plan

	2021	2022	2023	2024	2025
New Capacity (MW)	33 (CEB)	-	-	-	-
Retirements (MW)	-	-13(GT02)	-20 S1)	-	-

GENERATION INVESTMENTS SINCE 2010

74. Annually, capital investments are made for sustainability of existing assets, due to statutory, environmental, insurance and other compliance requirements. Since 2010, BLPC has invested more than $346M in its generation assets. Some of the major investments during this period were:

Alternative Cooling Water System for LSD B Station

75. Cooling water for the engines in the LSD B Station (D14 and D15) is provided from a cooling tower via a closed loop system. The cooling tower is therefore a critical piece of equipment for this station as 60 MW of capacity depends on the availability of the cooling tower. In order to reduce the possibility of the LSD B station capacity being unavailable due to a fault on the cooling tower, BLPC installed an alternative cooling water system to supply this station in the event that the cooling tower was unavailable. This system was commissioned in 2011 at a cost of $2.4 M.

Turbocharger Upgrades

76. The turbochargers on units D10 to D13 are critical components for the safe and efficient operation of the LSD 'A' engines. The Original Equipment Manufacturer (OEM) for the turbochargers ceased production of all parts for this model turbocharger in 2015. While key spare components were purchased in 2015, no additional spare components were available after that time. There was therefore a need to upgrade these turbochargers due to obsolescence in a phased manner. During 2018, the turbochargers on unit D10 were replaced and upgraded, which also resulted in increased efficiency of the unit. Similar replacements were conducted on D11 and D12 in 2019 and 2020 respectively.

Replacement of the last set of turbochargers on unit D13 is scheduled to be completed in 2022. To date the total investment of these upgrades is $10.3 M.

Reverse Osmosis Plant

77. Operation of the boilers on the steam and low speed diesel station requires large quantities of treated water to produce steam. Water is taken from the potable city water supply however; in 2016, the Company installed a reverse osmosis plant at a cost of $1.7 M to produce water for use in its generating stations. This plant utilises the available brackish water supply in the area and has reduced dependence on the city water supply.

Inlet Guide Vane (IGV) Upgrades

78. The IGVs on units GT04, GT05 and GT06 are critical components of the turbine on these units. Based on inspections and end of life assessment, the OEM recommended that these be changed out and replaced with an upgraded mechanism. These mechanisms were replaced between 2018 and 2020 at a total cost of $3.8M.

Control Systems

79. The operating and control systems for the gas turbines over the years have come to end of life and as such spare parts and support for the existing system were no longer available. These systems were therefore upgraded on units GT02 to GT06 between 2013 and 2020. Similarly, due to control systems for the LSD A and LSD B Stations reaching end of life, these systems were also upgraded over the past decade. Over the past decade, the Company has invested in excess of $7.0 M in the control systems for its generating units.

LSD End of Life Assessment

80. Units D10 and D11 were installed in 1981, D12 in 1987 and D13 in 1990. These units were originally scheduled to be retired in 2018 representing an average age of 33 years across the fleet. However due to the pending changes in the energy sector and delays in government and private generating projects which were envisioned when the Integrated Resource Plan was completed, it was necessary to extend the life of these units. An OEM contractor was engaged

and performed a life extension assessment on these units. This review recommended areas that should be addressed over time in order to ensure continued efficient operation of these units.

Fire Protection Systems

81. Fire protection systems are critical to protecting the generating assets and ensuring the safety of personnel working in the various stations. The Company has therefore continued to invest in fire protection systems and upgrades as required to comply with international standards, insurance and local requirements. Over the past ten years, the Company has invested $7.9M in fire protection systems across its generating assets.

System Upgrades

82. Over the years the Company has conducted upgrades on various systems on each generating unit based on end of life and/or obsolescence of components. These included, pumps, motors, compressors, purifiers, coolers, engine components and instrumentation among other components. Modifications were also conducted on various systems. These, over time, have also resulted in improved efficiency of various systems.

Routine Capital Expenditure

83. The Company maintains its fleet of units in accordance with the recommendations of the OEM in addition to schedules developed using condition based and preventative maintenance. The Company maintains routine capital provision accounts to cover the cost associated with refurbishment of parts for the units and purchase of replacement capital spare parts.

GENERATION INVESTMENT PLAN (**Schedule I-1** details the capital investment program for Generation)

<u>LSD A Station Control System</u>

84. The control system for the LSD Station has come to end of life making procurement of spares and vendor support difficult to obtain.. The control system for this 50 MW of capacity is scheduled to be replaced.

    Projected expenditure – LSD A Station Control System: $2.3M

<u>LSD B Control System</u>

85. The control system for the LSD B Station is approaching end of life which will make it increasingly difficult to obtain spares and vendor support. The control system for this 60 MW of capacity is scheduled to be replaced.

    Projected expenditures – LSD B Control System: $1.5M

<u>D13 Turbocharger Upgrade</u>

86. Similar to the upgrades completed on D10 to D12, it is intended to upgrade the turbochargers on unit D13 due to obsolescence and unavailability of spare parts.

    Projected expenditure - D13 Turbocharger Upgrade: $3.1M

<u>Gas Turbine Computerised Operator Station and Operating System Upgrade</u>

87. The Computerised Operator Stations used to control gas turbines GT02 to GT06 are nearing end of life and have to be upgraded. In addition, the operating system on these terminals is currently Windows 7 which is no longer supported. With the increased threats of Cyber related attacks, it is further necessary to update the control systems for these units to reduce the likelihood of cyber security risks.

    Projected expenditure - Gas Turbine Operator Station and Windows System Upgrade: $1.5M

Gas Turbine Fuel Burners

88. Fuel burners are critical components in the gas turbine units. During normal operation and over time, these experience wear and tear. Inspection of the burners are conducted periodically. Due to the long lead times for these burners and the criticality of these components to the operation of the units, the Company is required to purchase a spare set of burners.

Projected expenditure – Fuel Burners: $5.8M

D14 Alternator Preventative Maintenance

89. Based on inspections conducted on units D14 and D15 alternators, it was recommended that the alternators be re-wedged. Re-wedging of unit D15's alternator was completed in 2018 and a similar activity is scheduled to take place on unit D14.

Projected expenditures – D14 Alternator Re-wedging: $1.1M

D13 Alternator Re-wind

90. Based on inspections conducted on unit D13 alternator, it was recommended that the alternator be rewound. The necessary materials to complete this work have already been acquired and are scheduled to be installed during 2021.

Projected expenditures – D13 Alternator Re-wind: $4.1M

Spring Garden HFO Tank Inspection and Repairs

91. The Company proposes to conduct an inspection and repair on one of its HFO storage tanks at Spring Garden.

Projected expenditures – Spring Garden HFO Tank Inspection and Repairs: $6.0M

TRANSMISSION AND DISTRIBUTION INVESTMENT PLAN (**Schedule I-2** details the capital investment program for T&D.)

Overview

92. The Company previously engaged the consulting firm PB Power to examine the transmission infrastructure across the island, with particular emphasis on the central and northern areas in light of the projected growth, the possible location of that growth, and the decision to establish a new generating site in the north of the island. The transmission network will be designed to be sufficiently resilient to withstand an extended outage on any one line.

93. As part of the network upgrade between Trents and North substations the Company installed a 24,000 volt double circuit cable link from Trents to North substation. This cable installation and duct bank infrastructure was terminated in an area in close proximity to the Farrs Children's Home. To complete this cable link, additional ductwork was installed from the Farr's junction along Mile & A Quarter junction to the North Substation at Maynards. With the increased capacity and commissioning of the CEB project at the Trents site, there is a need for enhanced reliability plus the flexibility for interconnection of future IPPs in the north of the island.

94. Cable installation between Trents and North is targeted for completion during the second half of 2022 with installation of 24, 000 volt equipment at North Substation required to facilitate the cable interconnections during 2022. Purchase and installation of additional switchgear and protective relaying equipment at North is required for commissioning this underground cable connection and to make provision for future renewables expansion in the North of the island.

    Projected expenditure for North Switchgear: $2.0M

Trents to St. Thomas Equipment Upgrade

95. As previously mentioned, the double circuit underground cable between St. Thomas and Trents is currently operated at 24, 000 volts. However, future load growth and interconnection of proposed IPP projects at St. Thomas substation necessitates a transition in operating voltage to 69, 000 volts to provide a more

reliable and resilient transmission network. To facilitate this transition to higher operating transmission voltage, installation of additional infrastructure and equipment at Trents and St. Thomas is required. The requirement for 69, 000 volt transformers, busbars and associated 69, 000 volt equipment at both St. Thomas and Trents was identified in the recent 2020 Barbados Generation and Transmission Masterplan.

Northern Underground Projected expenditure: $13.1M
Trents 69,000 volt Upgrade Projected expenditure: $13.2M

St. Thomas to Warrens Underground Cable

96. BLPC has received an IPP proposal for the development of 25MW of firm waste-to-energy/biomass capacity and 5MW intermittent solar capacity to be implemented in the region of the Mangrove site along highway 2A. This development will necessitate additional grid infrastructure, taking into account generation dispatch from the CEB and the future Lamberts site, to facilitate power transfer into the southern corridor of the network.

97. To integrate this proposed waste-to-energy/biomass and solar power plant from the Mangrove site to the network requires additional substation equipment at the St. Thomas and Warrens Substations. Integration of the proposed baseload capacity from the biomass plant necessitates an upgrade to the existing overhead transmission line between Central and St. Thomas substations as a redundant path to ensure continued reliability of the network. To facilitate future expansion and interconnection to the existing 69, 000 volt transmission network between Spring Garden and Central substations requires installation of 69, 000 volt equipment, busbars, cables and transformers at both St. Thomas and Warrens substation during the proposed horizon.

Projected expenditure St. Thomas – Warrens 69, 000 volt Equipment Upgrade: $16.6M

Other Transmission Circuits

98. Energy from the proposed wind farm at Lamberts will be fed into the grid at 24, 000 volts, requiring the construction of a 24, 000 volt transmission line from Lamberts to Trents.

    Projected expenditure $0.95M.

99. To facilitate the transition to 100% RE by 2030, BLPC has made provision for interconnection to the transmission network at various locations to the 24, 000 volt high voltage network with provision for the associated switchgear and protection facilities by various IPPs. Provision for this investment has been made based on current interest on an annual basis over the planning horizon.

Distribution Routine Capital

100. This item caters to the routine expansion and enhancement of all aspects of the Distribution network. Some of the major areas covered here include:

    a) provision of service wire, meters and labour to provide new installations;
    b) installation of additional street lights for Government and individuals;
    c) relocation of poles, lines and stays and upgrading of the low tension network;
    d) replacement and upgrade of poles. Pole treatment and upgrade of the distribution feeders overhead and underground;
    e) purchase of distribution transformers; and
    f) purchase of replacement vehicles.

101. Projected Expenditures – Distribution Routine Capital:

    2021- $32.3M
    2022- $21.1M
    2023- $20.8M
    2024- $19.4M
    2025- $19.4M

Other Substation Work

Hampton Substation

102. In keeping with its intent to transition major substations to a more resilient indoor design, the Company obtained planning permission during 2018 for construction of the Hampton substation as the last outdoor substation that remained to be transitioned. Construction on this substation was delayed due to Covid 19 but has subsequently started with installation and commissioning of new indoor switchgear and a new power transformer by 2022. Given the interest by potential IPPs for interconnection of RE generation at various sites near Hampton substation, provision will also be made for possible future battery storage through competitive procurement for grid stability. This will help to firm intermittency of major renewable projects including the proposed solar PV project located in proximity to the Hampton substation.

Projected expenditure- Hampton Substation: – $3.1M

Projected expenditure over the next 5 years– Other Substation Work: $20M

Mobile Transformer

103. The mobile transformer is used as a backup in the event that there is a problem on a main transformer at any 24/11,000-volt substation. This critical asset currently requires a major rewind and it is proposed to purchase a new 24/11,000 volt transformer to be fitted to a new trailer along with associated switchgear and cables.

Projected expenditure- Mobile transformer: $2.1M

GENERAL PROPERTY

Buildings

104. It will be necessary for the Company to perform refurbishment to existing properties at the Garrison compound and make infrastructural improvements to various properties for safety and security of staff and other personnel.

Projected expenditure for General Property over the five (5) year period: $2.1M

ICT ENHANCEMENTS

105. Leveraging technology is a key strategic focus for BLPC, as we continue to grow and modernize our grid whilst facilitating our 100/100 vision. Over the next five years, a number of key strategic projects have been initiated to ensure that we are able to achieve significant business value by utilizing ICT technology in the following key areas – Infrastructure, Cyber Security, Enterprise Resource Planning (ERPs) and Operating Technologies.

106. Our underlying ICT infrastructure serves as our base platform for enabling all other technological projects, and as a result, annual reviews and upgrades are performed for various components to ensure that we achieve reliable and resilient performance for the various applications that support the business. This work consists of an assessment of software and hardware components within our servers, switches, datacenter, storage and end user computing platforms to meet performance requirements in alignment with vendor recommendations regarding support.

107. The Company has always viewed Cyber Security as critical to ensuring we secure out digital assets, in an environment where threats are constantly increasing. An overall Cyber Security policy was developed with 13 different standards covering areas such as asset management, vulnerability management and supply chain that will continuously be updated and actioned to ensure that we follow best practice approaches in securing our technology. Between 2019 and 2021, a number of solutions have been implemented, or are in progress, to achieve full compliance with these standards. The Company will continue to monitor trends within the industry and re-evaluate our position and plans based on such trends in the market to ensure we continue to maintain full compliance.

108. BLPC currently utilises a number of Enterprise Resource Planning (ERP) tools to facilitate key business processes such as Billing and Customer Management – Customer Care & Billing (CC&B), Asset and Workforce Management – PeopleSoft Maximo, Financials and Human Resources – PeopleSoft, Electronic Content Management – Documentum, Meter and Network Management – Command Center and MDMS. Consequently, BLPC maintains full vendor support and ensures the system is fully patched and secure along

with being able to utilise new features from the vendors. In addition, application upgrades are performed throughout the lifecycle of the application. Applications such as Command Center which manages our AMI meters and mesh network, due to its criticality and higher risk profile attract upgrades every other year, whereas other applications, based on risk, are reviewed and upgraded every four to five years.

109. Over the years there has been closer integration of our ICT and Operational Technologies (IT/OT) to drive business success. BLPC utilises a number of key applications such as its Geographic Information System (GIS) which maps all of our assets spatially. GIS also serves as the system of record as well as a foundational piece which integrates with other enterprise applications such as SCADA and AMI. Other key applications include Substation Data Analytics, Distribution Automation, OSI Enterprise Historian (PI Historian), etc. The Company carries out upgrades and functional enhancements for these applications based on business needs and vendor recommendations.

Projected Expenditures for ICT over the next 5 years: $34.8M

110. **Schedule I-3** details the capital program for General Property and ICT related investments.

NEW LICENSING REGIME- DISPATCH FUNCTION

111. With the implementation of the new licensing regime the Company would be required to operate under five (5) licenses, encompassed in three documents as follows: (1) Generation and Energy Storage (2) Transmission Distribution & Sales and (3) Dispatch or System Operator with the MESBE as the market monitor. The System Operator, under the Dispatch License, has responsibility for the open and transparent dispatch of energy from both traditional legacy generation assets plus sources of renewable energy generation to the public grid. The Company, in the first instance, has the obligation to establish the Dispatch Business Unit and System Operator (SO) function to plan, manage and monitor grid operations for optimal dispatch of power to the grid in a safe and reliable manner. With the establishment of the SO, the dispatch function will seek to optimize dispatch to minimize cost to customers through merit order

dispatch of generating units whilst balancing environmental constraints and reliability for the system. In addition to the investments already made in the upgrade of the existing SCADA system, near term investments are required in software, equipment and communications infrastructure as well as integration of SCADA with Automatic Generation Control (AGC) and future Energy Management Systems (EMS). The incremental costs in deploying the SO function and the costs associated with functional unbundling are not fully known at this time.

CONCLUSION

112. The Company over the years has demonstrated its commitment to leading innovations that has resulted in significant customer benefits. These include the implementation of the RER in 2010, the 10 MW solar PV farm in 2016, the ESD device during 2018 and more recently the implementation of the CEB project in 2021 to facilitate the transition to RE whilst balancing the need for fossil fuel generation in support of reliability and resiliency. The CEB project is projected to provide fuel savings benefits of ~$30M based on a USD$60 per barrel international oil price.

113. Further, significant investments continue to be made in grid enhancements for reliability and resilience in terms of indoor substations, underground and overhead T&D infrastructure and major power transformer assets that help to facilitate renewables integration on to the grid.

114. Transformational changes were made to the grid to facilitate smart technologies such as Distribution Automation, GIS, SCADA, AMI and communications infrastructure as the foundational elements in support of the transition to 100% RE.

115. Internal efficiency improvements were also pursued through reorganization of the business to respond to the external environment along with several customer centric initiatives such as upgrading the CIS system, introduction of a Customer Portal and other online initiatives to facilitate ease of transactions and customer interactions.

116. The Company has kept abreast of emerging and disruptive technologies over the years to leverage innovative tools for enhanced customer benefits. The Company is therefore seeking to recover costs for these efficiency improvements, technologic enhancements and capital reinvestments prudently incurred that are geared towards managing costs and stabilizing rates for our customers.

Dated this 30th Day of September, 2021

Paper prepared by:

Rohan Seale
Director Asset Management
The Barbados Light & Power Co. Ltd.

I-1

I-2

I-3

I-4

MAJOR DISTRIBUTION SUBSTATIONS

I-5

J-1

J-1 TARIFF FOR DOMESTIC SERVICE (DS)

APPLICATION

This tariff is available to residential customers who occupy for domestic purposes individually-metered dwelling houses, apartments or condominiums suitable for year-round family occupancy. The residence shall be occupied by the owner or shall be the principal place of residence for the occupant.

TYPE OF SERVICE

Under this tariff, the Company will supply single-phase alternating current electricity at 50 Hz, and one of the secondary voltages specified in the latest revision of the Company's booklet entitled "Information and Requirements Covering Installation of Electric Services and Meters".

CONDITIONS OF SERVICE

Single phase, 2 or 3 wire services up to a maximum of 200 amperes are eligible for this tariff. This tariff is not applicable to customers who occupy dwelling units used or registered for the purpose of transient occupancy such as rooming houses, hotels, guest-houses or villas, or primarily for commercial, industrial or non-domestic activities. No service may be transmitted from a customer who receives electric service to another premises without the prior written consent of the Company.

GENERAL PROVISIONS

When two or more rates are available for certain classes of service, the choice of such rates rests with the customer. The Company will at any time, upon request, advise any customer as to the rate best suited to existing or anticipated service requirements, as defined by the customer. The Company does not assume responsibility for the selection of such rate or the continuance of the lowest annual cost under the selected rate. A customer, having selected a rate, may not change to another rate within a 12-month period unless there is a substantial change in the character or conditions of the service. In the case of a new service, customers will be given reasonable opportunity to determine their service requirements before selecting their preferred rate.

MONTHLY RATE

1) **Customer Charge** - This applies to each electricity service under this tariff for the fixed costs of providing service including the service installation, meter reading, billing and customer service costs. The monthly Customer Charge is determined by the customer's 30 day average kWh consumption over the previous 12 months, or as many months during the past 12 months as are available.

   a) 0 - 150 kWh $ 6/ month + $0.90 VAT = $6.90/month
   b) 151- 500 kWh $10/ month + $1.50 VAT = $11.50/month
   c) Over 500kWh $14 / month + $2.10 VAT = $16.10/month

2) **Base Energy Charge** – This applies to each electricity service under this tariff for all other costs associated with the provision of this service, except the cost of fuel.

   a) First 150 kWh @ $ 0.150 /kWh + $0.0225 VAT = $0.1725 /kWh
   b) Next 350 kWh @ $ 0.176/kWh + $0.0264 VAT = $0.2024 /kWh
   c) Next 1000 kWh @ $ 0.200/kWh + $0.03 VAT = $0.230 /kWh
   d) Over 1500 kWh @ $ 0.224/kWh + $0.0336 VAT = $0.2576 /kWh

3) **Fuel Charge –** This applies to each electricity service under this tariff for the cost of fuel associated with the provision of this service.

   All kWh at the Fuel Clause Adjustment (cents/kWh) + VAT

   The Fuel Clause Adjustment is calculated according to the Fuel Clause approved by the Fair Trading Commission and may vary from month to month.

MINIMUM BILL

The minimum bill shall be the applicable Customer Charge.

DISCOUNT

A 10% discount on the Customer Charge and the Base Energy Charge is allowed if payment is made in full within 15 calendar days of the date of issue of the bill. The discount does not apply to the Fuel Charge portion of the bill.

METER READING AND BILLING

The meters of Domestic Service customers are normally read every other month but these accounts are billed monthly. In the month when the meters are not read, the customers' bills are estimated based on an average of their previous energy consumption.

RULES AND REGULATIONS

Service under this schedule is subject to the orders of the Fair Trading Commission and the latest publication of the "Information and Requirements Covering Installation of Electric Services and Meters". In case of a difference of interpretation between any provision of this schedule and the "Information and Requirements Covering Installation of Electric Services and Meters" booklet, the provision of this schedule shall apply. A bill calculated under this tariff is subject to change under the provisions of such applicable rider(s) as may be approved and / or amended by the Fair Trading Commission.

