# FAIR TRADING COMMISSION

**BARBADOS** **No. 01/2023**

**IN THE MATTER** of the Fair Trading Commission Act, Cap.326B of the Laws of Barbados;

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

**AND IN THE MATTER** of the Utilities Regulation (Procedural) Rules, 2003 and the Utilities Regulation (Procedural) (Amendment) Rules, 2009;

**AND IN THE MATTER** of an Application by the Barbados Light and Power Company Limited for a Review of Electricity Rates pursuant to Section 16 of the Utilities Regulation Act, Cap. 282 of the Laws of Barbados;

**APPLICANT**

The Barbados Light & Power Company Limited

**INTERVENORS**

Barbados Renewable Energy Association
Energy Division: The Ministry of Energy and Business Development
Mr. Kenneth Went
The Cooperative Society Ltd
Ms. Tricia Watson and Mr. David Simpson
Business Development Division: The Ministry of Energy and Business Development
The Barbados Association of Retired Persons

BEFORE:

| | |
|---|---|
| Dr. Donley Carrington | Hearing Chairman |
| Dr. Ankie Scott-Joseph | Commissioner |
| Ms. Ruan Martinez | Commissioner |
| Mr. Samuel Wallerson | Commissioner |
| Mr. John Griffith | Commissioner |

**DECISION AND ORDER**

## LIST OF ABBREVIATIONS

| ACRONYMN | ABBREVIATIONS |
|---|---|
| ADIT | Accumulated Deferred Income Taxes |
| A&G | Administrative and General |
| BARP | Barbados Association of Retired Persons |
| BLPC | Barbados Light & Power Company Limited |
| BNEP | Barbados National Energy Policy |
| BREA | Barbados Renewable Energy Association |
| CAPM | Capital Asset Pricing Model |
| CEB | Clean Energy Bridge |
| CETR | Clean Energy Transition Rider |
| COSS | Cost of Service Study |
| CRP | Country Risk Premium |
| CWIP | Capital Work in Progress |
| DCF | Discounted Cash Flow |
| ECAPM | Empirical Capital Asset Pricing Model |
| ECI | Emera (Caribbean) Incorporated |
| ESD | Energy Storage Device |
| FTCA | Fair Trading Commission Act CAP. 326B of the Laws of Barbados |
| FCA | Fuel Clause Adjustment |
| FERC | Federal Energy Regulatory Commission |
| GDP | Gross Domestic Product |
| HPS | High-Pressure Sodium |
| IAS | International Accounting Standards |
| IASB | International Accounting Standards Board |
| IFRS | International Financial Reporting Standards |
| LSD | Low-Speed Diesel |
| NARUC | National Association of Regulatory Utility Commissioners |
| O&M | Operations and Maintenance |
| ROE | Return on Equity |
| RPPA | Renewable Purchased Power Adjustment |
| SIF | Self-Insurance Fund |
| T&D | Transmission and Distribution |
| URA | Utilities Regulation Act CAP. 282 of the Laws of Barbados |
| URPR | Utilities Regulation (Procedural) Rules, 2003 |
| WACC | Weight Average Cost of Capital |

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## SECTION 1 – BACKGROUND

### THE APPLICATION

1. On October 4th, 2021, the Barbados Light & Power Company Limited ("BLPC") filed with the Fair Trading Commission (the "Commission") its Review of Electricity Rates Application pursuant to Section 16 of the Utilities Regulation Act Chapter 282 of the Laws of Barbados (the "URA")[1] and Rule 60 of the Utilities Regulation (Procedural) Rules, 2003 (the "URPR")[2] (the "Application").

2. The BLPC seeks approval for the following Orders, that:
   (a) Interim Rate Relief at the proposed rates, to come into effect from November 1, 2021, to apply to all bills from that date, remaining in effect until the Commission issues its final decision on the Application;
   (b) The Proposed Tariffs to come into effect from April 1, 2022;
   (c) The Rate Base as computed by the BLPC and calculated to be $825,891,134 be approved.
   (d) The capital structure of Debt of 35% and Equity of 65% used by the BLPC in the determination of its Rate of Return be approved.
   (e) The Rate of Return of 8.79% be approved;
   (f) The Revenue Requirement of $440,240,372 be approved.
   (g) The Existing Tariffs and Riders will be replaced by the Proposed Tariffs and Riders, details of which are described at Schedules K1 – K11 of the Application;
   (h) The current Fuel Clause Adjustment ("FCA") formula be modified to only recover fossil fuel related costs;
   (i) The renewable energy purchased power and the energy storage device (ESD) be removed from the FCA. The renewable energy purchased power be recovered through the establishment of a "Renewable Purchased Power Adjustment" (RPPA) and the ESD be included in rate base;

[1] As amended in 2020 by virtue of the Utilities Regulation (Amendment) Act 2020.
[2] As amended in 2009 by virtue of the Utilities Regulation (Procedural) (Amendment) Rules, 2009

(j) The existing Standards of Service be retained; and

(k) Such further Orders or other relief as may be warranted.

3. The Application was supported by the Affidavits of Mr. Roger Blackman, Mr. Ricaido Jennings, Mr. Rohan Seale, Mr. Johann Greaves, Dr. Adrian Carter, Dr. Philip Hanser (expert witness), Dr. Bente Villadsen (expert witness) and Mr. Peter Huck (expert witness).

4. Electricity rates for BLPC were last reviewed by the Commission following an application by BLPC dated May 8th, 2009, which was heard in 2009. The Commission's determination in that regard is contained in its Decision and Order dated January 25th, 2010 (the "2010 Decision")[3].

## LEGISLATIVE FRAMEWORK

5. By virtue of Section 4(3)(a) of the Fair Trading Commission Act, Chapter 326B of the Laws of Barbados (the "FTCA")[4], the Commission is responsible for establishing principles for arriving at the rates to be charged by service providers and setting maximum rates to be charged by service providers. The Commission is also given similar responsibilities under Section 3(1) (a) 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;*
> >
> > *(f) carry out periodic reviews of the rates and principles for setting rates and standards of service."*

6. Moreover, Section 3(2) of the URA stipulates that when arriving at the rates to be charged, the Commission must take into account certain principles as follows:

[3] Document NO. 0002/09

[4] As amended in 2020 by virtue of the Fair Trading Commission (Amendment) Act 2020.

*"In establishing the principles referred to in subsection 1(a) the Commission shall have regard to:*

*a) the promotion of efficiency on the part of service providers;*

*b) ensuring that an efficient service provider will be able to finance its functions by earning a reasonable return on capital; and*

*c) such other matters as the Commission may consider appropriate."*

7. Section 2 of the Fair Trading Commission (FTC) (Amendment) Act 2020 and the Utilities Regulation (Amendment) Act 2020 defines "principles" to mean the formula, methodology or framework for determining a rate for a utility service.

8. Additionally, Section 2 of the URA defines "rates" broadly to 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;"*

9. By virtue of Section 16 of the URA, where the Commission has not fixed a period of time in accordance with Section 15(1), the Commission may, on its own initiative or upon an Application by a service provider or consumer, review the rates, principles and Standards of Service for the supply of a utility service.

10. The BLPC submitted the Application to the Commission pursuant to Section 16 of the URA and the Utilities Regulation (Procedural) Rules, 2003 as amended (the "URPR"). In light of this provision, the BLPC correctly filed an Application with the Commission for a review of electricity rates. Therefore, the provisions of the URA and URPR governed the hearing of the Application which was held during the period September 21st to October 7th, 2022 and October 13th and 14th 2022 (the "Hearing").

11. By virtue of Section 5 of the FTCA, and Section 6(1) of the URA, the Commission exercised its power to sit, hear and determine this Application and in

accordance with Rule 4 of the URPR, the Commission issued six (6) Procedural Directions which governed the conduct of the proceedings.

12. The Commission also exercised its powers pursuant to Rule 19(1) of the URPR to hear expert witnesses during the Hearing.

13. Under the rate of return methodology, rate making involves three distinct steps:
    (a) The determination of a utility company's annual revenue requirement (i.e the sum total of the revenues required to pay all operating and capital costs, including return on its own investment) - recoverable from customers;
    (b) The allocation of the total costs of providing the service to each customer class or other service; and
    (c) The creation of a rate design that will recover those costs.

14. Intrinsic in the process set out in paragraph 13 is the legal grounded concept of "fairness and reasonableness". Section 10 of the URA states inter alia, that:

> *"Every rate made by the Commission shall be:*
>
> *(a) Fair and reasonable"*

15. "Fairness and reasonableness" for the Commission in rate setting relates to the balance between the interest of the consumers and the interest of the utility company. In this light, Section 3(3) of the URA states that:

> *"The Commission shall*
>
> *(a) protect the interests of consumers by ensuring that services providers supply to the public service that is safe, adequate, efficient and reasonable; and*
>
> *(b) hear and determine complaints by consumers regarding billings and the standards of service supplied."*

16. Further Section 3(2) (b) of the URA states that:

> *"In establishing the principles referred to in subsection 1(a) the Commission shall have regard to:*

> (b) *Ensuring that an efficient service provider will be able to finance its functions by earning a reasonable return on capital;"*

**<u>BURDEN & STANDARD OF PROOF</u>**

17. Section 14 of the URA provides that, "in any proceeding before the Commission involving an existing or proposed rate of a service provider, the burden of proof to show that the rate is fair and reasonable and in accordance with the principles established by the Commission shall be upon the service provider". Consequently, BLPC must discharge this burden by providing sufficient evidence for the Commission to grant the relief that BLPC is seeking. Hearings before the Commission are equivalent to civil proceedings in a Court of Law. The standard of proof in this instance would be the same as a civil proceeding in a Court of Law.

