BARBADOS

THE FAIR TRADING COMMISSION

IN THE MATTER of the Utilities Regulation Act, Cap 282 of the Laws of Barbados;

IN THE MATTER of the Utilities Regulation (Procedural) Rules, 2003;

IN THE MATTER of the Decision of the Fair Trading Commission on The Barbados Light & Power Company Limited Application to Establish a Clean Energy Transition Rider as a Cost Recovery Mechanism, dated and issued on 31 May, 2023 under Document # FTCUR/DECCETR/BLPC/2023-02;

AND IN THE MATTER of the Application by The Barbados Light & Power Company Limited for approval to acquire capacity and transmission & distribution resources and to allow the recovery of their costs through the Clean Energy Transition Rider (CETR) mechanism.

APPLICATION FOR PREAPPROVAL OF INVESTMENTS AND COST RECOVERY THROUGH THE CLEAN ENERGY TRANSITION RIDER

A. APPLICATION

1. Pursuant to item 1, paragraph 7.1 of the Fair Trading Commission's (FTC or Commission) Decision on The Barbados Light & Power Company Limited

Application to Establish a Clean Energy Transition Rider as a Cost Recovery Mechanism, dated and issued on 31 May, 2023 under Document # FTCUR/DECCETR/BLPC/2023-02 ('Decision') that established the Clean Energy Transition Rider (CETR), The Barbados Light & Power Company Limited (the BLPC) now applies for the approval of the following capacity and transmission & distribution resources which form its first Clean Energy Transition Plan (CETP) Project ("CETP Project 1"):

a. Interconnection infrastructure to facilitate the integration of Independent Power Producers (IPPs) onto the public grid;
b. 90-megawatt (MW) of Battery Energy Storage Systems;
c. Distributed Energy Resources Aggregation & Control platform ("the pilot");
d. Automatic Generation Control (AGC) systems; and
e. Synchronous Condensers.

2. The BLPC specifically seeks an order that costs related to its CETP Project 1 are approved for recovery through the CETR mechanism on the grounds that:

(i) those costs are unpredictable and volatile, reoccurring, and outside the BLPC's manageable costs within the meaning of the Decision;

(ii) those costs are prudently incurred transitionary and grid modernisation costs within the meaning of the Decision and

(iii) that, the acquisition of the resources identified for its CETP Project 1, are preconditions to achieve the objectives of the Barbados National Energy Policy 2019-2030 (BNEP),are critical to maintaining the reliability of the national grid and constitute necessary changes, extensions and improvements to BLPC's network and service required to ensure BLPC's provision of a safe, adequate, efficient and reasonable service to the public within the meaning of section 20(b) of the Utilities Regulation Act, Cap 282 of the Laws of Barbados.

B. BACKGROUND

3. The BLPC has long demonstrated its support towards increasing the deployment of RE systems by its: (1) Implementation of the Renewable Energy Rider (RER) programme in 2010 to facilitate distributed customer owned RE connections to the grid; (2) Commissioning of a 10 MW solar PV plant in 2016; (3) Commissioning of a 5 MW battery energy storage system at its Trents generation plant in 2018 and (4) Investments in grid modernization to safely and efficiently facilitate higher penetration of distributed intermittent RE onto the public grid.

4. These initiatives have facilitated customer investments in the adoption and integration of RE generation to supply energy to the public grid and as of August 2023 approximately 97 MW of distributed and utility scale RE capacity is interconnected to the public grid.

5. On this current trajectory, the level of intermittent RE generation connected to the public grid is anticipated to exceed 100 MW by the end of 2023. BLPC is aware of a further 300 MW of estimated additional solar PV at different stages of development. The demand for interconnection of intermittent RE to the public grid is expected to surpass the projections contained in the Integrated Resource and Resiliency Plan (IRRP) for Barbados (published in August 2021) and its accompanying Action Plan and Roadmap issued by the now Ministry of Energy and Business Development (MEBD)[1].

6. The higher penetration of intermittent RE is leading to a lower utilization factor on dispatchable synchronous fossil-fuel generation to meet the energy needs of BLPC's customers.

7. The greater reliance on intermittent RE generation primarily from wind and solar PV does, however, give rise to some important technical challenges in

[1] A copy of the IRRP and the IRRP Action Plan and Roadmap is attached at Appendix B

maintaining the reliability of the grid. Firstly, output from these RE generators is intermittent and non-dispatchable given their dependence on weather conditions. Investments in firming technologies in the form of Battery Energy Storage Systems (BESS) are therefore needed to smooth out the variability of intermittent RE generation as their grid penetration increases. Secondly, solar PV and wind harness energy and transform it into electrical power using inverters, which lack the inherent stabilizing qualities found in conventional synchronous generators that contribute to grid stability. Investments in grid stabilization solutions such as Synchronous Condensers (SCOs) and Automatic Generation Control (AGC) systems are therefore required to maintain a stable electrical voltage and frequency to reduce the potential for grid outages.

8. The necessity for BESS both at the distributed and utility scale level will also require the need for investments in a communication and control platform to aggregate these battery resources in order to optimize the grid stability services benefits they are required to provide.

9. Further, to interconnect both RE generation and BESS into the public grid, investments are required for upgrades as well as new transmission and distribution (T&D) interconnection infrastructure to facilitate the two-way flow of energy between Independent Power Producers (IPPs) and BLPC to enable the ultimate consumption by customers. BLPC has already made significant investments in grid modernization initiatives such as its Automatic Metering Infrastructure (AMI) to facilitate two-way communications. However, additional investments are required in both T&D and communication infrastructure to facilitate large-scale IPP interconnections.

10. The long-term interests of customers and ability to safely and reliably integrate the large proportion of intermittent RE required by the BNEP are therefore the primary reasons for the investments being proposed in the CETP Project 1.