J-2

J-2 TARIFF FOR GENERAL SERVICE (GS)

APPLICATION

This tariff is available to all customers who meet the required conditions of service.

TYPE OF SERVICE

Under this tariff, the Company will supply single-phase alternating current electricity at 50 Hz, and one of the nominal secondary voltages specified in the latest revision of the Company's booklet entitled "Information and Requirements Covering Installation of Electric Services and Meters". Three-phase service may be furnished but only under special arrangements.

CONDITIONS OF SERVICE

Single phase, 2 or 3 wire services up to a maximum of 10 kVA are eligible for this tariff. No service may be transmitted from a customer who receives service to another premises without the prior written consent of the Company.

GENERAL PROVISIONS

When two or more rates are available for certain classes of service, the choice of such rates rests with the customer. The Company will at any time, upon request, advise any customer as to the rate best suited to existing or anticipated service requirements, as defined by the customer. The Company does not assume responsibility for the selection of such rate or the continuance of the lowest annual cost under the rate selected. A customer, having selected a rate, may not change to another rate within a 12-month period unless there is a substantial change in the character or conditions of the service. In the case of a new service, customers will be given reasonable opportunity to determine their service requirements before selecting their preferred rate.

MONTHLY RATE

1) **Customer Charge** - This applies to each electricity service under this tariff for the fixed costs of providing service including the service installation, meter reading, billing and customer service costs. The monthly customer charge is determined by the customer's 30 day average kWh consumption over the previous 12 months, or as many months during the past 12 months as are available.

   a) 0 -100 kWh $ 8/month + $1.20 VAT = $9.20/month

b) 101 - 500 kWh $ 11/month + $1.65 VAT = $12.65/month
c) Over 500 kWh $ 14/month + $2.10 VAT = $16.10/month

2) **Base Energy Charge** - This applies to each electricity service under this tariff for all other costs directly associated with the provision of this service, except the cost of fuel.

a) First 100 kWh $ 0.184/kWh + $0.0276 VAT = $0.2116 /kWh
b) Next 400 kWh $ 0.217/kWh + $0.03255 VAT = $0.24955 /kWh
c) Next 1000 kWh $ 0.259/kWh + $0.03885 VAT = $0.29785 /kWh
d) Over 1500 kWh $ 0.290/kWh + $0.0435 VAT = $0.3335 /kWh

3) **Fuel Charge** - This applies to each electricity service under this tariff for the cost of fuel associated with the provision of this service.

All kWh at the Fuel Clause Adjustment (cents/kWh) + VAT

The Fuel Clause Adjustment is calculated according to the Fuel Clause approved by the Fair Trading Commission and may vary from month to month.

MINIMUM BILL

The minimum bill shall be the applicable Customer Charge.

METER READING AND BILLING

The meters of General Service customers are normally read every other month but these accounts are billed monthly. In the month when the meters are not read, the customers' bills are estimated based on an average of their previous energy consumption.

RULES AND REGULATIONS

Service under this schedule is subject to the orders of the Fair Trading Commission and the latest publication of the "Information and Requirements Covering Installation of Electric Services and Meters". In the case of a difference of interpretation between any provision of this schedule and the "Information and Requirements Covering Installation of Electric Services and Meters" booklet the provision of this schedule shall apply. A bill calculated under this tariff is subject to change under the provisions of such applicable rider(s) as may be approved and / or amended by the Fair Trading Commission.

J-3

J-3 TARIFF FOR SECONDARY VOLTAGE POWER (SVP)

APPLICATION

This tariff is available to all customers.

TYPE OF SERVICE

Under this tariff, the Company will supply single-phase or three-phase alternating current electricity at 50 Hz, at one of the nominal secondary voltages specified in the latest revision of the Company's booklet entitled "Information and Requirements Covering Installation of Electric Services and Meters".

CONDITIONS OF SERVICE

This tariff is available for customers with a billing demand of not less than 5 kVA. No service may be transmitted from a customer who receives this service to another premises without the express prior written consent of the Company.

GENERAL PROVISIONS

When two or more rates are available for certain classes of service, the choice of such rates rests with the customer. The Company will at any time, upon request, advise any customer as to the rate best suited to existing or anticipated service requirements, as defined by the customer. The Company does not assume responsibility for the selection of such rate. A customer, having selected a rate, may not change to another rate within a 12-month period unless there is a substantial change in the character or conditions of the service. In the case of a new service, customers will be given reasonable opportunity to determine their service requirements before selecting their preferred rate.

MONTHLY RATE

1) **Customer Charge** - This applies to each electricity service under this tariff for the fixed costs of providing service, including service installation, meter reading, billing and customer services.

$20.00/month + $3.00 VAT = $23.00/month

2) **Demand Charge** – This applies to each electricity service under this tariff for the costs associated with the generating facilities, transmission and distribution lines, substations, transformers and other facilities required to meet individual and combined customer peak demand.

(a) For Company-owned transformer(s):
$24.00/kVA of Billing Demand + $3.60 VAT = $27.60 /kVA

(b) For Customer-owned transformer(s):
$22.00/kVA of Billing Demand + $3.30 VAT = $25.30 /kVA

Note that (b) is not available for new connections or for expansion of existing customer transformer installations unless approved by the Company under special circumstances.

3) **Base Energy Charge** - This applies to each electricity service under this tariff for the variable energy costs associated with the provision of this service, except the cost of fuel.

All kWh @ $0.1380 + $0.0207 VAT = $0.1587 /kWh

4) **Fuel Charge** - This applies to each electricity service under this tariff for the cost of fuel associated with the provision of this service.

All kWh @ the Fuel Clause Adjustment (cents / kWh) + VAT

The Fuel Clause Adjustment is calculated monthly according to the Fuel Clause approved by the Fair Trading Commission and may vary from month to month.

BILLING DEMAND

(a) Customers connected under this rate shall be metered as to demand and the billing demand shall be the maximum measured demand of the current month or 5 kVA, whichever is greater. The measured demand may be measured in either kW or kVA at the option of the Company depending upon the character of the service. If the demand is measured in kW then the maximum kW reading shall be divided by a correction factor of 0.85 for conversion to kVA for billing purposes.

(b) The Company shall reserve the right to assess the billing demand in cases where an accurate demand reading cannot be obtained, for example, due to the inaccessibility of the meter or a demand seal being broken. In these cases, the billing demand shall be assessed using the best estimate of the customer's kWh/kVA ratio and energy usage for the period. These will normally be determined using an average of the previous three months of the customer's billing information.

(c) The Company shall reserve the right to assess the billing demand based on a connected load for installations with high momentary demands including lifts, cranes, X-ray equipment and welders.

(d) For customers with a contracted demand, the billing demand shall be the higher of (a) or (b) or the contracted demand.

MINIMUM BILL

The minimum bill shall be the Billing Demand Charge plus the Customer Charge

TERMS OF SERVICE

Not less than one year.

RULES AND REGULATIONS

Service under this schedule is subject to the orders of the Fair Trading Commission and the latest publication of the "Information and Requirements Covering Installation of Electric Services and Meters". In case of a difference of interpretation between any provision of this schedule and the "Information and Requirements Covering Installation of Electric Services and Meters" booklet the provision of this schedule shall apply. A bill calculated under this tariff is subject to change under the provisions of such applicable rider(s) as may be approved and / or amended by the Fair Trading Commission.

J-4

J-4 TARIFF FOR LARGE POWER (LP)

APPLICATION

This tariff is available to all customers receiving supply at primary voltage.

TYPE OF SERVICE

Under this tariff, the Company will supply three-phase alternating current electricity at 50 Hz, and one of the nominal primary voltages specified in the latest revision of the Company's booklet entitled "Information and Requirements Covering Installation of Electric Services and Meters".

CONDITION OF SERVICE

This tariff is available for customers with a billing demand of not less than 50 kVA. No service may be transmitted from a customer to another premises without the express written prior consent of the Company.

GENERAL PROVISIONS

When two or more rates are available for certain classes of service, the choice of such rates rests with the customer. The Company will at any time, upon request, advise any customer as to the rate best suited to existing or anticipated service requirements, as defined by the customer. The Company does not assume responsibility for the selection of such rate. A customer, having selected a rate, may not change to another rate within a 12-month period unless there is a substantial change in the character or conditions of the service. In the case of a new service, customers will be given reasonable opportunity to determine their service requirements before selecting their preferred rate.

MONTHLY RATE

1) **Customer Charge** - This applies to each electricity service under this tariff for the fixed costs of providing service, including service installation, meter reading, billing and customer services.

   $300.00/month + $45.00 VAT = $345.00/month

2) **Demand Charge** - This applies to each electricity service under this tariff for the costs associated with the generating facilities, transmission and distribution lines, substations, transformers and other facilities required to meet individual and combined customer peak demand.

$22.00 / kVA of Billing Demand + $3.30 VAT = $25.30 /kVA

Note: In cases where a customer's transformer may fail, or otherwise be unavailable, the Company may provide a transformer on a temporary basis for an additional charge as set out in the Schedule of Service Charges.

3) **Base Energy Charge** - This applies to each electricity service under this tariff for the variable energy costs associated with the provision of this service, except the cost of fuel.

All kWh @ $0.1170 / kWh + $0.01755 VAT = $0.13455 /kWh

4) **Fuel Charge** - This applies to each electricity service under this tariff for the cost of fuel associated with the provision of this service.

All kWh @ the Fuel Clause Adjustment (cents/kWh) + VAT

The Fuel Clause Adjustment is calculated according to the Fuel Clause approved by the Fair Trading Commission and may vary from month to month.

METERING ON LOW VOLTAGE SIDE

Normally the usage for customers under this tariff will be metered on the high voltage side of their transformer. However, under special circumstances, at the Company's discretion, their usage may be metered on the low voltage side of the transformer. On these occasions the Company shall increase the Billing Demand and energy consumed by a loss factor for the calculation of the Demand, Base Energy and Fuel Charges to account for losses incurred in the customer's transformer.

MINIMUM BILL

The minimum bill shall be the Billing Demand Charge plus the Customer Charge.

BILLING DEMAND

(a) Customers connected under this rate shall be metered as to demand and the billing demand shall be the maximum measured demand of the current month or 50 kVA, whichever is greater. The measured demand may be measured in either kW or kVA at the option of the Company depending upon the character of the service. If the demand is measured in kW then the maximum kW reading shall be divided by a correction factor of 0.85 for conversion to kVA for billing purposes.

(b) The Company shall reserve the right to assess the billing demand in cases where an accurate demand reading cannot be obtained, for example due to the inaccessibility of the meter or a demand seal being broken. In these cases, the demand will be assessed using the best estimate of the customer's kWh/kVA ratio and energy usage for the period. These will normally be determined using an average of the previous three months of the customer's billing information.

(c) The Company shall reserve the right to assess the billing demand based on a connected load for installations with high momentary demands including lifts, cranes, X-ray equipment and welders.

(d) For customers with a contracted demand, the billing demand shall be the higher of (a) or (b) or the contracted demand.

TERMS OF SERVICE

Not less than one year.

RULES AND REGULATIONS

Service under this schedule is subject to the orders of the Fair Trading Commission and the latest publication of the "Information and Requirements Covering Installation of Electric Services and Meters". In case of a difference of interpretation between any provision of this schedule and the "Information and Requirements Covering Installation of Electric Services and Meters" booklet the provision of this schedule shall apply. A bill calculated under this tariff is subject to change under the provisions of such applicable rider(s) as may be approved and / or amended by the Fair Trading Commission.

J-5

J-5 TARIFF FOR EMPLOYEES

APPLICATION

This tariff is available to present and retired employees of The Barbados Light & Power Co. Ltd. It applies to an individually-metered dwelling house or apartment occupied for domestic purposes by the employee.

TYPE OF SERVICE

Under this tariff, the Company will supply single-phase alternating current electricity at 50 Hz, and one of the secondary voltages specified in the latest revision of the Company's booklet entitled "Information and Requirements Covering Installation of Electric Services and Meters".

CONDITIONS OF SERVICE

Single phase, 2 or 3 wire services up to a maximum of 200 amperes are eligible for this tariff. This tariff is not applicable to employees who occupy dwelling units used or registered for the purpose of transient occupancy such as rooming houses, hotels, guest-houses or villas, or primarily for commercial, industrial or non-domestic activities. No service may be transmitted from a customer who receives service to another premises without the prior written consent of the Company.

MONTHLY RATE

1. **Base Energy Charge** - This applies to each electricity service under this tariff for all costs associated with the provision of this service, except the cost of fuel.

   a) First 150 kWh @ $0.108 /kWh + $0.0162 VAT = $0.1242 /kWh
   b) Next 350 kWh @ $ 0.127 /kWh + $0.01905 VAT = $0.14605 /kWh
   c) Next 1000 kWh @ $ 0.180 /kWh + $0.027 VAT = $0.207 /kWh
   d) Over 1500 kWh @ $ 0.202 /kWh + $0.0303 VAT = $0.2323 /kWh

2. **Fuel Charge** - This applies to each electricity service under this tariff for the cost of fuel associated with the provision of this service.

   All kWh at the Fuel Clause Adjustment (cents/kWh) + VAT

   The Fuel Clause Adjustment is calculated according to the Fuel Clause approved by the Fair Trading Commission and may vary from month to month.

RULES AND REGULATIONS

Service under this schedule is subject to the orders of the Fair Trading Commission and the latest publication of the “Information and Requirements Covering Installation of Electric Services and Meters”. In case of a difference of interpretation between any provision of this schedule and the “Information and Requirements Covering Installation of Electric Services and Meters” booklet the provision of this schedule shall apply. A bill calculated under this tariff is subject to change under the provisions of such applicable rider(s) as may be approved and / or amended by the Fair Trading Commission.

J-6

J-6 TARIFF FOR STREET LIGHTS

APPLICATION

This tariff is available for Street Lighting provided by the Company.

MONTHLY RATE

1. **Customer Charge** - This applies to each street light of the stated type and size under this tariff for the costs associated with the provision of this service, except the cost of fuel.

   a) 50W (HPS): $7.04/month + $1.056 VAT = $8.096/month
   b) 70W (HPS): $7.73/month + $1.1595 VAT = $8.8895/month
   c) 100W (HPS): $8.59/month + $1.2885 VAT = $9.8785/month

2. **Fuel Charge** - This applies to each street light of the stated type and size under this tariff for the cost of fuel associated with the provision of this service.

   a) 50W (HPS : 25 kWh x Fuel Clause Adjustment (cents/kWh) + VAT
   b) 70W (HPS): 33 kWh x Fuel Clause Adjustment (cents/kWh) + VAT
   c) 100W (HPS): 43 kWh x Fuel Clause Adjustment (cents/kWh) + VAT

   The Fuel Clause Adjustment is calculated according to the Fuel Clause approved by the Fair Trading Commission and may vary from month to month.

RULES AND REGULATIONS

Service under this schedule is subject to the orders of the Fair Trading Commission and the latest publication of the “Information and Requirements Covering Installation of Electric Services and Meters”. In case of a difference of interpretation between any provision of this schedule and the “Information and Requirements Covering Installation of Electric Services and Meters” booklet the provision of this schedule shall apply. A bill calculated under this tariff is subject to change under the provisions of such applicable rider(s) as may be approved and / or amended by the Fair Trading Commission.

J-7

J-7 SERVICE CHARGES SCHEDULE

Charge	Service	Approved Service Charge (exc VAT)	Approved Service Charge (inc VAT)
New Service	Below 200 Amps	$50.00	$57.50
	Above 200 Amps	$200.00	$230.00
Reconnection/Transfer of Service	Below 200 Amps	$20.00	$23.00
	Above 200 Amps	$40.00	$46.00
Debt Reconnection	During Regular Working Hours	$20.00	$23.00
	After Hours	$40.00	$46.00
Shift Meter	Below 200 Amps	$50.00	$57.50
	Above 200 Amps	$200.00	$230.00
Upgrade Service	Below 200 Amps	$50.00	$57.50
	Above 200 Amps	$200.00	$230.00
Damaged Meter	1-PH Meter	$50.00	$57.50
	3-PH Meter	$200.00	$230.00
Special Events/Temporary Service	Below 200 Amps	$60.00	$69.00
	Above 200 Amps	$210.00	$241.50
One Day Event	One Day Event Service. 1-PH below 200 Amps	$75.00	$86.25
Tampering Fee	Each	$250.00	$287.50
Provide & Install Sealing Ring	Each	$20.00	$23.00
Special Read	Each	$20.00	$23.00
Meter Test	Each	$50.00	$57.50
Returned Cheque	Each	Bank Charge plus $10.00	Bank Charge plus $11.50
Transformer Rental	Primary voltage	$1.00/kVA of transformer capacity	$1.15/kVA of transformer capacity
Renewable Service-Application Fee	Each	$50.00	$57.50

J-8

J-8 TIME-OF-USE TARIFF (TOU)

APPLICATION

The Time-of-Use Tariff (this "Tariff") is available as a pilot programme for two (2) years to customers who satisfy the criteria for the Large Power (LP) tariff on a first come first serve basis. This Tariff is available for a maximum of thirty (30) electricity services, with no more than six (6) services per entity subscribing unless otherwise approved by the Company.

TYPE OF SERVICE

Under this Tariff, the Company will supply three-phase alternating current electricity at 50 Hz, and one of the nominal primary voltages specified in the latest revision of the Company's booklet entitled "Information and Requirements Covering Installation of Electric Services and Meters".

CONDITION OF SERVICE

This Tariff is available to customers with a billing demand of not less than 50 kVA. No service may be transmitted from a customer to another premise without the express prior written consent of the Company.

GENERAL PROVISIONS

When two or more rates are available for certain classes of service, the choice of such rates rests with the customer. The Company will at any time, upon request, advise any customer as to the rate best suited to existing or anticipated service requirements, as defined by the customer. The Company does not assume responsibility for the selection of such rate or the continuance of the lowest annual cost under the selected rate. A customer, having selected a rate, may not change to another rate within a 12-month period unless there is a substantial change in the character or conditions of the service. In the case of a new service, customers will be given reasonable opportunity to determine their service requirements before selecting their preferred rate.

MONTHLY RATE

1) **Customer Charge** - This applies to each electricity service under this Tariff for the fixed costs of providing service, including the service installation, meter reading, billing and customer service.

   $300.00/month + $45.00 VAT = $345.00/month

2) **Demand Charge** - This applies to each electricity service under this Tariff for the costs associated with the generating facilities, transmission and distribution lines, substations, transformers and other facilities required to meet individual and combined customer peak demand.

$18.00/kVA of Billing Demand + $2.70 VAT = $20.70/kVA

3) **Base Energy Charge** - This applies to each electricity service under this Tariff for the variable energy costs associated with the provision of this service, except the cost of fuel, within the time periods shown below:

On-peak: $0.2190 / kWh + $0.03285 VAT = $0.25185/kWh
Off-peak: $0.0620 / kWh + $0.0093 VAT = $0.0713/kWh

4) **Fuel Charge** - This applies to each electricity service under this Tariff for the cost of fuel associated with the provision of this service, within the time periods shown below:

On-peak: 1.12 times the Fuel Clause Adjustment (cents/kWh) plus VAT
Off-peak: 0.92 times the Fuel Clause Adjustment (cents/kWh) plus VAT

The Fuel Clause Adjustment is calculated according to the Fuel Clause approved by the Fair Trading Commission and may vary from month to month.

DEFINITION OF TIME PERIOD

On-peak: 10:00am to 09:00pm Monday through Friday, except annually published public holidays
Off-peak: All hours other than on-peak

METERING ON LOW VOLTAGE SIDE

Normally the usage for customers under this Tariff will be metered on the high voltage side of their transformer. However, under special circumstances, at the Company's discretion, their usage may be metered on the low voltage side of the transformer. On these occasions the Company shall increase the Billing Demand and energy consumed by a loss factor for the calculation of the Demand, Base Energy and Fuel Charges to account for losses incurred in the customer's transformer.

MINIMUM BILL

The minimum bill shall be the Billing Demand Charge plus the Customer Charge.

BILLING DEMAND

(a) Customers connected under this rate shall be metered as to demand and the billing demand shall be the maximum measured demand of the current month or 50 kVA, whichever is greater. The measured demand may be measured in either kW or kVA at the option of the Company depending upon the character of the service. If the demand is measured in kW then the maximum kW reading shall be divided by a correction factor of 0.85 for conversion to kVA for billing purposes.

(b) The Company shall reserve the right to assess the billing demand in cases where an accurate demand reading cannot be obtained, for example due to the inaccessibility of the meter or a demand seal being broken. In these cases, the demand will be assessed using the best estimate of the customer’s kWh/kVA ratio and energy usage for the period. These will normally be determined using an average of the previous three months of the customer’s billing information.

(c) The Company shall reserve the right to assess the billing demand based on a connected load for installations with high momentary demands including lifts, cranes, X-ray equipment and welders.

(d) For customers with a contracted demand, the billing demand shall be the higher of (a), (b), (c) or the contracted demand.

TERMS OF SERVICE

The initial contract period for this Tariff is for a minimum of one year. At the end of the pilot programme the Company will review the experience it has gained from the programme and determine whether to continue to offer this tariff. Customers will be advised accordingly. If the Company decides to continue to make this Tariff available, customers who wish to remain on it with the new arrangements will not be required to take any further action. However, if the Company decides not to continue with it or the customer no longer wants to participate, the other party shall be advised and the customer will revert to the LP tariff.