18. Section 133 (1) of the Evidence Act, Chapter 121 of the Laws of Barbados provides that:

    > *"In a civil proceeding, the Court shall find the case of a party proved if it is satisfied that the case has been proved on the balance of probabilities."*

19. In this regard, the Commission must be satisfied that BLPC's case has been proved on a balance of probabilities.

**<u>REVIEW PROCESS</u>**

20. On October 31st, 2021, the Commission issued a Public Notice advising members of the public of the receipt of the Application and invited interested parties to submit letters of intervention in order to be granted intervenor status in the proceeding.

21. The Commission received eight letters of intervention and two motions for late intervention. The Commission granted Intervenor status to eight parties, namely:

    1. The Barbados Renewable Energy Association (BREA)

2. The Energy Division, Ministry of Energy & Business
3. Dr. Roland Clarke
4. Tricia Watson & David Simpson, jointly
5. Kenneth Went
6. The Barbados Sustainable Energy Co-operative Society Ltd.
7. The Business Development Division of the Ministry of Energy and Business Development - represented by Public Counsel and
8. The Barbados Association of Retired Persons (BARP) – represented by the Public Counsel.

22. Please note that Dr. Roland Clarke later indicated his unavailability to participate due to other commitments.

23. The Commission was represented at the Hearing by Dr. Marsha Atherley-Ikechi, Chief Executive Officer; Mr. Kevin Webster, General Legal Counsel/Commission Secretary, assisted by members of the Legal Department; Ms. Kathyann Belle, Director of Utility Regulation (Ag), assisted by members of the Utility Regulation Division; Consultants - GDS Associates, Inc., Mr. Alrick Scott K.C. and Mr. Roger Forde K.C.

24. The Commission's Procedural Order No. 1 issued on July 12th, 2022 sets out a list of issues that the Commission determined it would consider during the Hearing. These issues are as follows:
    1) Test Year - suitability and methodology
        a. Additional Financial Data (management accounts)
        b. Operational modality
        c. Assumptions and adjustments
    2) Rate Base and Revenue Requirement
        a. Prudence and reasonableness of the fixed assets
        b. Depreciation
        c. Capital Works in Progress
        d. Operations and Maintenance Expenses

e. Administrative and general expenses

f. Insurance

i. Captive Insurance Fund[5]

g. Taxes (amortization of Accumulated Deferred Income Tax)

h. Adjustment for known and measurable changes for the items listed

3) Financial Forecasting
   a. Adequacy and Appropriateness
   b. Prudence of Capital Expansion Plan
   c. Key Assumptions/Inputs
4) Capital Structure
   a. Debt/equity
   b. Capital Employed
   c. Components of the Weighted Average Cost of Capital
   d. Cost of Equity
   e. Cost of Debt
      i. Rate of return
      ii. Dividend Policy
5) Rate Design
   a. Objectives and philosophy
      i. Compliance with applicable legislation in relation to customer class
   b. Cost Allocation
   c. Functionalization
   d. Accountability/Clawback Mechanism
6) Disaggregation of the FCA
   a. Energy Storage Device
   b. Fossil Fuel and Renewable Energy ("RE")
   c. RE requirement/ Impact of generation and supply
7) Customer Impact

[5] Referred to by the Commission herein as the "Self Insurance Fund" (the "SIF").

a. Operating Performance
b. Safety
c. Tariffs

## REGULATORY FINANCIAL REPORTING

25. The Commission will require BLPC to create regulatory deferral accounts that will be used to reflect the rate decisions for the 2019 income tax rate change, the 2016 Self-Insurance Fund withdrawal, and depreciation, as discussed in this Decision. For future events the Commission may require or the BLPC may request the use of such accounts to reflect the deferral of costs that are likely to be approved for rate recovery or returned to customers in a future rate proceeding. The Commission has determined that the use of regulatory accounts is a necessary regulatory tool to implement rate outcomes that achieve fair and reasonable results. Regulatory accounts allow for certain expenses and losses, generally of a nature not expected to be recovered in existing rates, to be deferred for regulatory accounting and ratemaking purposes to a future period for consideration in future rates. Costs deferred are the specific revenues, expenses, gains, or losses that would have been included in net income determination in one period for financial reporting to the Commission but for it being determined that, in the case of regulatory assets, such items will be considered for rate recovery in a future rate proceeding or, in the case of regulatory liabilities, that refunds to customers will be considered in a future rate proceeding.

26. Deferred expenses and losses are referred to as regulatory assets under the Federal Energy Regulatory Commission's Uniform System of Accounts ("FERC Accounting Regulations").[6] There are also certain revenues and gains that are

[6] Under the FERC Accounting Regulations, Regulatory Assets and Liabilities are assets and liabilities that result from rate actions of regulatory agencies. Regulatory assets and liabilities arise from specific revenues, expenses, gains, or losses that would have been included in net income determination in one period under the general requirements of the Uniform System of Accounts but for it being probable: (A) that such items will be included in a different period(s) for purposes of developing the rates the utility is authorized to charge for its utility services; or (B) in the case of regulatory liabilities, that refunds to customers, not provided for in other accounts, will be required.

generally of a nature not expected to be considered in existing rates that are proper to be deferred for accounting and ratemaking purposes to a future period for consideration in future rates. Deferred revenues and gains are referred to as regulatory liabilities under the FERC Accounting Regulations. The types of costs subject to regulatory deferral accounting and rate treatment will not always be known or anticipated at the time of a rate review and may be requested by the BLPC or required by the Commission at a time between the rate reviews. For example, at the time of the corporate income tax rate change in 2019, the Commission staff instructed the BLPC to defer a $19 million tax gain in a regulatory deferral account for consideration in the next rate review.

27. The Commission understands that the BLPC issues stand-alone financial statements under International Financial Reporting Standards ("IFRS") for financial reporting to investors. Currently, IFRS does not permit the financial reporting of regulatory assets and liabilities in IFRS-based financial statements. Accordingly, it is not the expectation or requirement that the BLPC report regulatory assets and liabilities in its IFRS-based financial statements to investors. The Commission is aware that the International Accounting Standards Board ("IASB") has a proposed accounting standard that would permit the reporting of regulatory assets and liabilities in IFRS-based financial statements. If the IASB issues a new accounting standard on regulatory assets and liabilities, the Commission may re-evaluate the accounting provisions established here to align with the newly established IFRS standard in a separate proceeding.

28. The Commission also understands that on a consolidated basis, BLPC's regulatory assets and liabilities are reported by BLPC's ultimate beneficial owner, Emera Incorporated ("Emera"), who does not follow IFRS. Accordingly, any regulatory assets or liabilities directed by the Commission can be tracked, maintained, and reported generally consistent with the processes already in place at Emera. The Commission will require such regulatory assets and liabilities to be reported in the regulatory financial statements provided annually with the Commission.

29. These deferral accounts shall be accounted for as regulatory assets and liabilities and shall be reported on a separate line in the liability section of the balance sheet. Also, the regulatory assets and liabilities shall be amortized consistent with the inclusion in rates as determined in this Decision or subsequent decisions by the Commission. The amortization expense for each regulatory deferral shall be reported as a separate line in the income statement for regulatory financial reporting purposes to the Commission. In addition, the regulatory financial statements reported to the Commission shall include disclosures that describe the nature of each regulatory deferral, the amortization period and method, the unamortized balance and other relevant facts.

30. Additional regulatory deferrals (assets or liabilities) may be requested by the BLPC or required by the Commission in periods following this Rate Review. To establish a new regulatory deferral account, the BLPC shall request authorization in writing from the Commission and shall be approved or denied, in whole or in part, in written correspondence. Similarly, the Commission may direct the use of regulatory deferral accounts to address ratemaking effects of future unique events that cannot be expected or measured during this rate review. The Commission's action on such requests will be on a case-by-case basis. However, the Commission is bound by the principles of fairness and reasonable rates and consistency. Moreover, the approval to use regulatory deferral accounts does not constitute a final ratemaking action by the Commission. Recoveries and refunds associated with costs included in regulatory deferral accounts are determined through formal rate proceedings before the Commission.

## DISCUSSION OF THE COMMISSION'S FINDINGS ON THE APPLICATION

31. The Commission discusses its findings regarding approval of or modification to specific items within the Application which it finds pertinent within this Decision.

32. Adjustments made by BLPC to test year values not discussed below or addressed in subsequent orders are to be deemed appropriate for ratemaking purposes as presented within the Application.

## SECTION 2 – TEST YEAR

33. The test year, as defined by the National Association of Regulatory Utility Commissioners' ("NARUC") Rate Case and Audit Manual (the "NARUC Manual"), is "a period of measurement for a recent, consecutive twelve-month period consisting of a full year of operations where data is readily available". The test year can be based on a historical, partially forecast, or fully forecast period.

34. According to the NARUC Manual, the determination of whether a test year is appropriate for setting rates is whether it is "representative, after adjustments, of the period in which rates take effect".