11. In its Decision, the Commission established the CETR as a cost recovery mechanism and acknowledged that the CETR…. ***“may be appropriate to recover prudently incurred costs with respect to capital investments needed to support the energy transition, taking account the volume of investments which are expected to actualize the 100% RE target.”*** The BLPC submits that its CETP Project 1 comprises of some of the initial capital investments needed to support the energy transition and therefore these costs qualify for recovery through the CETR mechanism.

12. The BLPC also submits that its CETP Project 1 is a prerequisite to aligning customer interest in reliable service with the BNEP objectives to transition the generation of electricity to 100% RE by 2030.

C. CONCISE STATEMENT OF FACTS (Rule 26(1) (a) of the URP Rules)

13. The BLPC is a vertically integrated electric utility company, established on May 6, 1955, and continued, under the *Companies Act***,** Cap 308 of the Laws of Barbados. Its registered office is at Garrison Hill, St. Michael, Barbados. Pursuant to the Electric Light & Power Order, No. 3, set out in the Third Schedule of the *Electric Light and Power Act***,** Cap 278 of the Laws of Barbados, the BLPC was granted the right to supply energy for all public and private purposes for forty-two years from August 1, 1986.

14. The BLPC is a wholly owned subsidiary of Emera Caribbean Inc. (the ’Holding Company’). It is required to manage the grid to ensure the electricity network meets the rapidly evolving demands of power producers that supply services to the grid and customers supplied from the grid. The BLPC, therefore, must maintain a safe, efficient, reliable network and must continue to invest in its infrastructure to fulfill that obligation.

15. To satisfy the needs of the electric system, the BLPC currently operates generating plants from three (3) locations (Spring Garden, St. Michael, Seawell,

Christ Church and Trents, St. Lucy) using a mix of technologies including both low speed and medium speed diesel engines, gas turbines, and solar PV equipment to produce electricity. Electricity is transmitted and distributed across 3,000 kilometers of distribution and transmission lines and eighteen (18) substations dispersed across the island.

16. The BLPC has an aspirational goal to facilitate achieving a 100/100/100 Barbados - 100% renewable or clean energy, 100% electrification of business, industry and transportation, and 100% resilience. That goal aims to:

    a) Move our island from a high carbon-intensive generation portfolio to low carbon sources;
    b) Reduce the country's dependence on imported fossil fuel;
    c) Mitigate foreign exchange pressure;
    d) Introduce price stability; and
    e) Maintain high levels of reliability for customers.

17. In June 2019, the Government of Barbados (GoB) approved, through Parliament, the BNEP and its accompanying Implementation Plan[2]. The BNEP outlines, among other matters, a policy to transition the generation of electricity to 100% renewable energy (RE) by 2030.

18. The BLPC's vision is aligned with the policy objectives outlined in the BNEP, which delineates a strategy to transition the energy and transportation sectors towards 100% RE.

19. To sustainably facilitate the transition towards this clean energy future, the BLPC needs to make the investments outlined in its CETP Project 1 and recover such costs in a timely manner to safeguard the financial integrity of the utility.

[2] A copy of the BNEP and its Implementation Plan are attached at Appendix A.

20. The Commission in its Decision acknowledged that investments will be required in consideration of the energy transition and for achievement of the 100% RE target by 2030. In the Decision, the Commission also approved cost recovery of prudently incurred costs through an alternative cost recovery mechanism and determined that the scope of cost recovery through the CETR shall be limited to all prudently incurred transitionary and grid modernization expenditure.

21. The Decision also provided[3] that BLPC be required to submit an individual application for the recovery of costs of each asset/project through the cost recovery mechanism and that each application should meet the following minimum criteria:

a) Prior notice of application at least thirty (30) business days before making an application;
b) Description of tracker formula to be implemented;
c) Itemized description and computation to reflect updated rate base;
d) Type, updated costs and function of each asset per CETP;
e) Allocation of assets in CETP to conform to the USOA;
f) Cost benefit analysis for asset(s) where applicable;
g) Summary and calculation of individual proposed/actual annual costs, incremental revenue requirement, rate of return, rate and bill impact per CETP;
h) Summary and calculation of cumulative proposed/actual annual costs, revenue requirement, rate of return, rate and bill impact under COSR framework;
i) Statement of the effect on the number of rate case filings, with increases or decreases in rates;
j) Computation of the effect on all rate classes; and

[3] See item (1) Section 7.1 at page 27 of the Decision

k) Where appropriate the above information should be submitted in Excel Spreadsheet format with appropriate tabs.

22. In compliance with the Decision and as outlined at paragraph 21 hereof, BLPC states that 30 business days' notice of the Application was provided to the FTC by letter dated June 2, 2023 (copy attached at Appendix 'AC1'). BLPC further states that:

(i) A description of the tracker formula to be implemented is provided at paragraph 41 of this Application;

(ii) An itemized description and computation to reflect updated rate base is provided at Exhibits AGC-1, BESS- 1, INTER-1, PLA-1, SYN-1 of this Application;

(iii) The Type, updated costs and function of each asset per CETP is provided at Section D.1 of this Application;

(iv) Allocation of assets in CETP to conform to the USOA is reflected in Exhibits AGC-1, BESS- 1, INTER-1, PLA-1, SYN-1 to this Application;

(v) A summary and calculation of individual proposed/actual annual costs, incremental revenue requirement, rate of return, rate and bill impact per CETP is included in Exhibits AGC-1&2, BESS- 1&2, INTER-1&2, PLA-1&2, SYN-1&2 to this Application;

(vi) A summary and calculation of cumulative proposed/actual annual costs, revenue requirement, rate of return, rate and bill impact under COSR framework is included at Exhibits AGC-1&2, BESS- 1&2, INTER-1&2, PLA-1&2, SYN-1&2, CEPT Project 1-1&2 to this Application;

(vii) A statement of the effect on the number of rate case filings, with increases or decreases in rates is provided at paragraph 139 of this Application;

(viii) Computation of the effect on all rate classes has been included at Exhibits AGC-2, BESS-2, INTER-2, PLA-2, SYN-2, CEPT Project 1-2 to this Application; and

(ix) Where appropriate, the above information has been submitted in Excel Spreadsheet format with appropriate tabs.