RULES AND REGULATIONS

Service under this schedule is subject to the orders of the Fair Trading Commission and the latest publication of the "Information and Requirements Covering Installation of Electric Services and Meters". In case of a difference of interpretation between any provision of this schedule and the "Information and Requirements Covering Installation of Electric Services and Meters" booklet the provision of this schedule shall apply. A bill calculated under this Tariff is subject to change under the provisions of such applicable rider(s) as may be approved and / or amended by the Fair Trading Commission.

J-9

J-9 RENEWABLE ENERGY RIDER (RER)

APPLICATION

This rider is available to customers who qualify for the Domestic Service (DS), Employee (EMP), General Service (GS), Secondary Voltage Power (SVP), Large Power (LP) and Time-of-Use (TOU) pilot programme customers. All of the provisions of the applicable DS, EMP, GS, SVP, LP and TOU tariffs will apply except as amended by this rider. This rider is specific to customers with renewable generation system (hereinafter collectively referred to as "Customer-Generators" and each as a "Customer-Generator") utilizing a wind turbine, solar photovoltaic or hybrid (wind/solar) power source located on the customer's owned or rented premises.

The Customer-Generator shall have up to a maximum capacity limit of 500 kW. This rider is available on a first-come first-serve basis up to a maximum combined installed capacity as approved by the appropriate designated authority. The Company reserves the right to limit the number of services per individual or entity.

This rider is applicable only to the energy produced by the Customer-Generator to the Company's electric grid. All other services supplied to the customer will be billed in accordance with the rates and charges under the customer's applicable standard tariff. Service under this rider is conditional on the continuance of service to the customer under one of the applicable standard tariffs.

CONDITIONS OF SERVICE

The service under this rider will be provided to the entire premises through a single point of delivery at a single voltage in accordance with the terms of the standard tariff applicable to the
customer. The Customer-Generator must be:

a) capable of providing single or three phase voltage at 50 Hz, with its rated output not exceeding 50% of the Ampere rating of the main breaker of the installation, and
b) manufactured, installed and operated to meet the Company's standards for interconnection as set out in the Company's "Renewable Energy Rider Agreement" and the "Requirements for Grid Interconnection of Renewable Generation Systems" and all applicable Government and industry safety and performance standards.

The Company reserves the right to disconnect the electricity supply to the entire premises to which the Customer-Generator is connected, without notice and without incurring any liability, for failure to comply with the requirements of the interconnection agreement or for other reasons relating to safety and reliability. Provision must be made for the measurement of energy produced by the Customer-Generator through a meter provided by the Company.

INTERCONNECTION

Before interconnection to BL&P's Grid can be completed, the Customer-Generator is required to do the following:

a) Understand BL&P's interconnection requirements before starting the project;
b) Submit an "Application for Grid Interconnection for Renewable Energy Rider" form along with an Electrical One-Line Diagram;
c) Ensure a visible lockable AC disconnect is in an accessible location at or near BL&P's meter;
d) Submit an "Application for Grid Interconnection" form along with an Electrical One-Line Diagram;
e) Submit a GEED certificate for the RGS;
f) Submit a valid certificate of insurance evidencing general liability insurance coverage;
g) Submit a specification sheet of the inverter showing the product listing;
h) Sign and submit a "Renewable Energy Rider Agreement" ("***RER*** Agreement")
i) Submit certification documentation from the inverter manufacturer prior to interconnection to verify that voltage and frequency ride through requirements have been satisfied.

MONTHLY RENEWABLE ENERGY RIDER (RER) CREDIT

The RER credit is temporary set at BB$0.416/kWh for solar PV and BB$0.315/kWh for wind, until such time as a permanent rate may be established. This credit will apply to RE suppliers with capacities up to 500 kW.

BILLING

The Company will utilize a Net Billing with Rolling Credit and Buyback methodology for billing purposes. At the end of each billing period, if the account is in debit after the renewable energy credits have been applied, the balance due will be billed and payable. If the account is in credit, the credit will be carried forward (rolled over) to the next billing period.

If at the end of each quarter, the customer has accumulated a credit greater than or equal to $100.00, the customer shall be provided with a refund of the credit from the Company. All new DS, GS, EMP, SVP and LP customers on the RER will be billed under the "buy all/sell all" billing arrangement with the exception of DS, GS, and EMP customer with a Customer-Generator capacity of 2 kW or less who will also have the option of the "sale of excess" billing arrangement. This billing arrangement will remain in place for the duration of the agreement.

Customer-Generators interconnected before September 1st, 2014 may remain on their current billing arrangement or exercise the option within 3 months of this date to change to the buy all/sell all billing arrangement.

METERING CONFIGURATION

The following metering configurations are permitted:

a) Metering configuration 1 – point of interconnection on the customer's side of the revenue meter
b) Metering configuration 2 – point of interconnection on the grid side of the revenue meter.

The "sale of excess" billing arrangement is not available for Customer-Generators interconnected using metering configuration 2.

TERMS OF SERVICE

The duration of the agreement between BL&P and the Customer–generator for interconnection to the grid and purchase of energy shall be offered for a minimum of ten years. The value of the RER credit shall be subject to review every 3 years or as periodically determined by the Fair Trading Commission.

RULES & REGULATIONS

Service under this schedule is subject to the orders of the Fair Trading Commission and the latest publication of the "Information and Requirements Covering Installation of Electric Services and Meters". In case of a difference of interpretation between any provision of this schedule and the "Information and Requirements Covering Installation of Electric Services and Meters" booklet the provision of this schedule shall be deemed to apply.

J-10

J-10 INTERRUPTIBLE SERVICE RIDER (ISR)

APPLICATION

This Interruptible Service Rider (ISR) is available on a permanent basis from the effective date of February 1, 2016 to customers in the Secondary Voltage Power (SVP) and Large Power (LP) tariffs (“eligible customers”) as follows:

(a) to eligible customers with a Billing Demand in excess of 200 kVA and a Monthly Interruptible Demand of not less than 100 kVA.

All of the provisions of the applicable SVP and LP tariffs will apply except as amended by this Rider.

Customers on the Time-of-Use Tariff are not eligible to participate under this Rider.

CONDITIONS OF SERVICE

To be eligible, customers must be able to demonstrate the ability to reduce their load to the Firm Demand Level (FDL) within 30 minutes of being notified to do so via the communication channel agreed between the customer and the Company. The minimum FDL shall be zero. The customer shall not be required to exceed 240 hours of interruption in a contractual year.

POWER INTERRUPTION NOTIFICATION

The Company will notify the customer, using an agreed method of the time the customer will be required to interrupt their load at least thirty minutes in advance and the Company will notify them, at an appropriate time, when the interruption will end.

INTERRUPTIBLE CAPACITY CREDITS

The Company will credit the customer for their Monthly Interruptible Demand (MID) at the following rates:

(a) $12.00 / kVA of Monthly Interruptible Demand (MID) for customers agreeing to be interrupted between 8.00 am and 9.00 pm on any day except Saturdays, Sundays and public holidays.

(b) $9.00 / kVA of Monthly Interruptible Demand (MID) for customers agreeing to be interrupted between 8.00 am and 4.30 pm on any day except Saturdays, Sundays and public holidays.

where:

(c) The **Monthly Interruptible Demand (MID)** is the difference between the **Monthly Average Demand (MAD)** and the **Firm Demand Level (FDL)**

MID = MAD –FDL:

(d) The **Monthly Average Demand (MAD)** is the number of kilowatt hours (kWh) consumed by the customer for the billing period divided by the number of days (DOS) in the billing period times 24 hours minus the number of hours interrupted in the month (Ih) and divided by power factor of 0.85:

MAD = (kWh/(DOS*24-Ih))/0.85

(e) The **Firm Demand Level (FDL)** is the kVA demand level established between the Company and the customer that specifies the load limit of interruption. The customer must reduce the demand to this level or below during periods of required reductions.

SPECIAL PROVISIONS

In the event the Monthly Interruptible Demand (MID) is less than the minimum of 100 kVA no credit will be paid for that month.

In the event that the Company notifies the customer of an interruption and the customer fails to reduce power usage as required by the Agreement, no monthly credit will be issued for the month in which the customer failed to reduce power usage. In addition, the value of the credit that would otherwise have been afforded to the customer had it reached its FDL during an interruptible period for that billing month, will be added to the customer's bill for the current month.

INTERRUPTIBLE RIDER AGREEMENT

Customers who wish to participate in this program must register for this Rider. Eligible customers must enter into an Interruptible Rider Agreement with the Company (the Agreement) for a contract period of not less than one year. Customers may request termination of the contract by giving the Company at least three (3) months' notice of its desire to terminate the contract.

TERMS OF SERVICE

The minimum contract period for this Rider is one year. Periodically, terms and conditions of service under the ISR Agreement will be subject to regulatory review and may change once regulatory approval has been granted to the Company to amend them. Where the Company has sought a review of the ISR terms and conditions of service and as a result the ISR Agreement has been amended to reflect regulatory determinations which are different to what currently exist, customers participating in the ISR program will be advised immediately of any new arrangements. Following this, existing customers desirous of continuing on with the ISR program will be required to enter into a new contractual agreement with the Company.

RULES AND REGULATIONS

Service under this schedule is subject to the orders of the Fair Trading Commission and the latest publication of the "Information and Requirements Covering Installation of Electric Services and Meters" booklet. In case of a difference of interpretation between any provision of this schedule and the "Information and Requirements Covering Installation of Electric Services and Meters" booklet the provision of this schedule shall be deemed to apply. A bill calculated under this is subject to change as may be approved and / or amended by the Fair Trading Commission under the provisions of applicable riders.

J-11

J-11 TARIFF FOR FUEL CLAUSE ADJUSTMENT

The Fuel Clause Adjustment (FCA) shall be calculated according to the following formula:

Fuel Clause Adjustment = (the Projected Cost of Fuel + the Projected Cost of Purchased Power for the billing month + (or -) net amount under-recovered or over-recovered and brought forward from the previous month) divided by Projected kWh sales for the billing month.

In determining the FCA the Company will:

a) use its best estimates of the Projected Cost of Fuel, the Projected Purchased Power and the Projected kilowatt hour (kWh) sales for the month.

b) reconcile monthly the revenue from the fuel charges billed in the previous month with the actual Cost of Fuel used during that month and calculate the under or over recovery, as the case may be, for that month. The net balance of the under or over recovery will be carried forward to the next billing month.

c) where the net under or over recovery in a previous billing month is of an amount, such that, when added or subtracted (as the case may be) to the Cost of Fuel and of Purchased Power, there may be significant fluctuations in the FCA in subsequent months the Company may spread the balance of the under or over recovery amount over one or more subsequent months, so as to smooth fluctuations in the FCA for these months.

K

MEMORANDUM ON PROPOSED TARIFFS

INTRODUCTION

1. The Memorandum presents the electricity rates that The Barbados Light & Power Company Limited ("BLPC" or “the Company”) is proposing in its Application to the Fair Trading Commission ("the Commission") for a rate review and to provide the rationale for revenue allocation and rate design.

2. The proposed rate design recovers the test year revenue increase of $46.475 million, which the Revenue Requirement Memorandum supports.

3. BLPC utilized an embedded cost of service study to develop its class revenue allocations and rate design proposals. The “Allocated Class Cost of Service ("COS") Study”, attached to the Affidavit of Dr. Philip Hanser of the Brattle Group, as Exhibit PH2 serves as the primary tool for guiding the rate design process.

4. This Memorandum sets out proposed revisions to existing tariffs and riders and offers updates to service charges for certain activities carried out by BLPC. BLPC also proposes the establishment of a permanent Time-of-Use (TOU) tariff and the disaggregation of the current Fuel Clause Adjustment (FCA) to allow for the establishment of a Renewable Purchased Power Adjustment (RPPA) clause to recover the cost of renewable energy purchases. A description of the proposed tariffs and riders is shown in schedules K-1 to K-11.

5. Table K.6 provides revenues at current and proposed rates.

6. Table K.7 displays a summary comparison of the current and proposed rates.

RATE DESIGN & REVENUE ALLOCATION OBJECTIVES

7. BLPC's rate design and revenue allocation objectives are efficiency, fairness, and revenue adequacy. Efficiency requires that the rate design recover costs from customers in a manner that reflects as far as practical how BLPC incurs costs. Simultaneously, fairness calls for allocating BLPC's revenue requirement

among customer classes to reflect the cost of providing the electricity service to each customer class. The revenue adequacy objective ensures that rates recover the revenue requirements outlined in the Memorandum on Revenue Requirement.

8. Another essential objective is rate stability. This objective recognizes that revenue allocation and rate design based primarily on the other objectives described above, must be moderated to acknowledge impacts on the total electricity bill of customers.

9. BLPC's proposed rate design achieves revenue adequacy by designing rates to recover the proposed revenue requirement for the respective customer classes. The results of the COS Study facilitated the achievement of the efficiency and fairness objectives, as BLPC's rate design relies less heavily on the recovery of fixed costs through variable kWh energy charges. The continued overreliance on volumetric energy charges to recover a significant portion of fixed costs, coupled with a decline in usage, will render BLPC unable to recover all of its costs.

10. In acknowledgement and support of the Government of Barbados' (GoB) policy objective to encourage the increased adoption of renewable generation by customers, BLPC proposes a transition to increased reliance on the fixed components of the bill to recover fixed costs. This rate structure provides a more accurate and efficient price signal to customers that self-generate a significant proportion of their electricity requirements and rely on the electricity grid for backup supply.

11. The objectives of fairness, efficiency and adequacy often conflict with the rate stability objective in the rate design process. Moving to a rate design based strictly on the results of the COS Study will result in rate changes with substantial total bill impacts. Bill impacts were therefore taken into consideration and imposed constraints on the revenue allocation and rate design process.

EXISTING TARIFFS & RIDERS

12. The existing tariffs, shown in Schedules J-1 to J-6, were approved by the Commission in its Decision dated January 25, 2010. These tariffs are:
    a) Domestic Service (DS);
    b) General Service (GS);
    c) Employee (EMP);
    d) Secondary Voltage Power (SVP);
    e) Large Power (LP) and
    f) Street Lighting (SL)

13. Schedule J-7 sets out the existing miscellaneous Service Charges.

14. In March 2010, the Commission approved the establishment of a Time-of-Use (TOU) tariff, an Interruptible Service Rider (ISR) and a Renewable Energy Rider (RER) on a pilot basis initially for a period of two years. The Commission granted extensions for the period of the TOU tariff pilot and the ISR and RER were subsequently approved permanently. The TOU tariff, the ISR and the RER are shown in Schedules J-8 to J-10.

15. All tariffs are currently subject to the FCA shown in Schedule J-11. The monthly FCA is based on the sum of the previous month's cost of energy purchased and cost of fuel consumed, plus any cumulative over and under recovery divided by the kWh sales of the previous month. Currently, energy purchase costs include energy purchased from renewable energy resources.

16. In the Commission's Decision of April 23, 2019, Document Number: FTCUR/MTNDECESD/BL&P-2019-01[1], it was determined that the calculation of the FCA would also include Heat Rate targets for all baseload plants and cost recovery for a 5 MW Energy Storage Device (ESD), annually recovered in February of each year.

17. Customers served under the existing tariffs and riders totalled 131,522 at the end of 2020, representing 11% growth over the 118,798 customers in the 2008

[1] https://www.ftc.gov.bb/library/2019-04-17_commission_decision_blandp_motion_esd_decision.pdf

test year, which formed the basis of the tariff design in the Commission's 2010 Decision.[2]

18. Customers on the Domestic Service tariff totalled 114,812 at the end of 2020 and accounted for approximately 87% of customers, compared to 83% in 2008. The 11,651 customers on the General Service tariff were about 3,350 fewer than in 2008 as its share of total customers declined to 8.9%.

19. The number of customers on the Secondary Voltage Power and the Large Power tariffs was lower at the end of 2020 than the number registered in 2008, as shown in Table K.1. The Secondary Voltage Power tariff comprised of 4,441 customers, 4% lower than in 2008, while the Large Power tariff accounted for one hundred and thirty-eight (138) customers, a 22% decline since 2008 as the current customers on the Time of Use tariff pilot shifted from the Large Power tariff during the period.

Table K.1: Customers by Rate Class

Rate Class	Number of Customers		Proportion of Customers	
	2008	2020	2008	2020
Domestic Service	98,423	114,812	82.8%	87.3%
General Service	15,005	11,651	12.6%	8.9%
Secondary Voltage Power	4,615	4,441	3.9%	3.4%
Large Power	178	138	0.1%	0.1%
Time of Use	-	20	-	0.0%
Employees	577	463	0.5%	0.4%

20. Energy sales totalled approximately 889.9 million kilowatt-hours (kWh), 5.7% lower than energy sales registered at the end of 2008. The proportion of energy sales attributed to customers on the Domestic Service tariff rose from 31.6% in 2008 to 38.8% at the end of 2020 to register approximately 345.2 million kWh. Energy sales to Secondary Voltage Power customers accounted for 32.2% of total energy sales to record about 286.3 million kWh, 16.6% lower than in 2008. Large Power energy sales stood at 166.1 million kWh and contributed 18.7% to total energy sales. The proportion of energy sales attributed to the General

[2] https://www.ftc.gov.bb/library/blip_app/2010-01-22_commission_decision_No2_of_09_rate_review_barbados_light_and_power_company_limited.pdf

Service tariff remained unchanged at 5.6%; however, its energy sales of 49.9 million kWh was 5.3% lower than in 2008. Energy sales on the pilot Time of Use tariff stood at 32.6 million kWh, as highlighted in Table K.2.

Table K.2: Energy Sales by Rate Class

Rate Class	Energy Sales (MWh)		Proportion of Energy Sales	
	2008	2020	2008	2020
Domestic Service	298,696	345,229	31.6%	38.8%
General Service	52,774	49,960	5.6%	5.6%
Secondary Voltage Power	343,250	286,287	36.4%	32.2%
Large Power	236,622	166,151	25.1%	18.7%
Time of Use	-	32,635	-	3.7%
Employees	2,282	1,852	0.2%	0.2%
Street Lighting	10,411	7,830	1.1%	0.9%
Total Energy Sales	**944,036**	**889,944**	**100%**	**100%**

REVENUE ALLOCATION PROCESS

21. BLPC analyzed the results of the COS study as presented in the Affidavit of Dr. Philip Hanser of the Brattle Group as an initial step in the revenue allocation process. Table K.4 summarizes the results of the COS study.

22. Column (4) of Table K.4 shows the test year overall Realized Rate of Return on Rate Base of 3.31% with contributions from the tariff groups varying from -4.39% for the Employee tariff to 7.04% for the Time of Use tariff.

23. To place comparisons of each rate class on an equal footing, we calculate the cost of service for each class at an equalized return rate. A comparison can then be made of these class revenue requirements to the existing revenue levels achieved under currently approved rates. Subtracting these current class revenues in column (6) from the full cost of service results in column (9) shows the amounts, in columns (10) and (11), needed to modify each class' required revenues to produce the same rate of return for each class.

24. While it is an ideal goal to achieve the same rate of return for each class and eliminate inter-class subsidies, the proposed rate design reduces the impact on the Domestic Service class and classes whose current realized return is negative.

25. The targeted class revenue requirements do not achieve rates that collect the fully allocated cost of service for each rate class, recognizing that significant increases result in rate impacts that may be considered unduly burdensome. Due consideration was also given to the observation that reductions in revenues recovered from one class of customers result in an increase in required revenue from other classes when meeting BLPC's overall revenue requirement target.

26. Table K.5 shows the results of establishing the class revenue targets to achieve the overall targeted rate of return of 8.79%. As an initial step in the revenue allocation process, classes that produce a negative return at existing rates were set at a zero percent targeted return, as shown in column (6). Next, the targeted rate of return for the Domestic Service class was set at 90% of the overall targeted rate of return to reduce the rate impact of full cost of service parity. Finally, a uniformed targeted rate of return was applied to the remaining classes to achieve the overall targeted rate of return. Columns (10) and (11) contain the overall increase in revenues and the targeted increase contribution of each customer class.

RATE DESIGN PROCESS

27. The following criteria guided the general approach to rate design:
    i. Individual rates should move towards their unit cost of service as provided by the COS Study;
    ii. The reliance on volumetric charges such as energy charges for fixed cost recovery should be reduced;
    iii. Emphasis should be placed on the recovery of a higher proportion of the fixed costs through fixed customer charges;
    iv. To the extent practicable, a similar rate design process should be used for all rate classes;
    v. The proposed rates should be reasonably straightforward for ease of administration and customer understanding.

28. The unit costs from the COS study, as summarized in Table K.3, provides the starting point for individual class rate design and outlines three cost drivers. The table depicts customer, demand and energy (excluding fuel) – by class,

required to achieve fully allocated cost of service as shown in the COS Study, Table 2A presented in the Affidavit of Dr. Philip Hanser of the Brattle Group.

