FAIR TRADING COMMISSION

DECISION

The Barbados Light & Power Company Limited's Application for the Recovery of the Rental and Operating Costs of 11 MW of Temporary Aggreko Generator Units through the Fuel Clause Adjustment (FCA)

Document No.: FTCUR/DECTEMPGEN/2024-05 **Date of Issue: October 29, 2024**

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LIST OF ABBREVIATIONS

BLPC	The Barbados Light & Power Company Limited
BNEP	Barbados National Energy Policy 2019 – 2030
CEB	Clean Energy Bridge
CF	Capacity Factor
COD	Commercial Operation Date
CRM	Capacity Reserve Margin
ELCC	Effective Load Carrying Capability
ELPA	Electric Light and Power Act, 2013-21
ESD	Energy Storage Device
EUE	Expected Unserved Energy
FCA	Fuel Clause Adjustment
FTCA 2020	Fair Trading Commission Act, CAP. 326B, as amended
GM	Generation Margin
GoB	Government of Barbados
GTs	Gas Turbines
GT03	Gas Turbine unit 3
GT04	Gas Turbine unit 4
GT05	Gas Turbine unit 5
GT06	Gas Turbine unit 6
ICC	International Cricket Council
IPPs	Independent Power Producers
IRP	Integrated Resource Plan
IRRP	Integrated Resource and Resiliency Plan
LSD 1	Low Speed Diesel 1
LSD 2	Low Speed Diesel 2
MEB	Ministry of Energy and Business
MSD	Medium Speed Diesel
MW	Megawatt
LF	Load Factor
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
OC	Out of Commission
PRM	Planning Reserve Margin

PV	Photovoltaic
RE	Renewable Energy
The Commission	The Fair Trading Commission
URA 2020	Utilities Regulation Act CAP. 282, as amended
URPR	Utilities Regulation (Procedural) Rules (the URPR).

SECTION 1 EXECUTIVE SUMMARY

On January 29, 2024, the Barbados Light & Power Company Limited (the "BLPC" or the "Applicant") submitted to the Fair Trading Commission (the "Commission") an application for the recovery of the rental and operating costs of 11 MW of temporary Aggreko Generator Units through the Fuel Clause Adjustment (FCA) until such time that adequate additional permanent generation become available. After consideration of the BLPC's Application, intervenor submissions, and the Commission's own research, the Commission makes the following determination:

A. **The rental of the Aggreko units, 11 MW in capacity, is approved for a period of at least twelve (12) consecutive months from the actual COD of the units. The possibility of approval for a further twelve (12) months may be granted where the Commission is satisfied that market conditions sufficiently warrant the need for the additional capacity at that time.**

In such circumstances, the BLPC will be required to formally inform the Commission of the need for the extension of approval, and any revised contractual details no later than four (4) months prior to the expiration of the approved twelve (12) months.

Costs associated with the rental of the 11 MW capacity is approved for recovery via the FCA and shall commence one (1) month from the date of this Decision for the approved period.

B. **The FCA formula shall be:**

$$FCA_n = \frac{\sum_{n-1}(FuelCost_{n-1}\frac{THR^i_{n-1}}{AHR^i_{n-1}} + PurchasedPowerCost_{n-1} + TemporaryGenerationRecovery_{n-1}}{\sum_i EnergyGeneration_{n-1} * \left(1 - Aux^i_{n-1}\right) * \left(1 - losses^i_{n-1}\right) + \sum_j Purchased\ Power\ Generation_{n-1}}$$

Where:

$TemporaryGenerationRecovery_{n-1}$ **= Aggreko rental and operating costs recovery in previous month**

And where:

FCA_n =	**FCA for each (current) month**
Energy $Generation_{n-1}$ =	**Energy generated in the month n-1**
Aux_{n-1} =	**Auxiliary consumption as a percentage (%) of total generation in the month n-1**
Losses =	**System losses as a percentage (%) of total generation calculated based on a 12-month running average**
Fuel $cost_{n-1}$ =	**Fuel cost in the month n-1 including cumulative under/over recovery**
Purchase $Power_{n-1}$ =	**Cost of Purchase power from renewable sources in the month n-1**
Purchase Power $Generation_{n-1}$ =	**Purchase power from renewable sources in the month n-1**
i =	**Thermal Generation plant/unit**
BD$/kWh =	**Barbados dollars per kilowatt hour**
j =	**Purchased Power Generation**
AHR^i_{n-1} =	**Actual Heat Rate for generation plant/unit i, for month n-1**
THR^i_{n-1} =	**Target Heat Rate for generation plant/unit i, for month n-1**

C. Costs to be recovered shall be contingent on the BLPC's ability to demonstrate that the 11 MW Aggreko units are utilised and dispatched according to demand, taking into account the impact of fuel prices and fuel efficiency of all plant, thereby providing service to customers in the most cost effective manner;

D. Where the utilisation of the 11 MW of capacity is found to be imprudent, that is, not being used and useful during the period of its operation, the quantum of costs recovered shall be reconciled and returned to customers;

E. The BLPC is not allowed to recover the non-recurring costs past twelve (12) months, if the asset is kept past that duration;

F. If the asset is kept for a period shorter than the twelve (12) months, the outstanding balance of the non-recurring cost be spread over the remaining balance of the twelve (12) months so that the impact on the consumer is mitigated; and

G. The BLPC shall include in its quarterly regulatory reporting, monthly information on the following:

i. Rated and dependable capacity (MW-AC) for all generation plant and units[1];
ii. Total aggregate output capacity (MW-AC) of each generator;
iii. Forced outage hours for all generation plant and units;
iv. Planned outage hours for all generation plant and units;
v. Effective Forced Outage Rates for all generation plant and units;
vi. The peak load (MW-AC) for each month, time of occurrence, and temperature;
vii. Generation duration curve (kWh and MW-AC) for each month at peak time;
viii. The availability factor for all generating plants and units;
ix. Details and status of planned and unplanned generation maintenance activities. The report shall include time and dates of actual activities completed and pending, and account for forced outages; and
x. Generation reliability for each plant and unit.

The above shall be submitted no later than one (1) month after the end of each quarter of the calendar year;

H. The BLPC shall provide the Loss of Load Expectation (LOLE), Expected Unserved Energy (EUE) and Planning Reserve Margin (PRM) determination, based on market conditions and the forecasted hourly peak load for the prior twenty-four (24) months from December 2023. The PRM shall be deduced from the LOLE computation.

The LOLE, EUE and PRM obtained shall then be recalibrated for the next thirty-eight (38) months to determine forward-looking values. The computation shall consider RE/storage projects that are expected to be commissioned within thirty-eight (38) months of the COD of the Aggreko units. The requested information shall be submitted to the Commission no later than six (6) months after the end of the approved twelve (12) month period. Thereafter, the LOLE information shall be submitted biannually;

[1] Units refer to individual generators/technologies such as gas turbine units, and energy storage systems.

I. Maintenance reports for all generating plant/units shall be submitted to the Commission on an annual basis and no later than one (1) month after the end of the calendar year;

In addition:

J. The Commission will conduct an investigation with respect to unit GT04 being out of commission (OC) unexpectedly. This shall be executed immediately; and

K. The Commission reserves the right to conduct audits at any time as it relates to the operation and management of any and all components of the power system.

SECTION 2 INTRODUCTION

1. The BLPC currently operates generating plants with rated capacity of 245.14 MW (excluding the 5 MW Energy Storage Device (ESD)) at three locations – Spring Garden, St. Michael, Trents in St. Lucy and Seawell in Christ Church. The plants at these locations are of varying technologies, both renewable energy (RE) and fossil fuel driven. These include low and medium speed diesel (LSD, MSD) engines, gas turbines (GTs), and solar photovoltaic (PV) panels. Previously, the BLPC also operated generation plants at the location at Garrison, St. Michael on both a temporary and permanent basis.

2. The BLPC has a legal obligation to provide electricity to the public of Barbados that is safe, adequate, efficient and reasonable pursuant to Section 20 of the Utilities Regulation Act (URA) which states:

   "20. Every service provider

   (a) shall maintain its property and equipment in such condition as to enable it to provide service to the public which is safe, adequate, efficient and reasonable; and

   (b) shall make such repairs, changes, alterations, substitutions, extensions and improvements to such service as shall be necessary to ensure the provision of service to the public that is safe, adequate, efficient and reasonable. "

3. The BLPC contends that this application is a key component to the provision of such reliable and resilient service, as Barbados transitions from a fossil fuel driven economy to one powered by RE. Both solar and wind energy are expected to be the foundation of RE generation for Barbados and with that comes its own challenges including that of intermittency. Furthermore, the RE transition brings with it a commitment that investments in new fossil fuel generation must be limited[2].

4. In addition to managing the RE transition, the BLPC notes that it also has to contend with normal operational challenges, managing scheduled and unscheduled maintenance, changes in demand caused by changing weather conditions, general economic growth and one-off national events such as the International Cricket Council (ICC) T20 Men's

[2] See paragraph 17 of the BLPC's Application dated January 29, 2024.

Cricket World Cup such as was hosted in the Caribbean in June 2024. Barbados hosted nine (9) of these fixtures, including the coveted final at the end of June 2024[3].

5. The BLPC has, based on its own technical and operational assessment, determined that an adequate reserve margin of 41% is appropriate[4] for the national grid. This compares to a capacity reserve margin of 38%[5] over the 12 months preceding January 2024.

The Application

6. On January 29, 2024, the BLPC submitted an application to the Commission for approval for the recovery of the rental and operating costs of 11 MW of temporary Aggreko generator units through the FCA. BLPC expects that the generators will be needed for a period of twelve (12) months, from May 1, 2024, or until additional firm generation capacity becomes available[6].

7. The cost being sought for recovery includes rental costs which comprises a monthly capacity payment ($589,600) and an energy power payment ($0.0210 per kWh), and operation and maintenance charges which include one-off mobilisation and demobilisation costs ($1,280,000). The one-off mobilisation and demobilisation costs will be amortised over the twelve (12) month duration. BLPC proposes to recover the costs through the FCA, which it contends is an appropriate mechanism[7].

[3] Ibid, paragraph 10.
[4] Ibid, paragraph 9.
[5] Ibid, 10.
[6] Ibid, paragraph 11.
[7] Ibid, paragraph 25-30.

SECTION 3 LEGISLATIVE FRAMEWORK

Power to Set Rates

8. The Utilities Regulation Act, CAP 282 of the Laws of Barbados (the "URA") and the Fair Trading Commission Act, CAP 326B of the Laws Barbados, (the "FTCA") together empower the Commission to set and monitor rates for the supply and distribution of electricity. More particularly, pursuant to Section 4(3) of the FTCA, the Commission has the responsibility to, inter alia:

   (a) establish principles for arriving at rates to be charged by service providers and renewable energy producers;

   (b) set the maximum rates to be charged by service providers and renewable energy producers;

   (c) monitor the rates charged by service providers and renewable energy producers to ensure compliance;

   (d) …

9. The Commission also has these duties under Section 3(1) of the URA, which states:

   "The functions of the Commission under this Act are, in relation to service providers, to

   (a) Establish principles for arriving at the rates to be charged;

   (b) Set the maximum rates to be charged;

   (c) Monitor the rates charged to ensure compliance

   (d) ….".

Principles and Rates

10. Section 2 of the FTCA and Section 2 of the URA both define "principles" as the "formula, methodology or framework for determining a rate for a utility service", and stipulate that "rates" include:

    (a) every rate, fare, toll, charge, rental or other compensation of a service provider or renewable energy producer;

    (b) a rule, practice, measurement, classification or contract of a service provider or renewable energy producer relating to a rate; and
    (c) a schedule or tariff respecting a rate.

11. Section 3(3)(a) states that

    "The Commission shall

    (a) protect the interests of consumers by ensuring that service providers supply to the public service that is safe, adequate, efficient and reasonable;"

SECTION 4 INTERVENORS AND SUBMISSIONS

12. On February 16, 2024 the Commission issued a public notice of application requesting that interested parties submit letters of intervention to the Commission no later than February 26, 2024.

13. Following this request, intervenor status was conferred to the following parties:

    a. Barbados Consumer Empowerment Network (BCEN);
    b. The Barbados Renewable Energy Association (BREA);
    c. The intervenor team of Senator Ms. Tricia Watson and Mr. David Simpson; and
    d. Mr. Kenneth Went.

14. Procedural Direction No. 1 was issued on February 24, 2024 to all parties to the Application in accordance with Rule 4 of the URPR. All parties were advised of the requisite timelines and conditions for making submissions with respect to the BLPC's Application. Procedural Direction No. 2 was issued on April 22, 2024, to all parties.