D. GROUNDS FOR THE APPLICATION (Rule 26 (1)(b) of the Rules)

23. The grounds of the Application are as set out at paragraph 2 herein.

24. In addition, BLPC submits that the Ministry of Energy and Business Development (MEBD) developed an Integrated Resources and Resilience Plan (IRRP) in 2021 to guide the implementation of the BNEP as it relates to the electricity sector.

25. In 2022, the MEBD subsequently published the Barbados Action Plan for the IRRP which outlined a roadmap to achieve the transition to RE given the acceptance of Scenario 3 within the IRRP.

26. In pursuit of the RE policy objectives, the roadmap and the IRRP projected that the total installed intermittent RE resources would include 286 MW of solar PV and 166 MW of wind resources by 2030.

27. The IRRP and roadmap also recognized that the transition towards the 2030 targets will create challenges to the public grid, related to handling new patterns of power flow, accommodating the variable output of intermittent RE, and balancing a system that includes IPPs' generation. The technical challenges of integrating high amounts of intermittent RE onto an isolated island grid like Barbados are more specifically described in the publication of IRENA[4] to include:

[4] Transforming Small-Island Power Systems: Technical Planning Studies for The Integration of variable Renewables. Available at https://www.irena.org/media/Files/IRENA/Agency/Publication/2019/Jan/IRENA_Transforming_SIDS_Power_2018.pdf

i. Challenges of generation adequacy to ensure that the generation fleet is able to reliably supply the electrical load at all times;
ii. The challenge of variability and uncertainty of intermittent RE, to accommodate the intraday variations of load with the generation system;
iii. Ensuring system stability - given that the electro-mechanical characteristics of the system often change significantly with high penetrations of intermittent RE, the response of the system to disturbances also changes and could impact grid operations;
iv. Integrating a large amount of intermittent RE into the grid can lead to power flows for which the system was not initially designed, giving rise to the potential to exceed the thermal capacity of lines, cables, transformers and other grid elements;
v. Given the limited short circuit currents that characterize intermittent RE sources, at high penetration levels there is the potential for the grid's protection systems to be more easily compromised. The lower short-circuit currents in the high RE scenario are likely to compromise the protection systems' ability to identify and co-ordinate to isolate faults on the grid;
vi. The challenge of maintaining the grid's power quality given the inherent variability characteristics of intermittent RE generation sources.

28. To mitigate the challenges that the transition to high penetration of intermittent RE presents to delivering a secure and reliable supply of electricity to customers, some of which are currently being experienced, the BLPC seeks approval for its CETP Project 1, which is consistent with the infrastructural and operational investments recommended in the IRRP.

D.1. *The CETP Project 1*

29. The BLPC's CETP Project 1 consists of infrastructural and operational investments that are preconditions required to operate the grid at an acceptable resilience and reliability level to facilitate the transition to the BNEP's goals and

objectives. The initial investments as contained in the CETP Project 1, for which approval is sought in this application are:

- 90 MW of Battery Energy Storage Systems;
- Automatic Generation Control (AGC) systems;
- Synchronous Condensers;
- Distributed Energy Resources Aggregation & Control platform ("the pilot");
- Interconnection infrastructures to facilitate the integration of Independent Power Producers (IPPs) onto the public grid.

30. The BLPC seeks the recovery of the revenue requirements associated with the CETP Project 1 through the CETR.

31. The revenue requirement for all the resources in the CETP Project 1, consist of a return on invested capital and all costs associated with the acquisition, construction, administration, operation, and maintenance of these resources employed in the supply of electricity. More specifically, the standard regulated revenue requirement formula is used to develop Test Period Revenue Requirement, which is as follows:

$$RR = [(RC - D) * RoR] + EDT$$

where RR=Revenue Requirement; RC=Resource Costs; D=Accumulated Depreciation; RoR=Allowed Rate of Return; EDT=Expenses (i.e., operation & Maintenance, Depreciation & taxes)

32. The calculation of all resource costs includes the capitalization of an estimate of the weighted cost of capital during construction otherwise known as Allowance for Funds Used During Construction (AFUDC).

33. The Revenue Requirement includes an Allowed Rate of Return that is applied to all of CETP Project 1 investments. The BLPC is requesting an Allowed Rate

of Return (RoR) consistent with the Commission's February 15, 2023 Decision on the Application by the BLPC for a Review of Electricity rates, adjusted for the cost of long-term debt that will be raised to finance the CETP Project 1.

34. The Commission in its February 15, 2023, Decision on the Application by the BLPC for a Review of Electricity Rates determined a notional capital structure of 45% long-term debt and 55% equity for financing BLPC's operations. The BLPC therefore adopted this capital structure for financing of the CETP Project 1.

35. In its February 15, 2023 Decision, the Commission also determined the rate for the return on equity to be 11.75%. The BLPC accepts 11.75% as the cost of equity financing for the CETP Project 1.

36. The BLPC estimates that the cost of long-term debt that will be raised to finance the CETP Project 1 will be 5.96%. This estimate is based on a market scan of interest rates on offer in the market and quotations from potential sources of long-term debt[5].

37. The resulting RoR of 9.14% or weighted average cost of capital as calculated on page 2 of Exhibit BESS-1, was derived using the Commission's determined capital structure (45% debt:55% equity) and cost of equity (11.75%) and the BLPC's 5.96% estimate of the cost of long-term debt financing.

38. The Revenue Requirements discussed below are based on estimates of equipment cost and debt interest rates available at the time of filing this Application, and therefore will be subject to change.

39. The BLPC recommends that the review and recovery of the ultimate, actual costs for the CETP Project 1 be handled through regulatory reporting with the Commission 60 days prior to the commercial operation date of individual

[5] The BLPC will issue an RFP to financial institutions to secure long-term debt at the most competitive rates available.

investments within the CETP Project 1. The report filing will include the actual Revenue Requirements for inclusion in the CETR rates.