35. Mr. Ricaido Jennings, Director Finance for BLPC and witness for adjustments to the test year, agreed in the Hearing that the test year should be representative of the time that rates were likely to be in effect.

36. The Application proposed a historic test year consisting of the twelve months ending December 31st, 2020. At the time of filing the selected test year was the most recent period for which audited financial statements were available.

37. Commission included the appropriateness of a 2020 Test Year as an issue to be reviewed during the Hearing.

*Intervenor Positions*

38. Various parties questioned the appropriateness of BLPC's decision to use a 2020 test year given the effects of COVID-19 on consumption patterns of ratepayers and the business activities of BLPC.

*The Commission's Analysis and Findings*

39. When assessing a historical test year, the NARUC Manual recommends questioning whether (1) the selected period is too old to be representative of future operations, (2) historic costs and revenues are normal or reoccurring, and (3) changes in growth or revenue have occurred since the period. If any

identified deficiency with the test year cannot be resolved by adjustments to the book values, then the Test Year may be inappropriate.

40. The Commission finds that necessary adjustments can be made to the Test Year data to appropriately reflect future operations, costs, and revenues, which will be discussed in subsequent sections. On this basis, the Commission approves the use amended of 2020 financial information and operating statistics for purposes of the base Test Year.

## SECTION 3 – RATE BASE

41. BLPC proposed a rate base of $825,891,134 based on the utility plant in service in the 2020 test year. BLPC's proposed rate base also includes cash working capital, materials, supplies, and construction work in progress ("CWIP") anticipated to be in service within 12 months of the end of the test year, together with other known and measurable changes.

42. Rate Base is the net amount of investment in the utility plant and associated assets, on which a fair and reasonable rate of return may be earned. For a component to be considered in the rate base it must be considered to have been prudently incurred and that it is used and useful.

43. The table below sets out the various components and associated values that BLPC proposes to include in its rate base.

**Table 1 Rate Base - 2020**

| Requested Rate | 2020 |
|---|---|
| Cost of Plant | $1,462,099,998 |
| Accumulated Depreciation | ($815,589,598) |
| **Utility Net Plant** | **$646,510,400** |
| Construction work in Progress (CWIP) | $143,004,791 |
| **Total Net Plant** | **$789,515,191** |
| **Current Asset and Liability Adjustment** | |
| Cash Working Capital | $13,579,651 |
| Materials & Supplies and Prepayments | $29,323,147 |
| Customer Contributions for Work Not Yet Started | ($3,171,092) |
| Accumulated Deferred Income Tax Liability | ($3,355,763) |
| **Total Adjustment** | **$36,375,943** |
| | |
| **TOTAL RATE BASE PROPOSED:** | **$825,891,134** |

44. The Commission reviewed BLPC's request regarding rate base and the sections below describe and discuss the Commission's findings regarding the most pertinent issues that need to be determined.

45. As a preliminary matter, due to the unique set of circumstances at issue and the significant passing of time since the Application was filed, the Commission directs BLPC to update the rate base valuation related to net utility plant, regulatory asset and liabilities, and the associated plant-related accumulated deferred income tax liabilities as of the effective date of Interim Rate Decision, September 16th, 2022 (the "Interim Rate Effective Date") per the Commission's decision setting interim rates of even date (the "Interim Rate Decision")[7]. This will entail an update to annual depreciation expense as well. This will be performed by applying the depreciation rates established in this Decision to updated plant in service balances recovered through base rates.

46. For avoidance of doubt, in a compliance filing BLPC must submit a revised Revenue Requirement to be utilized in determining final base rates (the "Compliance Filing"), which shall utilize a rate base that includes updated book valuation of plant in service, accumulated depreciation, accumulated deferred income taxes ("ADIT") and regulatory assets or liabilities as of the Interim Rate Effective Date, as modified to reflect the decisions below. The plant-related rate base items shall be determined using BLPC's management accounts for the period ending December 31st, 2022, to determine utility plant, accumulated depreciation, and ADIT balances, with appropriate adjustments to remove the effects of depreciation, additions, and retirements that occurred from the Interim Rate Effective Date to the end of 2022. This shall be supported by detailed worksheets detailing the year end balances, required adjustments, and methodologies used. As a compliance filing, BLPC is directed to provide audited financial statements for the period ending December 31st, 2022 by June 30th, 2023 with a detailed analysis report. The report must provide a detailed listing of plant-related rate base items to compare the management account balances for the period ending December 31st, 2022 to the audited financial statements. Specifically, the detailed report must provide this variance analysis of utility

[7] Document NO. FTC-01/2021-BL&P-RRA-IRRDEC.

plant and accumulated depreciation for each detailed plant account.[8] The report must also provide the variance analysis of ADIT balances by account and for each inventory of ADIT.[9] Finally, the report must identify any changes to depreciation expense determined using the management accounts based on any adjustments made through the independent audit review.

## PRUDENCE AND REASONABLENESS OF THE FIXED ASSETS

*Energy Storage*

47. In 2018, BLPC installed a 5 MW energy storage device (the "ESD") to lower fuel cost and enhance grid reliability and resilience.[10] The ESD, which stores approximately 20 MWh of energy, is capable of providing 4 hours of electricity at full output of 5 MW and has an operating life of 10 years. The initial capital cost of the ESD was $22,947,770.[11] Currently, the cost of the ESD is funded through a provision in the annual FCA, as approved by the Commission on April 13, 2018.

48. The Commission finds that the costs associated with the ESD were reasonable and its use would facilitate the realization of Barbados' clean energy vision in its April 13th, 2018 order.[12]

49. BLPC proposed to recover the ESD costs through the FCA and the Commission in its April 13th, 2018 order, found the FCA was a prudent method for ESD cost recovery.[13] The Commission found that the use of the FCA would also mitigate the need for an overall rate review, stating "Such reviews are costly in terms of time, human resources and capital and said cost would ultimately be borne by the customer."[14]

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8 The detailed utility plant accounts are the FERC Account 300 series accounts.
9 The detailed ADIT accounts include FERC Accounts 190, 281, 282, and 283.
10 Application Volume 1, page 13, paragraph 52.
11 FTC Decision issued in April 13, 2018, Document No. FTCUR/DECESD/BL&P-2018-02, page 6, second paragraph.
12 Ibid, page 29, Decision (i).
13 Ibid, Page 29 Decision (ii).
14 Ibid, Page 23, last paragraph.

50. The Commission approved recovery of the ESD costs for a period of three (3) years, commencing on September 1st, 2018, and a review was necessary to assess the continued appropriateness and applicability of the recovery mechanism.[15]

51. The formula established for the ESD cost recovery provided 95% of the fuel savings each year would be used for the ESD cost recovery.

52. BLPC seeks the Commission's approval in the Application to include the undepreciated portion of the 5 MW ESD capital investment and operating costs in Rate Base.[16] According to BLPC Witness Ricaido Jennings, the undepreciated ESD cost is $16.448 million.[17]

53. Mr. Jennings testified that the amount of revenue recovery over the first three (3) years of the ESD operation was $2.7 million (95% of the fuel cost savings).[18] Adjusting for the 95%/5% split between customers and ESD cost recovery, the total fuel savings equates to $2.84 million over the three-year period.

54. Assuming the same rate of recovery over the 10-year life of the ESD, total ESD life cycle fuel savings would only be $9.47 million. Thus, fuel savings over the life of the ESD would only pay for about 41.3% of the ESD capital costs.

*The Commission's Analysis and Findings*

55. BLPC made the recommendation in its July 11th, 2017 application for limited application to recover the costs of the 5MW energy to recover the ESD costs through the FCA and provided formulas for the cost recovery. The Commission conducted extensive research and analysis before determining that the FCA was an acceptable mechanism to recover the ESD costs. The Application does not provide any evidence of the need to change the current cost recovery method and the basis for using the FCA as the ESD cost recovery mechanism has not

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15 Ibid, page 30, Decision (iii).
16 Application Volume 1, page 21, paragraph 82.
17 Hearing Transcript, October 4, 2022, page 1177, line 1300 & Table 3 of application volume 4, "Allocation by FERC Account".
18 Hearing Transcripts, October 4, 2022, page 1177, lines 1298-1300.

changed. Thus, the FCA cost recovery mechanism established in the Commission's April 13th, 2018 decision, shall continue to be the mechanism for ESD cost recovery for its useful life.

56. BLPC witness Rohan Seale stated that BLPC has a request for proposal for 45 megawatts of additional energy storage.[19]

57. BLPC has not demonstrated that the current ESD is economical over the life of the facility, nor does it provide ratepayers an acceptable fuel cost reduction as compared to the capital investment. Prior to purchasing additional energy storage, BLPC shall submit a full economic cost benefit analysis for the new energy storage, which demonstrates that it provides an acceptable economic benefit to ratepayers, to the Commission for approval.

*Steam Plant Operations*

58. BLPC includes in its rate base Steam Plant Unit 1 (S1) and Unit 2 (S2). BLPC stated that Unit S2 was repurposed during 2020 to provide spares for S1.

59. BLPC has also added the 33 MW CEB generation facility to its portfolio of generation assets. The CEB has an average heat rate of 7,963.56 BTU/kWh (converted from 8,402 kj/kWh).[20]

60. BLPC is proposing to continue operation of 20 MW S1, through the end of 2023. BLPC maintains that use of the S1 has been an economical resource because its variable cost of operation is lower than BLPC's combustion turbines.