Table K.3: Cost of Service Unit Cost by Rate Class

Rate Class	Customer ($/Customer)	Energy ($/kWh)	Demand ($/kVA)
Domestic Service	$20.19	$0.175	-
Employees	$20.87	$0.160	-
General Service	$24.70	$0.232	-
Secondary Voltage Power	$281.00	$0.009	$52.27
Large Power	$2,644.83	$0.009	$60.19
Time of Use	$2,788.39	$0.009	$65.61
Street Lights	$9.68	$0.620	-

Table K.4: Cost of Service Summary

Rate Class (1)	Rate Base (2)	Current Realized Return (3)	Current Realized Rate of Return on Rate Base (4)	Current Rate of Return Parity Ratio (5)	Current Tariff Revenues (6)	Cost of Service Rate of Return (7)	Operating Income at the Cost of Service Rate of Return (8)	Cost of Service Tariff Revenue Requirement (9)	Revenue Deficiency at the Cost of Service (10)	Change in Revenue to meet Tariff Revenue Requirement (11)
Domestic Service	$295,653,094	$7,344,704	2.48%	75%	$145,983,629	8.79%	$25,993,156	$165,049,182	$19,065,553	13.1%
Employees	$1,415,982	-$62,203	-4.39%	-133%	$639,074	8.79%	$124,490	$827,765	$188,691	29.5%
General Service	$54,589,934	$2,572,675	4.71%	143%	$24,128,365	8.79%	$4,799,424	$26,432,129	$2,303,764	9.5%
Large Power	$144,534,215	$5,283,735	3.66%	111%	$67,454,055	8.79%	$12,707,124	$75,081,349	$7,627,294	11.3%
Secondary Voltage Power	$264,926,648	$12,451,959	4.70%	142%	$134,424,542	8.79%	$23,291,756	$145,638,091	$11,213,549	8.3%
Time of Use	$19,550,071	$1,377,010	7.04%	213%	$12,073,896	8.79%	$1,718,798	$12,443,265	$369,369	3.1%
Street Lights	$45,221,191	-$1,667,548	-3.69%	-112%	$4,313,441	8.79%	$3,975,746	$10,020,531	$5,707,090	132.3%
Overall	**$825,891,134**	**$27,300,331**	**3.31%**	**100%**	**$389,017,002**	**8.79%**	**$72,610,495**	**$435,492,312**	**$46,475,310**	**11.9%**

Table K.5: Revenue Allocation Summary

Rate Class (1)	Rate Base (2)	Current Realized Return (3)	Realized Rate of Return on Rate Base (4)	Current Parity Ratio (5)	Target Rate of Return on Rate Base (6)	Target Parity Ratio (7)	Target Revenue (without Fuel) (8)	Target Returns (9)	Deficiency in Revenue (10)	Change in Tariff Targeted Revenue Requirements (11)
Overall	**$825,891,134**	**$27,300,331**	**3.31%**	**100%**	**8.79%**	**100%**	**$232,513,487**	**$72,610,495**	**$46,475,310**	**11.9%**
Domestic Service	$295,653,094	$7,344,704	2.48%	75%	7.91%	90%	$84,447,266	$23,386,160	$16,458,556	11.3%
Employees	$1,415,982	-$62,203	-4.39%	-133%	0.00%	0%	$286,280	$0	$64,201	10.0%
General Service	$54,589,934	$2,572,675	4.71%	143%	10.18%	116%	$15,817,621	$5,556,552	$3,060,891	12.7%
Large Power	$144,534,215	$5,283,735	3.66%	111%	10.18%	116%	$39,672,803	$14,711,720	$9,631,891	14.3%
Secondary Voltage Power	$264,926,648	$12,451,959	4.70%	142%	10.18%	116%	$82,112,641	$26,966,118	$14,887,911	11.1%
Time of Use	$19,550,071	$1,377,010	7.04%	213%	10.18%	116%	$5,496,933	$1,989,945	$640,516	5.3%
Street Lights	$45,221,191	-$1,667,548	-3.69%	-112%	0.00%	0%	$4,679,943	$0	$1,731,345	40.1%

Table K-6: Base Rate Revenues at Current and Proposed Rates

Rate Class	Base Rate Revenues ('000)	
	Current Rates	Proposed Rates
Domestic Service	$66,104	$84,447
General Service	$12,984	$15,818
Secondary Voltage Power	$68,401	$82,113
Large Power	$30,328	$39,673
Time of Use	$5,005	$5,497
Employees	$231	$286
Street Lighting	$2,984	$4,680
Total Base Rate Revenue	**$186,038**	**$232,513**

Table K.7 Summary of Current and Proposed Rates (page 1 of 2)

Tariff (1)	Bill Components (2)	Parameters (3)	Cost to Serve RATES Monthly (4)	CURRENT RATES Monthly (5)	PROPOSED RATES Monthly (6)	$ Impact (7)
DS-Domestic Service						
	Customer Charge ($/month)	0-150kWh	$20.00	$6.00	$8.00	$2.00
		151-500kWh	$20.00	$10.00	$14.00	$4.00
		Over 500 kWh	$20.00	$14.00	$20.00	$6.00
	Demand Charge ($/kVA)	Not applicable	---------	---------	---------	
	Base Energy Charge ($/kWh)	0-150 kWh, per kWh	$0.174	$0.150	$0.168	$0.02
		Next 350 kWh, per kWh	$0.174	$0.176	$0.214	$0.04
		Next 1,000 kWh, per kWh	$0.174	$0.200	$0.249	$0.05
		Over 1,500 kWh, per kWh.	$0.174	$0.224	$0.280	$0.06
EM-Employee						
	Customer Charge ($/month)	Not applicable	---------	---------	---------	
	Demand Charge ($/kVA)	Not applicable	---------	---------	---------	
	Base Energy Charge ($/kWh)	0-150 kWh, per kWh	$0.159	$0.108	$0.133	$0.03
		Next 350 kWh, per kWh	$0.159	$0.127	$0.157	$0.03
		Next 1,000 kWh, per kWh	$0.159	$0.180	$0.227	$0.05
		Over 1,500 kWh, per kWh	$0.159	$0.202	$0.255	$0.05
GS-General Service						
	Customer Charge ($/month)	0-100kWh	$25.00	$8.00	$12.00	$4.00
		101-500kWh	$25.00	$11.00	$15.00	$4.00
		Over 500 kWh	$25.00	$14.00	$24.00	$10.00
	Demand Charge ($/kVA)	Not applicable	---------	---------	---------	
	Base Energy Charge ($/kWh)	0-100 kWh, per kWh	$0.231	$0.184	$0.204	$0.02
		Next 400 kWh, per kWh	$0.231	$0.217	$0.256	$0.04
		Next 1,000 kWh, per kWh	$0.231	$0.259	$0.311	$0.05
		Over 1,500 kWh, per kWh	$0.231	$0.290	$0.354	$0.06
SVP-Secondary Voltage Power						
	Customer Charge ($/month)	Each service	$280.00	$20.00	$169.00	$149.00
	Demand Charge ($/kVA)	per kVA	$52.00	$24.00	$28.82	$4.82
	Base Energy Charge ($/kWh)	All kWh, per kWh.	$0.009	$0.1380	$0.1380	$0.00
LP-Large Power						
	Customer Charge ($/month)	Each service	$2,618.00	$300	$1,587	$1,287.00
	Demand Charge ($/kVA)	per kVA	$60.00	$22	$33.30	$11.30
	Base Energy Charge ($/kWh)	All kWh, per kWh.	$0.009	$0.1170	$0.1170	$0.00

Table K.7 Summary of Current and Proposed Rates (page 2 of 2)

Tariff (1)	Bill Components (2)	Parameters (3)	Cost to Serve RATES Monthly (4)	CURRENT RATES Monthly (5)	PROPOSED RATES Monthly (6)	$ Impact (7)
TOU-Time of Use						
	Customer Charge ($/month)	Each service	$2,760.00	$300	$1,675	$1,375.00
	Demand Charge ($/kVA)	per kVA	$65.00	$18	$22.88	$4.88
	Base Energy Charge ($/kWh)	On-Peak, per kWh.	$0.009	$0.219	$0.219	$0.00
		Off-Peak, per kWh.	$0.009	$0.062	$0.062	$0.00
SL-Street Lights	**Customer Charge**					
		Each 50 Watt HPS light	---------	$7.04	---------	
		Each 70 Watt HPS light	---------	$7.73	---------	
		Each 100 Watt HPS light	---------	$8.59	---------	
		Each service	$9.65	---------	$10.00	N/A
	Demand Charge ($/kVA)	Not applicable	---------	---------	---------	
	Base Energy Charge ($/kWh)	All kWh, per kWh.	$0.613	---------	$0.231	

29. The unit costs from the COS Study guided the rate design process and the billing components applied[3]:

    a) **The Customer Charge:** This recovers the customer-related costs.
    b) **The Demand Charge:** This recovers the demand-related costs.
    c) **The Base Energy Charge:** This recovers the variable non-fuel energy-related costs. The demand-related costs are included in the energy charge for the Domestic Service, General Service, Street Lights and Employee tariffs since, as is common in the electric utility industry, the meters used for these tariffs do not register customer demand.
    d) **The Fuel Charge:** This recovers the total cost of fuel, which varies with the amount of energy supplied to the customer. The Fuel Charge is comprised of an FCA charge and a Renewable Purchased Power Adjustment (RPPA) charge, discussed below.

30. A sequential process was followed to derive the unit rates and amounts to be recovered by each billing component. First, customer charges were set to approximately 60% of the class unit cost of service. Once the customer charges were determined for the class, the calculated revenue was subtracted from the class targeted revenue given in column (8) of Table K.5 to determine the remaining revenue to be recovered from base rates. The remaining, or residual, revenue was then recovered by increasing the energy charge component in those classes where demand charges did not apply. In the classes which have a demand charge, the remaining, or residual, revenues were recovered by adjusting the demand charge component while maintaining the energy charge component at its current level.

[3] See the COS Study attached to the Affidavit of Dr. Philip Hanser of the Brattle Group.

PROPOSED REVISION TO TARIFFS & RIDERS

Fuel Clause Adjustment

31. The Fuel Clause Adjustment (FCA) was initially established in 1965 for commercial and industrial customers and extended to include all customers in 1974. The Commission's forerunner, the Public Utilities Board (PUB), accepted that BLPC has to purchase fuel to generate electricity and permitted the recovery of all its fuel expenditure from all customer classes through a monthly fuel clause adjustment mechanism.

32. On April 13, 2018, the Commission issued its Decision on BLPC's Application to Recover the Cost of the 5 MW Energy Storage Device (ESD) through the FCA[4]. This Decision adjusted the formula of the FCA to allow for the recovery of the costs associated with the ESD in addition to the cost of fossil fuel used to generate electricity and the cost of energy purchased from renewable energy resources.

33. Given the GoB's goal to transition to 100% renewable energy generation by 2030, as outlined in the Barbados National Energy Policy (BNEP),[5] BLPC anticipates the use of fossil fuels in the production of electricity to decline during this transition. To better track progress towards this transition, BLPC proposes removing the recovery of non-fossil fuel costs from the FCA. The FCA will be limited to the recovery of only fossil fuel costs used to generate electricity, as shown in Schedule K-8 and the costs of renewable power purchases, currently recovered through the FCA, will be transferred to a new Renewable Purchased Power Adjustment (RPPA).

34. This RPPA is being proposed to recover the costs of energy purchased from renewable energy resources as outlined in Schedule K-11. It is also proposed that the ESD be removed from the calculation of the FCA.

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[4]Decision on The Barbados Light & Power Company Limited Application to Recover the Costs of the 5MW Energy Storage Device through the Fuel Clause Adjustment, 2020FTCUR/DECESD/BL&P-2018-02

[5] https://energy.gov.bb/download/barbados-national-energy-policy-2019-2030/

DS-DOMESTIC SERVICE

35. The proposed Domestic Service (DS) tariff will be available to customers using the service for domestic purposes (i.e. over 50% of their energy consumption) and who occupy individually-metered houses, apartments or condominiums suitable for year-round family occupancy. Customers will be limited to a single-phase, 2- or 3-wire electrical installation up to a maximum capacity of 200 Amperes. Customers with more significant electrical requirements will be classified under the Secondary Voltage Power tariff.

36. BLPC proposes a 7.91% Rate of Return for this class. This return rate will require $16.5 million in additional sales revenue from this tariff group as outlined in Table K.5, an overall revenue increase of 11.3%. BLPC will maintain the first usage block up to 150 kWh and proposes collecting base revenues through a Customer Charge and an Energy Charge.

Customer Charge

37. The inclining block customer structure will be retained at the current usage blocks. The charges within each usage block will be increased to reflect the objective of moving closer to the fully allocated cost of service by recovering approximately 60% of the customer-related unit cost of service. The customer charge increase on lower usage blocks will be kept below full cost of service to reduce bill impacts on lower usage customers, many of whom may have low incomes, while the customer charge of the higher usage blocks will be at the cost of service.

38. The proposed customer charges are as follows:

    a) 0 to 150 kWh $8/month
    b) 151 to 500 kWh $14/month
    c) Over 500 kWh $20/month

39. The amount to be charged to a customer in a particular month will be determined by the 30-day average kWh consumption calculated based on energy consumption as recorded over the previous 12 months or as many months available within this period.

Base Energy Charge

40. The inclining block rate structure and usage blocks will be retained for energy charges. The increase on the first block will be limited to an additional two cents per kWh ($0.02/kWh) to lessen the impact on the low usage customers. The energy charges at the higher usage bands will vary from an additional 4 cents per kWh for the second usage block to an additional 6 cents/kWh for the highest block.

41. The proposed Base Energy Charges are as follows:

a)	First 150 kWh @	$ 0.168/kWh
b)	Next 350 kWh @	$ 0.214/kWh
c)	Next 1,000 kWh @	$ 0.249/kWh
d)	Over 1,500 kWh @	$ 0.280/kWh

Early Payment Discount

42. It is proposed to continue the 10% discount on the Customer and Base Energy charges for customers who pay their bills within 15 days of the date of issue.

Fuel Charge

43. This will be calculated based on the FCA and RPPA as determined by the formula shown in Schedule K-8 and Schedule K-11.

All kWh @ FCA (in cents/kWh)
All kWh @ RPPA (in cents/kWh)

Impact Analysis

44. The FCA for September 2021 of 32.8251 cents/kWh was used in calculating the impact of the changes on customers' bills.

45. The average increase for customers under this tariff is approximately 6 cents per kWh, an average increase of roughly 9% on their total bill.

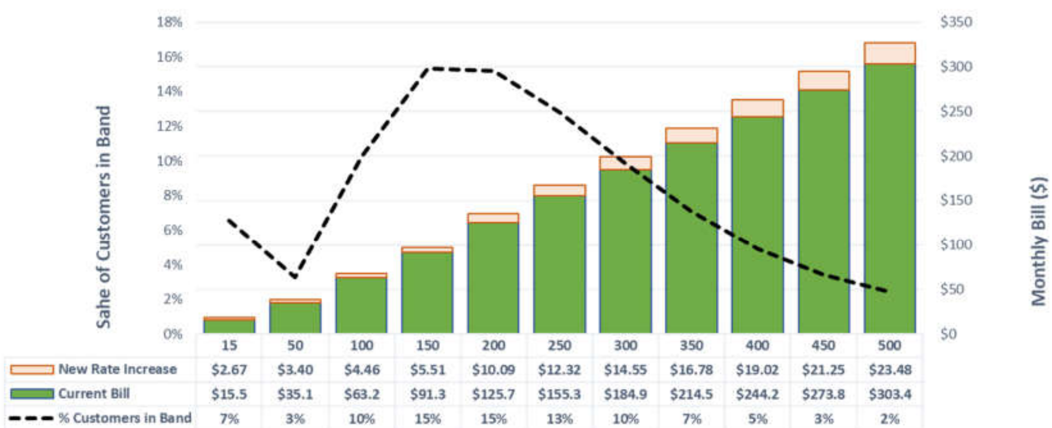
46. The bill impact of the change in rates for customers at different usage levels and the number of customers within each usage band are shown in Figure K.1

and Figure K.2. Figure K.1 shows the impact on bills for customers with usages from 15 kWh to 500 kWh per month. Just over 90% of Domestic Service customers consume less than 500 kWh per month.

47. The usage block up to 150 kWh accounts for 35% of all Domestic Service customers. This block has been maintained in its usage band to mitigate the required class revenue increase on low usage customers. The bill impact for customers within this block has been capped not to exceed a bill increase of $6 per month.

48. The typical Domestic Service customer using 250 kWh per month will see a monthly bill increase of $12 or 8%, about a 22% lower bill when adjusted for inflation. BLPC proposes to continue to offer the 10% base rate early bill payment discount to help mitigate the bill impacts of the additional revenue requirement.

Figure K.1: Bill Impact for Domestic Service Customers – 15 kWh to 500 kWh

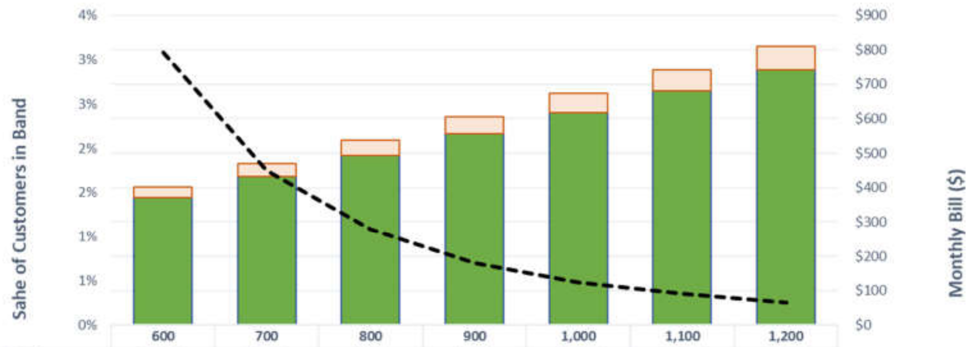


	15	50	100	150	200	250	300	350	400	450	500
New Rate Increase	$2.67	$3.40	$4.46	$5.51	$10.09	$12.32	$14.55	$16.78	$19.02	$21.25	$23.48
Current Bill	$15.5	$35.1	$63.2	$91.3	$125.7	$155.3	$184.9	$214.5	$244.2	$273.8	$303.4
% Customers in Band	7%	3%	10%	15%	15%	13%	10%	7%	5%	3%	2%

49. An estimated 10% reduction in fuel costs anticipated from the commissioning of the Clean Energy Bridge, discussed in the Memorandum on Capital Expansion, is expected to mitigate the impact of the proposed increase in rates.

50. Figure K.2 shows the impact on bills for customers with usages from 600 kWh to 1,200 kWh per month.

Figure K.2: Bill Impact for Domestic Service Customers - 600 kWh to 1,200 kWh



	600	700	800	900	1,000	1,100	1,200
New Rate Increase	$31.58	$37.33	$43.07	$48.82	$54.57	$60.32	$66.07
Current Bill	$370.2	$432.3	$494.3	$556.4	$618.5	$680.5	$742.6
% Customers in Band	3%	2%	1%	1%	0%	0%	0%

EM-EMPLOYEES

51. As per the existing tariff, the proposed tariff will be available to employees and pensioners of BLPC who use their premises for domestic purposes as described under the Domestic Service tariff.

Base Energy Charge

52. The inclining block rate structure and usage blocks will be retained for the energy charge, similar to the structure for Domestic Service customers.

53. Energy charges are proposed to increase on average by 4 cents/kWh, and the existing parity between the Domestic Service energy rates maintained.

54. The proposed Base Energy Charges are as follows:

a) First 150 kWh @ $ 0.133/kWh
b) Next 350 kWh @ $ 0.157/kWh
c) Next 1,000 kWh @ $ 0.227/kWh
d) Over 1,500 kWh @ $ 0.255/kWh

Fuel Charge

55. This will be calculated based on the FCA and RPPA as determined by the formula shown in Schedule K-6 and Schedule K-7.

All kWh @ FCA (in cents/kWh)
All kWh @ RPPA (in cents/kWh)

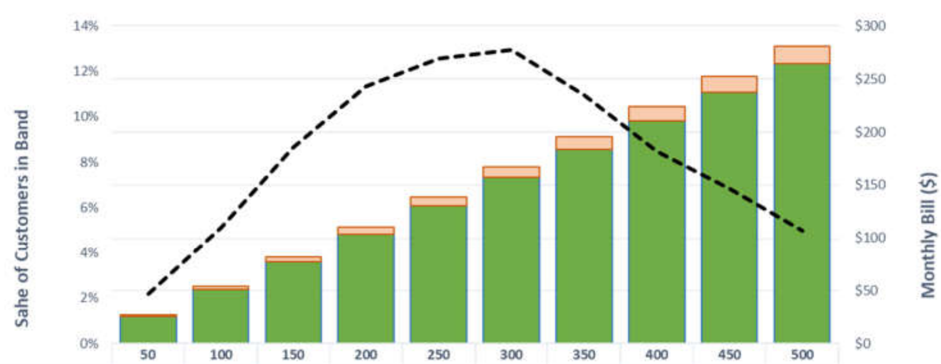
Impact Analysis

56. The FCA for September 2021 of 32.8251 cents/kWh was used in calculating the impact of the changes on customers' bills.

57. The proposed rates will result in an increase of 6% for employees using less than 500 kWh per month. The typical customer within the class consuming just over 300 kWh per month will experience a monthly bill increase of around $10 as shown in Figure K.3. An approximate 8% bill increase will impact employees consuming more than 800 kWh per month.