40. The estimated CETR rates are calculated using the current forecast of electricity sales for 2023 to illustrate the rate design and customer bill impacts of investments within the CETP Project 1.

41. The CETR tracker rate formula can be represented by:

$$CETR = \frac{[(RC - D) * RoR] + EDT}{Sales}\left[\frac{\$}{kWh}\right]$$

where Sales=Electricity Sales; RC=Resource Costs; D=Accumulated Depreciation; RoR=Allowed Rate of Return; EDT=Expenses (i.e., operation & Maintenance, Depreciation & taxes)

42. The BLPC proposes that the CETR rate related to CETP Project 1 investments approved by the Commission, be established or adjusted based on the date the investments go into service.

D.1.1. 90 MW of Battery Energy Storage Systems

43. The generation and consumption of electricity on the grid must be balanced to keep the frequency of the grid at a constant level or within acceptable limits. Therefore, within fractions of a second following an imbalance, generation capacity with fast frequency needs to be activated to restore balance.

44. Conventional power plants normally provide inertia to the grid as these rotate at a frequency which is synchronized with the frequency of the grid. When an imbalance occurs, this rotational inertia provides support to the system to resist changes in frequency thereby providing grid operators and generating equipment with a brief but essential window of time to take corrective actions like activating available reserve capacity.

45. Intermittent RE such as wind and solar PV do not on their own provide such inertia to the grid, thus necessitating the integration of BESS, SCOs and power electronics in inverters to provide the frequency support required to facilitate the transition towards 100% RE integration whilst using a high penetration of intermittent RE.

46. The generation from Intermittent RE is non-dispatchable and does not match the daily pattern of electricity consumption. When weather conditions are favorable, and the generation from RE exceeds consumption, BESS will be required to store excess energy for situations when the RE sources are not producing, or when weather conditions limit their production.

47. BESS are also required to manage the thermal loading of transmission lines by absorbing surplus energy from intermittent RE. The integration of distributed BESS near the RE generator, will allow for the storage of the excess energy for release when the lines are no longer fully loaded.

48. The IRRP and its roadmap highlighted that the integration of BESS is a precondition to achieving the BNEP objectives. The IRRP scenario 3 called for investments in storage of which 204 MW is expected to be supplied by BESS by 2030.

49. The IRRP anticipated the capacity of distributed installed solar PV would reach 84 MW by 2025 and stated a requirement for 144 MW of BESS to support this level of intermittent RE penetration. However, as of August 31, 2023, the total installed solar PV and wind was 87 MW which exceeds the 84MW which was projected to be on the grid by 2025. In addition, only 5MW of BESS capacity which was installed by BLPC in 2018 is currently available to support this level of high intermittent RE penetration.

50. It is therefore critical that the BLPC procures and installs the required amount of BESS as prescribed in the IRRP to maintain the integrity of the grid to match

the exponential growth in intermittent RE whilst firm generation is being concomitantly retired.

51. The BLPC identified in its CETP Project 1, the need to include 90 MW of BESS to support the transition towards the BNEP targets and mitigate risks to reliability for customers.

52. The portfolio of BESS includes eight (8) x 10 MW- 4-hour systems to be located at various sites on the transmission network and ten (10) x 1 MW- 4-hour systems to be located on the distribution network at various sites.

53. The BESS consists of hardware and software components. The hardware includes lithium-ion battery modules, battery packs and a power conversion system, while the key software components are the Energy Management System (EMS), the Battery Management System (BMS) and a Supervisory Control and Data Acquisition System (SCADA). The EMS acts as a higher-level operating system for the battery, while the BMS is used to monitor the performance data of the battery modules and to regulate charging and discharging. The SCADA controls, monitors and integrates the BESS along with other balance of plant elements.

54. The dominant technology for battery storage is the lithium-ion battery. This has several benefits that allow for the effective mitigation of short-term and intraday imbalances that may occur on the network because of the transition towards a greater share of intermittent RE.

55. Some of the key advantages of lithium-ion batteries include: the lowest long term current costs, fast charging and discharging; storage of energy for several hours; charging and discharging can occur multiple times per day; high power density and high round trip efficiency.

56. In August 2022, the BLPC issued a Request for Proposals (RFP)[6] for the installation of BESS on its transmission and distribution network. The RFP identified the locations for the installation of the BESS, technical specifications such as the expected energy and power capacity as well as the services the BESS should provide.

57. The BLPC administered a competitive solicitation process that involved an evaluation of price and non-price factors such as technical characteristics and requirements for project development.

58. Based on an evaluation of the highest ranked proposals, the BLPC estimates a total capital cost for the BESS, included in the CETP Project 1, to be $558.9 Million as shown on page 1 of Exhibit BESS-1. This figure consists of the estimated purchase costs of the BESS, installation costs and capitalization of the weighted average cost of capital during construction otherwise known as Allowance for Funds Used During Construction (AFUDC).

59. The BESS are expected to begin supplying services to the grid in 2024, when one (1) 10 MW and five (5) 1 MW systems with a capacity of 15 MW would have been commissioned on the transmission and distribution network at an estimated cost of $107.8 million. A further capacity of 35 MW provided by eight (8) systems consisting of three (3) 10 MW and five (5) 1MW that will be commissioned in 2025 at an estimated cost of $223.7 million followed by 40 MW in 2026 at an estimated cost of $227.4 million.

60. The total Cash Working Capital of $930,967 at line 19, page 1 of Exhibit BESS-1, accounts for the timing differences between when the BESS is providing services to customers and the receipt of revenues expressed as an addition to rate base.

[6] The Technical Scope and Specifications for the RFP are appended at Appendix C

61. Total Year End Rate Base for 2024 through to 2026 was derived by adding cash working capital to the total Net Plant.

62. The BLPC is requesting an authorized return on this investment over 2024, 2025 and 2026 estimated at $9,865,800, $20,47,858 and $20,822,047 respectively, computed by multiplying the Rate Base by the RoR.