SECTION 5 COMMISSION'S ANALYSIS

4.1 Background

15. The BLPC's Integrated Resource Plan (IRP) 2012 stated that the reliability criterion adopted at that time for expansion planning was based on one (1) day per year, Loss of Load Probability (LOLP)[8]. As stated by the BLPC, a minimum reserve margin of 32%[9] was found to be reasonable and equivalent to the above criterion. Through 2019, the BLPC upheld this standard as the relied upon reliability criterion in fulfilment of resource adequacy and system security[10] obligations. Since 2019, market conditions in the electricity sector have changed[11] significantly with the increased RE penetration and the expected transition to 100% RE by 2030, which is mandated by the Barbados National Energy Policy (BNEP), 2019 - 2030.

16. In implementing the BNEP, the Ministry of Energy undertook an Integrated Resource and Resiliency Plan (IRRP) 2021 study. The IRRP identifies amongst other things, on an annual basis, expected additions and retirements of generation technology resources through 2021 – 2030. Additionally, the document provides details for each year on the peak load and Capacity Reserve Margins (CRM) expected[12]. It is understood that the 2021 IRRP is under revision but has not been finalised to the date of this Decision.

4.2 BLPC's Application

17. According to the BLPC, the need for the additional capacity sought is predicated on the high penetration of RE online, high seasonal temperatures, new commercial projects becoming operational, as well as the T20-Cricket World Cup[13]. The BLPC claims that

[8] This metric is used to identify in terms of time, when the load on the power system has exceeded the dependable capacity of the power system.
[9] See page 45 - 46 of the Barbados Light and Power Limited 2012 Integrated Resource Plan.
[10] The BLPC, when asked in 2020, confirmed that the 32% CRM was utilised based on LOLP which determines the capacity required to meet future demand. Please refer to Exhibit RS3 and JG9, which shows the BLPC's response to question 10 of the Commission's interrogatories dated February 7, 2020.
[11] Issuances of Feed-in Tariffs for RE technologies and amendments to the Electric Light and Power Act which the deregulation of the electricity sector, and issuance of energy policy.
[12] See page 217 and 218 of the IRRP for Table G.15: Refer Figure 7.12: Scenario 3 – Installed capacity mix and peak load (MW). The CRM in the IRRP is the reserve capacity beyond the peak load that is required to meet future demand. Please note that CRM actually relates to the amount of reserves expressed as a percentage of the total firm capacity. The meaning in the IRRP, indicates the reserves as a percentage of peak load. The CRM expressed by the BLPC takes this same meaning.
[13] Ibid, 3 paragraph 8-10.

based on their research, a CRM at or near to 41% would be needed to sustain reliability of supply[14] over the next year or until firm capacity is established[15].

18. This section therefore provides an appraisal of the operational performance of the BLPC as it pertains to its current capacity and its purported additional requirements. The outcome of the assessment considers the relevant perspectives and arguments of the Applicant, intervenors, and the Commission's own research that informed the determination herein.

19. The Commission's assessment of the BLPC's request includes but are not limited to:

    a. Generation adequacy and security of supply;
    b. Function of additional capacity; and
    c. Other considerations.

<u>Generation Adequacy and Security of Supply</u>

20. Under Section 20 of the URA, the BLPC is required to ensure that service to customers is safe, adequate, efficient and reasonable. Compliance with this legal obligation is contingent on the proper maintenance of plant and equipment. As the sole grid operator, this statutory requirement makes the BLPC accountable for generation adequacy and security of supply[16] provisions.

21. Electricity is an essential commodity and a principal driver of economic development in society. Given this significant importance, it is incumbent on the BLPC to ensure that the electricity provision is adequately sustained.

22. Managing the electricity grid is complex and this responsibility is further complicated through the integration of disruptive technologies (solar and energy storage)[17] on the grid, which are in support of achieving the carbon neutral goal of 100% RE by 2030. Such a responsibility requires effective planning to ensure that the same or higher level of

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[14] Ibid.
[15] Ibid, paragraph 11.
[16] System adequacy refers to the capability of the power system to meet demand under the steady state conditions it operates under. Security of supply relates to the provision of energy at all times, in various forms, sufficient quantities, and at reasonable prices.
[17] These are considered technologies which bring a new paradigm and impacts the traditional business model. The electricity sector which was traditionally fossil fuel driven now includes the utilisation of non-fossil energy resources.

continuity of supply is achieved. The timing of retirement and acquisition of generation assets by licensees is also a pivotal factor to consider when maintaining the health of the electricity eco-system at the appropriate level of security.

Generation Changes

23. At the beginning of 2023, the BLPC asserted that the reserve margin was adequate at that time to meet reliability needs[18]. However, this view changed following the Commission's February 15, 2023 ruling which directed the retirement of the 20 MW steam generator unit one (S1) as soon as possible, but no later than December 31, 2023[19]. The BLPC retired S1 in March 2023[20,21].

24. The Commission notes however, that unit S1 informally ceased operation at the end of November 2022[22]. This action highlights the inadequate planning of the BLPC in mitigating issues related to demand forecasting at that time, since in their view, unit S1 was expected to be operational towards year end 2023[23].

25. According to the BLPC, consideration was given to extending the life of gas turbine GT02[24]. However, this option was found to be infeasible, and GT02 was subsequently retired as scheduled at the end of December 2022[25]. These retirements reduced the reserve margin provision and made apparent, the concern of generation adequacy being insufficient, since the demand during the second half of 2023 and into 2024 increased[26].

26. New RE generation expected to be operational in 2023, according to the 2021 IRRP, schedule would have provided reserves for the short term, however, these projects did not come to fruition[27].

27. The BLPC purports that these developments prompted it to explore options to procure additional capacity. The utility considered the rental of Aggreko units, purchase of

[18] Ibid, 4, paragraph 12.
[19] Ibid, 4, paragraph 13.
[20] Ibid paragraph 13.
[21] See the BLPC's letter to the Commission dated May 3, 2023.
[22] Regulatory Reports 2022.
[23] See page 4, paragraph 13 of the BLPC's Application.
[24] Gas turbine unit 02.
[25] Ibid paragraph 14.
[26] Ibid paragraph 15.
[27] Ibid paragraph 16.

additional capacity which included caterpillar units, solar PV, batteries and a Clean Energy Bridge (CEB) cube[28] as alternative options to mitigate the short fall in reserve margin capacity. The rental of the 11 MW Aggreko units was determined to be most feasible, having considered the 2021 IRRP stipulations[29].

28. Changes to the BLPC's generation fleet from 2014 to 2023 were assessed in order to comprehend how these adjustments impacted the BLPC's CRM and the reasonableness of the request for additional capacity. These alterations to the overall installed capacity are shown in Table 1 following. The 5 MW ESD is not included in this calculation given its short capacity duration. The capacity that remained after adjustments at the end of the calendar year is recognised as the total installed capacity with respect to that year.

Table 1 - Historical Generation Portfolio

Year	Additions (MW)	Retirements (MW)	Capacity (MW)
2014 - 2015			239.1
2016[30]	10 (solar PV)		249.1
2016 - 2018			249.1
2019[31]	12 (Aggreko)		261.1
2019 - 2020[32]	15 (Small Diesels)	20 (Unit S2)	256.1
2020 - 2022[33]	34.04 (CEB)	12 (Aggreko)	278.14
2022 - 2023[34]		13 (GT02), 20 (Unit S1)	245.14

29. Based on the data from Table 1, the total installed capacity of the BLPC at the end of 2023 was 245.14 MW. In simple operational terms, the total installed generation capacity equates to the sum of capacity, committed (online and spinning), out of service (offline but available) and OC (offline and inoperable). This information was used to compute the reserve margin taking into account the generators' historic force outage rates.

[28] Additional capacity module in the form of a prime mover that can augment the existing power capacity.
[29] Ibid 5, paragraph 17. The IRRP indicates annual schedules for clean energy additions and retirements of generation technologies.
[30] 10 MW solar PV added in 2016.
[31] 12 MW of temporary generation was added in December 2019.
[32] At paragraph 4 of the BLPC's letter dated December 28, 2020, the BLPC determined that steam unit S2 would not be returned to service. Unit S2 was retained as spares for unit S1. In 2020 15 MW of additional capacity was added.
[33] The CEB was commissioned in 2022. 12 MW of temporary generation was removed in 2022.
[34] GT02 retired at the end of 2022 and S1 did not operate after November 2022. S1 also did not operate in 2023.

30. The quantum of reserve capacity determined is crucial to preserve the reliability, and security of supply of the power system. This value is usually calibrated by deterministic or probabilistic approaches and is based on many factors, such as size, maintenance, forced outages, contingencies, failure of the largest unit, and reliability levels. In response to the Commission's interrogatories on the methodology of computation of the 41% reserve margin referenced in the Application, the BLPC implied that this value (41%) was actually realised in 2021, and the intent is to maintain this value to ensure reliability[35]. The reserve margin here was claimed to be based on a peak demand of 159 MW and firm capacity of 224 MW[36], these statistics being actually achieved in 2021[37]. Based on the BLPC's prior regulatory reporting, the Commission revisited the peak load achieved in 2021 and this value was 142.5 MW[38] which is inconsistent with the BLPC's figure claimed using the same data. A further review showed that the total installed capacity at that time was 256.1 MW. Excluding the RE plant and BESS, this would be 246.1 MW. Considering applicable force outage rates[39] for each generator, the firm capacity available was 224.74 MW. Accordingly, this results in a CRM[40] of 57.71%. It is noted that the values claimed to be actually achieved for 2021 results in a CRM of about 41%. According to the 2021 IRRP, the peak demand used at that time was 159.24 MW[41]. The fact that this policy document was completed in August 2021, suggests that the peak demand value stated for 2021 was forecasted and not actual.

31. There appears to be inconsistency in the BLPC's comparison of the adopted 41% CRM and the referenced CRMs of the 2021 IRRP. The BLPC's representation of the IRRP CRMs from 2021 to 2025 are significantly lower than projections[42]. The Commission is unsure how these values were derived.

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[35] See the BLPC's response to question 2 (a) of the Commission's interrogatories dated February 27, 2024.
[36] See the BLPC's response to question 2 (a) of the Commission's interrogatories dated April 5, 2024.
[37] See the BLPC's response to question 2 (b) of the Commission's interrogatories dated April 5, 2024
[38] Extracted from the non-consolidated Financial Report of the BLPC for 2021.
[39] Force outage rates were extracted from the IRRP study 2021. These values are considered historical.
[40] CRM = (Firm Capacity/Peak Demand) -1. This computation is similar to the planning reserve margin (PRM). In order to not confuse the two distinct definitions, for analysis purposes, the meanings are considered to same in this document. However, the true CRM = 1- (Peak Demand/Firm Capacity). PRM=CRM/(1-CRM).
[41] See page 218 of the IRRP 2021 for Table G.15.
[42] See the BLPC's response to question 2(a) of the Commission's interrogatories dated April 5, 2024.

32. This brings into question, the accuracy of the BLPC's adopted CRM value. It can be accepted that this target CRM was not based on the BLPC's adopted methodology of LOLP/LOLE determination utilised in its IRP 2012, which would account for the additional capacity required for the targeted CRM. When the BLPC was asked about the frequency of revision to the CRM, the BLPC indicated that this was computed and reviewed monthly[43]. In the past, the CRM or LOLP was used as part of their Generation Expansion Planning studies. However, since 2021 this activity was spearheaded by the Ministry of Energy. Despite this change, the BLPC continues to monitor generation reserves to ensure that its reserve margin level remains adequate[44].