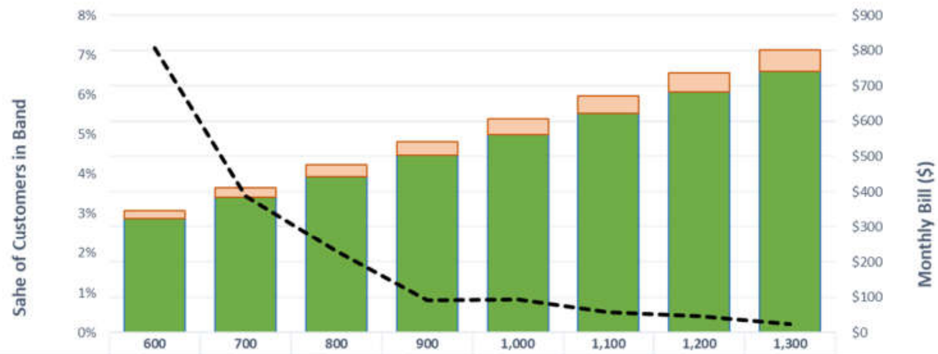
58. Figure K.3 below shows the impact on bills for employees using 50 kWh to 500 kWh per month, while Figure K.4 shows the impact on bills for employees using 600 kWh to 1,300 kWh per month.

Figure K.3: Bill Impact for Employees - 50 kWh to 500 kWh



	50	100	150	200	250	300	350	400	450	500
New Rate Increase	$1.49	$2.99	$4.48	$6.27	$8.06	$9.85	$11.64	$13.43	$15.22	$17.01
Current Bill	$25.63	$51.26	$76.89	$103.64	$130.38	$157.13	$183.87	$210.62	$237.37	$264.11
% Customers in Band	2%	5%	9%	11%	13%	13%	11%	8%	7%	5%

Figure K.4: Bill Impact for Employees - 600 kWh to 1,300 kWh



	600	700	800	900	1,000	1,100	1,200	1,300
New Rate Increase	$22.51	$28.01	$33.51	$39.01	$44.51	$50.01	$55.51	$61.01
Current Bill	$323.83	$383.55	$443.27	$502.99	$562.71	$622.43	$682.15	$741.87
% Customers in Band	7%	3%	2%	1%	1%	1%	0%	0%

GS-GENERAL SERVICE

59. The proposed tariff will be available to non-residential customers for lighting and power service and to whom no other tariff schedule applies. This tariff will apply to any customer with a single-phase, 2- or 3-wire electrical installation with a maximum demand of up to 10 kVA. Customers with greater demands will be classified under the Secondary Voltage Power tariff. Three-phase 4-wire service installations may be provided under this tariff under special arrangements.

60. BLPC proposes achieving a 10.18% Rate of Return from this customer class. This will require $3.1 million in additional sales revenue as outlined in Table K.5, an overall increase of 12.7% in revenue. It is proposed that the base revenues be collected through a Customer Charge and an Energy Charge.

<u>Customer Charge</u>

61. It is proposed that the inclining block customer charge be retained at the current usage blocks, varying depending upon the customer's usage level. The lower usage blocks will increase by an additional $4.00, while the higher usage block will be increased to the cost of service.

62. The proposed customer charges are as follows:

    a) 0 to 100 kWh $12/month

b)	101 to 500 kWh	$15/month
c)	Over 500 kWh	$24/month

63. The amount to be charged to a customer in a particular month will be determined by the 30-day average kWh consumption calculated based on energy consumption over the previous 12 months or as many months available within this period.

Base Energy Charge

64. An increase in base energy charges is proposed for each of the existing usage bands. The average increase proposed in energy charges is approximately four cents per kWh ($0.04/kWh). However, the energy charge increase will be limited to about two cents ($0.02/kWh) for the first 100 kWh of usage.

65. The proposed Base Energy Charges are as follows:

a)	First 100 kWh @	$ 0.204/kWh
b)	Next 400 kWh @	$ 0.256/kWh
c)	Next 1000 kWh @	$ 0.311/kWh
d)	Over 1500 kWh @	$ 0.354/kWh

Fuel Charge

66. This will be calculated based on the FCA and RPPA as determined by the formula shown in Schedule K-8 and Schedule K-11.

All kWh @ FCA (in cents/kWh)
All kWh @ RPPA (in cents/kWh)

Impact Analysis

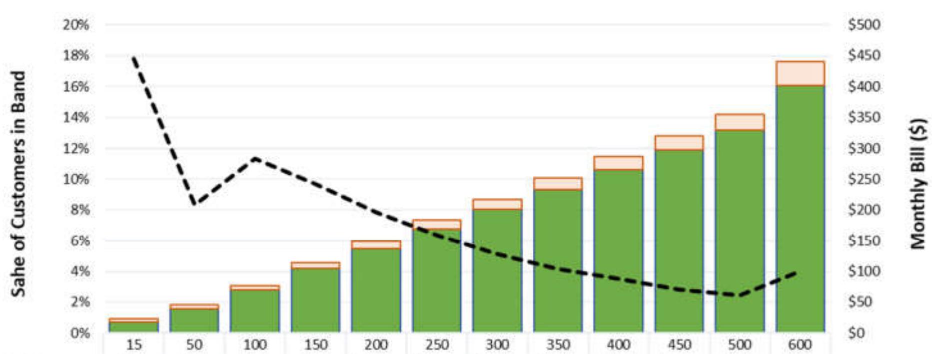
67. The FCA for September 2021 of 32.8251 cents/kWh was used in calculating the impact of the changes on General Service bills.

68. The average increase for customers under this tariff is approximately seven cents per kWh ($0.07/kWh), an average increase of roughly 10% on their bill.

69. The typical customer within this class consumes just over 350 kWh per month; customers (79% of total customers) at this level of consumption will observe a bill increase of 8%.

70. Comparisons of the increases for customers at different usage levels and the number of customers within each usage band are shown in Figures K.5 and K.6. Figure 10 shows the bills for usages from 15 kWh to 600 kWh/month. Approximately 83% of the GS customers use less than 600 kWh/month.

Figure K.5: Bill Impact for GS Customers - 15 kWh to 600 kWh



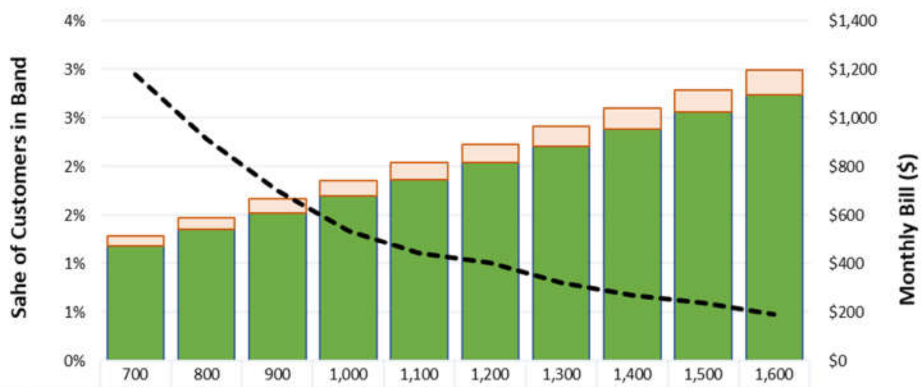
	15	50	100	150	200	250	300	350	400	450	500	600
New Rate Increase	$5.06	$5.89	$7.08	$9.38	$11.69	$13.99	$16.29	$18.60	$20.90	$23.21	$25.51	$38.65
Current Bill	$18.43	$39.49	$69.59	$105.15	$137.18	$169.21	$201.25	$233.28	$265.32	$297.35	$329.38	$401.91
% Customers in Band	18%	8%	11%	10%	8%	6%	5%	4%	3%	3%	2%	4%

71. A significantly large group of users (37% of total users) who consume electricity within this tariff has an average consumption below 100 kWh. The bill increase for these customers is expected not to increase beyond $8 per month.

72. An estimated 10% reduction in fuel costs anticipated from the commissioning of the Clean Energy Bridge, discussed in the Memorandum on Capital Expansion, is expected to mitigate the impact of the proposed increase in rates further.

73. Figure K.6 shows the impact for usages from 700 kWh to 1,200 kWh per month.

Figure K.6: Impact on Bills for GS Customers - 700 kWh to 1,200 kWh



	700	800	900	1,000	1,100	1,200	1,300	1,400	1,500	1,600
New Rate Increase	$44.73	$50.82	$56.91	$62.99	$69.08	$75.17	$81.25	$87.34	$93.43	$100.92
Current Bill	$470.91	$539.91	$608.92	$677.92	$746.92	$815.92	$884.92	$953.93	$1,022.93	$1,095.57
% Customers in Band	3%	2%	2%	1%	1%	1%	1%	1%	1%	0%

SVP-SECONDARY VOLTAGE POWER

74. This proposed tariff will be available to all customers with a billing demand of 5 kVA or greater who require service at the secondary voltage level.

75. It is proposed that the Rate of Return to be achieved from this tariff class be 10.18%. This will require $14.9 million in additional revenue as outlined in Table K.5, an overall increase of 11.1% in revenue. To achieve this, it is proposed that base revenues be collected through a Customer Charge, a Demand Charge, and a Base Energy Charge.

76. The cost of service results indicate that the customer and demand-related unit costs are significantly higher than their current charges. The base energy-related unit cost is substantially lower than the current energy charge of 13.8

cents/kWh. As a result, a significant portion of the fixed customer and demand costs is presently collected through the Base Energy charge.

77. By moving these component prices closer to cost, better price signals are sent to customers, enabling them to make more efficient usage decisions, and their bills will more closely align with their cost of service.

78. It is proposed to have new rates which more closely reflect the cost of providing service. However, it is not proposed to achieve full unit cost for the proposed rate of return. Moving to rates that fully match the cost of service while benefiting customers with high load factors (i.e., higher energy used in proportion to the maximum demand they impose on the system) would create significant rate shock for those with low load factors, many of whom may be smaller business operations.

Customer Charge

79. It is proposed to introduce a customer charge for all usage levels, which reflects 60% of the cost of service as follows:

All customers $169/month

Demand Charge

80. It is proposed that the monthly Demand Charge will be as follows:

a) Company-owned transformer:
All kVA @ $ 28.82/kVA of Billing Demand

81. The Billing Demand shall be the maximum measured demand of the current month but not less than five (5) kVA.

Base Energy Charge

82. It is proposed to retain the flat energy rate at the current rate of:

All kWh @ $ 0.138/kWh

Fuel Charge

83. This will be calculated based on the FCA and RPPA as determined by the formula shown in Schedule K-8 and Schedule K-11.

All kWh @ FCA (in cents/kWh)
All kWh @ RPPA (in cents/kWh)

Impact Analysis

84. The FCA for September 2021 of 32.8251 cents/kWh and usage information from 2020 were used in calculating the impact of the changes on bills for Secondary Voltage Power customers.

85. The current rates have a low customer charge as a significant portion of the customer-related cost was incorporated in the energy charge. As a result, customers with low usage levels did not pay their allocated share of the customer costs they impose. As the rates move closer to unit cost-based rates, and the customer charge increases relative to the energy charge, customers with low usage will pay a relatively higher bill and, hence, provide a more significant contribution towards their customer-related cost.

86. The average increase for customers on this tariff is approximately 30%, as shown in Table K.8, about a 6% lower bill on an inflation-adjusted basis.

87. The monthly energy usages within this class average of 5,370 kWh. In general, the bill for customers with monthly usage above this average will increase by under 10% under the proposed rates. Customers with low power factors (i.e. those who use a smaller amount of electricity relative to their maximum demand) have a more considerable percentage bill impact.

88. The average monthly energy usages for 14% of customers within this class was below the average consumption within the Domestic Service class. Bill impacts of over 60% are expected for these customers, adding just under $200 per month to their bills. Further, for 66% of customers who receive service under this tariff, the monthly bill impact resulting from the proposed rates will be under $250 per month.

Table K.8: Impact on Bills for Secondary Voltage Power Customers

Percentage Bill Change	Average Bill Increase	Average Monthly Usage (kWh)	Average Monthly Demand (kVA)	Average kWh/kVA	Share of Customers
Under 5%	3.8%	34,058	93	495	9%
5% - 10%	7.4%	7,781	35	307	17%
10% - 15%	12.3%	3,203	18	254	15%
15% - 20%	17.4%	1,902	12	216	11%
20% - 40%	27.5%	1,030	9	148	25%
40% - 60%	48.0%	440	6	81	9%
60% - 80%	68.7%	229	5	45	5%
80% - 100%	89.8%	111	5	22	3%
100% - 120%	110.7%	36	5	7	3%
120% - 140%	123.6%	2	5	0	3%
Overall	**30.0%**	**5,370**	**22**	**206**	**100%**

89. Customers in this tariff, who have flexibility in their electricity usage, may reduce their bill by participating in the Interruptible Service Rider programme.

90. An estimated 10% reduction in fuel costs anticipated from the commissioning of the Clean Energy Bridge, discussed in the Memorandum on Capital Expansion, is expected to mitigate the impact of the proposed increase in rates further.

LP-LARGE POWER

91. This tariff will be available to all customers who receive electricity at primary voltage with a billing demand of 50 kVA or greater.

92. It is proposed that the Rate of Return to be achieved from this tariff class be 10.18%. This will require $9.6 million in additional revenue as outlined in Table K.5, an overall increase of approximately 14% in revenue. To achieve this, it is proposed that base revenues be collected through a Customer Charge, a Demand Charge, and a Base Energy Charge.

93. The COS Study indicates that the customer-related unit cost is significantly higher than the existing charge of $300 per customer per month. The energy-related unit cost is substantially less than the current charge of 11.7 cents/kWh.

This results from a significant portion of the fixed customer cost presently collected through the Base Energy charge.

94. By moving these component rates closer to cost, better price signals are sent to customers enabling them to make more efficient usage decisions, and their bills will more closely align with their cost of service.

95. It is proposed to have the new rate more closely reflect the cost of providing service. However, it is not proposed to achieve the full unit cost of service. Moving to rates that fully match the cost of service while benefiting customers with high load factors (i.e. higher energy used in proportion to the maximum demand they impose on the system) would create a significant rate shock for those with low load factors.

Customer Charge

96. It is proposed to introduce a monthly customer charge for all usage levels to reflect the cost of service, as follows:

All customers $1,587/month

Demand Charge

97. It is proposed that the monthly Demand Charge will be as follows:

All kVA @ $ 33.30/kVA of Billing Demand

98. The Billing Demand shall be the maximum measured demand of the current month, but not less than fifty (50) kVA.

99. There may be occasions, for example, where a customer's transformer fails and BLPC installs its own transformer temporarily. In those circumstances, the customer will be required to pay an additional $1/kVA of transformer capacity as shown in the Service Charges in Schedule K-10.

Base Energy Charge

100. It is proposed to continue the base energy charge at the current flat rate as follows:

All kWh @ $ 0.117/kWh

101. These services will typically be metered on the primary side of the transformer. However, there may be occasions when BLPC, at its discretion, decides to meter a service on the low voltage side of the transformer. On these occasions, BLPC will increase the maximum demand and energy consumed by a loss factor for the calculation of the Demand Charge, Base Energy Charge and Fuel Charge to account for the losses incurred in the customer's transformer.

Fuel Charge

102. This charge will be calculated based on the FCA and RPPA as determined by the formula shown in Schedule K-8 and Schedule K-11.

All kWh @ FCA (in cents/kWh)
All kWh @ RPPA (in cents/kWh)

Impact Analysis

103. The FCA for September 2021 of 32.8251 cents/kWh and usage information from 2020 were used in calculating the impact of the changes on bills for Large Power customers.

104. The average increase for customers on this tariff is approximately 22% under the proposed rates, as shown in Table K.9. On an inflation-adjusted basis since 2010, this translates to an approximately 12% lower bill.

105. Under the current rate, which has a low customer charge, most customer-related costs are incorporated in the energy charge. As a result, customers with low usage do not pay their allocated share of the customer costs imposed. As the rates move closer to unit cost-based rates, and the customer charge increases relative to the energy charge, the impact will be that low usage

customers will pay a relatively higher bill, and hence a more significant contribution towards their customer cost.

Table K.9: Impact on Bills for Large Power Customers

Percentage Bill Change	Average Bill Increase	Average Monthly Usage (kWh)	Average Monthly Demand (kVA)	Average kWh/kVA	Share of Customers
Under 5%	4.6%	414,596	694	960	3%
5% - 10%	7.7%	183,982	468	456	35%
10% - 15%	12.1%	58,743	215	343	22%
15% - 20%	18.1%	28,302	133	285	12%
20% - 40%	27.6%	17,386	183	167	15%
40% - 60%	47.7%	5,749	84	90	3%
60% - 80%	71.2%	2,453	69	46	3%
80% - 100%	86.2%	1,628	54	30	3%
100% - 120%	111.9%	576	50	12	3%
Overall	**21.5%**	**97,597**	**287**	**332**	**100%**

106. The bill for over 60% of customers will increase by less than 15% under the proposed rates, while customers with lower load factors will have significantly larger bill increases. Approximately 39% of customers' bill increases will be under $3,000, while a further 17% will be impacted by between $3,000 and $4,000 increases in their monthly bill.

107. Customers who can reduce their maximum demand through measures such as power factor correction and load shifting may lessen the increase in their bill.

108. Customers in this tariff, who have flexibility in their electricity usage, may be able to reduce their bill by participating in the Interruptible Service Rider programme.

109. Those customers who use a significant portion of their energy in "off-peak" periods, and those who can shift a substantial part of their energy use to such periods, may alternatively consider transferring to the Time-of-Use Rate to reduce their bills.

110. An estimated 10% reduction in fuel costs anticipated from the commissioning of the Clean Energy Bridge, discussed in the Memorandum on Capital

Expansion, is expected to mitigate the impact of the proposed increase in rates further.

TOU-TIME OF USE

111. The Time-of-Use (TOU) tariff was approved on a pilot basis and implemented in 2010. A permanent tariff is proposed and will be available to all customers who receive electricity at primary voltage with a billing demand of 50 kVA or greater.

112. It is proposed that the Rate of Return to be achieved from this tariff class be 10.18%. This will require $641 thousand in additional revenue as outlined in Table K.5, an overall increase of approximately 5% in revenue. To achieve this, it is proposed that the revenue be collected through a Customer Charge, a Demand Charge, Base Energy Charges and Fuel Charges.

113. The COS Study indicates that the customer-related unit cost is significantly higher than the existing charge of $300 per customer per month. The energy-related unit cost is substantially less than the current charge.

Customer Charge

114. It is proposed that the monthly customer charge for the TOU tariff will be as follows:

All customers $1,675/customer

Demand Charge

115. It is proposed that the monthly Demand Charge will be as follows:

All kVA @ $22.88/kVA of Billing Demand

116. The Billing Demand shall be the maximum measured demand of the current month, but not less than fifty (50) kVA.

117. There may be occasions, for example, where a customer's transformer fails, and it becomes necessary for BLPC to install its own transformer temporarily.

On these occasions, the customer will be required to pay an additional $1 per kVA of transformer capacity as shown in the Service Charges in Schedule K-10.

Base Energy Charge

118. It is proposed that the base energy rates for the periods would remain at the current rates as follows:

a) Peak kWh @ $0.219/kWh consumed during the Peak period.
b) Off-Peak kWh @ $0.062/kWh consumed during the Off-Peak period.

where:

- The Peak period is defined as hours between 10.00 a.m. and 9.00 p.m. weekdays except for annually published public holidays.
- The Off-Peak period is defined as all other hours.

119. These services will typically be metered on the primary side of the transformer. However, there may be occasions when BLPC, at its discretion, decides to meter a service on the low voltage side of the transformer. On these occasions, BLPC will increase the Billing Demand and energy consumed by a loss factor for the calculation of the Demand Charge, Base Energy Charge and Fuel Charge to account for the losses incurred in the customer's transformer.

Fuel Charge

120. It is proposed likewise to have two time-based fuel charges for the same TOU periods as follows:

a) **Peak kWh @ 1.12 times the FCA and RPPA** for energy consumed during Peak Periods. The Fuel Clause Adjustment is calculated as shown in Schedule K-8 and Schedule K-11.
b) **Off-Peak kWh @ 0.92 times the FCA and RPPA** for energy used during Off-Peak periods. The Fuel Clause Adjustment is calculated as shown in Schedule K-8 and Schedule K-11.

Impact Analysis

121. Although the Fuel Charge will vary depending on the period, the TOU rate is designed to reflect the average cost within that period. As a result, this is expected to be neutral in its effect and not impact other customers.

122. This tariff is likely to continue to attract customers in the Large Power tariff who have flexibility in their use of electricity or standby generation that would enable them to shift their usage to lower-cost periods.

123. The tariff currently consists of twenty customers, with an average bill increase of 5% due to the proposed rates.

124. An estimated 10% reduction in fuel costs anticipated from the commissioning of the Clean Energy Bridge, discussed in the Memorandum on Capital Expansion, is expected to mitigate the impact of the proposed increase in rates further.

SL-STREETLIGHTS

125. BLPC has replaced over 90% of its stock of High-Pressure Sodium (HPS) streetlights with Light Emitting Diode (LED) lights and anticipates that by the end of 2021, all of the streetlights would be LEDs. Reference will no longer be made in the tariff to HPS lights or any other lighting technology. There is little difference in the capital and maintenance costs per light for the different wattage LED streetlights, with the only variable being the energy usage per light.