63. The operation and maintenance expense represents the estimated annual costs to operate and maintain the BESS. This includes the costs estimated for the service contract with BESS suppliers, and other fixed O&M costs.

64. Depreciation expense is calculated on a straight-line basis for book purposes over a 10-year asset life for the BESS. The BLPC used the 10-year life for the BESS assets based on information provided by the highest ranked BESS suppliers.

65. Insurance cost at line 30, relates to the general property insurance for the BESS while taxes include the cost of corporation tax and deferred manufacturers tax credit. Corporation tax is expected to be payable to the Commissioner of Inland Revenue on the taxable income for the asset. The deferred manufacturers tax credit is a 50% allowance associated with the construction of plant and equipment which is earned ratably over the related income tax life.

66. The revenue requirement includes the cost of service plus the authorized return as computed at line 39. The total revenue requirement for the BESS is estimated at $115,149,695 and consists of an estimate of $22,171,702 for 2024, $46,134,877 in 2025 and $46,843,116 for 2026.

67. In calculating the per kilowatt hour rate to be recovered through the CETR for the BESS investments, the BLPC used a forecast of electricity sales for 2023 to calculate the illustrative rate design at Exhibit BESS-2. The CETR rate for

2024, 2025 and 2026 associated with the BESS investments is estimated at $0.023 per kWh, $0.049 per kWh and $0.049 per kWh respectively.

68. The potential bill impact of the application of the CETR rate for the BESS is provided from page 3 of Exhibit BESS-2. In comparison to current rates, a residential customer on the Domestic Service tariff using 250 kilowatt-hours per month would experience an estimated monthly bill increase of $6.90 in 2024, $14.36 in 2025 and $14.58 in 2026 based on the estimated Revenue Requirements for the BESS investments and illustrative sales presented in this Application.

D.1.2. Automatic Generation Control (AGC) Systems

69. The IRRP and its roadmap also recommended the implementation of Automatic Generator Control (AGC) systems for the public network.

70. AGCs are crucial to help maintain a balance between electricity generation and consumption as they automatically regulate power output from multiple conventional generation plants in response to fluctuations in electricity demand and supply.

71. As a consequence of the transition to a high penetration of intermittent RE, the availability of electricity generation will vary significantly due to weather conditions and other factors. This intermittency poses challenges for grid stability since sudden fluctuations in renewable generation can lead to imbalances between supply and demand.

72. AGCs will be relied upon to help mitigate some of these challenges, by continuously monitoring the grid's frequency and automatically adjusting the output of BLPC’s fossil-fuel generation and BESS to compensate for variations in RE generation.

73. On occasions when there is an excess of intermittent RE, AGCs will be called upon to reduce the output from BLPC's dispatchable plants and BESS. Conversely, when intermittent RE generation is insufficient to meet demand, AGCs will increase the output from BLPC's dispatchable plants and BESS to bridge the gap.

74. By maintaining grid frequency within acceptable limits, AGCs will help ensure the stability and reliability of the public grid even with intermittent RE. This will become more critical as the transition intensifies, and as maintaining this balance becomes more challenging to avoid potential disruptions to customers, overloading of components and excess cycling of BESS.

75. The AGC systems included in BLPC's CETP Project 1 are thus critical in enabling the smooth integration of intermittent RE and supporting the achievement of BNEP targets.

76. The AGC system will consist of various components and control algorithms, namely sensors and measurement devices, and an AGC Controller responsible for adjustment to power plants and communication infrastructure.

77. The AGC system is expected to be commissioned in 2024 at an estimated capital cost of $3,580,855 (Exhibit AGC-1) inclusive of AFUDC. Cash working capital of $7,500 and accumulated deferred income tax liability is added to the asset cost to derive its rate base of $3,581,197.

78. BLPC is requesting an authorized return on this investment of $327,321, computed by multiplying the Rate Base by the RoR.

79. Cost of service expenses of $213,358 are added to the authorized return to obtain an estimated revenue requirement of $540,679.

80. The CETR rate related to the AGC investments, calculated in Exhibit AGC-2, is estimated at $0.0006 per kWh and the rate impact on a typical residential

customer's usage of 250 kWh per month is an additional seventeen cents ($0.17) per month.

D.1.3. Synchronous Condensers

81. The implementation of synchronous condensers was also recommended by the IRRP as necessary for maintaining the reliability of the grid during the transition to the BNEP targets.

82. Synchronous condensers are devices deployed on the grid to provide reactive power support and grid stability. They are specialized rotating machines that resemble conventional synchronous generators but lack a prime mover to generate mechanical power. Instead, they are connected to the grid and can either draw or supply reactive power as needed to stabilize the grid.

83. Synchronous condensers are required to facilitate the high penetration of intermittent RE which is unable to provide essential grid services that would have been provided by conventional fossil-fuel generators such as:

    a. Reactive Power Compensation: Synchronous condensers can supply or absorb reactive power, which helps maintain a stable voltage level in the grid. This balances the reactive power demand and supply and prevents voltage fluctuations thereby maintaining the voltage profile within acceptable limits.
    b. Grid Inertia Support: Unlike fossil-fuel generators, intermittent RE does not provide the same level of inertia to the grid. Inertia is essential for maintaining grid stability during sudden changes in load or generation. Synchronous condensers, being rotating machines, offer inertia support, helping stabilize grid frequency and minimizing disruptions during contingency events.
    c. Fault Current Contribution: With the removal of conventional sources of Synchronous generation there is a concomitant reduction in sources that can provide the necessary fault current to aid rapid fault clearance.

SCOs are well placed to provide both the reactive vars and fault current required to maintain the adequacy of existing protection schemes without compromising critical fault clearance times as we transition to more inverter based RE technologies compared to traditional generation sources.

d. Dynamic Voltage Control: Synchronous condensers can respond rapidly to voltage fluctuations and help maintain the desired voltage level across the grid, thereby supporting grid stability and reliability.