61. Referring to the Commission's Decision of April 23rd, 2019 and including the CEB, the targeted heat rates of BLPC's generation assets are shown below in order of best to worst heat rate:

- CEB 7936.56 BTU/kWh
- Low Speed Diesel (LSD) 2 7,980.5 BTU/kWh
- Low Speed Diesel (LSD) 1 9,067.28 BTU/kWh

[19] Hearing Transcript, October 4, 2022, page 1159, lines 899 – 900.
[20] Interrogatory Response Exhibit RB34, August 31, 2022, Response 4(f).

- Steam Plant 15,370.20 BTU/kWh

62. Based on the heat rates on the above generation assets, the steam plant has the least efficient heat rate.

63. BLPC has generation assets capable of producing 282.5 MW, 267.2 MW excluding solar and battery generation.[21]

64. BLPC's maximum load is around 145 MW according to BLPC witness Mr. Johann Greaves.[22] BLPC has approximately 110 MW of excess capacity or about 41% excess capacity according to Mr. Greaves.[23]

65. BLPC claims the continued use of the steam plant is beneficial to customers due to its lower variable operating costs prior to completion of the CEB project. BLPC has not provided any evidence in this proceeding that the total cost of continued operation of the steam plant justifies its continued operation. In addition, BLPC has not provided evidence that its dispatch protocol incorporates all costs impacted by plant operation, nor has it provided proof that plant start-up costs, low load operation to remain in service, or other costs are included in the dispatch protocol.

*The Commission's Analysis and Findings*

66. Although the Commission has previously approved life extension investment in the steam plant, continued operation of S1 through the end of 2023 is unnecessary with the commercial operation of the CEB, because it results in higher costs for BLPC ratepayers. The Commission therefore directs that BLPC shall discontinue operation of S1 and place the unit into reserve operation status through its retirement as soon as possible but no later than December 31st, 2023.

67. As a result of the impending retirement of S1, the Commission finds it appropriate to recover the 2023 monthly operating expenses for S1 through the

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21 Ibid, page 7, Table 2.
22 Hearing Transcript, October 4, 2022, page 1146, lines 538-540.
23 Ibid, page 1148, lines 563-566.

FCA as opposed to base rate. The BLPC shall be entitled to recover the monthly S1 operating expenses and BLPC shall take all necessary efforts to minimize steam plant operating costs through its retirement date. The recovery of investment in the S1 is dealt with in Section 5 – Depreciation Expense.

*BLPC Reporting*

68. BLPC operation of its generation assets appears to result in higher plant outage rates and lower plant availability than typical of the type of generation assets owned by BLPC. Based on information in the proceeding and BLPC's lack of transparency in the Application and in interrogatory responses, the Commission finds it necessary to implement monthly reporting requirements. The Commission shall require BLPC to provide monthly reports on each generation unit which includes the following information in the format shown in Attachment A. Although the BLPC may be providing this information to the Commission in other formats, the Commission directs that the information be consolidated in this format.

*BLPC Operations Study*

69. BLPC's information provided in the Application and in response to interrogatories has raised concerns with the Commission regarding plant operations, plant dispatch protocol, plant availability, and the utilization of plant assets. During the Hearing, it appears that a full understanding of BLPC's operation of its generation assets was not achieved by all parties because of the apparent deficiencies in the information provided. The Commission shall undertake a study to obtain a full understanding of BLPC's operating practices as it relates to generation assets. The Commission expects full cooperation from BLPC and BLPC's personnel during the process of this study. It is anticipated that the aforementioned study will commence in 2023.

## CONSTRUCTION WORK IN PROGRESS

70. BLPC proposes to include $143,004,791 of plant and equipment, which were expected to be in service within a 12-month period immediately following the

end of the Test Year, be considered "used and useful" and included as part of the Rate Base. The plant and equipment were primarily associated with the CEB investment, which was commissioned on June 28, 2022, at a cost of $141,453,175.

*Intervenor Positions*

71. None of the intervenors have articulated a particular position with regard to BLPC's CWIP proposal.

*The Commission's Analysis and Findings*

72. As previously stated, the Commission directs BLPC to update the plant-related rate base balances to the Interim Rate Effective Date. This adjustment will result in all plant that is used and useful as of that date, including the CEB, being included in rate base.

73. As all used and useful plant is included in rate base, there is no longer a need to include any CWIP in rate base to recognize plant that will be in service. For purposes of the compliance filing, BLPC is to exclude CWIP from rate base.

**WORKING CAPITAL**

74. Working capital is a specific subset of investments made by the utility that support the safe and efficient operation of the utility. Generally speaking, working capital has four primary components: prepaid expenses or "prepayments," fuel stock, materials and supplies, and cash working capital. Following the Commission's review, the matter of cash working capital is the primary aspect at issue in this proceeding.

*Cash Working Capital*

75. BLPC proposes to include approximately $13.6 million in rate base as a cash working capital allowance based on the application of the 45-day rule. As part of its justification for its use of the 45-day rule, BLPC points to the fact that it is largely excluding $19 million of prepayments from rate base and presuming that those amounts are covered by its use of the 45-day rule.

*Intervenor Positions*

76. An affidavit sworn by Mr. Ralph Smith was filed on behalf of the Energy Division of the Ministry of Energy and Business. However, Mr. Smith was not tendered as a witness during the Hearing as he was unavailable on dates fixed for the Hearing. It follows that he was not cross-examined on his affidavit.

77. Cross examination is central to the proceedings before the Commission where facts are in dispute. It is essential that an opposing party is able to test evidence he disputes by cross examination. A person who wishes to give evidence must do two things, file written evidence where the Commission so directs and generally, must attend the oral earing to give evidence. Rules 16(4) and 16(5) of the URPR provide as follows:

> "*(4) Any party who wishes to present evidence at an oral hearing shall prior to the appearance of his witness, file and serve written evidence as directed by the Commission.*
>
> *(5) The witness of a party presenting evidence at an oral hearing must confirm under oath or affirmation that the written evidence was prepared by the witness or under the direction or control of the witness and is accurate to the best of the witness's knowledge or belief.*"

78. Where a person has filed written evidence but does not attend the oral hearing to be cross-examined, the witness statement may, at the discretion of the Commission, be admitted into evidence. Rule 17(1) of the URPR seems to give the Commission broad power to admit "any evidence", which would include written evidence where the maker of the affidavit or witness statement has not been tendered for cross-examination. However, written evidence, where the maker has not been cross-examined, raises questions concerning the weight to be attached to such evidence. It appears that the written evidence of a witness who was not cross-examined should be treated with caution. Rule 17(2) of the URPR provides as follows:

> *"17(2) The rules of evidence will not be applied strictly but the Commission will be cautious in assessing evidence which is hearsay and evidence contained in documents which have been attested to or in which there has been no opportunity for full cross-examination."*

79. The Commission has referred to the evidence of Mr. Smith in this judgment, but it treats such evidence with caution, and attaches little weight to it, having regard to the fact that it was not tested by cross-examination.

*The Commission's Analysis and Findings*

80. The Commission agrees with the contention of BLPC that, at least for electric utilities, the FERC permits utilities to instead rely on a ratemaking convention commonly referred to as the 45-day rule or 1/8th method, where a utility multiplies its total operations and maintenance and administrative and general expenses (as distinct from its total "operating expenses," which would include other items such as taxes) by (45 ÷ 360), or 1/8th. However, the FERC has also moved away from this permitted approach for other industries, such as the natural gas pipelines it regulates, and instead directs those entities to justify any cash working capital allowance in rate base with a fully developed and reliable lead/lag study. Several state public utilities commissions in the United States also do not allow utilities to use the 1/8th method to calculate cash working capital in rate base and instead require lead/lag analyses conducted consistent with their own rules and regulations.

81. While the Commission acknowledges that the FERC permits electric utilities to use the 45-day rule, the Commission is of the view that the rule and its traditional implementation have several flaws and shortcomings. For example, the premise and application of the methodology only reflects revenue lags without consideration for the utility's payment lags.

82. The Commission has determined that the most accurate method to determine the appropriate amount of a utility's cash working capital allowance is a fully

developed and reliable lead/lag study, which is at its core a broader and disaggregated analysis similar to the simplistic example above. A good lead/lag study will, at a minimum, account for the following factors:

a. provide for the disaggregation of expenses by type;
b. reflect revenue leads (i.e., instances where the utility actually recovers revenue from customers for an expense in advance of actually expending funds for that expense);
c. analyze customer payment patterns by relevant customer class, subtracts fuel and purchased power expenses; and
d. subtracts non-cash expenses (e.g., depreciation expense).

83. In his affidavit, Mr. Smith asserts that the 45-day rule does not produce reasonable results and that based on lead/lag studies conducted by other utilities in disparate jurisdictions indicate a negative cash working capital need. Given our comments above the Commission is not persuaded that these other lead/lag studies provide a sufficient basis to conclude that BLPC does not have a cash working capital need. It is not clear what each of those jurisdictions' particular rules, requirements, and assumptions for conducting lead/lag studies are, and may reflect considerations that are not necessarily reasonable. Additionally, as noted above, there was no opportunity to cross-examine Mr. Smith during the Hearing to verify the reasonableness of his assertions.