33. The CRM requirement is informed by the LOLP or LOLE determination. Historically, this approach has been adopted by the BLPC. This previously adopted methodology, the BLPC admits, was not utilised in its most recent assessment[45]. While the BLPC has calibrated a CRM based on a deterministic approach, the Commission is unsure of the origin of the values utilised. The Commission also notes that deterministic approaches, though simpler do not consider the stochastic nature of conventional thermal plant nor the capacity value contribution of indigenous energy resource-based generators[46]. While the reserve margin methodology, which is deterministic in origin, is accepted as an alternative approach, it may not be the best way to determine the appropriate level for generation adequacy and security of supply, when considering the reliability needs for an island grid such as Barbados that is currently transitioning to full utilisation of RE resources[47]. In the past, the reliance on the reserve margin approach was considered reasonable for long term planning, where the generation mix consisted of a dominant fossil-fuel and a small RE portfolio. In such situations, the output from conventional generation would remain unchanged over the course of the year and hence, the applicability to long term planning. The gradual shift away from fossil fuel-based generation to an increasing fleet of RE oriented generators, under the aegis of Government policy, now requires consideration to more appropriate methodologies

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[43] Ibid question 4.
[44] Ibid.
[45] Ibid question 3 (a), 3(b).
[46] Blanco, M. P., Spisto, A., Hrelija, N., & Fulli, G. (2016). Generation Adequacy Methodologies Review. Brussels: Joint Research Centre, European Commission.
[47] International Renewable Energy Agency (IRENA). (2018). Transforming Small-Island Power Systems: Technical Planning Studies for the Integration of Variable Renewables. Abu Dhabi: IRENA.

which take into account the current and future generation mix. The high RE penetration that is expected in light of the energy transition brings into focus, security of supply concerns and with this, there is a shift away from deterministic methodologies because probabilistic approaches return a more accurate assessment for resource adequacy[48]. In the Commission's view, the LOLP/LOLE methodology appears to be more robust and felicitous to the Barbados energy context. These probabilistic approaches consider the random nature of outages, load variability, resource volatility, load flow, effective load carrying capability (ELCC)[49] of generators and contingencies[50] which are not uniquely captured by the reserve margin calculation. The existing generation mix for Barbados comprises energy resources derived from fossil fuels and RE. The future energy consumption for Barbados is expected to be coalesced to full RE by 2030.

34. **The Commission will make provisions for the LOLP/LOLE and EUE[51] to be computed and included in the regulatory requirements of the BLPC to ensure that the obligations to generation adequacy and security of supply is appropriately monitored and accounted for.**

35. The BLPC has maintained that the target CRM for 2023 was 41% but realised an average of 28%, while for 2024 the BLPC's CRM expects to decline further owing to the increase in demand[52]. Based on the BLPC's forecast, the peak load expected in 2024 is 155.18 MW; thermal plant capacity for 2024 remains the same as 2023 at 245.14 MW.

36. Expected peak demand for 2024, 155.18 MW is about a 3.6% increase from the 2023 position. The Commission examined the firm capacity portfolio of the BLPC based on historical forced outage rates. The BLPC's firm capacity grew by 5% in 2019 and was reduced by 1.5% the following year. Growth in firm capacity improved and reached 9.8% in 2022 and fell by 12% in 2023 owing to adjustments in the thermal generation portfolio. This leaves a value of 217 MW in 2024. Based on the projected peak load of 155.18 MW, the BLPC's CRM is 39.84% compared with the BLPC's projected CRM of

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48 International Energy Agency (IEA). (2020). Power Systems in Transition: Challenges and Opportunities Ahead for Electricity Security. Paris: IEA.
49 ELCC measures the capacity contribution that the generator makes towards resource adequacy.
50 Ibid, 35.
51 This metric provides an indication of the expected energy that failed to supply during the analysis period. It also measures the capability of the power system to serve load continuously. See Billinton, R., & Allan, R. N. (1996). *Reliability Evaluation of Power Systems.* New York: Plenum Press.
52 See the BLPC's response to question 4 of the Commission's Interrogatories dated April 11, 2024.

23.6%. The variance in CRM values may be due to the amount of firm capacity projected, 191.85 MW. On average, the BLPC's projected available capacity stated for 2024 on a monthly basis is below 190 MW overall. These statistics brings into perspective the frequency of planned maintenance and results in a capacity deficiency of 30 MW per month on average.

37. **The Commission remains particularly concerned about this observation and will monitor closely the annual trend in generation availability, the correlation between the frequency of maintenance activities conducted by the BLPC and dependable generation capacity, generation plant reliability, and the impact on the PRM.**

38. An assessment of the BLPC's operational performance was executed to also inform on whether the 11 MW of additional capacity was required.

Operational Assessment 2014 – 2023

39. The BLPC's operational performance from 2014 – 2023 (Figure 1) suggests that the capability of the generation plant to meet peak demand was reasonable over the period taking into account the evolution of increasing RE capacity online, which supplemented meeting the energy demanded during the day.

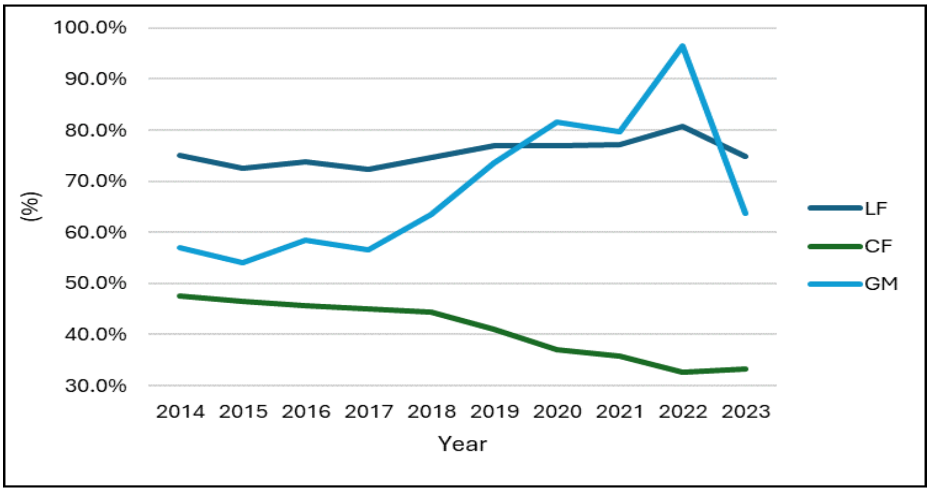

Figure 1 - BLPC's Performance for the period 2014 - 2023

40. The Load Factor (LF), which measures the ratio of average load to peak load for the referenced period returned a mean and median value of 76.0% and 75.9% respectively. In 2022, this ratio peaked at 80.7% and fell to 75% in 2023, owing to a 1.76% decline in

the total generation and a corresponding increase in peak demanded (149.8 MW) by 5.79%. Overall, the average to peak load ratio ranged between 70% and 80% and the statistics infer reasonable utilisation of the available energy resources.

41. The Commission notes that this performance considers the contribution from fossil fuel and RE sources. Contribution from RE resources therefore assisted the BLPC in meeting the load demanded, thus freeing-up the full capacity and energy obligation from thermal plants/units during the referenced period, particularly during daylight hours at peak time. **This reinforces the point that the value of 95.7 MW of RE currently online[53] and its generation profile should be taking into account in determining the PRM.**

Generation Margin

42. The generation margin (GM)[54] represents the installed capacity above the peak demand that is available, from which dependable resources are chosen to meet the peak demand, taking into account, maintenance schedules, forced outages and derations. The curve profile shows a generally increasing trend and the GM average and median value was 71.7% and 68.65%, respectively. Adequate installed capacity is a matter of cost-effective capital investments to ensure generation sufficiency. Over-investment can result in ratepayers compensating the utility for plant that may not be required, rendering these not used and useful.

43. In 2022, the GM peaked at 96.4% and remained above 60% in 2023. This change was as a consequence of capacity retirements which followed from 2022. The ratio of average load to installed capacity was also assessed.

Capacity Factor

44. The capacity factor (CF)[55] was also used to inform on the BLPC's effectiveness of utilisation of generation resources. This metric measures the average power to the installed plant capacity. The CF profile (Figure 1) appears to be trending downwards

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[53] Regulatory Reporting Statistics for the Quarter ending March 31, 2024.
[54] GM = 1- (Peak load/Installed Capacity)
[55] CF is the ratio of the actual energy delivered by generation resources to the maximum energy potential over the period. Alternatively, this value provides an indication of the average load (MW) to the installed capacity (MW) of the BLPC.

over the period 2014 - 2023. Based on the CF curve, the average and median CF for the period was 40.9% and 42.7%, respectively. It is important to note here that the CF values include the contribution from RE sources as well. A low value for CF can imply that adequate reserve capacity is available to meet future load demand, taking into account maintenance and forced outages. The Commission accepts this observation and contends that the high RE penetration reduces the BLPC's dependency on the total firm capacity available during the daytime peak. This is evident from 2019 onwards, where a sharp decline in the CF occurred.

45. Additionally, a low value can signal overinvestment. However, this is not evident in the BLPC's case. The reduction in the CF observed is associated with the increasing RE contribution online and not what would obtain under a typical conventional generation scenario. On the contrary, a high CF value may imply that the average load is approaching the installed capacity and signal that available generation is inadequate to meet future growth in demand. Such a situation can create difficulties in scheduling maintenance, and this would imply that there may not be sufficient generation to meet future demand. This situation was not evidenced by the CF profile shown and these values indicate that available resources may be reasonable. In 2022 and 2023 the CF remained flat at around 33.0%.

46. While the curve profiles depict reasonable utilisation of generation asset on an annual basis, the Commission remains concerned about the frequency of maintenance which can impact capacity availability of the BLPC to meet projected load.

47. **An appraisal of the BLPC's maintenance plans and activities should be conducted to determine whether the maintenance schedules are optimal, thus ensuring adequate generation is actually available to meet future needs.** The Commission will also apply appropriate metrics which can better inform on the cost effectiveness of generation utilisation.

48. The prior assessments included the GT04's contribution to generation adequacy, thus allowing the BLPC to maintain a reasonable level of service under an increasing RE penetration scenario. The following considers the impact of its exclusion on the reserve margin level of the BLPC.

Impact of GT04 on Generation Availability

49. The BLPC stated in its final submission dated April 30, 2024, that during the inspection of GT04, a number of components required replacement, and this would render the unit unavailable for service until late July/early August 2024. The need for replacements were not of a mechanical origin. As a consequence, the average reserve margin declined from 20.1% to 0.1%[56].

50. The Commission is very concerned about this sudden development and the implication of this on the BLPC's ability to meet statutory obligations of generation adequacy and security of supply provisions to customers. Based on the 2023 statistics (average to peak load ratio and CF) previously stated the BLPC should be in a reasonable position to maintain generation adequacy provisions. The vacancy in capacity due to GT04's inoperability further underpins the need for a review of the BLPC's maintenance practices and schedules. According to the BLPC, GT04's absence appears to significantly exacerbate the dependable capacity quota such that the reserve margin is depleted.

51. This observation and the impromptu nature of GT04's exclusion has reinforced the Commission's view that the BLPC's maintenance of its generation resources is questionable. Additionally, the Commission is deeply concerned about the prudence with regard to effective scheduling of maintenance activities and how this impacts generation adequacy. Where emergency events occur, the BLPC must notify the Commission of the occurrence, expected impact such occurrence may cause, and mitigation to be implemented. The BLPC is reminded that it is required to submit ad-hoc reports to the Commission as it pertains to critical events which can impact the provision of adequate and safe service.

52. The impact of GT04 on the PRM was examined based on the projected values provided by the BLPC for 2024 (Figure 2). With GT04 OC[57], the average and median PRM is 16.25% and 17.14%, respectively. These values differ significantly from the depleted margin stated by the BLPC. Again, this highlights the need to investigate the nature and

[56] See paragraph 19 of the BLPC's Final Submission dated April 30, 2024.
[57] The term indicates the status of the generator when it is inoperable.

periodicity of maintenance practices of the BLPC and the impact of these on the dependable generation capacity.

53. Including the 11 MW of Aggreko units returned an average and median value of 23.45 and 24.30%, respectively. Despite including the additional capacity to boost the PRM, the overall value was still below the 32% benchmark used in 2019 and the new adopted target of 41%. It is evident that the PRM improves when the additional capacity of 11 MW is considered. Notably, from June to August and towards to the end of 2024, the PRM appears to recover.

54. The reduction in the PRM 2024 during May to August suggests that less plant would be 'available' to support the PRM. The Commission remains concerned as to why less dependable capacity is expected to be available prior to GT04 being OC when compared to the PRM 2- 2023[58] profile. The Commission notes that the installed capacity remained the same in 2023 and 2024 at 235.14 MW[59].

55. The absence of available generation brings into question again, the maintenance of the BLPC's plants being available for service. Intervenor Mr. Went argued that the BLPC's availability is questionable when compared to 2007 and implies that the high priority that was placed on maintenance then[60] has been reduced.

[58] PRM with maximum availability in 2023. This does not include the steam plant after March 2023.
[59] This value excludes the 10 MW solar plant.
[60] See paragraph 27 of Mr. Went's submission dated April 8, 2024.