84. By providing these critical grid support services, synchronous condensers will play a vital role in the grid characterized by a high penetration of intermittent RE.

85. Based on the current trajectory of intermittent RE, the IRRP recommended that four (4) 10 MVA synchronous condensers were required. More recent studies and analysis conducted by BLPC indicate that based on the existing RE connected to the grid and future trajectory, four (4) synchronous condensers rated at 20 MVar are required in order to facilitate stable grid operation. It is anticipated that three (3) SCOs in active operation along with a fourth SCO available will facilitate an appropriate maintenance regime and provide backup capability as necessary.

86. The first two synchronous condensers are expected to be commissioned in 2025 at an estimated capital cost of $25,140,100. In 2026 the additional two condensers will be installed, also at an estimated cost of $25,140,100.

87. Page 1 of Exhibit SYN-1 shows the calculation of the estimated total capital cost of the synchronous condensers included in the CETP Project 1 to be $50,280,199. The total rate base for each year that an SCO is commissioned is presented at line 20.

88. The BLPC is requesting an authorized return of $2,302,230 in 2025 and 2026, computed by multiplying the Rate Base by the RoR.

89. The operating and maintenance costs associated with the synchronous condensers include costs such as lubricants, spares and other retrofit costs.

90. The total cost of service estimates related to the synchronous condensers are presented at line 36 of Exhibit SYN-1 and comprise of $1,127,515 for each year 2025 and 2026.

91. The total revenue requirement for the synchronous condensers is estimated at $6,859,490 of which $3,429,745 relates to the first two condensers in 2025.

92. The CETR rate to recover the estimated revenue requirements is calculated in Exhibit SYN-2 to be $0.0036 per kWh for each year - 2025 and 2026.

93. The estimated rate impact of the investments in synchronous condensers is an additional $1.00 per month for a residential customer with a monthly consumption of 250 kWh.

D.1.4. Distributed Energy Resources Aggregation & Control Platform ("the pilot")

94. The anticipated proliferation onto the grid of intermittent RE and BESS, both at the utility and distributed level, will require a coordination control platform to optimize the integration of these resources.

95. The BLPC has included in its CETP Project 1, a Distributed Energy Resources Aggregation & Control Platform as a pilot to test an aggregation platform and remote communication of BESS.

96. The pilot is critical to operationalizing the Commission's Decision of June 28, 2023, on Energy Storage Framework and Tariffs. The Decision established energy storage tariffs for BESS that meet the criteria of "used and useful".

97. The "used and useful" criteria may be efficiently evaluated by the implementation of the aggregation platform which can monitor the grid services provided by individual BESS.

98. BLPC's pilot is an initial small-scale implementation for the remote communication, control and aggregation of distributed storage and solar PV. Successful deployment would result in the ability to combine multiple BESS into a larger, virtual energy storage network that would optimize their services to the grid.

99. By aggregating several smaller BESS units, the collective energy storage capacity and capabilities can be harnessed to provide more significant benefits and services to the electrical grid.

100. The platform is expected to manage and optimize the charging, discharging, and overall operation of all the connected BESS units as a unified system. The aggregated BESS can then be utilized to provide various grid services such as:

   a. Grid Stability: Intermittent RE sources like solar and wind can lead to fluctuations in electricity generation, causing grid instability. Aggregating BESS will provide a collective capacity that can help mitigate these fluctuations by absorbing excess energy during periods of high renewable generation and releasing it when renewable generation is low. This stabilizes the grid and ensures a steady and reliable electricity supply.
   b. Energy Balancing: Intermittent RE can create mismatches between electricity supply and demand, leading to imbalances. By aggregating BESS, surplus energy can be stored during periods of excess generation and discharged during peak demand, effectively balancing the grid's energy flow.
   c. Peak Load Management: Energy production from intermittent RE may not align with peak electricity demand periods. BESS aggregation allows for peak shaving, where stored energy can be used during peak hours

to alleviate strain on the grid and reduce the need for legacy fossil-fuel-based power plants to meet peak demands.

d. Grid Flexibility: As intermittent RE generation fluctuates, the grid needs to adapt quickly. Aggregated BESS can provide a flexible resource to respond rapidly to changes in demand and generation, helping to maintain grid stability and better manage voltage and frequency fluctuations.
e. Ancillary Services: The move towards a high-penetration RE grid will require ancillary services, such as frequency regulation and voltage support. BESS aggregation can provide these services effectively, enhancing the overall grid performance.
f. RE Integration: The platform would facilitate real time control of distributed RE systems to ensure grid stability, avoid overloading the grid and prevent issues of voltage instability and frequency deviations.
g. Demand Response: Aggregated BESS can also participate in demand response programs. During times of peak demand or grid stress, BESS can be signaled to discharge stored energy, reducing the need to dispatch more expensive plant.

101. The platform is expected to be functional in 2024 at an estimated capital cost of $1,172,943. The capital cost includes the hardware, integration software and communication installation costs.

102. The BLPC is requesting an authorized rate of return of $107,015, computed by multiplying the Rate Base by the RoR.

103. The total revenue requirement as shown in Exhibit PLA-1 is $167,429 and in Exhibit PLA-2 the estimated rate impact is detailed. The CETR rate related to the pilot is estimated at $0.0002 per kWh. The potential customer bill impact for a residential customer consuming 250 kWh per month, as shown on page 3 of Exhibit PLA-2, is a bill increase of five cents ($0.05) per month over current rates.

D.1.5. Interconnection Infrastructure

104. In support of the BNEP, fourteen (14) large potential Independent Power Producers (IPPs) representing capacity of over 146 MW have approached BLPC to construct an RE generation facility and are desirous of connecting to the BLPC's transmission and distribution system.

105. Also pending connection to the BLPC's transmission and distribution system is an additional 150 MW of intermittent RE which are at different stages of construction.