84. Based on the evidence before the Commission, and for the purposes of the instant rate case, the Commission accepts BLPC's proposed use of the 45-day rule to calculate cash working capital. The amount of working capital ultimately included in the revenue requirement must be recalculated to account for the Commission's adjustments to the operating and maintenance expenses determined in this Decision. The Commission also directs BLPC to include, as part of its next base rate application, a cash working capital allowance in rate base that is supported by a fully developed and reliable lead/lag study.

## ACCUMULATED DEPRECIATION

85. Beginning in 2013, BLPC's depreciation expense for financial reporting purposes under IFRS began to diverge from depreciation expense used for ratemaking purposes. As a result, BLPC began reporting accumulated depreciation in the regulatory financial statements to the Commission by including an adjustment to reflect the difference between depreciation computed for investor financial statements under IFRS and regulatory financial reporting to the Commission. The difference between the two accumulated depreciation amounts is the result of higher regulatory depreciation rates and expenses than for investor financial statements under IFRS. This difference has accumulated to $32 million as of 2021.

86. BLPC's depreciation rates for distribution, transmission and general plant were approved in the Commission's decision dated March 25th, 2022 (the "Depreciation Decision")[24]. In the instant Decision, the Commission determined the depreciation rate for the generation plant. These new depreciation rates and associated reserves for accumulated depreciation are based on a depreciation study using BLPC's financial statements under IFRS for utility plant and accumulated depreciation amounts. Accordingly, the difference in accumulated depreciation that has accumulated since 2013 must be determined as of the Interim Rate Effective Date and included in base rates to ensure rate base is properly stated for ratemaking purposes.

87. BLPC proposes that its rates and accumulated depreciation for financial reporting purposes to investors be adopted for regulatory purposes. At the Hearing, in response to questioning from the Commission about the $32 million difference, Mr. Ricaido Jennings stated "*I believe an adjustment should be done to the annual regulatory reports but I don't think it is needed for the Application.*"[25] It appears that BLPC does not believe it necessary to make further adjustments for

[24] Document No. FTCUR/DEC/BLPCDP/2022-01
[25] Ibid, Day 10, lines 726-731

ratemaking purposes associated with the $32 million difference in accumulated depreciation reflected in the Application.

*Intervenor Positions*

88. None of the intervenors have articulated a particular position with regard to BLPC's accumulated depreciation reserves.

*The Commission's Analysis and Findings*

89. As noted in the Depreciation Decision, there has been a significant disconnect between BLPC's approved depreciation rates for the purposes of financial reporting, and its depreciation rates for the purposes of its cost of service. The disconnect began in 2013 when BLPC revised its depreciation rates for financial reporting purposes without a corresponding change to its base rates. This means that since 2013, the accumulated depreciation reflected in BLPC's books and financial reporting diverged substantially from the accumulated depreciation exhibited by its recovery of depreciation expense from consumers.

90. Specifically, BLPC's depreciation rates for most, if not all, of the period for which the rates have diverged, for cost recovery purposes have been substantially higher than its rates for financial reporting purposes. As of the end of the year 2021, BLPC's accumulated depreciation for its regulatory depreciation rates is $32.1 million larger than its accumulated depreciation based on its financial statements.[26] The rate treatment for this prior depreciation difference is addressed in the paragraphs below. However, the Commission recognises that differences for accumulated depreciation used for financial reporting and ratemaking purposes can re-emerge when BLPC undertakes future depreciation studies for financial reporting purposes. Consequently, BLPC is directed to apply to the Commission for and obtain approval for the regulatory treatment associated with changes to its depreciation rates. BLPC may propose rate treatment for new depreciation rates through two (2) options. First, BLPC may request a change to base rates to reflect the revised depreciation

[26] Per BLPC's Annual Regulatory Report, Q1 2021, its accumulated depreciation per Financial Statements at 12/31/21 was $853,673,227 and its accumulated depreciation based on the approved depreciation policy is $885,839,445.

rates when it makes changes to its depreciation rates for financial reporting purposes. This option may not always be appropriate as changes to base rates would generally not be a single-issue adjustment. Under the second option, BLPC must submit an application to the Commission to request authorization to reflect the difference between the accumulated depreciation used for financial accounting and ratemaking purposes as a regulatory asset or liability as appropriate. Under either option, the accumulated depreciation reserve used for ratemaking purposes will be readily available for the establishment of future rates effectively remain aligned in the future.

91. As it relates to BLPC's depreciation differences that have emerged since 2013, the Commission finds that the final difference between the two (2) accumulated depreciation amounts should be recognized as a regulatory liability, included in rate base, and returned to ratepayers. The period of the amortization of this liability is not mandated by any particular principle, but a fifteen (15) year amortization approximately aligns with the weighted average remaining life of BLPC's plant. Therefore, the Commission determines that this regulatory liability shall be refunded using a fifteen (15) year amortization.

92. For the purposes of estimating an adjustment, the Commission has utilised the 2021 balance of accumulated depreciation to estimate a $32.1 million regulatory liability. This adjustment results in an annual refund of the accumulated depreciation excess of $2,144,414, which will be subtracted from depreciation expense until the amortization period ends in 2037. In addition, the adjustment shall also include adjustments for the associated reduction to rate base. Consistent with the Commission's determination that the BLPC is to update its rate base balances to the Interim Rate Effective Date, this regulatory liability balance shall be updated as part of the compliance process. The date of final difference between the two accumulated depreciation dates for the purposes of calculating the regulatory liability will be the Interim Rate Effective Date. The resulting amortization shall be updated to reflect the final difference between the two accumulated depreciation amounts.

## SECTION 4 – TEST YEAR REVENUES AND EXPENSES

### TEST YEAR REVENUES

93. As discussed in Section 3 – Test Year above, adjustments must be made to the test year to reflect conditions at the time that the rates will go into effect.

94. As explained in Accounting for Public Utilities, 1983, by Hahne et al., the adjustments to the test year ensure an accurate measure of "costs incurred in conducting operations over a twelve-month period (i.e., the test period cost of service) and to fix rates that will produce revenues to match the costs of that period."

95. Hahne et al further explains that pro-forma adjustments that may be made to revenues and expenses fit into the following categories:
    a. Normalizing Adjustments;
    b. Annualizing Adjustments;
    c. Out-of-Period Adjustments;
    d. Attritional Adjustments; and
    e. Reclassification Adjustments.

    Normalization adjustments are "made to revenues or expenses to offset for unusual operating events".

96. BLPC made several adjustments to account for future increases in costs such as insurance and the placement of the CEB into service.

97. When discussing whether the recorded sales for a period are representative of normal sales, Hahne et al gives the following examples that may indicate that normalization adjustments would be necessary to ensure the revenue requirement is recovered:
    a. abnormal consumption levels;
    b. changes in revenue recovery billing procedures;
    c. significant changes in usage patterns of existing customers; and
    d. significant changes in customers.

98. The level of sales in BLPC's proposed test year was an issue explored by parties during the Hearing.

99. According to Mr. Roger Blackman, Managing Director of BLPC, the level of sales in 2020 was not normal due to the impact of COVID[27].

100. Sales in 2019, 2020 and 2021 were 944, 890, and 905 gigawatt-hours respectively. BLPC provided a forecast of sales of 944, 953, and 968 gigawatt-hours in 2023, 2024 and 2025.

101. In the 12 months ending June 30th, 2022, the BLPC had sales of 932 gigawatt-hours[28], an increase of 4.7% over the sales in the test year. Large changes in usage have occurred at the rate class level, particularly for large commercial, time-of-use, and streetlighting customers:

**Table 2 - Comparison of 2020 and 6/30/2022 Sales by Rate Class**

| | Year Ending | | Increase/(Decrease) | |
|---|---|---|---|---|
| | **12/31/2020** | **6/30/2022** | **KWh** | **%** |
| Domestic Service | 345,229,145 | 351,113,042 | 5,883,897 | 1.7 |
| Employee | 1,851,785 | 1,825,774 | (26,011) | -1.4 |
| General Service | 49,959,785 | 51,859,160 | 1,899,375 | 3.8 |
| Large Power | 166,151,481 | 180,620,849 | 14,469,368 | 8.7 |
| Secondary Voltage Power | 286,186,657 | 303,635,158 | 17,448,501 | 6.1 |
| Time of Use | 32,635,154 | 38,539,933 | 5,904,779 | 18.1 |
| Streetlights | 7,829,716 | 4,702,458 | (3,127,258) | -39.9 |

102. During the test year, the economy was depressed, and businesses were closed due to stay-at-home orders associated with the Covid-19 Pandemic.

27 Transcript Day 9 at 96.
28 BLPC response to FTC Interrogatories Dated Sept. 9, 2022, Question 8 (Revised)

103. Streetlight usage has dropped significantly due to the change from High-Pressure Sodium (HPS) to Light-Emitting Diode (LED) lighting. The change will reduce the usage of the streetlight class in excess of 50%, according to BLPC's witness Dr. Adrian Carter, Manager of Regulatory Affairs[29]. As of the Hearing, the change from HPS to LED lighting has been substantially completed[30].

*Intervenor Positions*

104. Intervenor Mr. Kenneth Went proposed a $9.351 million adjustment to revenues to account for the drop in demand in the test year.