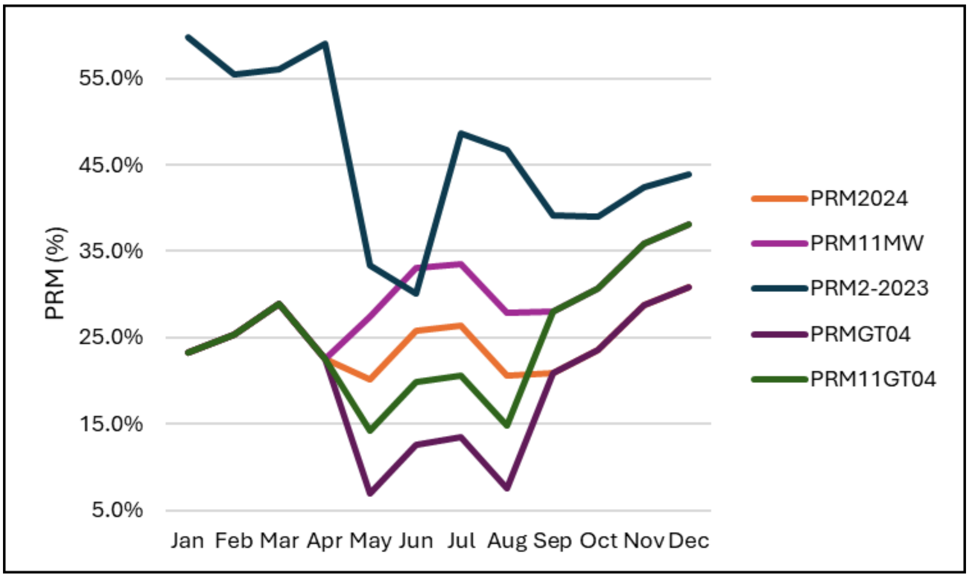

Figure 2 - Impact of GT04's unavailability

56. **The reduction in dependable capacity due to GT04 being OC at such a critical time when the T20-Cricket World Cup event was ensuing, presents generation risks and reliability of supply issues which should not be ignored. Furthermore, maximum daily temperatures are expected to be elevated during the month of April to September 2024. Considering the 95.7 MW of customer owned generators online, which is intermittent and variable, GT04 inoperability further lowers the BLPC's firm capacity generation portfolio.**

57. **It is evident that the sudden absence of GT04 to support generation adequacy and security of supply obligations now poses an imminent national energy supply risk for Barbados. In light of the confluence of these events and as a matter of contingency, the Commission considers approving the rental of the 11 MW Aggreko units.**

58. **While the BLPC has not detailed the specific issues that warrant this unit GT04 becoming inoperable, the Commission is of the view that an investigation into the cause of this development should be initiated.**

59. The Commission also acknowledges the impact of the high penetration of RE currently online and the difficulty this poses in balancing the supply and electricity demanded from the grid. This challenge can be mitigated by the provision of an adequate reserve margin when RE cannot support demand[61]. Favourable consideration of the BLPC's

[61] See paragraph 6 of the BLPC's Final Submission dated April 30, 2024.

request for additional capacity is therefore reinforced given the reduction in firm capacity to mitigate against the volatility in RE online.

60. Non-firm energy resources complicate the management of the grid and firm resources are needed to cure any deficiency that may arise from an operational perspective. Additionally, the amount of storage contemplated in the 2021 IRRP for 2023 did not materialise such that existing capacity reserves could have been supported. Firm RE capacity projects (Biomass, Landfill Gas, Waste to Energy) as noted in the IRRP[62] are not expected until 2025. It is universally accepted that the inherent characteristics of non-firm RE aggravates the stability of the grid as well and this calls for generation flexibility- sufficient firm capacity which can be applied to balance void in capacity that results from the uncertainty and variability RE. The Commission also considered the need for IPPs to have storage in order to integrate RE projects as stipulated in the Barbados Clean Energy and EV Policy (BCEEVP)[63]. Currently, the RE sector remains in a critical position given the unavailability of storage to facilitate the integration of non-firm RE systems and the uncertainty of these being implemented. This vacancy, however, leaves the grid vulnerable to stability issues given the high RE penetration currently exhibited online. Based on the review of the BLPC's peak load for 2023, the system peak occurred 83.3% of the time at night[64]. Thus, the utilisation of additional capacity can boost reserves during the night when RE is unavailable.

<u>Function of Additional Capacity</u>

61. While the BLPC asserts that the additional capacity is required to boost the reserve margin in light of increased temperatures and demand, the proposed mode of operation of the 11 MW Aggreko units was not detailed. The Application nor the BLPC's final submission do not specify how the proposed 11 MW Aggreko rental will operate in terms of merit order. The additional capacity is expected to generate 1,437,738 kWh/month and cost $900,000/month[65]. The information provided by the BLPC[66] seems

[62] See Table G.15 on page 2017-218 of the IRRP 2021.
[63] See page 20, paragraph 2.3.1.1 of the BCEEVP. Also see page 13, item (vi) of the Cabinet of Barbados' recommendations.
[64] See BLPC's response to Mr. Went's Interrogatories dated March 12, 2024.
[65] See page 5 for the BLPC's response to the question 9 of the Commission's Interrogatories dated February 27, 2024.

to suggest that this requested capacity will function similar to the rental of 12 MW that operated in 2020[67].

62. It appears from the BLPC's comparison of marginal cost of generation[68] (GT vs 11 MW) that the prior mode of operation is assumed. The BLPC expects that based on the dispatch of plant, that fuel savings of about $925,000 will accrue to customers[69]. The CF and heat rate values for rental in 2020 - 2023 compared to 2024 is shown in Table 2.

63. The data shows that the 12 MW rental in 2020-2021 had a CF lower than the majority of the GTs and a heat rate ranking of 4, in terms of thermal efficiency. The data implies that less efficient plant operated more than the rental at that time which had a better heat rate. Specifically, in 2020 the units' utilisation was 26.98% compared to 16.41% in 2021. It is apparent that the average monthly generation (1,437,738 kWh) for the 12 MW rental in 2021 is the same monthly quantum projected for the 11 MW rental in 2024. Based on this amount of energy contracted per month, the utilisation for the 11 MW rental is expected to be 17.90% during its operation. In 2023, the CF (14.79%) of the SDs (15 MW) improved from 3.29% in 2021 considering that the use of 12 MW rental was discontinued in 2022, while this was 11.16% in 2020. Additionally, it was observed that GT04 and GT06 in 2020 and GT05 in 2021 and GT06 in 2023 appeared to be operating as baseload units, based on their CFs. GTs are typically less efficient than baseload units; these are used for peaking operations (times of high demand) and are usually the least operated plant annually.

[66] See the BLPC's response to RW-DR.#2 (1) of the Mr. Went's Interrogatories dated January 26, 2024 and question B.1. of Mr. Went's Interrogatories dated March 12, 2024.
[67] The 12 MW rental became fully operational in 2020 – 2022 based on regulatory reports submitted during this period.
[68] See page the BLPC's response to question B.2.of Mr. Went's Interrogatories dated March 12, 2024.
[69] Ibid.

Table 2 - Operational Performance of Specific Generators

Year	Plant/Unit CF (%) and Heat Rate (Btu/kWh)								
Year	**Rental Aggreko**[70]	**SD**[71]	**GT03**[72]	**GT04**	**GT05**	**GT06**	**LSD 1**[73]	**LSD 2**	**CEB**[74]
2020									
CF (%)	26.98	11.16	17.28	54.40	30.51	51.84	67.76	39.84	
Heat Rate (Btu/kWh)	10,085.03	9,519.02	14,384.19[75]	12,848.73	12,905.88	12,638.38	9,156.75	8,160.47	
Heat Rate Ranking	4	3	8	6	7	5	2	1	
2021									
CF (%)	16.41	3.29	20.33	31.91	43.94	66.25[76]	65.88	56.63	
Heat Rate (Btu/kWh)	10,131.798	10,116.94	14,928.79	12,291.89	12,892.08	12,866.65[77]	9,142.38	8,187.18	
Heat Rate Ranking	4	3	7	5	6		2	1	
2023									
CF (%)		14.79	4.71	30.53	21.68	47.91	50.29	51.36	77.87
Heat Rate (Btu/kWh)		9,058.91	14,909.08	13,507.05	13,353.55	13,687.43	9,146.98	8,378.55	8,627.03
Heat Rate Ranking		3	8	6	5	7	4	1	2
2024									
CF (%)	17.90%[78]								
Heat Rate (Btu/kWh)	10,121.00								

64. The Commission considers that given the previous operation of the 12 MW rental in 2020-2021, the BLPC should optimise the utilisation of the 11 MW rental considering the heat rate of these units. To do otherwise will impose unwanted cost on ratepayers. The results here imply that the BLPC may not have been utilising all plant/units in the most efficient manner from a cost-effective perspective. It is acknowledged that the increased cost of additional generation must be balanced with an economic dispatch of plant that results in the most cost-effective energy provisions to the benefit of customers. With a

[70] Aggreko rental here refers to 12 MW of capacity that was utilised in 2020.
[71] SD refers the permanent generation facility, located at Spring Garden.
[72] GT03 through GT06, refers to individual gas turbines.
[73] LSD 1 & 2 plant refers to low speed diesel plants at Spring Garden.
[74] The CEB is a MSD plant located at Trents, St. Lucy.
[75] GT03 average heat rate for seven (7) months of operation.
[76] Based on 6 months of operation, the heat rate was 12,866.7 Btu/kWh. The rental then had a CF value of 9.94% and 10,219.3 Btu/kWh.
[77] Heat rate not used in the ranking due to its limited operation.
[78] Projected CF (17.90 %) is based on one year's generation (17,252,856 kWh). See the BLPC's comparison for the Aggreko Rental and GT0 3 and GT04 shown in its response to Mr. Kenneth Went's interrogatories dated March 12, 2024.

high penetration of intermittent RE, this may create operational challenges in terms of optimal operation of all plant, thus resulting in sub-optimal heat rates in some cases. On the contrary, prior to GT04 being OC, the BLPC had adequate peaking plant to mitigate some of the variability and uncertainty effects which the RE online imposes on grid operations.

65. The BLPC is required to provide an electricity supply that is adequate, safe, reliable and at least-cost. Such an outcome is conditional on plant availability and prudent dispatch of said plant in order to achieve the best marginal cost of electricity overall. As expressed previously, the availability of sufficient plant/units is a critical part of meeting system adequacy and ensuring security of supply.

66. **The Commission is of the view that the BLPC must dispatch the 11 MW rental prudently to avoid unnecessary cost being imposed on customers. Consideration should be given to the utilisation of plant with the best fuel efficiency sufficiently to meet the expected demand.**

OTHER CONSIDERATIONS

67. The assessment looks at the need for additional generation, the financial implications, regulatory compliance and customer impact of the proposed cost recovery.

Justification for Additional Generation

68. The BLPC has stated an expected growth in electricity demand as one of the reasons for the need for the additional capacity. The BLPC notes that the rise in tourism and the completion of commercial projects has contributed to a 3.9% growth in electricity sales at the end of 2023, with electricity sales for the year to February 2024 being 11.1%[79] higher. BLPC is forecasting growth in sales for the year 2024 at 2.2% and growth in 2025 at 0.5%, respectively[80].

69. Intervenor BCEN opines that it is insufficient for the BLPC to base its projections of load growth on data provided by the Central Bank of Barbados and not its own analysis. Intervenor Went computed growth of 4.2% in comparison with the 3.9% presented by

[79] Exhibit AC1 paragraph 1.
[80] Ibid page 3

the BLPC. However, Mr. Went does not agree with the projections presented by the BLPC, estimating higher growth, and thus opining that increased demand will support the need for a higher reserve margin[81].

70. The Commission opines that the use of Central Bank data can provide a reasonable estimate for projecting growth in sales. Gross Domestic Product (GDP) is a measure of the dollar value of the final goods and services produced in a country. Changes in GDP is a widely used indicator of a country's overall economic health. Generally, there is a positive relationship between energy use per capita and GDP per capita. There is strong evidence of this relationship as displayed in Figure 3, which shows the total generation and real gross domestic product per capita over the period 2012 to 2022.