106. The high level of demand from both large and small IPPs to interconnect to the BLPC's transmission and distribution system necessitates the upgrade of existing lines and the build-out of additional transmission and distribution infrastructure.

107. Transmission lines are a key component of interconnection infrastructure. These lines transport electricity over longer distances, allowing RE generated in one area to be transmitted to another.

108. Based on current interconnection requests from potential IPPs, the Highway 2A corridor stretching from the St. Thomas to Trents and North substations have a high RE interconnection demand. This corridor is currently serviced by a double circuit 132 kV U/G cable network from Trents to St. Thomas along with a single 24 kV UG cable servicing St. Thomas and Carlton substations. In addition, there is an overhead 24 kV transmission line consisting of a 336 MCM[7] cable size conductor available for IPP interconnection. However, to maximize the interconnection capacity and availability, the size conductor will have to be upgraded to 795 MCM to facilitate the high demand for future interconnections on this overhead circuit.

[7] MCM is equivalent to thousand circular mils

109. The 11 kV distribution circuits in general also require upgrades to facilitate the increased integration of RE generation along the laterals of these circuits. Historically, especially in rural areas, the conductors located on the laterals of these circuits that emanate from the main feeder artery were appropriately sized based on the moderately lower loads and low load growth anticipated along these laterals. These rural areas have now become particularly attractive sites for the build-out of customer owned RE generation, however the existing conductor sizes on the circuit laterals limit the amount of RE capacity that can be interconnected. The conductor sizes on lateral sections of some 11 kV circuits are required to be upgraded to a 336 MCM conductor to match the conductor size of the main feeder artery thereby removing any existing constraints to the interconnection of RE generation on the circuits.

110. Interconnection infrastructure is also required to interconnect individual IPPs to the electricity grid. Some of this new infrastructure may be unique to a specific RE developer and may include transformers, distribution lines, poles, switchgear, substations, and substations' equipment.

111. The Commission, in its Decision of December 30, 2022, on Feed-in-Tariffs for Renewable Energy Technologies up to and Including 1MW and its December 31, 2022 Decision on Feed-in-Tariffs for Renewable Energy Technologies above 1MW and up to 10 MW, provided FIT rates that compensated IPPs for some of their anticipated interconnection costs. In its Decisions, the Commission ordered that the BLPC be responsible for 75% of the interconnection costs not covered in the FIT and that all interconnection costs borne by the BLPC should be recovered through an approved appropriate recovery mechanism[8].

[8] As per the Commission's Decision of December 30, 2022, IPPs are expected to be responsible for 25% of any additional interconnection costs that were not included in their FIT rates.

112. The BLPC submits that the CETR is the appropriate mechanism for the recovery of the costs for the interconnection infrastructures included in its CETP Project 1.

113. The capital cost included in the interconnection infrastructure for recovery through the CETR relates to upgrades to the 24 kV and 11 kV circuits along with 75% of the cost of interconnecting individual IPPs as ordered by the Commission.

114. The BLPC has utilized project specific information presented by potential IPPs to estimate their interconnection infrastructure requirements and the timing of the commissioning of their projects.

115. On page 1 of Exhibit INTER-1, the estimated capital cost related to interconnection infrastructure for the years 2024 through to 2026 total $69,998,586 and are shown at line 10.

116. Interconnection costs shown for 2024 relate to four utility scale IPP projects that are expected to be interconnected in that year at a cost of $15,719,186 of which $11,789,390 (75%) is included in the revenue requirement computation for 2024. Also included is $1,637,100 related to upgrades to the 11 kV circuits.

117. The BLPC is requesting a total authorized rate of return of $6,394,750 as shown at line 25 for year-end investments in interconnection infrastructure, computed by multiplying the Rate Base by the RoR for the years 2024 through to 2026.

118. Operation and maintenance costs were not included in the revenue requirement given the challenge of isolating these asset specific expenses from the O&M of the distribution and transmission network, however other expenses such as depreciation and taxes are included in the revenue requirement calculation.

119. Depreciation expense is estimated at $390,397 in 2024 and taxes are projected to be $20,670 in that year.

120. The revenue requirement at line 39 for interconnection infrastructure investments completed in 2024, 2025 and 2026 amounts to $1,637,648, $2,727,956 and $4,173,901 respectively.

121. Exhibit INTER-2 summarizes the estimated CETR rates necessary to recover the revenue requirements associated with the interconnection infrastructures included in CETP Project 1. The estimated CETR rate applicable to the investments made in 2024, 2025 and 2026 are $0.002 per kWh, $0.003 per kWh and $0.004 per kWh respectively.

122. The typical residential customer on the Domestic service tariff will observe an estimated monthly bill increase of approximately $0.51 in 2024, $0.85 in 2025 and $1.30 in 2026 related to the total investments in interconnection infrastructures compared to current bill.

<u>E. STATUTORY PROVISIONS UNDER WHICH THE APPLICATION IS BEING MADE (Rule 26(1) (c) of the Rules)</u>

125. Notwithstanding that the Decision approved the CETR as an appropriate mechanism for cost recovery, the Commission's Decision also requires BLPC to submit '*an individual application for the recovery of costs of each asset/project through the cost recovery mechanism'*. The URPR defined 'application' non-exhaustively as 'includes a complaint'.

126. BLPC has submitted this application in line with the requirements for applications under the URPR and the requirements set out by the Commission in its Decision.

127. Section 6 of the URA empowers the Electricity Panel to sit to hear and determine any matter related to utility regulation. In addition, Section 3 of the URA empowers

the Commission to monitor the Application of the CETR cost-recovery mechanism by BLPC. BLPC therefore asks the Commission to exercise its power to hear BLPC's Application pursuant to the Decision and to the relevant provisions of the URA and URPR.

128. Section 2 of the URA defines "principles" as "the formula, methodology or framework for determining a rate for a utility service." In keeping with this definition, the Application for cost recovery under the CETR is deemed a formula for the purposes of the URA.