105. BREA supports BLPC's use of an unadjusted test year, stating that the financial forecasts provided by BLPC provided sufficient comfort that overearning will not occur in future years.

106. Public Counsel/BARP believes that the use of a 2020 test year is not appropriate due to the sales loss related to the pandemic.

*The Commission's Analysis and Findings*

107. The Commission finds that energy usage and demand in the test year was abnormal in that it deviated from what is normal or usual.

108. The Commission finds that usage patterns and levels in the test year are not representative of usage patterns and levels currently occurring on the BLPC system or those that can be reasonably expected to occur going forward.

109. Given the changes in usage patterns since the test year, the Commission believes that a normalizing adjustment to test year revenues is necessary to ensure that the usage and demand values used to set rates are representative of those expected to be incurred going forward.

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[29] Transcript Day 13 at 1446-1447.

[30] Transcript Day 13 at 698.

110. Additionally, the Commission is of the opinion that an adjustment to test year revenues is necessary to have the revenues serving as the basis from which the increase is calculated be more representative of revenues going forward.

111. In addition to ensuring that sales used to set rates are representative of those going forward, the Commission is also of the opinion that an adjustment is necessary to ensure that costs are accurately allocated to customer classes.

112. Allocations are made to customer classes within the Cost of Service based on the amounts of demand and usage in proportion to total demand and usage.

113. If certain classes experienced large, abnormal, or temporary drops in usage and demand in comparison to the system as a whole during the test year, that would cause those classes to be allocated a lower cost of service than would occur in normal conditions. These conditions would also cause higher revenue requirements to be assigned to classes without the proportional decreases in demand.

114. The allocation of costs to streetlights based on usage and demand values from a different, less efficient, streetlight technology than is in place currently is unsupportable. Use of updated usage and demand values will better capture the change in technology and will arrive at a more accurate cost of service.

115. The Commission orders the use of base revenue, customer count, usage and demand values from the period ended June 30$^{th}$, 2022 for purposes of determining the overall revenue increase, tariff revenue requirement of each rate class.

116. This is to be reflected as an adjustment to test year revenues included in BLPC's Compliance Filing.

## TEST YEAR EXPENSES

117. Expenses that are prudently incurred, with known and measurable adjustments, may be included in the revenue requirement. Apart from the fuel expense, which is managed through the FCA, the largest expense categories impacting the revenue requirement include Operations and Maintenance ("O&M"), Administrative and General ("A&G"), and Depreciation Expenses. All expenses must be properly accounted for and allocated to the proper service, and expenses may not be double counted. Expenses that fall under the O&M category include, but are not limited to, power production expenses, transmission expenses, distribution expenses, customer accounts expenses, and sales expenses. A&G expenses include executive salaries, office supplies, property insurance, pensions and benefits, and consultant services, etc., that are generally attributable to the overall management and operation of the utility, rather than to a specific function (with the exception of property insurance and pensions and benefits, where the industry standard is to record these items to A&G). The matter of depreciation expense is dealt with in a separate section of this Decision.

118. In the Application, BLPC used 2020 actual test year expenses, adjusted for known and measurable changes, to calculate its O&M and A&G expenses. BLPC's O&M and A&G expenses in the test year 2020, based on audited results amounted to $107,950,982. The Application included an increase of $686,226 in respect of known and measurable changes bringing the total requested O&M and A&G expense to $108,637,208.

*Intervenors*

119. Intervenors questioned the reasonableness of BLPC's request regarding insurance expense. Mr. Went proposes a $4.1 million reduction in insurance expense to recognize the impact of the reduction of the SIF. BREA suggested the increase may not have been as high if the SIF had been maintained.

120. Intervenor Mr. Kenneth Went also focused on generation expenses and, in particular, whether the known and measurable increase of $1,700,000 regarding the cost of lubricants for the LSD B-D15 was appropriate together with whether any reduction in the Steam Units 1 and 2 were required as a result of the CEB coming online.

*The Commission's Analysis and Findings*

121. The Commission reviewed the expenses included as part of the requested revenue requirement and finds that specific adjustments are necessary in respect of two items, namely, insurance expense and charitable donations.

*Insurance Expenses*

122. The cost of insurance included by BLPC in the application was $12,348,641, an adjustment of $4,150,559 over the amount incurred in 2020. BLPC explained that it based its requests on estimates that were available at the time of the filing. However, the Commission does not find the evidence supporting the increase sought by BLPC to be adequate. As a result, the Commission determines that it is appropriate to utilize the 2020 reported insurance expense of $8,198,082. In addition, the Commission is of the view that SIF funds were established, in part, to cover the higher tier costs of insurance and that BLPC should not incur excessive insurance costs when it has SIF funds available in the trust. In the absence of an actuarial assessment the Commission is not satisfied that the sum requested by BLPC should form part of the revenue requirement. In the event that BLPC is of the view that the $8,198,082 is not adequate it shall file an actuarial assessment with the Commission in order for the Commission to make a determination as to the premium to be paid to the SIF and the amount which shall be reserved by the SIF for a payment of any claim. Based upon the actuarial assessment the BLPC may also make an application to the Commission to decrease its regulatory liability associated with the withdrawal from the SIF in 2016 by the annual amount paid for insurance in excess of $8,198,082.

*Charitable Donations and Sponsorship*

123. Regarding BLPC's proposal to include recovery of $252,000 related to donations to charities and sponsorships in rates, the Commission finds BLPC's argument to include them on the basis that they would increase demand through increased tourism and would result in improvements to youths, culture, and sports to be unavailing. It is the Commission's view that while these costs are noble in purpose, they are not necessary or useful with respect to providing utility service. Ratepayers should not be mandated to make donations that are determined by BLPC. The Commission therefore determines that charitable donations and sponsorships expenditures shall be removed from BLPC's revenue requirement. The utility's sole shareholder may, at its discretion, elect to continue the donations out of the net income.

124. In the event that the utility's shareholder determines that donations will continue, such expense is to be excluded from the calculation of the return earned by BLPC in future reports to the Commission.

*Affiliate Expenses*

125. The Commission notes that BLPC reimburses, Emera Caribbean Inc. for the cost of various corporate services, including human resources, internal audit, insurance support, health and safety, board of directors fees, and engineering.

126. The Commission recognises that the BLPC has provided information regarding the expenses provided by its affiliates in response to interrogatories, during the Hearing, and has provided the agreement governing shared services. Notwithstanding the aforementioned, the Commission is concerned that some of the aforementioned affiliate costs which have been included in the Revenue Requirement are not supported by the shared services agreement or any of the testimony of BLPC during the Hearing. Specifically, the Commission disallows the following: (i) Staff Secondments; (ii) Board Fees; and (iii) Other from recovery in base rates.

## SECTION 5 - DEPRECIATION EXPENSE

*Depreciation Expense – Procedural history and determination on process*

125. On April 30, 2019, BLPC filed an application with the Commission for review of BLPC's depreciation rates and approval of a depreciation policy. As part of that application, BLPC filed an update to its 2017 Depreciation Study.

126. On October 4th, 2021, prior to the Commission issuing the Depreciation Decision, BLPC filed the Application. As part of the Application BLPC stated that:

> *"As of the filing of this Application, the Commission's Decision on BLPC's application for approval of its Depreciation Policy is still pending. BLPC will request leave of the Commission to adjust its depreciation rates as required when the Commission's Decision is issued and resubmit any revised rate application documentation.*[31]

127. In the Depreciation Decision, the Commission approved BLPC's proposed depreciation rates for the transmission, distribution, and generation plant. However, the Depreciation Decision rejected BLPC's proposed depreciation rates for generation, citing concerns about two factors in particular. First, the "*arbitrary assigning of the 25% depreciation rate to Garrison GT No. 2 and 20% depreciation rate to Spring Garden Steam Equipment*." Second, that BLPC "*has not supplied compelling evidence why the account balances for Garrison GT No. 2 and Spring Garden Steam Equipment differ so drastically in the 2019 Update from the number reported in the Depreciation Study of 2017."*[32] Additionally, in the Depreciation Decision, the Commission determined that "the depreciation rates approved herein will become effective concurrent with the rates to be approved on the effective date ordered in the ongoing Rate Review."

128. Thus, this Decision will address the outstanding question of BLPC's depreciation rates for generation, and issues related to those rates and policies.

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[31] Application, Volume 1, pg. 19, paragraph 71.

[32] March 25, 2022 Decision on The Barbados Light & Power Company Limited Application for a Review of Depreciation Rates and Approval of the Depreciation Policy, paragraphs 96 and 97.

This Decision will not address issues related to depreciation rates for transmission, distribution and general plant categories, having already approved those rates in the Depreciation Decision.

<u>*General Discussion of Depreciation Expense*</u>

129. In 1958, the NARUC provided the following definition of depreciation:

> *"Depreciation," as applied to depreciable utility plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of elements, inadequacy, obsolescence, changes in the art, changes in demand, and requirements of public authorities".*[33]

130. Further, the International Accounting Standards Number 16 - Property, Plant, and Equipment defines depreciation as *"the systematic allocation of the depreciable amount of an asset over its useful life. The depreciation method must reflect the pattern in which the asset's future economic benefits are expected to be consumed by the entity".*

131. Depreciation is the process of recovering the initial investment in tangible capital assets in a systematic fashion over the useful service life of the plant, recognizing that utility plant is typically a group of investments. Depreciation cannot be calculated with precision, but to ensure that the analysis is as accurate as is reasonably possible, it requires the knowledge and informed judgment of an expert trained in the field of utility depreciation. The judgment pertains to the estimation of the future surviving life of plant as indicated by past patterns of retirements, industry trends, and corporate investment plans.