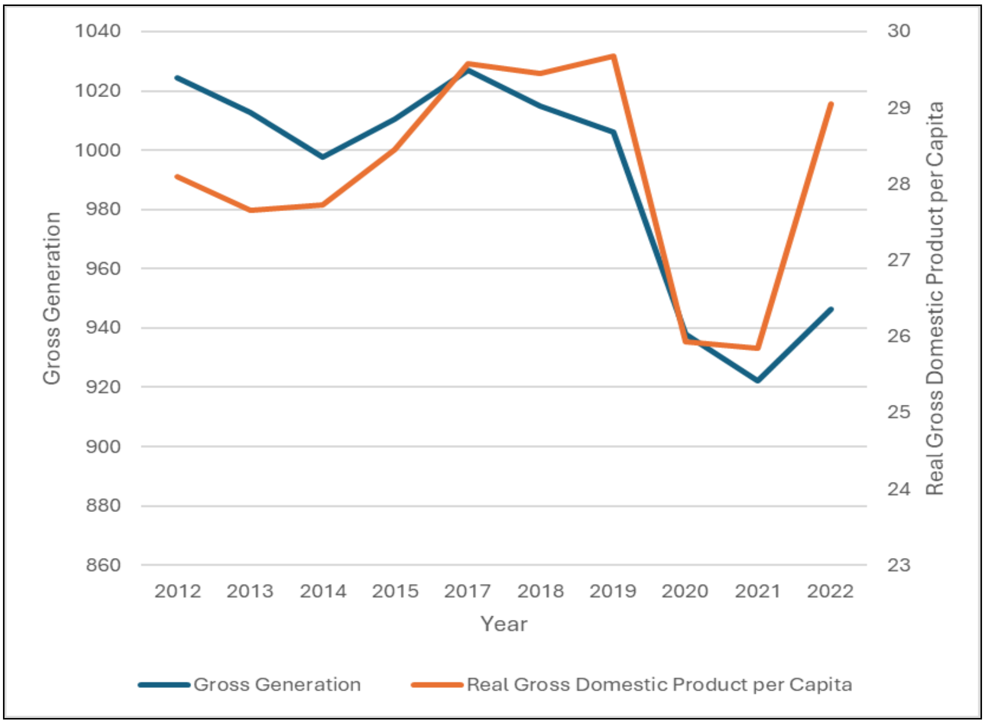

Figure 3 - Comparison of Generation and GDP 2012 - 2022[82]

71. As evidenced by Figure 4, energy generation over the past six (6) years has approximated a cyclical pattern. Total generation including power purchased from distributed energy resources however shows a general increasing trend over the period presented. This general upward trend is one of the bases on which the BLPC has

[81] Went & Team Submission on BLPC's Application for the recovery of the rental and operating costs of 11MW of Temporary generation units through the fuel clause adjustment (FCA) Exhibit RW 1 paragraph 43.
[82] Barbados Statistical Services (BSS) . (2024, June 15). *GDP* . Retrieved from The Barbados Statistical Service : https://stats.gov.bb/statistics/national-summary-data-page/ and the Commission's own data

projected its growth in sales. With the increasing rollout of RE resources on the electricity grid, there is some evidence of a widening gap between total generation and generation including purchased power. Indeed, there is some evidence of a downward trend in the BLPC's generation, and this is to be expected.

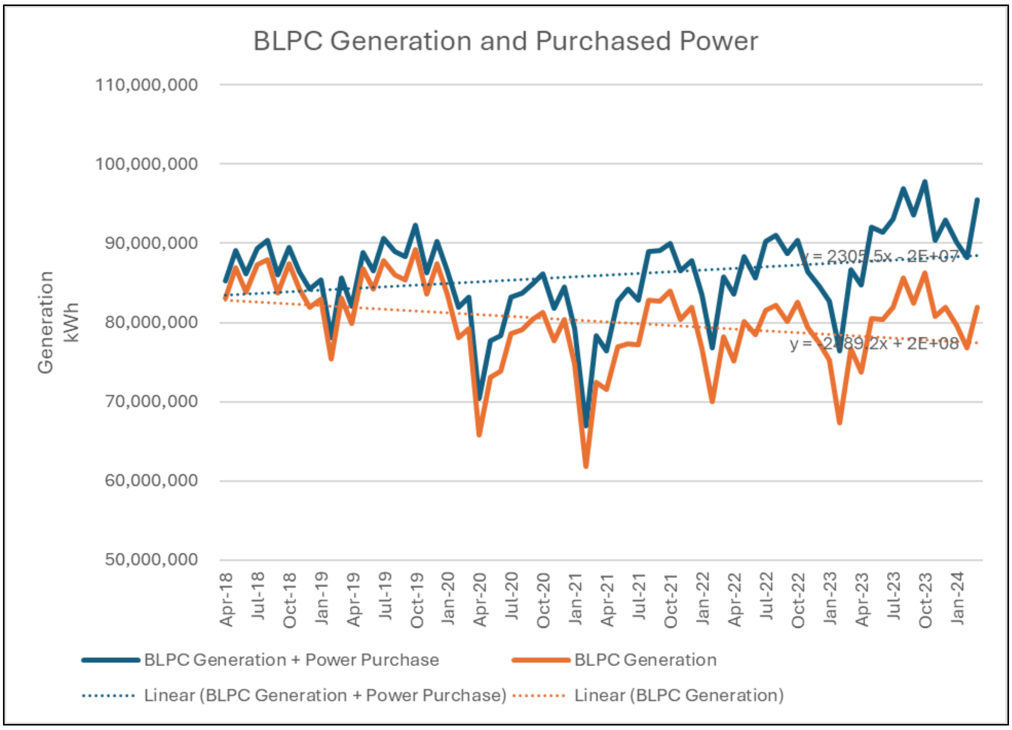

Figure 4 - Generation 2018 - 2024

72. As it relates to the increased demand expected due to events such as the T20 Cricket World Cup, BREA highlights that it would be expected that there should be adequate standby generation at the cricket ground for the games to continue and be televised[83].Additionally, BCEN questioned if Kensington Oval had the capacity to generate some of its own electricity[84]. The Commission agrees with this position as additional generation for one off event can be burdensome to the consumer, and as such, the entities hosting these events should bear the brunt of the associated costs. However, the Commission also acknowledges that additional generational load will be demanded due to higher daily temperatures, increased hotel accommodations, and new projects becoming operational.

[83] See paragraph 12 Exhibit SW1 Barbados Renewable Energy Association's Written Submission

[84] See page 6 of BCEN Considerations and Questions in Opposing the Barbados Light and Power BL&P Application to Recover Rental & Operating Costs of 11MW Aggreko Generator Units through Fuel Clause Adjustment (FCA)

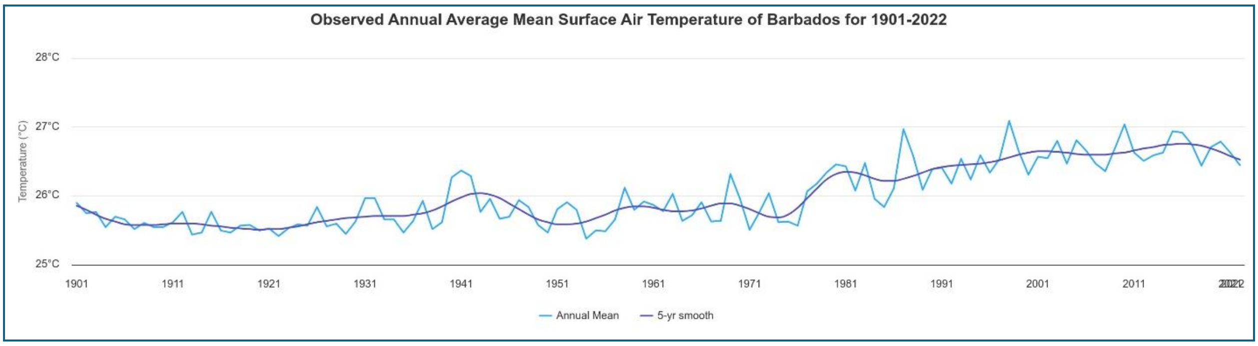

Figure 5 - Barbados Temperature Changes[85]

73. With respect to rising temperatures as noted in the BLPC's application, (Figure 5) above shows the change in average temperatures over the period 1901 to 2022[86]. Additionally, on September 30, 2023, the maximum temperature was 34.2 degrees Celsius, an extreme event[87]. Peak demand for September 2023 was 149.2 MW, the peak for the year 2023. This compares with peak demand for 2022 of 141.6 MW. As evidenced by the Figure 5, temperatures in Barbados have been rising over time, and it is expected that this will continue to occur in the foreseeable future. According to the Caribbean Institute for Meteorology and Hydrology, the heat outlook for June to November 2024 is for near record temperatures causing significant heat stress especially in August and September[88]. BLPC projects growth in sales of 2.2% in 2024 and 0.5% in 2025.

[85] World Bank, Climate Change Knowledge Portal (2024). Barbados - Climatology | Climate Change Knowledge Portal (worldbank.org) Date Accessed June 5, 2024
[86] Ibid
[87] Climate Data BDOS.pdf
[88] The Caribbean Heat Season: Improving Early Warning Information for decision-making (cimh.edu.bb) accessed June 6, 2024

Financial Costs

74. The utility anticipates the following costs at Table 3:

Table 3 - Description of Projected Costs

Cost Item	***Description***	***Amount $***
	Rental Costs	
Capacity Charge	Aggreko Monthly Rental	589,600
Energy Charge	Aggreko monthly energy charge	$0.021/kWh
Operating & Maintenance		
Mobilisation	Aggreko Mobilisation amortised over 12 months	78,333
Demobilisation	Aggreko Demobilisation amortised over 12 months	28,333
Local Mobilisation & Demobilisation[89]	Cranes, trucking, labour amortised over 12 months	36,667
Lubricants	lubrication oil for engines	32,256
Operating Personnel		50,000
Other Costs	Other operating costs	10,665
Total Monthly Cost Estimate		856,046
Fuel Costs	Vary monthly dependant on the purchase cost of fuel.	

Over a 12-month period, the utility estimates that the total costs of the additional generator excluding the cost of fuel, will be $10.3 million. The variable costs included in this determination are the energy power charge, which is charged per generation and therefore will vary over the usage of the asset. The mobilisation and demobilisation costs are one off payments, amortised over a 12-month period.

Recovery Mechanism

75. The BLPC proposes the use of the existing FCA as the recovery mechanism for the above referenced costs. These costs will be added on top of the existing costs that are fed through the FCA and will be reflected on the customers' monthly bills. The BLPC will be recovering the actual variable costs.

[89] Demobilisation compares to US274,644 for the 12MW Aggreko demobilised in 2022. See exhibit AC2 – responses to Went Interrogatories

76. The Commission acknowledges that utility companies recover the cost of temporary generation through various mechanisms, dictated by regulatory frameworks and contractual arrangements. The pass-through of costs to consumers via rate adjustments, in the form of temporary surcharge or a fuel adjustment clause without a lengthy rate case is but one such method. These mechanisms can ensure that utilities may recover the cost of temporary generation without compromising the financial stability, while adhering to regulatory requirements and maintaining service reliability.

77. An example of a utility that has an approved pass-through cost mechanism (MPIR/EPRM) for temporary costs is Hawaiian Electric (HECO) in Hawaii[90]. Also, Regulatory Research Associates of S&P Global Market Intelligence in a discussion of adjustment clauses used by electric utilities indicate that some sort of adjustment clause is used and approximately two thirds of utility commissions allow or consider the use of an adjustment clause for new capital investment[91].

78. There are various benefits of using the FCA to recover the cost of this additional 11 MW generation. The generators are expected to be used over a limited time frame and not as permanent assets. The use of the FCA is beneficial in that the duration of the increased rate can be limited to match the duration of the use of the temporary assets. The normal way that the utility would recover the cost of generation is through cost-of-service regulation, through the rate base. However, the process of determining rates through such means is a long one. Using the FCA, regulatory oversight is facilitated with the provision of detailed reports on a monthly basis. In this way, the Commission will ensure that only actual costs are passed on to the consumer.

79. **The Commission determines that the FCA is approved as the method by which the costs are recovered with the proviso that monthly detailed reports on all related costs are submitted to the Commission by the end of the following month. The FCA shall be adjusted for only one (1) month past the decommissioning of the generators. If the**

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[90] MPIR/EPRM: Subject to prior Hawaii Public Utilities Commission (PUC) approval, Hawaiian Electric is able to recover the costs of certain large projects, such as renewable energy and grid modernization projects, through the MPIR (Major Project Interim Recovery) adjustment mechanism and its replacement mechanism, the EPRM (Exceptional Project Recovery Mechanism). Cost Control | Hawaiian Electric Date Accessed June 5, 2024

[91] Adjustment Clauses State-By-State Overview | S&P Global Market Intelligence (spglobal.com) Accessed June 5, 2024

BLPC retains use of the generators longer than twelve (12) months, at the 12-month mark, the FCA should be adjusted to remove any one-off costs which have been fully amortised such as the mobilisation and demobilisation costs.