126. Street lighting is an essential social service provided for security and safety purposes for the benefit of the entire country. It is therefore proposed to limit the increase for this class. As a result, it is being proposed that the Rate of Return for this customer class be 0.00%. This will require $1.7 million in additional sales revenue as outlined in Table K.5, an increase of 40.1%. It is proposed that the tariff be modified to allow total revenue to be collected by an Energy Charge in addition to the current Customer Charge.

Customer Charge

127. The proposed monthly Customer Charge for all types of streetlights is as follows:

All streetlights $10/month

Base Energy Charge

128. It is proposed to introduce a flat energy charge rate for all streetlights as follows:

All kWh @ $ 0.231/kWh

Fuel Charge

129. This will be calculated based on the FCA and RPPA as determined by the formula shown in Schedule K-8 and Schedule K-11.

All kWh @ FCA (in cents/kWh)
All kWh @ RPPA (in cents/kWh)

Impact Analysis

130. Upon completing the streetlights replacement programme, the 50 and 100 wattage HPS light fixtures would be replaced by LED fixtures of 21 and 49 wattage, respectively.

131. The overall impact on the billing per light using the FCA for September 2021 of 32.8251 cents/kWh is a bill decrease of 6.0% for the 21 Watt LED light relative to the 50 Watt HPS light it replaced. The 49 Watt LED light bill will decrease by 12.3% relative to the 100-watt HPS light it replaced.

ISR-INTERRUPTIBLE SERVICE RIDER

132. This Rider is available to SVP and LP customers who have flexibility in their electricity use and who have a minimum billing demand of 200 kVA and minimum monthly interruptible demand of 100 kVA.

133. Interruptible loads provide BLPC with the opportunity to reduce the overall demand on the system. As long as the interruptible demand can be relied upon, it is expected that BLPC will be able to reduce its investment in the long term. This benefit can be passed on to the customers with interruptible loads through a capacity credit.

134. No significant restructuring of the Rider is proposed in this filing. The only material change is to move the time for a potential interruption from 8:00 a.m. to 7:00 a.m.

135. The proposed Interruptible Service Rider is shown in Schedule K-9. This rider will not be available for customers on the TOU tariff.

RER-RENEWABLE ENERGY RIDER

136. The Renewable Energy Rider was approved by the Commission in 2014 to facilitate the sale of surplus electricity generation from distributed Renewable Energy (RE) systems.

137. On September 24, 2019, the Commission issued its Decision to implement Feed-In-Tariff (FIT) rates for renewable energy technologies up to and including 1 MW. The development of the FIT rates terminated the Renewable Energy Rider effective October 1, 2019.

138. Customers on the RER before October 2019 were grandfathered under the FIT and maintain their existing arrangements for twenty (20) years commencing from the system's original commissioning date.

SERVICE CHARGES

139. The proposed Service Charges are shown in Schedule K-10.

SUMMARY

140. The proposed rates are designed to recover the test year revenue increase of $46.475 million, as supported by the embedded cost of service study. The rate design proposed reduce the overreliance on volumetric charges such as

energy charges for fixed cost recovery to facilitate the sustainable transition towards the nation's 100% renewable energy generation target. Bill increases have been capped not to exceed $6 per month for customers with usage up to 150 kWh, which account for 35% of Domestic Service, assumed to consist disproportionately of low-income customers.

141. The typical bill increase resulting from the proposed rates are estimated to range from 5% to 20% depending on the tariff on which customers receive their service. This increase is expected to be mitigated by lower fuel charges as a result of the commissioning of the Clean Energy Bridge in 2021.

142. Given prices within the economy have risen by over 38% since 2010, the effective cost of electricity under the proposed rates represent a decline relative to the other costs in the economy.

Dated this 30th day of September, 2021

Paper Prepared by:

Adrian Carter
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The Barbados Light & Power Company Ltd.

K-1

K-1: PROPOSED TARIFF FOR DOMESTIC SERVICE (DS)

APPLICATION

This tariff is available to residential customers who occupy for domestic purposes individually-metered dwelling houses, apartments or condominiums suitable for year-round family occupancy. The residence shall be occupied by the owner or shall be the principal place of residence for the occupant.

TYPE OF SERVICE

Under this tariff, the Company will supply single-phase alternating current electricity at 50 Hz, and one of the secondary voltages specified in the latest revision of the Company's booklet entitled "Information and Requirements Covering Installation of Electric Services and Meters".

CONDITIONS OF SERVICE

Single phase, 2 or 3 wire services up to a maximum of 200 amperes are eligible for this tariff. This tariff is not applicable to customers who occupy dwelling units used or registered for the purpose of transient occupancy such as rooming houses, hotels, guest-houses or villas, or primarily for commercial, industrial or non-domestic activities. No service may be transmitted from a customer who receives electric service to another premises without the prior written consent of the Company.

GENERAL PROVISIONS

When two or more rates are available for certain classes of service, the choice of such rates rests with the customer. The Company will at any time, upon request, advise any customer as to the rate best suited to existing or anticipated service requirements, as defined by the customer. The Company does not assume responsibility for the selection of such rate or the continuance of the lowest annual cost under the selected rate. A customer, having selected a rate, may not change to another rate within a 12-month period unless there is a substantial change in the character or conditions of the service. In the case of a new service, customers will be given reasonable opportunity to determine their service requirements before selecting their preferred rate.

MONTHLY RATE

1) **Customer Charge** - This applies to each electricity service under this tariff for the fixed costs of providing service including the service installation, meter reading, billing and customer service costs. The monthly Customer Charge is determined by the customer's 30 day average kWh consumption over the previous 12 months, or as many months during the past 12 months as are available.

   a) 0 - 150 kWh $ 8/month
   b) 151- 500 kWh $14/month
   c) Over 500kWh $20/month

2) **Base Energy Charge** – This applies to each electricity service under this tariff for all other costs associated with the provision of this service, except the cost of fuel.

   a) First 150 kWh @ $ 0.168/kWh
   b) Next 350 kWh @ $ 0.214/kWh
   c) Next 1000 kWh @ $ 0.249/kWh
   d) Over 1500 kWh @ $ 0.280/kWh

3) **Fuel Charge** – This applies to each electricity service under this tariff for the cost of fuel associated with the provision of this service. This charge is recovered through a Fuel Clause Adjustment (FCA).

   Fossil fuel portion of kWh @ the Fuel Clause Adjustment (cents/kWh)

4) **Renewable Purchased Power Charge** – This applies to each electricity service under this tariff for the cost of renewable power purchases associated with the provision of this service. This charge is recovered through a Renewable Purchased Power Adjustment (RPPA).

   Renewable purchases portion of kWh @ the Renewable Purchased Power Adjustment (cents/kWh).

   Energy consumed under this tariff is delivered from both fossil fuel and renewable generation sources. The costs associated with each source of generation is recovered through the FCA and the RPPA in proportion to their respective contributions.

   The FCA and RPPA may vary from month to month.

MINIMUM BILL

The minimum bill shall be the applicable Customer Charge.

TAXES

All rates are subject to Value Added Tax (VAT)

DISCOUNT

A 10% discount on the Customer Charge and the Base Energy Charge is allowed if payment is made in full within 15 calendar days of the date of issue of the bill. The discount does not apply to the Fuel Charge portion of the bill.

METER READING AND BILLING

The meters of Domestic Service customers are normally read every month, and billed monthly. On the occasion when meters are not read, the customers' bills will be estimated based on an average of their previous energy consumption.

RULES AND REGULATIONS

Service under this schedule is subject to the orders of the Fair Trading Commission and the latest publication of the "Information and Requirements Covering Installation of Electric Services and Meters". In case of a difference of interpretation between any provision of this schedule and the "Information and Requirements Covering Installation of Electric Services and Meters" booklet, the provision of this schedule shall apply. A bill calculated under this tariff is subject to change under the provisions of such applicable rider(s) as may be approved and/or amended by the Fair Trading Commission.

K-2

K-2: PROPOSED TARIFF FOR GENERAL SERVICE (GS)

APPLICATION

This tariff is available to all customers who meet the required conditions of service.

TYPE OF SERVICE

Under this tariff, the Company will supply single-phase alternating current electricity at 50 Hz, and one of the nominal secondary voltages specified in the latest revision of the Company's booklet entitled "Information and Requirements Covering Installation of Electric Services and Meters".

CONDITIONS OF SERVICE

Single phase, 2 or 3 wire services up to a maximum of 10 kVA are eligible for this tariff. No service may be transmitted from a customer who receives service to another premises without the prior written consent of the Company.

GENERAL PROVISIONS

When two or more rates are available for certain classes of service the choice of such rates rests with the customer. The Company will at any time, upon request, advise any customer as to the rate best suited to existing or anticipated service requirements, as defined by the customer. The Company does not assume responsibility for the selection of such rate or the continuance of the lowest annual cost under the rate selected. A customer, having selected a rate, may not change to another rate within a 12-month period unless there is a substantial change in the character or conditions of the service. In the case of a new service, customers will be given reasonable opportunity to determine their service requirements before selecting their preferred rate.

MONTHLY RATE

1) **Customer Charge** - This applies to each electricity service under this tariff for the fixed costs of providing service including the service installation, meter reading, billing and customer service costs. The monthly customer charge is determined by the customer's 30 day average kWh consumption over the previous 12 months, or as many months during the past 12 months as are available.

   a) 0 -100 kWh $ 12/month

   b) 101 - 500 kWh $ 15/month

c) Over 500 kWh $ 24/month

2) **Base Energy Charge** - This applies to each electricity service under this tariff for all other costs directly associated with the provision of this service, except the cost of fuel.

a) First 100 kWh $ 0.204/kWh
b) Next 400 kWh $ 0.254/kWh
c) Next 1000 kWh $ 0.311/kWh
d) Over 1500 kWh $ 0.354/kWh

2) **Fuel Charge –** This applies to each electricity service under this tariff for the cost of fuel associated with the provision of this service. This charge is recovered through a Fuel Clause Adjustment (FCA).

Fossil fuel portion of kWh @ the Fuel Clause Adjustment (cents/kWh)

3) **Renewable Purchased Power Charge –** This applies to each electricity service under this tariff for the cost of renewable power purchases associated with the provision of this service. This charge is recovered through a Renewable Purchased Power Adjustment (RPPA).

Renewable purchases portion of kWh @ the Renewable Purchased Power Adjustment (cents/kWh).

Energy consumed under this tariff is delivered from both fossil fuel and renewable generation sources. The costs associated with each source of generation is recovered through the FCA and the RPPA in proportion to their respective contributions.

The FCA and RPPA may vary from month to month.

MINIMUM BILL

The minimum bill shall be the applicable Customer Charge.

TAXES

All rates are subject to Value Added Tax (VAT)

METER READING AND BILLING

The meters of Domestic Service customers are normally read every month, and billed monthly. On the occasion when meters are not read, the customers' bills will be estimated based on an average of their previous energy consumption.

RULES AND REGULATIONS

Service under this schedule is subject to the orders of the Fair Trading Commission and the latest publication of the “Information and Requirements Covering Installation of Electric Services and Meters”. In the case of a difference of interpretation between any provision of this schedule and the “Information and Requirements Covering Installation of Electric Services and Meters” booklet the provision of this schedule shall apply. A bill calculated under this tariff is subject to change under the provisions of such applicable rider(s) as may be approved and/or amended by the Fair Trading Commission.

K-3

K-3: PROPOSED TARIFF FOR SECONDARY VOLTAGE POWER (SVP)

APPLICATION

This tariff is available to all customers.

TYPE OF SERVICE

Under this tariff, the Company will supply single-phase or three-phase alternating current electricity at 50 Hz, at one of the nominal secondary voltages specified in the latest revision of the Company's booklet entitled "Information and Requirements Covering Installation of Electric Services and Meters".

CONDITIONS OF SERVICE

This tariff is available for customers with a billing demand of not less than 5 kVA. No service may be transmitted from a customer who receives this service to another premises without the express prior written consent of the Company.

GENERAL PROVISIONS

When two or more rates are available for certain classes of service, the choice of such rates rests with the customer. The Company will at any time, upon request, advise any customer as to the rate best suited to existing or anticipated service requirements, as defined by the customer. The Company does not assume responsibility for the selection of such rate. A customer, having selected a rate, may not change to another rate within a 12-month period unless there is a substantial change in the character or conditions of the service. In the case of a new service, customers will be given reasonable opportunity to determine their service requirements before selecting their preferred rate.

MONTHLY RATE

1) **Customer Charge** - This applies to each electricity service under this tariff for the fixed costs of providing service, including service installation, meter reading, billing and customer services.

$169.00/month

2) **Demand Charge** – This applies to each electricity service under this tariff for the costs associated with the generating facilities, transmission and distribution

lines, substations, transformers and other facilities required to meet individual and combined customer peak demand.

a) For Company-owned transformer(s):
$28.82/kVA of Billing Demand

3) **Base Energy Charge** - This applies to each electricity service under this tariff for the variable energy costs associated with the provision of this service, except the cost of fuel and renewable power purchases.

All kWh @ $0.1380

4) **Fuel Charge** - This applies to each electricity service under this tariff for the cost of fuel associated with the provision of this service. This charge is recovered through a Fuel Clause Adjustment (FCA).

Fossil fuel portion of kWh @ the Fuel Clause Adjustment (cents/kWh)

5) **Renewable Purchased Power Charge** – This applies to each electricity service under this tariff for the cost of renewable power purchases associated with the provision of this service. This charge is recovered through a Renewable Purchased Power Adjustment (RPPA).

Renewable purchases portion of kWh @ the Renewable Purchased Power Adjustment (cents/kWh).

Energy consumed under this tariff is delivered from both fossil fuel and renewable generation sources. The costs associated with each source of generation is recovered through the FCA and the RPPA in proportion to their respective contributions.

The FCA and RPPA may vary from month to month.

BILLING DEMAND

(a) Customers connected under this rate shall be metered as to demand and the billing demand shall be the maximum measured demand of the current month or 5 kVA, whichever is greater. The measured demand may be measured in either kW or kVA at the option of the Company depending upon the character of the service. If the demand is measured in kW then the maximum kW reading shall be divided by a correction factor of 0.85 for conversion to kVA for billing purposes.

(b) The Company shall reserve the right to assess the billing demand in cases where an accurate demand reading cannot be obtained, for example, due to the inaccessibility of the meter or a demand seal being broken. In these cases, the billing demand shall be assessed using the best estimate of the customer's kWh/kVA ratio and energy usage for the period. These will normally be determined using an average of the previous three months of the customer's billing information.

(c) The Company shall reserve the right to assess the billing demand based on a connected load for installations with high momentary demands including lifts, cranes, X-ray equipment and welders.

(d) For customers with a contracted demand, the billing demand shall be the higher of (a) or (b) or the contracted demand.

MINIMUM BILL

The minimum bill shall be the Billing Demand Charge plus the Customer Charge

TAXES

All rates are subject to Value Added Tax (VAT)

TERMS OF SERVICE

Not less than one year.

RULES AND REGULATIONS

Service under this schedule is subject to the orders of the Fair Trading Commission and the latest publication of the "Information and Requirements Covering Installation of Electric Services and Meters". In case of a difference of interpretation between any provision of this schedule and the "Information and Requirements Covering Installation of Electric Services and Meters" booklet the provision of this schedule shall apply. A bill calculated under this tariff is subject to change under the provisions of such applicable rider(s) as may be approved and / or amended by the Fair Trading Commission.

K-4

K-4: PROPOSED TARIFF FOR LARGE POWER (LP)

APPLICATION

This tariff is available to all customers receiving supply at primary voltage.

TYPE OF SERVICE

Under this tariff, the Company will supply three-phase alternating current electricity at 50 Hz, and one of the nominal primary voltages specified in the latest revision of the Company's booklet entitled "Information and Requirements Covering Installation of Electric Services and Meters".

CONDITION OF SERVICE

This tariff is available for customers with a billing demand of not less than 50 kVA. No service may be transmitted from a customer to another premises without the express written prior consent of the Company.

GENERAL PROVISIONS

When two or more rates are available for certain classes of service, the choice of such rates rests with the customer. The Company will at any time, upon request, advise any customer as to the rate best suited to existing or anticipated service requirements, as defined by the customer. The Company does not assume responsibility for the selection of such rate. A customer, having selected a rate, may not change to another rate within a 12-month period unless there is a substantial change in the character or conditions of the service. In the case of a new service, customers will be given reasonable opportunity to determine their service requirements before selecting their preferred rate.

MONTHLY RATE

1) **Customer Charge** - This applies to each electricity service under this tariff for the fixed costs of providing service, including service installation, meter reading, billing and customer services.

   $1,587.00/month

2) **Demand Charge** - This applies to each electricity service under this tariff for the costs associated with the generating facilities, transmission and distribution

lines, substations, transformers and other facilities required to meet individual and combined customer peak demand.

$33.30/kVA of Billing Demand

Note: In cases where a customer's transformer may fail, or otherwise be unavailable, the Company may provide a transformer on a temporary basis for an additional charge as set out in the Schedule of Service Charges.

3) **Base Energy Charge** - This applies to each electricity service under this tariff for the variable energy costs associated with the provision of this service, except the cost of fuel.

All kWh @ $0.1170/kWh

4) **Fuel Charge -** This applies to each electricity service under this tariff for the cost of fuel associated with the provision of this service. This charge is recovered through a Fuel Clause Adjustment (FCA).

All kWh @ the Fuel Clause Adjustment (cents/kWh)

5) **Renewable Power Purchase Charge –** This applies to each electricity service under this tariff for the cost of renewable power purchases associated with the provision of this service. This charge is recovered through a Renewable Power Purchase Adjustment (RPPA).

All kWh @ the Renewable Power Purchase Adjustment (cents/kWh)

The FCA and RAPP may vary from month to month.

METERING ON LOW VOLTAGE SIDE

Normally the usage for customers under this tariff will be metered on the high voltage side of their transformer. However, under special circumstances, at the Company's discretion, their usage may be metered on the low voltage side of the transformer. On these occasions the Company shall increase the Billing Demand and energy consumed by a loss factor for the calculation of the Demand, Base Energy and Fuel Charges to account for losses incurred in the customer's transformer.

MINIMUM BILL

The minimum bill shall be the Billing Demand Charge plus the Customer Charge.

BILLING DEMAND

(a) Customers connected under this rate shall be metered as to demand and the billing demand shall be the maximum measured demand of the current month or 50 kVA, whichever is greater. The measured demand may be measured in either kW or kVA at the option of the Company depending upon the character of the service. If the demand is measured in kW then the maximum kW reading shall be divided by a correction factor of 0.85 for conversion to kVA for billing purposes.

(b) The Company shall reserve the right to assess the billing demand in cases where an accurate demand reading cannot be obtained, for example due to the inaccessibility of the meter or a demand seal being broken. In these cases, the demand will be assessed using the best estimate of the customer's kWh/kVA ratio and energy usage for the period. These will normally be determined using an average of the previous three months of the customer's billing information.

(c) The Company shall reserve the right to assess the billing demand based on a connected load for installations with high momentary demands including lifts, cranes, X-ray equipment and welders.

(d) For customers with a contracted demand, the billing demand shall be the higher of (a) or (b) or the contracted demand.

TERMS OF SERVICE

Not less than one year.

RULES AND REGULATIONS

Service under this schedule is subject to the orders of the Fair Trading Commission and the latest publication of the "Information and Requirements Covering Installation of Electric Services and Meters". In case of a difference of interpretation between any provision of this schedule and the "Information and Requirements Covering Installation of Electric Services and Meters" booklet the provision of this schedule shall apply. A bill calculated under this tariff is subject to change under the provisions of such applicable rider(s) as may be approved and/or amended by the Fair Trading Commission.

K-5

K-5: PROPOSED TARIFF FOR EMPLOYEES

APPLICATION

This tariff is available to present and retired employees of The Barbados Light & Power Co. Ltd. It applies to an individually-metered dwelling house or apartment occupied for domestic purposes by the employee.

TYPE OF SERVICE

Under this tariff, the Company will supply single-phase alternating current electricity at 50 Hz, and one of the secondary voltages specified in the latest revision of the Company's booklet entitled "Information and Requirements Covering Installation of Electric Services and Meters".

CONDITIONS OF SERVICE

Single phase, 2 or 3 wire services up to a maximum of 200 amperes are eligible for this tariff. This tariff is not applicable to employees who occupy dwelling units used or registered for the purpose of transient occupancy such as rooming houses, hotels, guest-houses or villas, or primarily for commercial, industrial or non-domestic activities. No service may be transmitted from a customer who receives service to another premises without the prior written consent of the Company.

MONTHLY RATE

1. **Base Energy Charge** - This applies to each electricity service under this tariff for all costs associated with the provision of this service, except the cost of fuel.

   a) First 150 kWh @ $0.133/kWh
   b) Next 350 kWh @ $ 0.157/kWh
   c) Next 1000 kWh @ $ 0.227/kWh
   d) Over 1500 kWh @ $ 0.255/kWh

2. **Fuel Charge** – This applies to each electricity service under this tariff for the cost of fuel associated with the provision of this service. This charge is recovered through a Fuel Clause Adjustment (FCA).