132. At its simplest level, the only parameter that is absolutely required is an estimate of the service life of the asset being retired. The reciprocal of that number can be

[33] Uniform System of Accounts for Class A and Class B Electric Utilities, 1958, rev. 1962.

used as the depreciation rate.[34] Because most utility depreciation rates are applied to groups of assets with varying lives, however, the industry standard is to use “remaining life” depreciation. This “remaining life” procedure computes the depreciation rate by dividing the unrecovered net investment by the estimated remaining years of the asset’s (or group of assets’) service life. It is intended to ensure that any past under- or over-accruals of depreciation are recovered during the remaining life of the asset.

133. BLPC’s generation depreciation rates have been calculated using what is known as the “life span procedure”. The life span procedure is a version of the remaining life procedure, in which the remaining life is primarily determined by a final retirement date at which the entirety of the remaining plant will be retired.

134. As a result of the use of the life span method the determination of the final retirement date is particularly important. The NARUC Public Utility Depreciation Practices (the “Depreciation Manual”) sets forth numerous factors that should be incorporated into the determination of a final retirement date:

> *“Several factors are considered in selecting retirement dates, e.g., economic studies, retirement plans, forecasts, technological obsolescence, adequacy of capacity and competitive pressure.”*

135. Generally speaking, as a result of this list of factors, in regulatory proceedings utilities are typically afforded considerable leeway in determining the appropriate final retirement date for any given unit.

136. Once the final retirement date is set, depreciation rates and expenses using the life span procedure are calculated in similar fashion to how they are calculated with the remaining life procedure. Typically, with the life span procedure, this additionally incorporates estimates of future interim retirements. However,

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[34] In general, the reciprocal of a fraction simply interchanges the numerator and denominator of the fraction. Thus, the reciprocal of 5 is 1/5.

BLPC is not proposing to include interim retirements or interim retirement-related cost of removal in its calculations. In the absence of interim retirements, BLPC has proposed rates that are calculated in accordance with ordinary remaining life procedure calculations, except that the remaining lives themselves are determined by the difference between the study date and the final retirement date.[35]

137. In the Depreciation Decision, the Commission discussed, assessed and approved the methodology that BLPC has utilised to estimate future net salvage for all categories of plant. Accordingly, the Commission will not address net salvage estimates in detail in this Decision.

*Depreciation Expense – Generation Depreciation Expense*

138. The Commission reviewed BLPC's 2019 update to its 2017 depreciation study and found that it contained basic calculation errors for generation plant. The errors which relate to four different generation plant accounts (Garrison GT No. 2, Spring Garden Steam Buildings, Spring Garden Steam Equipment, and LSD No. 10-13 Building), can be classified into the following categories:

- Failure to properly include future net salvage in the rate calculation;
- Failure to calculate GT No. 2 and Steam Equipment rates based on the proper plant balances; and
- Failure to base the remaining life calculations on consistent remaining lives.

139. Of the aforementioned categories, the first is the most substantive, in that correcting the error will result in a substantial impact on BLPC's revenue requirement.

140. During the oral hearing, answers were solicited from Mr. Huck, the BLPC's expert witness on depreciation, regarding some of these issues. In particular,

[35] Exhibit PH-1, "Further Explanation of 2019 Update Depreciation of Garrison GT No.2 and Spring Garden Steam Equipment"

Mr. Huck explained precisely how the depreciation expense for Garrison GT No. 2 and Spring Garden No 2. were calculated,[36] how the depreciation rates noted for these accounts came to be included,[37] and most crucially, his rationale for excluding net salvage from the calculation of the depreciation rates for the four accounts noted above.[38]

141. While acknowledging that his calculation of the depreciation expense and rates were not performed in a consistent manner, and that the inclusion of incorrect depreciation rates resulted in confusion, Mr. Huck maintained that the depreciation expenses resulting from his calculations were reasonable.[39]

*Intervenor Positions*

142. While multiple intervenors have noted irregularities in the depreciation rates, and questioned Mr. Huck regarding his depreciation proposals, no intervenors have proposed specific adjustments to BLPC's depreciation rates. In Mr. Went's written submissions dated October 28th, 2022, he noted potential revenue requirement reductions related to rejecting BLPC's proposed changes to generation depreciation rates.[40] Mr. Went identified the impact of such a rejection as resulting in a $7 million reduction to rate base.

*Commission's Analysis and Findings*

143. In the Depreciation Manual, the method for properly calculating depreciation expense and rate is outlined. Both calculations are included here, first the calculation of depreciation expense:

$$DE = \frac{GP - AD - FNS}{RL}$$

Where DE is depreciation expense or annual accrual
Where GP is the book cost of the gross plant

[36] Hearing Transcript, Day 7, 934-936.
[37] Hearing Transcript, Day 7, lines 748-764.
[38] Hearing Transcript, Day 6, lines 2819-2921.
[39] Hearing Transcript, Day 6, lines 2828-2831.
[40] "Letter to FTC – Written Submission Addendum – 28 Oct 22"

Where AD is the accumulated depreciation reserve at the start of the year
Where FNS is the estimated future net salvage in dollars
Where RL is the estimated average remaining life

Next, the calculation of the depreciation rate:

$$\text{Depreciation rate DR} = \frac{DE}{GP} \times 100$$

144. The Commission notes that, as shown above, the most common practice is to first calculate the depreciation expense, and only then to calculate a rate by dividing the depreciation expense by the gross plant balance. It should also be noted that Mr. Huck has proposed using essentially a hybrid of the typical remaining life technique for group depreciation and the life span methodology for use with large units of plant. Specifically, he is essentially proposing to use the standard remaining life technique for group plant, but utilise a terminal retirement date for determining the remaining life.

145. Mr. Huck's schedules depart from the prescribed calculations in a number of crucial ways. First, once accumulated depreciation equals gross plant balance, Mr. Huck disregards the component of future net salvage in his calculations. Second, in the GT No. 2 and Steam Equipment Accounts, Mr. Huck has not utilized this calculation at all, but instead has stated that he simply divided the change to the gross plant between the 2017 study and the 2019 update over the remaining life for each account. Third, Mr. Huck stated that he has included a stated depreciation rate for GT No. 2 and Steam Equipment that is simply the reciprocal of a remaining life.

146. The four accounts in question, Garrison GT No. 2, Spring Garden Steam Buildings, Spring Garden Steam Equipment, and LSD No. 10-13 Building, should have their depreciation rates and expenses corrected to reflect the appropriate application of the remaining life technique, consistent with the Depreciation Manual as shown above.

*Depreciation Expense – Interim Additions on Steam Plant*

147. Once the issue of the appropriateness of the calculations has been resolved, the most pressing issue is how to treat the cost recovery of the $0.5 million in interim additions added to the Garrison GT. No. 2 unit, and $8.9 million in interim additions added to the Spring Garden Steam Equipment account in between the 2017 depreciation study and the 2019 update to generation unit depreciation. To be clear, BLPC has included interim additions for other generation units. However, as the terminal retirement dates for these two units is imminent, and these two units have already had their lives extended, cost recovery for these two units rightfully should be treated separately from the others.

148. BLPC has maintained the position taken in the 2019 update, which is that it should recover the amount of interim additions for these two accounts based on an annual depreciation expense of $94,645 for GT No. 2 and $2,293,283 for Spring Garden Steam Equipment.

*Intervenor Positions*

149. In Mr. Went's written submissions, dated October 28th, 2022, Mr. Went noted potential rate base reductions related to declaring BLPC's spending on depreciation charges related to imprudent spending on "S1&2".[41] Mr. Went identified the revenue requirement impact of removing this depreciation expense charge as resulting in a reduction of $4.5 million.

*Commission's Analysis and Findings*

150. Since the depreciation rates for regulatory books were last approved in 2010, there have been numerous changes in plans regarding BLPC's generation fleet. At present, the final retirement year for Garrison GT No. 2 is 2022 and for Spring Garden Steam Station is 2023. At the Hearing, Mr. Johann Greaves stated that it

41 "Letter to FTC – Written Submission Addendum - 28 Oct 22"

is BLPC's intention to retire the Spring Garden Steam Building and Steam Equipment in 2023.[42]

151. Mr. Greaves also detailed the steps that needed to be taken in 2018 to keep the Spring Garden unit operational. Mr. Greaves' testimony, in combination with information provided in data responses provide a clear picture of the necessity of the $8.9 million in interim additions that were included in the Spring Garden Equipment account between the 2017 study and the 2019 update. What has been stated by Mr. Greaves, is that these additional investments were necessary in order to maintain the steam units in working order until their terminal retirement date of 2023.

152. In the Depreciation Decision on the BLPC's request to amend its depreciation rates, the Commissioners have stated that, *"[f]or this reason, the Commission therefore recognized the conclusion by BLPC to defer its decision to remove aged infrastructure from generation as a reasonable one."* Once the decision to defer the retirement of the plant has been deemed reasonable, investments judged to be necessary to maintain the operating condition of the unit are presumed to be considered prudent.