80. The Commission determines the following FCA equation be used for recovery of the cost associated with the proposed rental. This modification includes the recognition of the aggregation of purchased power from RE technologies online.

Equation 1

$$FCA_n = \frac{\sum_{n-1}(FuelCost_{n-1}\frac{THR^i_{n-1}}{AHR^i_{n-1}} + PurchasedPowerCost_{n-1} + TemporaryGenerationRecovery_{n-1}}{\sum_i EnergyGeneration_{n-1} * \left(1 - Aux^i_{n-1}\right) * \left(1 - losses^i_{n-1}\right) + \sum_j Purchased\ Power\ Generation_{n-1}}$$

Where:

$TemporaryGenerationRecovery_{n-1}$ = Aggreko rental and operating costs recovery in previous month

And where:

FCA_n =	FCA for each (current) month
Energy $Generation_{n-1}$ =	Energy generated in the month n-1
Aux_{n-1} =	Auxiliary consumption as a % of total generation in the month n-1
Losses =	System losses as a % of total generation calculated based on a 12-month running average
Fuel $cost_{n-1}$ =	Fuel cost in the month n-1 including cumulative under/over recovery
Purchase $Power_{n-1}$ =	Cost of Purchase power from renewable sources in the month n-1
Purchase Power $Generation_{n-1}$ =	Purchase power from renewable sources in the month n-1
i =	Thermal Generation plant/unit
BD$/kWh =	Barbados dollars per kilowatt hour
j =	Purchased Power Generation
AHR^i_{n-1} =	Actual Heat Rate for generation plant/unit i, for month n-1
THR^i_{n-1} =	Target Heat Rate for generation plant/unit i, for month n-1

Maintenance Costs

81. Intervenors BCEN and BREA highlighted that continuous maintenance is necessary to address the risks of the existing generators failing, especially at times during peak demand. Maintenance should be planned especially for periods where demand is lowest. BREA states that "Poorly maintained generators increase the risk of forced outages of the generators occurring and will therefore also increase the risk of loadshedding"[92].

82. The Commission acknowledges the importance of plant maintenance on the operation of the utility, as it directly affects the BLPC's ability to meet its obligation of providing a service that is safe and reliable as stated at section 20 of the URA.

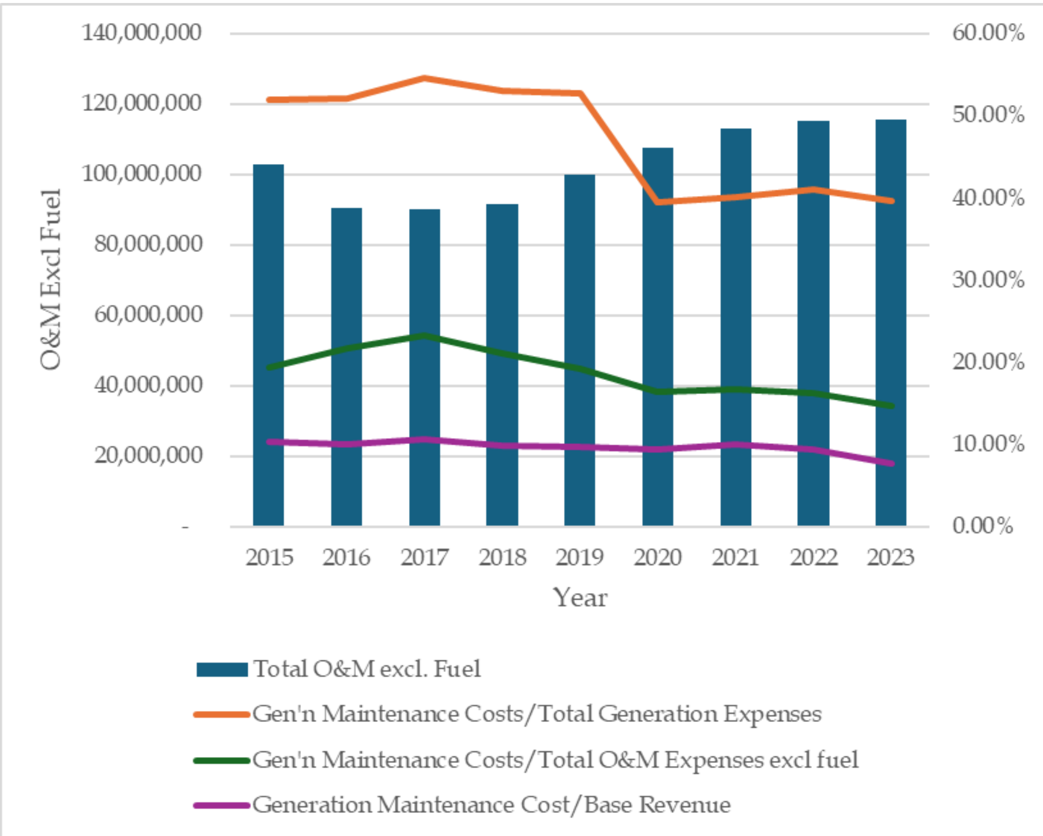

Figure 6 - Maintenance Expenses 2015 - 2023

83. Based on historical data, the BLPC's Total O&M (excluding fuel) increased on average by 2% per year from 2015 to 2023 ending the year 2023 at $115.8 million.

[92] See paragraph 14 Exhibit SW1 Barbados Renewable Energy Association's Written Submission

84. Changes in generation expenses which in 2023 accounted for 37% of O&M (excluding fuel) was consistent with the change in O&M, increasing by 2% over the same period. Generation expenses accounted for 19% of base revenue by the end of 2023, remaining fairly flat (averaging 21% over an eight year period) and comparing to 23% in 2022 and 25% in 2021.

85. There is some concern about the level of generation maintenance which accounted for 14.7% and 40% of Total O&M Expenses (excluding fuel) and Total Generation Expense respectively in 2023. Year on year, the change in generation maintenance fell by 2% on average over an eight year period 2015 to 2023.

86. As a percentage of base revenue, generation maintenance accounted for 8% in 2023. On average over eight years, generation maintenance as a percentage of base revenue was 10%, ranging from a low of 8% in 2023 to 11% in 2017, the highest for any one year.

87. Generation maintenance cost has remained generally stable over the last eight years. The sharp reduction seen in 2019 – 2020 in generation maintenance cost as a percentage of generation expenses is a reflection of increased generation expenses as a result of the rental of temporary generation. Generally, the statistics do not show any significant increase in maintenance cost that could be justified by an aging asset base.

88. The Commission reiterates calls from the intervenors for proper maintenance to mitigate the risks of outages and support adequate grid reserve capacity and resiliency.

Customer Impact

89. The impact on customers is a critical consideration. The proposed rate adjustment will result in a modest increase in monthly bills as the estimated $856,046 is passed on to customers.

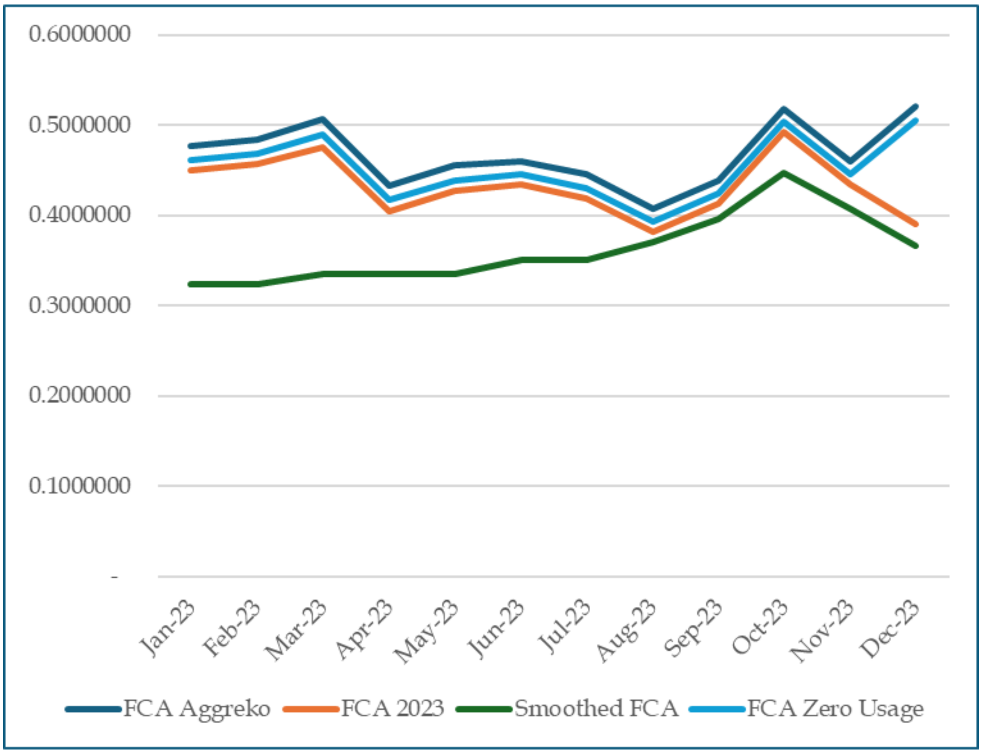

Figure 7 - FCA Computation for 2023

90. Figure 7 presents a scenario where the costs related to the temporary generators have been imposed on 2023 actual operations. The actual FCA for 2023 is compared with the revised FCA including the 11 MW, generating 1.4 GWh per month. As expected, the FCA including the temporary generation is higher, by on average 6% per month for the year. If the generators are not put into action, then the FCA increases by 2.7% on average per month. Under this scenario, there is no recovery for energy charge or fuel usage, but all other costs must still be accounted for. As depicted in Figure 8 (Customer Impact), the increase in FCA results in a domestic customer's bill increasing in January 2023 ranging from $2 for a customer using 75 kWh to $5.41 for a domestic customer using 200 kWh.

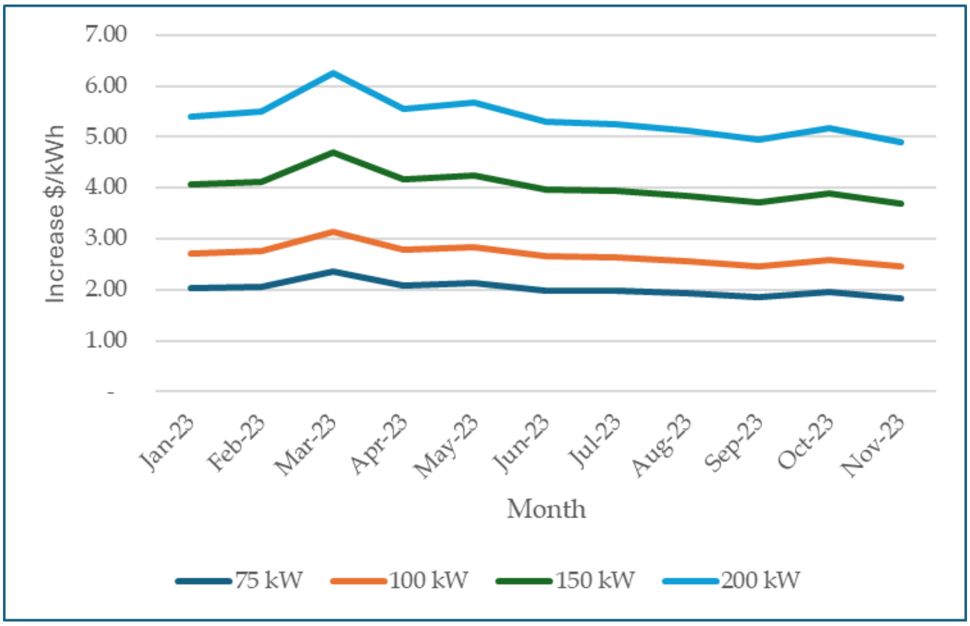

Figure 8 - Customer Impact

91. Intervenor Went makes a case for the purchase, and not the rental of additional fossil fuel generation. This, he posits, is in support of the targetted growth in RE generation. Mr. Went opines that given the scheduled retirements of a significant portion of BLPC's existing conventional generation, it is also projected that the utility will find itself in a situation that it needs to rent more temporary generation in 2026 and 2028 to cover its generation needs. This has already occurred given that in 2020 the BLPC rented temporary generation and returned them during 2022. This periodic rental, he suggested, can be avoided by the purchase of additional fossil fuel generation.