Fossil fuel portion of kWh @ the Fuel Clause Adjustment (cents/kWh)

3. **Renewable Purchased Power Charge –** This applies to each electricity service under this tariff for the cost of renewable power purchases associated with the provision of this service. This charge is recovered through a Renewable Purchased Power Adjustment (RPPA).

   Renewable purchases portion of kWh @ the Renewable Purchased Power Adjustment (cents/kWh).

Energy consumed under this tariff is delivered from both fossil fuel and renewable generation sources. The costs associated with each source of generation is recovered through the FCA and the RPPA in proportion to their respective contributions.

The FCA and RPPA may vary from month to month.

TAXES
All rates are subject to Value Added Tax (VAT)

RULES AND REGULATIONS

Service under this schedule is subject to the orders of the Fair Trading Commission and the latest publication of the “Information and Requirements Covering Installation of Electric Services and Meters”. In case of a difference of interpretation between any provision of this schedule and the “Information and Requirements Covering Installation of Electric Services and Meters” booklet the provision of this schedule shall apply. A bill calculated under this tariff is subject to change under the provisions of such applicable rider(s) as may be approved and/or amended by the Fair Trading Commission.

K-6

K-6: PROPOSED TARIFF FOR STREET LIGHTS

APPLICATION

This tariff is available for Street Lighting provided by the Company.

MONTHLY RATE

1) **Customer Charge** - This applies to each electricity service under this tariff for the fixed costs of providing service including the service installation, billing and customer service costs.

    All streetlights $10/month

2) **Base Energy Charge –** This applies to each electricity service under this tariff for all other costs associated with the provision of this service, except the cost of fuel.

    All kWh @ $ 0.231/kWh

3) **Fuel Charge** – This applies to each electricity service under this tariff for the cost of fuel associated with the provision of this service. This charge is recovered through a Fuel Clause Adjustment (FCA).

    Fossil fuel portion of kWh @ the Fuel Clause Adjustment (cents/kWh)

4) **Renewable Purchased Power Charge –** This applies to each electricity service under this tariff for the cost of renewable power purchases associated with the provision of this service. This charge is recovered through a Renewable Purchased Power Adjustment (RPPA).

    Renewable purchases portion of kWh @ the Renewable Purchased Power Adjustment (cents/kWh).

    Energy consumed under this tariff is delivered from both fossil fuel and renewable generation sources. The costs associated with each source of generation is recovered through the FCA and the RPPA in proportion to their respective contributions.

    The FCA and RPPA may vary from month to month.

MINIMUM BILL

The minimum bill shall be the applicable Customer Charge.

TAXES
All rates are subject to Value Added Tax (VAT).

RULES AND REGULATIONS
Service under this schedule is subject to the orders of the Fair Trading Commission and the latest publication of the “Information and Requirements Covering Installation of Electric Services and Meters”. In case of a difference of interpretation between any provision of this schedule and the “Information and Requirements Covering Installation of Electric Services and Meters” booklet the provision of this schedule shall apply. A bill calculated under this tariff is subject to change under the provisions of such applicable rider(s) as may be approved and/or amended by the Fair Trading Commission.

K-7

K-7: PROPOSED TARIFF FOR TIME-OF-USE (TOU)

APPLICATION

The Time-of-Use Tariff (this “Tariff”) is available to customers receiving supply at primary voltage.

TYPE OF SERVICE

Under this Tariff, the Company will supply three-phase alternating current electricity at 50 Hz, and one of the nominal primary voltages specified in the latest revision of the Company’s booklet entitled “Information and Requirements Covering Installation of Electric Services and Meters”.

CONDITION OF SERVICE

This Tariff is available to customers with a billing demand of not less than 50 kVA. No service may be transmitted from a customer to another premise without the express prior written consent of the Company.

GENERAL PROVISIONS

When two or more rates are available for certain classes of service, the choice of such rates rests with the customer. The Company will at any time, upon request, advise any customer as to the rate best suited to existing or anticipated service requirements, as defined by the customer. The Company does not assume responsibility for the selection of such rate or the continuance of the lowest annual cost under the selected rate. A customer, having selected a rate, may not change to another rate within a 12-month period unless there is a substantial change in the character or conditions of the service. In the case of a new service, customers will be given reasonable opportunity to determine their service requirements before selecting their preferred rate.

MONTHLY RATE

1) **Customer Charge** - This applies to each electricity service under this Tariff for the fixed costs of providing service, including the service installation, meter reading, billing and customer service.

   $1,675.00/month

2) **Demand Charge** - This applies to each electricity service under this Tariff for the costs associated with the generating facilities, transmission and distribution

lines, substations, transformers and other facilities required to meet individual and combined customer peak demand.

All kVA @ $22.88/kVA of Billing Demand

3) **Base Energy Charge** - This applies to each electricity service under this Tariff for the variable energy costs associated with the provision of this service, except the cost of fuel, within the time periods shown below:

On-peak:	$0.2190/kWh
Off-peak:	$0.0620/kWh

4) **Fuel Charge** - This applies to each electricity service under this tariff for the cost of fuel associated with the provision of this service. This charge is recovered through a Fuel Clause Adjustment (FCA).

On-peak:	1.12 times the Fuel Clause Adjustment (cents/kWh)
Off-peak:	0.92 times the Fuel Clause Adjustment (cents/kWh)

5) **Renewable Purchased Power Charge** – This applies to each electricity service under this tariff for the cost of renewable power purchases associated with the provision of this service. This charge is recovered through a Renewable Power Purchase Adjustment (RPPA).

On-peak: 1.12 times the Renewable Power Purchase Adjustment (cents/kWh)

Off-peak: 0.92 times the Renewable Power Purchase Adjustment (cents/kWh)

The FCA and RPPA may vary from month to month.

DEFINITION OF TIME PERIOD

On-peak	10:00am to 09:00pm Monday through Friday, except annually published public holidays
Off-peak	All hours other than on-peak

METERING ON LOW VOLTAGE SIDE

Normally the usage for customers under this Tariff will be metered on the high voltage side of their transformer. However, under special circumstances, at the Company's discretion, their usage may be metered on the low voltage side of the transformer. On these occasions the Company shall increase the Billing Demand and energy consumed by a loss factor for the calculation of the Demand, Base Energy and Fuel Charges to account for losses incurred in the customer's transformer.

MINIMUM BILL

The minimum bill shall be the Billing Demand Charge plus the Customer Charge.

BILLING DEMAND

(a) Customers connected under this rate shall be metered as to demand and the billing demand shall be the maximum measured demand of the current month or 50 kVA, whichever is greater. The measured demand may be measured in either kW or kVA at the option of the Company depending upon the character of the service. If the demand is measured in kW then the maximum kW reading shall be divided by a correction factor of 0.85 for conversion to kVA for billing purposes.

(b) The Company shall reserve the right to assess the billing demand in cases where an accurate demand reading cannot be obtained, for example due to the inaccessibility of the meter or a demand seal being broken. In these cases, the demand will be assessed using the best estimate of the customer's kWh/kVA ratio and energy usage for the period. These will normally be determined using an average of the previous three months of the customer's billing information.

(c) The Company shall reserve the right to assess the billing demand based on a connected load for installations with high momentary demands including lifts, cranes, X-ray equipment and welders.

(d) For customers with a contracted demand, the billing demand shall be the higher of (a), (b), (c) or the contracted demand.

TERMS OF SERVICE

The initial contract period for this Tariff is for a minimum of one year. At the end of the pilot programme the Company will review the experience it has gained from the programme and determine whether to continue to offer this tariff. Customers will be advised accordingly. If the Company decides to continue to make this Tariff available, customers who wish to remain on it with the new arrangements will not be required to take any further action. However, if the Company decides not to continue with it or the customer no longer wants to participate, the other party shall be advised and the customer will revert to the LP tariff.

RULES AND REGULATIONS

Service under this schedule is subject to the orders of the Fair Trading Commission and the latest publication of the "Information and Requirements Covering Installation of Electric Services and Meters". In case of a difference of interpretation between any provision of this schedule and the "Information and Requirements Covering Installation of Electric Services and Meters" booklet the provision of this schedule shall apply. A bill calculated under this Tariff is subject to change under the provisions of such applicable rider(s) as may be approved and/or amended by the Fair Trading Commission.

K-8

K-8: PROPOSED TARIFF FOR FUEL CLAUSE ADJUSTMENT

APPLICATION

The Fuel Clause Adjustment is applicable to customers that receive service under the Domestic Service, General Service, Employees, Secondary Voltage Power, Large Power, Street Lights and Time of Use tariffs.

FUEL CLAUSE ADJUSTMENT (FCA)

The FCA recovers the cost of fossil fuels used to generate electricity for use by its customers. Fuel purchases are a "pass through" cost that is applied equally to all customer groups through the FCA charge. The FCA is determined by the following formula:

$$FCA_n = \frac{\sum_i (Fuel\ Cost_{n-1}.\frac{THR_{n-1}^i}{AHR_{n-1}^i})}{Energy\ Generation_{n-1}\ .\ (1 - Aux_{n-1})\ .\ (1 - losses)} = \left[\frac{\$}{kWh}\right]$$

Where:

FCA_n =Fuel Clause Adjustments for the month

$Energy\ Generation_{n-1}$= Energy generated in the previous month

Aux_{n-1}=Auxiliary consumption as a percentage of total generation in the previous month

$losses$= System losses as a percentage of net generation calculated based on a 12 month running average.

$Fuel\ Cost_{n-1}$=Fuel cost in previous month including cumulative under/over recovery

THR_{n-1}^i=Targeted Heat Rate for generation plant/unit i, for previous month

AHR_{n-1}^i= Actual Heat Rate for generation plant/unit i, for previous month

In determining the FCA the Company will:

a) use its best estimates of the Projected Cost of Fuel, the Projected Purchased Power and the Projected kilowatt hour (kWh) sales for the month;

b) reconcile monthly the revenue from the fuel charges billed in the previous month with the actual Cost of Fuel used during that month and calculate the under or over recovery, as the case may be, for that month. The net balance of the under or over recovery will be carried forward to the next billing month;

c) where the net under or over recovery in a previous billing month is of an amount, such that, when added or subtracted (as the case may be) to the Cost of Fuel and of Purchased Power, there may be significant fluctuations in the FCA in subsequent months the Company may spread the balance of the under or over recovery amount over one or more subsequent months, so as to smooth fluctuations in the FCA for these months.

The FCA will be applied to the proportion of energy generated from fossil fuel resources.

K-9

K-9 PROPOSED INTERRUPTIBLE SERVICE RIDER (ISR)

APPLICATION

This Interruptible Service Rider (ISR) is available to customers in the Secondary Voltage Power (SVP) and Large Power (LP) tariffs ("eligible customers") as follows:

(a) to eligible customers with a Billing Demand in excess of 200 kVA and a Monthly Interruptible Demand of not less than 100 kVA.

All of the provisions of the applicable SVP and LP tariffs will apply except as amended by this Rider.

Customers on the Time-of-Use Tariff are not eligible to participate under this Rider.

CONDITIONS OF SERVICE

To be eligible, customers must be able to demonstrate the ability to reduce their load to the Firm Demand Level (FDL) within 30 minutes of being notified to do so via the communication channel agreed between the customer and the Company. The minimum FDL shall be zero. The customer shall not be required to exceed 240 hours of interruption in a contractual year.

POWER INTERRUPTION NOTIFICATION

The Company will notify the customer, using an agreed method of the time the customer will be required to interrupt their load at least thirty minutes in advance and the Company will notify them, at an appropriate time, when the interruption will end.

INTERRUPTIBLE CAPACITY CREDITS

The Company will credit the customer for their Monthly Interruptible Demand (MID) at the following rates:

(a) $12.00/kVA of Monthly Interruptible Demand (MID) for customers agreeing to be interrupted between 7.00 am and 9.00 pm on any day except Saturdays, Sundays and public holidays.

(b) $9.00/kVA of Monthly Interruptible Demand (MID) for customers agreeing to be interrupted between 7.00 am and 4.30 pm on any day except Saturdays, Sundays and public holidays.

where:

(c) The **Monthly Interruptible Demand (MID)** is the difference between the **Monthly Average Demand (MAD)** and the **Firm Demand Level (FDL)**

MID = MAD –FDL:

(d) The **Monthly Average Demand (MAD)** is the number of kilowatt hours (kWh) consumed by the customer for the billing period divided by the number of days (DOS) in the billing period times 24 hours minus the number of hours interrupted in the month (Ih) and divided by power factor of 0.85:

MAD = (kWh/(DOS*24-Ih))/0.85

(e) The **Firm Demand Level** (FDL) is the kVA demand level established between the Company and the customer that specifies the load limit of interruption. The customer must reduce the demand to this level or below during periods of required reductions.

SPECIAL PROVISIONS

In the event the Monthly Interruptible Demand (MID) is less than the minimum of 100 kVA no credit will be paid for that month.

In the event that the Company notifies the customer of an interruption and the customer fails to reduce power usage as required by the Agreement, no monthly credit will be issued for the month in which the customer failed to reduce power usage. In addition, the value of the credit that would otherwise have been afforded to the customer had it reached its FDL during an interruptible period for that billing month, will be added to the customer's bill for the current month.

INTERRUPTIBLE RIDER AGREEMENT

Customers who wish to participate in this program must register for this Rider. Eligible customers must enter into an Interruptible Rider Agreement with the Company (the Agreement) for a contract period of not less than one year. Customers may request termination of the contract by giving the Company at least three (3) months' notice of its desire to terminate the contract

TERMS OF SERVICE

The minimum contract period for this Rider is one year. Periodically, terms and conditions of service under the ISR Agreement will be subject to regulatory review and may change once regulatory approval has been granted to the Company to amend them. Where the Company has sought a review of the ISR terms and conditions of service and as a result the ISR Agreement has been amended to reflect regulatory determinations which are different to what currently exist, customers participating in the ISR program will be advised immediately of any new arrangements. Following this, existing customers desirous of continuing on with the ISR program will be required to enter into a new contractual agreement with the Company.

RULES AND REGULATIONS

Service under this schedule is subject to the orders of the Fair Trading Commission and the latest publication of the "Information and Requirements Covering Installation of Electric Services and Meters" booklet. In case of a difference of interpretation between any provision of this schedule and the "Information and Requirements Covering Installation of Electric Services and Meters" booklet the provision of this schedule shall be deemed to apply. A bill calculated under this is subject to change as may be approved and/or amended by the Fair Trading Commission under the provisions of applicable riders.

K-10

K-10: PROPOSED SERVICE CHARGES SCHEDULE

Charge	Service	Proposed Charges
New Service	Below 200 Amps	$130
	Above 200 Amps	$350
Reconnection/Transfer of Service Non-AMI	Below 200 Amps	$35
	Above 200 Amps	$80
Reconnection/Transfer of Service AMI	Each	$10
Debt Reconnection Non-AMI	Working Hours Reconnection	$35
	After Hours Reconnection	$70
Shift Meter	Below 200 Amps	$130
	Above 200 Amps	$350
Upgrade Service	Below 200 Amps	$130
	Above 200 Amps	$350
Damaged Meter	1-PH Meter	$260
	3-PH Meter	$650
Special Events/Temporary Service	Below 200 Amps	$85
	Above 200 Amps	$210
Tampering Fee	Each	$390
Provide & Install Sealing Ring	Each	$35
Meter Read - Non AMI	Each	$35
Meter Test	Each	$80
Returned Cheque	Each	$60
Transformer Rental	Primary voltage	$1.00/kVA of transformer capacity
Transformer Upgrade-Renewables	Each	As per BLPC's customer contribution policy
Off cycle billing - AMI	Each	$15
Renewable Service- Application Fee	Below 200 Amps	$200
	Above 200 Amps	$520
Connection Impact Assessment	Up to 1 MW Capacity	$200
	Above 1 MW Capacity	Cost to conduct study
Special After Hours Appointments	Weekday After Hours	$300
	Weekend	$600
Renewable refunds processing fee	Each	$7

NOTE
(1) All rates are subject to Value Added Tax (VAT)

K-11

K-11: PROPOSED RENEWABLE PURCHASED POWER ADJUSTMENT

APPLICATION

The Renewable Purchased Power Adjustment is applicable to customers that receive service under the Domestic Service, General Service, Employees, Secondary Voltage Power, Large Power, Street Lights and Time of Use tariffs.

RENEWABLE PURCHASED POWER ADJUSTMENT (RPPA)

The RPPA recovers the costs of energy purchased from renewable energy resources used to supply electricity for use by its customers. Renewable energy purchases are a "pass through" cost that is applied equally to all customer groups through the RPPA charge. The RPPA is determined by the following formula:

$$RPPA_n = \frac{Cost\ of\ Renewable\ Power\ Purchases_{n-1}}{Total\ Renewable\ Power\ Purchases_{n-1}} = \left[\frac{\$}{kWh}\right]$$

Where:

$RPPA_n$ = Renewable Purchased Power Adjustment for the month
$Cost\ of\ Renewable\ Power\ Purchases_{n-1}$= Total cost of renewable power purchased in the previous month
$Total\ Renewable\ Power\ Purchases_{n-1}$= Total renewable energy (kWh) purchased in the previous month

The RPPA will be applied to the proportion of energy purchased from renewable resources.

L

MEMORANDUM ON FIVE YEAR FINANCIAL FORECASTS

1. The Barbados Light & Power Company Limited ("the Company") prepares a budget and five-year financial forecast as part of its annual planning cycle. The financial forecast has been prepared taking into consideration the projected annual demand for electricity, the Company's anticipated role in safely delivering that demand under the developing new electricity market structure and the Barbados National Energy Policy 2019 - 2030. The new electricity market increases the difficulty in preparing a five year forecast as it introduces a greater level of uncertainty. The forecast has as its key objective meeting projected customer demand for electricity and is prepared using assumptions regarding changes in the costs of inputs e.g. plant, organization structure, labour and materials. The forecast does not currently include any assumptions regarding significant changes to the Company's structure driven by the developing market changes as the effect of these changes have not yet been fully determined.

2. The forecast has been prepared in accordance with International Financial Reporting Standards, which are the same accounting principles used in preparing the financial statements as at December 31, 2020. The process used to prepare the financial forecast included adequate review and approval of the financial forecast by the Company's management. The major assumptions used in the forecast are shown in the attached Schedule L-3.

BALANCE SHEET

Fixed Assets

3. The forecast of the Company's fixed assets is determined on a long-term basis through capital expansion studies to cover generation, transmission and distribution requirements. The sales forecast which is shown in the Memorandum on Sales Projections at Schedule H of the Company's Application, provides some of the information needed by the engineering teams to assist in evaluating the plant and equipment required annually to adequately supply electricity in order to meet customer demands. If demand increases or falls, the pace of the investment plan is amended accordingly. Utility plant and

equipment additions are included in the capital forecast for each year, based on the capital projects that are forecasted for that year. The Memorandum On Capital Expansion 2021–2025 outlines key elements of the program with details shown in Schedules I-1, I-2 and I-3 on Capital Expansion for the five-year period (2021-2025). Capital projects are treated as work in progress and are capitalized when the project is put into service. Interest during construction is charged on major projects.

4. Assets are shown at their depreciated value using a straight-line basis using the rates and methodology included in the Application by the Company for approval of the Depreciation Policy (Ref: FTCUR-0001/20)[1] currently being heard by the Fair Trading Commission (the "Commission" or the "FTC").

CURRENT ASSETS

Cash on Hand

5. Cash on Hand is taken from the Statement of Cash Flows which tracks the inflows and outflows relating to operating, investing and financing activities during the year.

Accounts Receivable

6. These consist primarily of trade receivables, which are estimated on the number of days outstanding. There is a provision for bad debts and discounts based on historical results. This head also includes prepaid expenses, which are principally insurance, land taxes and maintenance, which are calculated based on insurance premiums, land tax bills and maintenance contracts.

Inventories

7. Inventories consist of fuel stocks, spares for the generation units and vehicles, and transmission and distribution supplies such as poles and wire. Fuel stocks represent approximately two weeks usage. All inventories are determined on an average cost basis.

[1] https://www.ftc.gov.bb/index.php?option=com_content&task=view&id=377&Itemid=1

CURRENT LIABILITIES

Accounts Payable

8. Accounts Payable includes trade payables of which fuel is a significant amount. The Value Added Tax (VAT) liability is also included under this head and is paid in bi-monthly cycles. The payables are directly related to the fuel costs, capital investments and operating and maintenance expenses.

Current Portion of Loans

9. The current portion of loans is the sum of the repayments due within the next 12 months from the end of each forecasted year, based on related repayment schedules.

NON-CURRENT LIABILITIES

Loans

10. The Company has entered into a number of financial arrangements with local and international lending institutions in order to finance its capital program. These borrowings are negotiated in either US or BBD currency and therefore limit the exposure of the Company to exchange rate risks. The Company currently has its borrowings in fixed rate instruments thus minimizing interest rate risk.

Customer Deposits

11. In order to secure electricity service, commercial and non-resident customers are required to make a security deposit, equivalent to three months usage. Where customers pay the security deposit in the form of cash, these funds attract interest at 3.5% and are refundable at the termination of service. The projected growth in customers’ deposits is based on sales projection and customer growth.

Accumulated deferred income tax liability, accumulated investment tax credit and accumulated manufacturing tax credit

12. A deferred tax liability or asset results from temporary differences between the book value of assets and liabilities and their tax value, or timing differences between the recognition of gains and losses in the financial statements and their recognition in the tax computation.