129. Section 2 of the URA further sets out that the term "rates" includes every rate, fare, toll, charge, rental or other compensation of a service provider; a rule, practice, measurement, classification or contract of a service provider relating to a rate; and a schedule of tariff respecting a rate.

130. Additionally, the BLPC has structured its Application and the Order being sought per Rule 26 of the Rules.

F. NATURE OF ORDER BEING SOUGHT

131. The BLPC requests the approval of the costs of the following capacity and transmission & distribution resources which form its 2024-2026 Clean Energy Transition Plan (CETP) Project ("CETP Project 1"):
    a. 90 MW of Battery Energy Storage Systems;
    b. Automatic Generation Control (AGC) systems;
    c. Synchronous Condensers;
    d. Distributed Energy Resources Aggregation & Control platform ("the pilot");
    e. Interconnection infrastructures to facilitate the integration of Independent Power Producers (IPPs) onto the public grid.

132. BLPC reiterates paragraphs 1 and 2 of this Application.

G. PERSONS AFFECTED BY THE APPLICATION (Rule 26 of the Rules)

133. Pursuant to Rule 26 (4) of the Rules, the Applicant advises that it is impractical to set out all the names and addresses of each customer affected by the Application because they are too numerous. However, the persons affected can generally be described as customers of the Applicant that fall within our customer classes or tariff groups. These customers are affected because the Applicant supplies service to them.

H. SUMMARY

134. The BLPC seeks the approval of the Commission to apply an allowed rate of return consistent with the Commission's February 15, 2023 Decision on the Application by the BLPC for a Review of Electricity rates, adjusted for the cost of long-term debt that will be raised to finance the CETP Project 1 on investments estimated at $684,893,329 in addition to net rate base and approval of the estimated total revenue requirement of $131,256,797 (Exhibit CETP Project 1-1).

135. The Revenue Requirement is based on estimates available on equipment costs and the cost of debt at the time of filing this Application, and therefore will be subject to change. BLPC proposes to provide a report of the actual costs 60 days prior to the commercial operation date.

136. A CETR rate of $0.1386 per kWh is estimated to recover the revenue requirement associated with the CETP Project 1 (Table 1). The rate impact related to the total investment for a typical residential customer on the Domestic Service tariff using 250 kilowatt-hours per is estimated as an increase of approximately $41 or 21% on their monthly bill compared to current rates (Exhibit CETP Project 1-2).

137. The BLPC proposes that the CETR rate related to CETP Project 1 investments be established or adjusted based on the date the investments go into service.

Table 1: Clean Energy Transition Plan Project 1- Financial Summary

Investments	2024	2025	2026	Total
Rate Base				
90 MW of Battery Energy Storage Systems	$107,940,915	$224,046,588	$227,812,325	**$559,799,829**
Automatic Generation Control	$3,581,197	-	-	**$3,581,197**
IPP Interconnection	$13,419,928	$22,308,721	$34,239,864	**$69,968,513**
Distributed Energy Resources Aggregation & Control Platform	$1,170,843	-	-	**$1,170,843**
Synchronous Condensers	-	$25,188,512	-	**$50,377,023**
Total Rate Base	**$126,112,882**	**$271,543,821**	**$262,052,190**	***$684,897,405***
Authorized Return				
90 MW of Battery Energy Storage Systems	$9,865,800	$20,477,858	$20,822,047	**$51,165,704**
Automatic Generation Control	$327,321	-	-	**$327,321**
IPP Interconnection	$1,226,581	$2,039,017	$3,129,524	**$6,395,122**
Distributed Energy Resources Aggregation & Control Platform	$107,015	-	-	**$107,015**
Synchronous Condensers	-	$2,302,230	$2,302,230	**$4,604,460**
Total Authorized Return	**$11,526,717**	**$24,819,105**	**$26,253,800**	***$62,599,623***
Revenue Requirement				
90 MW of Battery Energy Storage Systems	$22,171,702	$46,134,877	$46,843,116	**$115,149,695**
Automatic Generation Control	$540,679	-	-	**$540,679**
IPP Interconnection	$1,637,458	$2,723,315	$4,187,546	**$8,548,318**
Distributed Energy Resources Aggregation & Control Platform	$167,429	-	-	**$167,429**
Synchronous Condensers	-	$3,429,745	$3,429,745	**$6,859,490**
Total Revenue Requirement	**$24,517,268**	**$52,287,936**	**$54,460,407**	***$131,265,611***
$/kWh Cost				
90 MW of Battery Energy Storage Systems	$0.0234	$0.0487	$0.0495	**$0.1216**
Automatic Generation Control	$0.0006	-	-	**$0.0006**
IPP Interconnection	$0.0017	$0.0029	$0.0044	**$0.0090**
Distributed Energy Resources Aggregation & Control Platform	$0.0002	-	-	**$0.0002**
Synchronous Condensers	-	$0.0036	$0.0036	**$0.0072**
Total $/kWh Cost	**$0.0259**	**$0.0552**	**$0.0575**	***$0.1386***

138. The BLPC submits that its CETP Project 1 investments do qualify for recovery through the CETR mechanism and aligns customer interest in a reliable and resilient electricity supply with the BNEP objectives to transition the generation of electricity to 100% RE by 2030.

139. The BLPC further submits that the approval of the investments under the CETP project 1 will ultimately reduce regulatory lag and likely limit the frequency of general rate reviews.

DATED THIS 5th DAY OF OCTOBER, 2023

SIGNED BY: ……………………………………………………………

ADRIAN CARTER

THE APPLICANT'S REPRESENTATIVE AND DULY AUTHORIZED OFFICER

APPLICANT'S ADDRESS: THE BARBADOS LIGHT & POWER COMPANY LIMITED
GARRISON HILL
ST. MICHAEL
BARBADOS
TELEPHONE NUMBER: (246) 626-9000
FACSIMILE NUMBER: (246) 429–600