92. The Commission acknowledges the constraints facedby the BLPC that would restrict its ability to utilise this option. For one, government's position as given in the BNEP is that the utility not invest in any more fossil fuel plant. Also, to date, the BLPC has not finalised the signing of new licenses with the current license expiring in 2028. Conventional generation assets have life spans well past the four years that remains under the BLPC's existing license, and also well beyond the current 100% RE target of 2030. There is a clear risk that the BLPC could be left with stranded assets.

93. The mobilisation of the additional generation, all things being equal, provides some level of comfort to customers as it is expected that there would be reduced outages.

SECTION 6 DETERMINATION

94. The Commission having reviewed the Application of BLPC for approval of the 11 MW of additional capacity (Aggreko Units) and recovery of costs associated with the proposed rental through the FCA, makes the following determinations:

A. **The rental of the Aggreko units, 11 MW in capacity, is approved for a period of at least twelve (12) consecutive months from the actual COD of the units. The possibility of approval for a further twelve (12) months may be granted where the Commission is satisfied that market conditions sufficiently warrant the need for the additional capacity at that time.**

In such circumstances, the BLPC will be required to formally inform the Commission of the need for the extension of approval and submit any revised contractual details no later than four (4) months prior to the expiration of the approved twelve (12) months.

Costs associated with the rental of the 11 MW capacity is approved for recovery via the FCA and shall commence one (1) month from the date of this Decision for the approved period;

B. **The FCA formula shall be:**

$$FCA_n = \frac{\sum_{n-1}(FuelCost_{n-1}\frac{THR_{n-1}^{i}}{AHR_{n-1}^{i}} + PurchasedPowerCost_{n-1} + TemporaryGenerationRecovery_{n-1}}{\sum_i EnergyGeneration_{n-1} * (1 - Aux_{n-1}^{i}) * (1 - losses_{n-1}^{i}) + \sum_j Purchased\ Power\ Generation_{n-1}}$$

Where:

$TemporaryGenerationRecovery_{n-1}$ **= Aggreko rental and operating costs recovery in previous month**

And where:

FCA_n =	**FCA for each (current) month**
Energy $Generation_{n-1}$ =	**Energy generated in the month n-1**
Aux_{n-1} =	**Auxiliary consumption as a percentage (%) of total generation in the month n-1**
Losses =	**System losses as a percentage (%) of total generation calculated based on a 12-month running average**
Fuel $cost_{n-1}$ =	**Fuel cost in the month n-1 including cumulative under/over recovery**
Purchase $Power_{n-1}$ =	**Cost of Purchase power from renewable sources in the month n-1**
Purchase Power $Generation_{n-1}$ =	**Purchase power from renewable sources in the month n-1**
i =	**Thermal Generation plant/unit**
BD$/kWh =	**Barbados dollars per kilowatt hour**
j =	**Purchased Power Generation**
AHR^i_{n-1} =	**Actual Heat Rate for generation plant/unit i, for month n-1**
THR^i_{n-1} =	**Target Heat Rate for generation plant/unit i, for month n-1**

C. **Costs to be recovered shall be contingent on the BLPC's ability to demonstrate that the 11 MW Aggreko units are utilised and dispatched according to demand, taking into account the impact of fuel prices and fuel efficiency of all plant, thereby providing service to customers in the most cost effective manner;**

D. **Where the utilisation of the 11 MW of capacity is found to be imprudent, that is, not being used and useful during the period of its operation, the quantum of costs recovered shall be reconciled and returned to customers;**

E. **The BLPC is not allowed to recover the non-recurring costs past twelve (12) months, if the asset is kept past that duration. This is to avoid over recovery of the non-recurring costs;**

F. **If the asset is kept for a period shorter than the twelve (12) months, then staff recommends that the outstanding balance of the non-recurring cost to be spread over the remaining balance of the twelve (12) months so that the impact on the consumer is mitigated;**

G. **The BLPC shall include in its quarterly regulatory reporting, monthly information on the following:**

i. Rated and dependable capacity (MW-AC) for all generation plant and units[93];

ii. Total aggregate output capacity (MW-AC) of each generator;

iii. Forced outage hours for all generation plant and units;

iv. Planned outage hours for all generation plant and units;

v. Effective Forced Outage Rates for all generation plant and units;

vi. The peak load (MW-AC) for each month, time of occurrence, and temperature;

vii. Generation duration curve (kWh and MW-AC) for each month at peak time;

viii. The availability factor for all generating plants and units;

ix. Details and status of planned and unplanned generation maintenance activities. The report shall include time and dates of actual activities completed and pending, and account for forced outages; and

x. Generation reliability for each plant and unit.

The above shall be submitted no later than one (1) month after the end of the quarter of the calendar year;

H. The BLPC shall provide the Loss of Load Expectation (LOLE), Expected Unserved Energy (EUE) and Planning Reserve Margin (PRM) determination, based on market conditions and the forecasted hourly peak load for the prior twenty-four (24) months from December 2023. The PRM shall be deduced from the LOLE computation.

The LOLE, EUE and PRM obtained shall then be recalibrated for the next thirty-eight (38) months to determine forward-looking values. The computation shall consider RE/storage projects that are expected to be commissioned within thirty-eight (38) months of the COD of the Aggreko units. The requested information shall be submitted to the Commission no later than six (6) months after the end of the approved twelve (12) month period. Thereafter, the LOLE information shall be submitted biannually;

[93] Units refer to individual generators/technologies such as gas turbine units, and energy storage systems.

I. **Maintenance reports on all generating plant/unit shall be submitted to the Commission on an annual basis and no later than one (1) month after the end of the calendar year;**

In addition:

J. **The Commission will conduct an investigation with respect to unit GT04 being out of commission (OC) unexpectedly. This shall be executed immediately; and**

K. **The Commission reserves the right to conduct audits at any time as it relates to the operation and management of the power system.**

Dated this 29th day of October 2024

Original signed by
……..……………………………..
Donley Carrington
Hearing Chairman

Original signed by
……..……………………………..
Jerry Franklin
Commissioner

Original signed by
……..……………………………..
Jennivieve Maynard
Commissioner

Original signed by
……..……………………………..
Ankie Scott-Joseph
Commissioner

APPENDIX 1

SUMMARY OF SUMMISSIONS

BREA

95. BREA opines that the generators are required, and this assessment is based on the potential for the resiliency and reliability as indicated by the CRM, may be under threat.

96. BREA suggest that a CRM of 41% is an appropriate level based on the island's own specific conditions. These include (a) the fact that our grid is an island grid, independent of any other electricity source in time of emergency, (b) there is some degree of concentration of risk given that at least one individual existing installed generator has a peak generation of 30 MW, 20 percent of the utility's peak load of 150 MW and (c) Barbados' vulnerability to existing supply challenges means that in emergencies, the procurement of much needed parts may be delayed.

97. BREA highlights that if electricity demand grows as expected, then CRM can fall to 23% in some months, an unacceptable level. BREA acknowledges that due to logistical constraints BLPC is only able to install 11 MW of generation but contends that this is "an acceptable compromise from both a cost and operational prospective"[94].

98. BREA opines that the timing of the commissioning of the temporary generators is guided by risk assessment and risk mitigation. Technical risk, BREA explains, is at its lowest when all of the generators are fully available for operation and peak demand is at its lowest. This risk is mitigated when generators are well maintained, with maintenance not being executed when load peaks are highest, thus reducing the probability of forced outages. BREA is of the opinion that the risk of disrupting the T20 ICC games as mentioned in the application is not included in the risk assessment, since this intervenor believes that there should be sufficient standby generation at the cricket ground to accommodate the continued play and televised should there be a grid outage affecting the area. BREA acknowledges that there is an expectation of increased peak demand in June 2024 arising out of the hosting of the T20 Men's Cricket World Cup and uses this

[94] Paragraph 6 Written summary of BREA date May 7, 2024

planned event as guide for the timing of the installation of the additional generation. BREA suggest that the generators should be in place by end of May.

99. As it relates to if the generators should be rented or purchased, BREA states that it "expects" that renting would be cheaper than purchasing the generators. BREA assumes that the stated duration of need for the additional generation is based on its expectations of the progression in the RE sector, including the installation of storage capacity on the grid, with a resulting overall improvement in CRM to cater to projected peaks. BREA states that it expects that the issues that are currently stalling the RE sector should soon be resolved. BREA's position is that the proof of the value the installation as a temporary solution will be seen if there is ever an event that results in the generations provides support to the grid.

100. BREA's position suggests some comfort in the costs of the generators presented by the Applicant. BREA appear to accept the Applicant's saying that the cost of the alternative solutions are higher and thus the Aggreko is the better option.

101. Who pays the cost of the additional generation? BREA believes that there is regulatory justification for the cost to be passed on to the consumer through approved rates. BREA suggests that Government may consider subsidising part or all of the additional cost.

102. BREA believes that the cost should be passed through the recently approved CETR given that it would be for a short duration of time.

103. BREA determines that the recovery could be amortised over a longer period than the year recommended, and as mentioned before, Government subsidise some of the cost, to the tune of ten million dollars for a year from the revenue received from the ICC Cricket World Cup.

104. In summary, BREA is of the view that the Commission should approve this request by the BLPC "with urgency". BREA is of the opinion that if the CRM drops to a level that is too low, the associated risk is not worth the potential cost impact.

105. BREA recommends that the cost recovery for these temporary generators be recovered through the Clean Energy Transition rider as long as it does not delay the BLPC's ability to install and commission the assets.

BCEN

106. BCEN, in its request for intervenor status, stated that its primary areas of concern and thus their focus of intervention were, proportional cost allocation, meaning that "consumers are not disproportionately burdened, especially where events are unspecified or unforeseeable", consumer impact assessment, transparency and accountability (in a cost recovery process), alternative consideration and existing supply and demand problem.

107. BCEN expresses its concern regarding what they perceive to be a lack of transparency and meaningful consumer engagement in the decision-making process, along with the financial impact on electricity bills and the limited exploration of alternative solutions. The use of the FCA to recoup cost will result in higher electricity bills. There will also be an effect of "energy inflation" as businesses are unlikely to absorb the rising energy costs.

108. BCEN opines that the BLPC should communicate if there is an overall energy supply challenge, exploring the options available to permanently address such. This discussion, BCEN suggests, should occur at the national level. BCEN further is of the opinion that the use of the FCA is "inappropriate and unfair to consumers". Its use is one of convenience and facilitates the avoidance of the BLPC searching for potential alternative funding sources.

109. BCEN states categorically that the BLPC should be "barred" from using the FCA to recover costs associated with the operating and leasing of diesel generators intended for short term electricity provision, because these costs cannot be classified as volatile, or outside of the BLPC's purview. BCEN contends that these costs are operational expenses. BCEN also notes that the "rental of the generators has evolved into a planned expense for the BLPC". Therefore, such costs cannot be considered as volatile and this inclusion of such will "distort the intended function" of the FCA.

110. BCEN acknowledges that expenses related to the rental of diesel generators is "imperative" for ensuring the dependable operation of the utility's grid, particularly amidst heightened demand periods or unforeseen disruptions.

111. BCEN contends that the BLPC should explore alternative avenues for cost recovery. Such options may include base rates, surcharges or adjustments tailored to operational expenses. BCEN is of the opinion that these mechanisms are more appropriate to recover operational expenses unrelated to fuel, such as those incurred from renting diesel generators.

112. BCEN expresses concern about the cost efficiency and efficacy of the BLPC's timeline for contracting installing and putting the rentals into operation, that being spread from February 2024 to May 2024. BCEN specifically questions the reasonableness of the expenses related to mobilisation and demobilisation. BCEN highlights the exclusion of fuel costs in the determination of the FCA and draws attention that fuel cost will effectively increase the total expenditure.

113. BCEN acknowledges the urgency of the use of alternative methods for cost recovery but expresses concern about the "coherence ad equity of a decision" to use the FCA. This intervenor desired the BLPC to justify why the rate base recovery methodology is impractical as a cost recovery mechanism in this instance.

114. With respect to the consumer focus, BCEN implies that the BLPC has neglected to consider the customer impact and affordability. Furthermore, the BLPC has provided no indication apart from conjecture, on what would occur if the generators were not acquired. This lack of evidence, BCEN asserts, is an aim to legitimise the shifting of the burden to the consumers.

115. BCEN points out that the utility company is required to maintain sufficient reserve margin solely through its existing infrastructure, and the absence of such should require investigation into the utility's planning, maintenance, and investment strategies. The impact of reserve margin deficiencies increases the risk of disruptions in electricity supply, but BCEN believes that this does not justify consumers bearing the financial burden of risk mitigation that is the responsibility of the BLPC.