13. Timing differences result from the fixed assets, stock provisions, bad debt provision and any unutilized tax losses and these are used in the calculation of the net deferred income tax amount.

14. The investment tax credit consists of tax credits from investment allowances and manufacturing allowances associated with the acquisition of plant and equipment which is being deferred and amortised to income over the estimated lives of the respective assets.

STATEMENT OF INCOME

Basic revenue

15. Basic revenue is based on the annual forecasted sales in the Memorandum on Sales Projections at Schedule H of the Company's Application. Multiplying the forecasted sales by the average electricity tariff produces the basic revenue. The financial forecast is based on interim rate relief at the proposed rates coming into effect from November 1, 2021 and the Proposed Tariffs coming into effect from April 1, 2022.

Fuel Revenue and Purchased Power Revenue

16. The fuel clause revenue is the same as the fuel and purchased power costs recovered through the Fuel Clause Adjustment.

Fuel Costs and Purchased Power Costs

17. Fuel costs include cost of fuel and is forecasted based on world market price trends and expected generation plant dispatch. Purchased power costs include cost of purchased power from third party suppliers of electricity from

Renewable Energy (RE) sources. The cost of purchased power is projected based on expected penetration levels of third party suppliers and applicable feed in tariffs.

Operating and Maintenance Expenses

18. Operating and maintenance expenses are derived based on the business units needs to meet the sales forecast identified above and to satisfy customer requirements. These expenses primarily comprise labour, materials and supplies. The forecast is prepared with respect to specific projects and planned maintenance costs. The forecast does not currently include any additional operating and maintenance expenses driven by the new licence requirements or the evolving market structure as the nature and timing of these changes are not yet fully determined.

19. With the exception of the generation business unit, insurance and land tax, the other business unit expenses are forecasted to grow at approximately 3% per annum. Changes in the expenses for the generation business unit, insurance and land tax during the forecast period reflect the expenses associated with the re-investment and proposed new investments to accommodate the transition to RE as per the Schedule on Capital Expansion shown at Schedule I-1.

Depreciation

20. Depreciation is on the straight-line basis using the rates and methodology included in the application by the Company for approval of the Depreciation Policy of the Barbados Light & Power Company Limited (Ref: FTCUR-0001/20) currently being determined by the Commission which amortise the assets over their estimated useful lives.

Interest and finance charges

21. These charges represent the interest on the Company's long-term liabilities. New loans have been forecasted at 3.5% interest rate amortised over ten years. Finance charges incurred on these loans are amortised to income over the life of the respective loan. Interest payable on customer deposits is also included under this head at 3.5% per annum. Interest during construction is

calculated on qualifying capital projects at the rate associated with the loan used to fund the project.

Other Taxes

22. Other Taxes category includes land tax and license fees. The land tax is prorated over the tax year of April 1st of one year to March 31st of the following year. The license fees are fixed fees payable annually to the Accountant General, and are estimated based on current fees levels.

Taxation

23. Income taxes are calculated in accordance with the Income Tax Act, using the current tax rate of sliding scale from 5% to 1%. Current tax is the expected tax payable on the taxable income for the period. Investment tax credit and manufacturing tax credit are computed according to the relevant tax legislation and are deferred and amortised over the useful lives of the relevant assets.

CONCLUSION

24. As outlined above and in the Company's Application, The Five Year Financial Forecast, based on existing rates, shows that the Applicant's revenues would be insufficient to allow it to:

    i. fund its planned investments;
    ii. have sufficient resources to attract capital and;
    iii. have sufficient financial resources to respond to financial, economic or environmental shock.

25. The Five Year Forecast, based on proposed rates, shows that the Applicant is being given the opportunity to improve its rate of return, but will fall short of the requested rate of return during the five year period due to capital investment required to maintain the existing plant and new investments required to support the transition to 100% RE sources. It is likely that the Company will require additional rate relief within the five year period to maintain a reasonable rate of return.

26. The Five Year Financial Forecast, based on existing rates and on proposed rates, may contain rounding differences.

Dated this 30th day of September, 2021

Paper Prepared by:

Ricaido Jennings
Director Finance
The Barbados Light & Power Company Ltd.

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THE BARBADOS LIGHT & POWER COMPANY LIMITED
L-1 Financial Forecast (Proposed rates)

BALANCE SHEET (BDS 000's)
As of December 31

	2021	2022	2023	2024	2025
NON-CURRENT ASSETS					
Generation	842,801	907,796	948,792	981,918	1,001,907
Transmission and distribution	667,192	698,361	749,822	784,498	807,742
Other	136,716	150,355	162,932	171,408	180,678
Work in progress	34,333	44,539	15,086	6,265	8,715
	1,681,042	1,801,052	1,876,632	1,944,088	1,999,041
Less Accumulated Depreciation	(840,344)	(862,046)	(903,761)	(943,409)	(985,437)
	840,698	939,006	972,871	1,000,679	1,013,604
Right of Use Asset	10,105	9,699	9,293	8,886	8,480
	850,803	948,705	982,163	1,009,565	1,022,084
CURRENT ASSETS					
Cash and cash equivalents	24,238	4,281	3,521	12,510	6,300
Trade and other receivables	59,321	65,192	71,362	62,430	75,131
Inventories Fuel	12,116	12,117	13,454	13,767	14,744
Inventories Other	26,971	32,879	28,596	20,514	19,765
Prepaid Expenses	16,780	17,852	16,646	16,266	15,652
Corporation Tax Receivable	981				
Related Parties	1,801	1,508	1,508	1,508	1,508
	142,207	133,828	135,086	126,995	133,100
TOTAL ASSETS	993,010	1,082,533	1,117,249	1,136,560	1,155,184
EQUITY					
Share capital	200,000	200,000	200,000	200,000	200,000
Retained earnings	339,506	390,879	418,079	431,224	438,606
	539,506	590,879	618,079	631,224	638,606
NON-CURRENT LIABILITIES					
Borrowings	247,905	290,526	292,605	295,877	303,306
Customers' deposits	48,866	50,020	50,854	51,665	52,394
Deferred credits	34,046	32,024	30,235	28,554	26,972
Customer contributions for work not yet started	3,409	3,808	3,946	4,058	4,111
Deferred tax liability	3,395	3,865	3,936	4,091	4,007
Long term lease liability	11,366	11,565	10,693	10,348	9,996
	348,988	391,808	392,269	394,593	400,786
CURRENT LIABILITIES					
Trade and other payables	77,584	65,777	68,631	69,501	70,390
Current portion of borrowings	17,932	23,844	26,565	29,809	33,968
Provision for other liabilities and charges	6,212	6,712	6,677	6,403	6,405
Due to Related Parties	2,728	3,453	3,453	3,453	3,453
Corporation Tax Payable			981	981	981
Short term lease liability	60	60	595	595	595
	104,516	99,845	106,902	110,742	115,792
TOTAL LIABILITIES & EQUITY	993,010	1,082,533	1,117,249	1,136,560	1,155,184

THE BARBADOS LIGHT & POWER COMPANY LIMITED
L-1 Financial Forecast (Proposed rates)

STATEMENT OF RETAINED EARNINGS (BDS 000's)
For the year ended December 31

	2021	2022	2023	2024	2025
Balance at January 1	553,986	539,506	590,879	618,079	631,224
Net income for Year	29,520	64,217	54,398	57,156	49,214
Dividends paid	(44,000)	(12,843)	(27,199)	(44,010)	(41,832)
Balance at December 31	539,506	590,879	618,079	631,224	638,606
	200,000	200,000	200,000	200,000	200,000

THE BARBADOS LIGHT & POWER COMPANY LIMITED
L-1 Financial Forecast (Proposed rates)

STATEMENT OF INCOME (BDS 000's)
For the year ended December 31

	2021	2022	2023	2024	2025
Operating Revenue					
Basic Revenue	195,869	243,204	246,736	249,226	252,945
Fuel Revenue	222,558	185,727	120,576	112,521	85,443
Purchase Power	24,142	36,730	119,320	132,955	177,466
Miscellaneous	4,436	4,690	3,877	3,439	3,139
	447,006	470,351	490,510	498,142	518,993
Operating Expenses					
Fuel	222,558	185,727	120,576	112,521	85,443
Purchase Power	24,142	36,730	119,320	132,955	177,466
Generation	47,909	43,390	44,447	38,853	39,343
General	36,117	35,601	37,711	41,732	45,639
Distribution	10,833	12,670	11,987	12,287	12,594
Depreciation	56,654	64,907	70,693	67,401	69,447
Insurance	11,213	12,883	15,459	18,551	22,261
Taxes, other than income	4,872	6,822	6,822	6,822	6,822
	414,298	398,729	427,017	431,122	459,015
Operating Income	32,708	71,621	63,493	67,019	59,978
Finance Income	988	411	419	427	435
Finance Costs	(7,029)	(9,369)	(11,231)	(11,817)	(12,865)
Income before Taxation	26,666	62,664	52,681	55,629	47,548
Current portion	-	-	-	-	-
Deferred Portion	(590)	469	71	155	(84)
Deferred investment tax credit	(1,268)	(1,251)	(1,215)	(1,176)	(1,176)
Deferred manufacturing tax credit	(997)	(772)	(574)	(505)	(407)
	(2,854)	(1,553)	(1,717)	(1,526)	(1,666)
Net Income for the year	29,520	64,217	54,398	57,156	49,214
Return on Average Equity	5.40%	11.36%	9.00%	9.15%	7.75%

THE BARBADOS LIGHT & POWER COMPANY LIMITED
L-1 Financial Forecast (Proposed rates)

STATEMENT of CASH FLOWS (BDS 000's)
For the year ended December 31

	2021	2022	2023	2024	2025
Cash flows from operating activates					
Income before taxation	26,666	62,664	52,681	55,629	47,548
… Adjustments for non-cash items:					
Depreciation	56,654	64,907	70,693	67,401	69,447
Finance income	(304)	(311)	(319)	(327)	(335)
Finance costs	7,029	9,369	11,231	11,817	12,865
Net change in provision for liabilities and other charg	2,402	499	(35)	(273)	1
Operating income before working capital changes	92,448	137,128	134,252	134,247	129,526
(Increase)/decrease in trade and other receivables	(10,863)	(6,943)	(4,965)	9,312	(12,087)
(Increase)/decrease in inventories	(6,929)	(5,909)	2,946	7,769	(229)
(Decrease)/increase in due from related parties	790	1,018			
(Decrease)/increase in trade and other payables	(125)	(11,807)	2,854	870	889
Cash generated from operations	75,322	113,486	135,088	152,198	118,099
Corporation tax paid		981	981		
Interest paid	(6,670)	(10,192)	(11,849)	(12,403)	(13,116)
Net cash from operating activates	68,652	104,275	124,220	139,795	104,983
Cash flows (used in)/ from investing activities					
Additions to property, plant and equipment	(115,918)	(161,735)	(103,276)	(93,967)	(81,472)
Proceeds from sale of property					
Interest received	304	311	319	327	335
Net cash used in investing activates	(115,614)	(161,424)	(102,956)	(93,640)	(81,137)
Cash flows (used in) / from financing activities					
Repayments of borrowings	(14,606)	(21,762)	(26,037)	(29,171)	(33,190)
Dividends paid	(44,000)	(12,843)	(27,199)	(44,010)	(41,832)
Proceeds from borrowings	84,906	70,304	30,837	35,686	44,778
Customers' contributions to property, plant and equipment	1,525	399	137	113	52
Customer deposits	1,465	1,153	834	811	730
Change in lease liability	(59)	(60)	(595)	(595)	(595)
Net cash from/(used in) financing activities	29,229	37,191	(22,022,823)	(37,166)	(30,056)
Net increase /(decrease) in cash and equivalents	(17,732)	(19,957)	(760)	8,989	(6,210)
Cash and cash equivalents - beginning year	41,970	24,238	4,281	3,521	12,510
Cash and cash equivalents - end of year	24,238	4,281	3,521	12,510	6,300

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THE BARBADOS LIGHT & POWER COMPANY LIMITED
L-2 Financial Forecast (Existing rates)

BALANCE SHEET (BDS 000s)
For the year ended December 31

	2021	2022	2023	2024	2025
NON-CURRENT ASSETS					
Generation	842,801	907,796	948,792	981,918	1,001,907
Transmission and distribution	667,192	698,361	749,822	784,498	807,742
Other	136,716	150,355	162,932	171,408	180,678
Work in progress	34,333	44,539	15,086	6,265	8,715
	1,681,042	1,801,052	1,876,632	1,944,088	1,999,041
Less Accumulated Depreciation	(840,344)	(862,046)	(903,761)	(943,409)	(985,437)
	840,698	939,006	972,871	1,000,679	1,013,604
Right of Use Asset	10,105	9,699	9,293	8,886	8,480
	850,803	948,705	982,163	1,009,565	1,022,084
CURRENT ASSETS					
Cash and cash equivalents	15,495	(7,120)	12,855	13,640	10,267
Trade and other receivables	59,321	65,192	51,202	54,798	54,280
Inventories Fuel	12,116	12,117	13,454	13,767	14,744
Inventories Other	26,971	32,879	28,596	20,514	19,765
Prepaid Expenses	16,780	17,852	16,646	16,266	15,652
Corporation Tax Receivable	981				
Related Parties	1,801	1,508	1,508	1,508	1,508
	133,464	122,427	124,261	120,492	116,216
TOTAL ASSETS	984,267	1,071,132	1,106,424	1,130,057	1,138,299
EQUITY					
Share capital	200,000	200,000	200,000	200,000	200,000
Retained earnings	330,994	345,840	348,389	352,657	348,118
	530,994	545,840	548,389	552,657	548,118
NON-CURRENT LIABILITIES					
Borrowings	247,905	323,309	340,183	356,200	365,610
Customers' deposits	48,839	49,831	50,499	51,142	51,703
Deferred credits	34,046	32,024	30,235	28,554	26,972
Customer contributions for work not yet started	3,409	3,808	3,946	4,058	4,111
Deferred tax liability	3,192	2,480	1,312	201	(1,168)
Long term Lease Liability	11,366	11,565	10,693	10,348	9,996
	348,757	423,019	436,867	450,504	457,223
CURRENT LIABILITIES					
Trade and other payables	77,584	65,777	78,631	79,501	80,390
Current portion of borrowings	17,932	26,273	30,832	35,963	41,134
Provision for other liabilities and charges	6,212	6,712	6,677	6,403	6,405
Due to Related Parties	2,728	3,453	3,453	3,453	3,453
Corporation Tax Payable			981	981	981
Short term lease liability	60	60	595	595	595
	104,516	102,274	121,169	126,896	132,958
TOTAL LIABILITIES & EQUITY	984,267	1,071,132	1,106,424	1,130,057	1,138,299

THE BARBADOS LIGHT & POWER COMPANY LIMITED
L-2 Financial Forecast (Existing rates)

STATEMENT OF RETAINED EARNINGS (BDS'000)
For the year ended December 31

	2021	2022	2023	2024	2025
Balance at January 1	553,986	530,994	545,840	548,389	552,657
Net income for Year	21,008	14,846	2,549	4,268	(4,539)
Dividends paid	(44,000)				
Balance at December 31	530,994	545,840	548,389	552,657	548,118

THE BARBADOS LIGHT & POWER COMPANY LIMITED
L-2 Financial Forecast (Existing rates)

STATEMENT OF INCOME (BDS 000s)
For the year ended December 31

	2021	2022	2023	2024	2025
Operating Revenue					
Basic Revenue	187,154	192,744	195,600	197,600	200,563
Fuel Revenue	222,558	185,727	120,576	112,521	85,443
Purchase Power	24,142	36,730	119,320	132,955	177,466
Miscellaneous	4,436	4,690	3,877	3,439	3,139
	438,290	419,891	439,373	446,515	466,611
Operating Expenses					
Fuel	246,700	222,457	239,896	245,476	262,909
Generation	47,909	43,390	44,447	38,853	39,343
General	36,117	35,601	37,711	41,732	45,639
Distribution	10,833	12,670	11,987	12,287	12,594
Depreciation	56,654	64,907	70,693	67,401	69,447
Insurance	11,213	12,883	15,459	18,551	22,261
Taxes, other than income	4,872	6,822	6,822	6,822	6,822
	414,298	398,729	427,017	431,122	459,015
Operating Income	23,993	21,162	12,356	15,393	7,596
Finance Income	988	411	419	427	435
Finance Costs	(7,029)	(9,461)	(13,184)	(14,344)	(15,522)
Income before Taxation	17,951	12,112	(409)	1,477	(7,491)
Current portion	-	-	-	-	-
Deferred Portion	(793)	(711)	(1,169)	(1,110)	(1,369)
Deferred investment tax credit	(1,268)	(1,251)	(1,215)	(1,176)	(1,176)
Deferred manufacturing tax credit	(997)	(772)	(574)	(505)	(407)
	(3,057)	(2,734)	(2,957)	(2,791)	(2,952)
Net Income for the year	21,008	14,846	2,549	4,268	(4,539)
Return on Average Equity	3.87%	2.76%	0.47%	0.77%	-0.83%

THE BARBADOS LIGHT & POWER COMPANY LIMITED
L-2 Financial Forecast (Existing rates)

STATEMENT OF CASH FLOWS (BDS 000's)
For the year ended December 31

	2021	2022	2023	2024	2025
Cash flows from operating activates					
Income before taxation	17,951	12,112	(409)	1,477	(7,491)
… Adjustments for non-cash items:					
Depreciation	56,654	64,907	70,693	67,401	69,447
Finance income	(304)	(311)	(319)	(327)	(335)
Finance costs	7,029	9,461	13,184	14,344	15,522
Net change in provision for liabilities and other changes	2,402	499	(34,806)	(273,431)	1
Operating income before working capital changes	83,733	86,668	83,115	82,621	77,144
(Increase)/decrease in trade and other receivables	(10,863)	(6,943)	15,195	(3,216)	1,133
(Increase)/decrease in inventories	(6,929)	(5,909)	2,946	7,769	(229)
(Decrease)/increase in due from related parties	790	1,018			
(Decrease)/increase in trade and other payables	(125)	(11,807)	12,854	870	889
Cash generated from operations	66,606	63,027	114,111	88,044	78,936
Corporation tax paid		981	981		
Interest paid	(6,670)	(10,284)	(13,802)	(14,929)	(15,772)
Net cash from operating activates	59,937	53,723	101,290	73,115	63,164
Cash flows used in investing activities					
Additions to property, plant and equipment	(115,918)	(161,735)	(103,276)	(93,967)	(81,472)
Proceeds from sale of property					
Interest received	304	311	319	327	335
Net cash used in investing activates	(115,614)	(161,424)	(102,956)	(93,640)	(81,137)
Cash flows (used in)/from financing activities					
Repayments of borrowings	(14,606)	(22,976)	(30,242)	(35,199)	(40,196)
Dividends paid	(44,000)				
Proceeds from borrowings	84,906	106,730	51,675	56,347	54,778
Customers' contributions to property, plant and equipment	1,525	399	137	113	52
Customer deposits	1,437	993	667	644	561
Change in lease liability	(59)	(60)	(595)	(595)	(595)
Net cash from/(used in) financing activities	29,202	85,086	21,642	21,309	14,600
Net increase /(decrease) in cash and equivalents	(26,475)	(22,615)	19,976	784	(3,373)
Cash and cash equivalents - beginning year	41,970	15,495	(7,120)	12,855	13,640
Cash and cash equivalents - end of year	15,495	(7,120)	12,855	13,640	10,267

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MEMORANDUM ON FIVE YEAR FINANCIAL

APPENDIX

MAJOR FORECAST ASSUMPTIONS

Fixed assets

- Capital additions are as per the Memorandum on Capital Expansion – Schedule I
- Inflation from 2021 - 2025 is applied at 2.5% per annum for additions to imported generation and transmission equipment
- Interest during construction is at 2.05 - 3.5%
- Depreciation rates and methodology are based on the Application by The Barbados Light & Power Company Limited for approval of the Depreciation Policy of the Barbados Light & Power Company Limited (Ref: FTCUR-0001/20) currently being heard by the Fair Trading Commission

Current assets

- Receivables are approximately 5-7 weeks of sales
- Fuel inventory is approximately 2 weeks

Equity

- No new issues of shares in the forecast period
- Dividend are determined by the target of 35% to 65% Debt to Equity

Long-term liabilities

- New loans are at 3.5% per annum
- New loans term period 5 years
- New loans principal repayment 10-18 years
- Customer deposit interest rate 3.5%

Current liabilities

- Accounts payable are approximately 6 weeks of expenses

Statement of Income

- Sales as per forecast Memorandum on Sales Projections at Schedule H
- Fuel cost projections as per US Energy Information Administration Short-Term Energy Outlook 2021 and the US Energy Information Administration Annual Energy Outlook 2021 (early release) - December 2020
- Depreciation rates and methodology are based on the Application by The Barbados Light & Power Company Limited for approval of the Depreciation

Policy of the Barbados Light & Power Company Limited (Ref: FTCUR-0001/20) currently being heard by the Fair Trading Commission

- Departmental expenses growth 2.5% per annum
- There is no rental generation from 2022
- Taxation rates
    - Current corporation tax - 5 – 1 %
    - Manufacturing tax credit - 50%