116. BCEN presents as an example the scenario presented by BLPC, where the largest unit becomes unavailable for an extended period, significantly reducing the average reserve margin. BCEN opines that the BLPC should have contingencies in place and maintenance schedules to mitigate against such risks. BCEN further notes that if outages are not due to normal wear and tear, then again investigations must be carried out in the utility's maintenance protocols, equipment dependability and investment strategies. BCEN questions whether it is fair if consumers bear the cost of temporary rentals if outages arise from maintenance issues or other factors within the utility's control.

117. In summary, BCEN asserts that the BLPC should bear the cost for maintaining a "dependable electricity supply" and should therefore be held accountable for absorbing expenses associated with ensuring adequate reserve margins and contingency plans.

Mr. Kenneth Went

118. The Intervenor Went and Team commented on a series of matters arising from the BLPC's Application: These include Reserve Margin (RM), Historical and Projected Sales, Penetration of RE systems, Performance of Aggreko Units, Rental vs Purchase Option, Financial Impact, including Potential Over Earning.

Reserve Margin

119. With respect the RM, the Intervenor Team's main contention relates to the BLPC's comment that the need for the 11 MW of additional generation was due to the unavailability of the steam unit S1 and the gas turbine GT02 to provide RM support beyond 2023[95]. The team posits that the BLPC's intention was to replace the now retired units with the CEB and disagrees with the BLPC reasoning[96]. This leads the Team to conclude that the acquisition of the CEB brings into question planning issues[97].

120. Additionally, the team draws heavily on the RM analysis from the Verlaan Consulting Report dated April 28, 2021, which was conducted on the BLPC's behalf. This analysis

[95] See paragraph 18 of Exhibit RW.1 of Mr. Ricky Went and Team Affidavit dated April 8, 2024.
[96] Ibid 23.
[97] Ibid 31.

implies that the BLPC's reserve margin increased substantially in 2019, up to 87%[98], based on a generating capacity of 276.1 MW[99]. According to the Team, the BLPC's total capacity for 2023 was 245.7 MW.

121. Based on the 87% RM referenced, the Team remains concerned why the BLPC's RM fell below 41%[100]. On the contrary, the Team wondered whether the BLPC's RM exceeded the 41% but had inactive capacity, which is a matter of system availability[101]. To this latter issue, reference was made concerning LD 15 (30 MW) past availability which was questionable prior to the commissioning of the CEB[102].

122. Given this concern, the team recommends that the Commission requests the availability "active" and "inactive" of the BLPC's generating system and apply adjustments as to the use and usefulness of capacity where warranted[103].

123. Optimisation of the RM through the exploitation of DSM strategies was also a point presented by the Team. Referring to a DSM study which was conducted in 2015, the team recommends that the Commission requests the BLPC to present the outcome of this study and account for what recommendations where actualised to reduce the peak demand and therefore enhance the RM[104].

124. Further, the Team commented on the impact of generation availability on RM. Referring to the Verlaan Consulting Report, the Team notes that the BLPC's system availability from 2014-2019 ranged 81%-84%, these values being less than that of 2007, which was 88.4%, this result being indicative of high priority proactive maintenance. On the contrary, system availability for January 2023 to February 2024 varied between 62.4% and 80%, thus reflecting a decline in system availability of the BLPC; this result being lower that the 84% marked that recommended by the Consultant then[105].

[98] Ibid 12, 19.
[99] Ibid 19.
[100] Ibid 20.
[101] Ibid 21.
[102] Ibid 15.
[103] Ibid 22.
[104] Ibid 24-25.
[105] Ibid 29.

125. The Team, therefore, claims that the RM being below 41% was due to inadequate system availability, emphasising that priority on maintenance has declined. Taking this into account, the Commission should examine the maintenance regime of the BLPC for the period where system availability was assessed in the above Report[106].

Historical Sales and Projected Sales

126. The Team reviewed the historical growth rate of the BLPC from 1981-2020, this being on a five-year cycle. The rate returned was 4.2% based on 1981-1985 and 1991-2005, which compares to closely with the 3.9% for 2023 stated by the BLPC[107]. It was observed that prior to the impact of the pandemic and downgrade, the BLPC's growth rate was at least 2% per year and this frequently exceeded 6%.

127. While the Team supports the outlook for 2024, it contends with the BLPC's forecasts of 2.2% and 0.5% load growth for 2024 and 2025, respectively[108] given the positive outlook. Based on historical growth trend of 2% per year, the Team expects the forecast growth to increase, this warranting the need for a higher RM.

Penetration of RE Systems

128. The Team supports that additional capacity will be required for grid stability given the RE penetration[109].

Performance of Aggreko Units

129. The Team also supports the BLPC's procurement of the 11 MW of generating capacity based the business experience between the BLCP and Aggreko, considering the short timeline to procure the plant and the ability to navigate learning curve issues which may arise from new suppliers[110].

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[106] Ibid 30.
[107] Ibid 32-35
[108] Ibid 39.
[109] Ibid 44-45.
[110] Ibid 46.

Potential Over Earning

130. The Team posits that the BLPC did not confirm the length of time for the rental of the 11 MW Aggreko units, and this raises a concern of the BLPC collecting in excess of non-recurring costs[111]. The Team expects the additional capacity will be required for 24 to 36 months, citing that the 28 months utilised by the previous rental. The Team notes that the BLPC has the potential to realise an excess of 2.6 to 3.4 million above what ratepayers should pay if the proposal is approved without adjustments. The Team argues that the BLPC's rental of the units should be at least 24 to 36 months[112].

Savings from Aggreko Units

131. With reference to savings to customers from the previous 12 MW rental and proposed 11 MW rental, Mr. Went indicated that the BLPC advised that $586,000 accrued annually for the forma, thereby reducing the FCA by that amount. Concerning the proposed rental, $925,000 per year in fuel savings is expected and this amount will reduce the monthly rental charges of $856,052. However, the FCA will increase by $778,969 per month ($856,052 - $925,000/12).

Purchase vs Rental of Aggreko Units

132. Under the previous rental arrangement (28 months), rental charges amount to $24,290,992[113]. Mr. Went claims that one reason for the BLPC's rental proposal was predicated on the retirement of GT03 in 2026. Based on this, he presumes that the 11 MW rental would be in place for the same 28 months at a total cost of $23,969,465[114] and if this proposal is approved, by the end of 2026, the total rental cost of $48,260,457 could exceed $50 million[115]. Mr. Went questioned the BLPC about the retention of the rental, and substitute storage beyond 2026, the BLPC advised that retention beyond 2026 is uncertain and depends on the availability of firm capacity to meet demand. Storage will support firm capacity but cannot substitute this. Based on this, Mr. Went claims that the proposed capacity is likely to be in place beyond the contract period. Having taken the

[111] Ibid 47.
[112] Ibid 47-49
[113] Ibid 54.
[114] Ibid 55.
[115] Ibid 56.

events into account, Mr. Went objects to renting but favors purchase of the units given the uncertainty about their need.

Non-Consolidate Financials -2022 and 2023

133. Mr. Went raised the lack of access to information including non-consolidate Financials reports among other things which would assists assessment. Without this information, the impact on rate of return cannot be assessed. Mr. Went reasoned that if the Commission agrees with the purchase of the 11 MW units, then this impact can be assessed when these are submitted.

134. In Mr. Went's opinion, the BLPC has no authority to determine the relevancy of information requested.

Capital Recovery of Aggreko Units-Rate Base vs FCA

135. Mr. Went does not support utilising the FCA to recover the BLPC's investment associated with the Aggreko units if the rented or purchased. The units should be purchased, and rate based.

Customer Impact

136. Mr. Went is of the view that ratepayers should not have to pay additional costs since they are already paying an interim rate of 50% of the average 74% increase in rates requested by the BLPC in its 2021 Rate Review Application. Mr. Went also expects a downward adjustment in rates due to possible contractions in the BLPC's revenue requirement.

Watson and Simpson Team

Governing Law

137. The Intervenor team identified legislation which is intended to guide the decision of the Commission in consideration of the Application of the BLPC.

Customers' Needs

138. The Team referred to the BLPC's claim to inadequacy of generation capacity and the targeted 41% CRM expected to contain system reliability[116]. Based on the evidentiary information on available generation, the proposed 11 MW Aggreko units does not remedy the generation shortfall issue[117]. The Team also referred to the absence of GT04 and the negative impact on the CRM as purported by the BLPC. In their view, such an occurrence would have warrant immediate redress[118]. In terms of plant availability, the Team estimates that 27% of firm installed capacity is unavailable and claims that the 239.1 MW[119] of firm capacity would meet a 159 MW peak demand without accounting for the cumulative capacity (53 MW) of the CEB, Small Diesels -2020 and the 5 MW BESS[120]. Considering retirements for the steam plant and GT02, the installed firm capacity exceeds the 2010 and 2011 peak of 167.5 MW and 160 MW respectively[121], thus negating additional capacity requests. The Team further posits that the installed capacity, if operational could support a N-1 and N-2 redundancy target[122].

Used and Useful

139. The Team draws on the definition of the used and useful criteria in utility regulation[123]as it pertains to cost recovery. In their view the BLPC's primary generators to be considered used as and useful, based on the average 6000 hours per year of operation[124]. Unlike the 11 MW Aggreko units which are expected to operate 1,600 hours per year, these would not qualify for cost recovery[125]. The Team referred to the previous 12 MW Aggreko units which had a 50% greater usage than the 1600 hours per year referenced, yet no recovery was offered to these backup generators[126]. The BLPC has not substantiated the used and usefulness of the 11 MW Aggreko units[127]. Additionally, no justification was given for

[116] Ibid, paragraph 26-27.
[117] Ibid, paragraph 31.
[118] Ibid, paragraph 30.
[119] Refers to 2009 rate base amount.
[120] Ibid, paragraph 43.
[121] Ibid, paragraph 44.
[122] Ibid, paragraph 45.
[123] Ibid, paragraph 46-47.
[124] Ibid, paragraph 49.
[125] Ibid, paragraph 50.
[126] Ibid, paragraph 51.
[127] Ibid, paragraph 52.

the cost of electricity from the 11 MW Aggreko units which is 2.5 times, the nominal electricity cost[128].

The Fuel Clause Adjustment

140. The team referred to the ESD and CETR Decisions which outlined criteria for recovery of costs via the FCA. In the Team's view, there is no comparison with this current Application and the ESD Application as it pertains to the capability of the 11 MW Aggreko units to realise fuel savings, as being claimed by the BLPC. Accordingly, this Application should have been dismissed[129]. The Team posits that the requested costs does not warrant recovery through the FCA[130].

Prudence Test

141. The Team referred to several case law extracts concerning prudence test and the URA as it pertains to the obligations of the BLPC to provide the specific utility service. Accordingly, the BLPC must maintain the specified level of reliability[131]. In the Team's view, the Commission must determine whether the BLPC's failure to acquire firm capacity to meet reliability needs was prudent, considering the 2019 outages. Moreover, the Commission must examine whether the BLPC was prudently managing its generation capacity in the absence of extenuating circumstances[132]. Analysis of information implies immoderate unavailability of generation that is atypical to routine scheduled maintenance. It is estimated that between 12 MW and 20 MW or more was unavailable[133]. This situation persisted while the BLPC relied upon the actualisation of the capacity expected under the 2021 IRRP would provide a short-term relief[134]. The Team referred to the number of events from 2017 - 2023 where generation capacity was impacted[135]. These imply that the Applicant breached the URA and the Standards of

[128] Ibid, paragraph 53.
[129] See paragraph 66 of the Watson and Simpson Team Final Submission.
[130] Ibid, paragraph 67.
[131] Ibid, paragraph 68-73.
[132] Ibid, paragraph 86-87.
[133] Ibid, paragraph 88.
[134] Ibid, paragraph 89.
[135] Ibid, paragraph 99.

Service repeatedly[136]. Referring to the retired capacity (53 MW), the BLPC invested $25 Million for repair of inefficient steam plant. GT02 was expected to be retired in 2016.

142. The Intervenor Team posits that the BLPC failed to justify the requests in the Application[137] and claims that it is seeking to rectify the issue which predates 2017.

143. The Team argues that the Application should be denied, since doing otherwise would allow repeated failure to remedy the CRM, persist with non-compliance with the URA Section 20 and the Standards of Service, allow inappropriate recovery via the fuel clause, allow ratepayers to compensate the BLPC inappropriately and facilitate the Applicant's persistence with information refusal[138].

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[136] Ibid, paragraph 100.
[137] Ibid, paragraph 112.
[138] Ibid, paragraph 115-116.