153. However, it remains the case that the circumstance of requesting cost recovery on such a relatively large investment, 16% of total plant in the case of Spring Garden Steam Equipment, over such a short period of time, produces a large and unusual increase in the BLPC's depreciation expense request. In this case, from $0 in annual accrual for Steam Equipment as of BLPC's 2017 depreciation study to the requested expense of $2.3 million. This sharp increase is exacerbated by the fact that, for the reasons described above, errors in BLPC's calculation of its depreciation expense indicates that the 2017 Study depreciation expense should have been considerably higher, and the properly adjusted depreciation expense based on its 2019 study is $0.3 million for Garrison GT No.

[42] Hearing Transcript, Day 10 lines 191-1894

2 and $4.7 million for Spring Garden Steam Equipment as shown in the Table 3 below.

154. To re-state the issue being addressed here, a large investment facing a much shorter than typical service life for the type of asset in question. In such cases, the challenge is to balance the considerations of assuring that BLPC will recover the entirety of the service value of its investments, and to protect ratepayers from excessive rate increases.

155. A common solution in such cases is to recognize the outstanding investment in the plant as a regulatory asset on the part of BLPC. This regulatory asset is then amortized to spread the cost recovery over a period that does not necessarily align with the early retirement date of that plant.

156. This treatment is recognized and defined by the FERC Accounting Regulations [43]:

> *"31. Regulatory Assets and Liabilities are assets and liabilities that result from rate actions of regulatory agencies. Regulatory assets and liabilities arise from specific revenues, expenses, gains, or losses that would have been included in net income determination in one period under the general requirements of the Uniform System of Accounts but for it being probable:*
>
> *A. that such items will be included in a different period(s) for purposes of developing the rates the utility is authorized to charge for its utility services; or*
>
> *B. in the case of regulatory liabilities, that refunds to customers, not provided for in other accounts, will be required."*

157. At the moment, regulatory assets and liabilities are not recognised by IFRS. However, IFRS has recognised that this is potentially an issue and is presently considering formally recognising regulatory assets and liabilities. Additionally, as discussed above, the Commission has determined that regulatory assets and

[43] 18 CFR Part 101 - Uniform System of Accounts prescribed for public utilities and licenses subject to the provisions of the Federal Power Act, Definitions.

liabilities are appropriate for establishing BLPC's rates and shall be used in financial reporting to the Commission.[44]

158. The Commission finds that the approximately $9.4 million in interim additions made to the Garrison GT No. 2 and Spring Garden Steam Equipment plants shall be transferred from production plant accounts into a regulatory asset account. The amount transferred shall be the $9.4 million in interim additions, net of accumulated depreciation through the effective date of revised date of the revised revenue requirement. This regulatory asset shall be amortized over a period consistent with the terminal retirement date of BLPC's remaining steam plant, which should end in 2030. This amortization recovers the full-service value of the Garrison GT No. 2 and Spring Garden Steam Equipment plant, including an appropriate estimate of future net salvage. This should be based on the net salvage percentage proposed by Mr. Huck, which is a reasonable estimate in lieu of a proper decommissioning cost estimate.

159. For purposes of determining the BLPC's revenue requirement in this Application, the annual amortization of this regulatory asset should be a separately identified component of BLPC's depreciation expense and the regulatory asset should be an addition to rate base.

160. Once the balance of the interim additions has been removed from the GT No. 2 and Steam Equipment plants, it will still be necessary for a depreciation expense to be calculated on the remaining balance, based on the future net salvage percentage that was erroneously excluded from BLPC's depreciation calculations, as discussed in the previous section. The table below lays out the resulting change to depreciation expense on plant in service. For comparison, Table 3 shows the three (3) sets of depreciation expenses and rates. First, as filed by BLPC, second, corrected with the appropriate expense and rate calculations, and finally with interim additions removed for GT No. 2 and Steam Equipment.

[44] See Section 2, Regulatory Deferral Accounts – Regulatory Assets and Liabilities.

## Table 3 – Comparison of Depreciation Rates and Expenses under three Scenarios

| | As Filed by BLPC | | Calculations Corrected | | With Interim Additions Removed | |
|---|---|---|---|---|---|---|
| | Depreciation | Rate | Depreciation | Rate | Depreciation | Rate |
| | $ | % | $ | % | $ | % |
| **GENERATION PLANT** | | | | | | |
| **Garrison** | | | | | | |
| GT No. 2 | 94,645 | 25.00% | 306,455 | 1.27% | 100,341 | 0.43% |
| **Total Garrison** | **94,645** | **0.39%** | **306,455** | **1.27%** | **100,341** | **0.43%** |
| | | | | | | |
| **Spring Garden** | | | | | | |
| Steam Building | - | 0.00% | 77,268 | 3.57% | 77,268 | 3.57% |
| Steam Equipment | 2,293,283 | 20.00% | 4,703,217 | 8.07% | 1,845,462 | 3.73% |
| Fuel Tank | 64,432 | 3.50% | 64,432 | 3.50% | 64,432 | 3.50% |
| LSD No. 10-13 Building | - | 0.00% | 115,619 | 0.47% | 115,619 | 0.47% |
| LSD No. 10-13 Equipment | 3,466,256 | 2.22% | 3,466,256 | 2.22% | 3,466,256 | 2.22% |
| LSD No. 14-15 Building | 1,119,708 | 4.80% | 1,119,708 | 4.80% | 1,119,708 | 4.80% |
| LSD No. 14-15 Equipment | 7,134,702 | 4.89% | 7,134,702 | 4.89% | 7,134,702 | 4.89% |
| **Total Spring Garden** | **14,078,381** | **3.42%** | **16,681,202** | **4.05%** | **13,823,447** | **3.43%** |
| | | | | | | |
| **Seawell** | | | | | | |
| GT No. 3 Building | 77,907 | 3.02% | 77,907 | 3.02% | 77,907 | 3.02% |
| GT No. 3 | 1,236,954 | 4.10% | 1,236,954 | 4.10% | 1,236,954 | 4.10% |
| GT No. 4 | 1,614,772 | 4.82% | 1,614,772 | 4.82% | 1,614,772 | 4.82% |
| GT No. 5 | 1,641,650 | 4.87% | 1,641,650 | 4.87% | 1,641,650 | 4.87% |
| GT No. 6 | 1,452,362 | 5.01% | 1,452,362 | 5.01% | 1,452,362 | 5.01% |
| Fuel Tank | 35,384 | 3.18% | 35,384 | 3.18% | 35,384 | 3.18% |
| **Total Seawell** | **6,059,030** | **4.66%** | **6,059,029** | **4.66%** | **6,059,029** | **4.66%** |
| | | | | | | |
| **Spares** | | | | | | |
| LSD A (No. 10-13) | 213,698 | 1.25% | 213,698 | 1.25% | 213,698 | 1.25% |
| LSD B (No. 14-15) | 714,318 | 5.34% | 714,318 | 5.34% | 714,318 | 5.34% |
| **Total LSD Spares** | **928,016** | **3.04%** | **928,016** | **3.04%** | **928,016** | **3.04%** |
| **Trents** | | | | | | |
| Solar Unit PV01 | 1,999,027 | 5.14% | 1,999,027 | 5.14% | 1,999,027 | 5.14% |
| Battery | 1,548,007 | 9.41% | 1,548,007 | 9.41% | 1,548,007 | 9.41% |
| **Total LSD Spares** | **3,547,034** | **6.41%** | **3,547,034** | **6.41%** | **3,547,034** | **6.41%** |
| | | | | | | |
| **TOTAL GENERATION PLANT** | **24,707,106** | **3.79%** | **27,521,737** | **4.22%** | **24,457,867** | **3.81%** |

161. Therefore, the Commission finds that a net decrease to BLPC's depreciation expense based on plant in service of $249,239 is appropriate based on the currently filed December 31st, 2019 plant balances. This expense adjustment will change when the rates adopted in this Decision are applied to updated plant balances as of the Interim Rate Effective Date. This is the net result of correcting depreciation expense calculations for Garrison GT No. 2, Spring Garden Steam Buildings, Steam Equipment and LSD No. 10-13 Building, and then removing the interim additions for Garrison GT No. 2 and Steam Equipment to a regulatory asset.

162. In addition, the amortization of the regulatory asset for the interim additions over an eight-year period results in an estimated $1,314,679 million annual increase to depreciation expense. Consistent with the Commission's determination that the BLPC is to update its rate base balances to the Interim Rate Effective Date, this regulatory liability balance shall be updated as part of the compliance process. Should BLPC be required to make prudent interim additions to the Garrison GT No. 2 or Spring Garden Steam Equipment, those amounts should be added to the regulatory asset and amortized over the remainder of the amortization period.

163. In combination, then, these two adjustments will result in an estimated $1, 065,440 increase to annual depreciation expense in the revenue requirement. However, this estimate is subject to change as the amount of interim additions and resulting amortization are updated, as noted above in the Decision.

*Service Life for the CEB*

164. The issue in question here is the cost recovery period for the CEB which determines its annual depreciation expense.

165. BLPC has utilised a 25-year straight line depreciation rate for the CEB, resulting in an effective 4% depreciation rate for this diesel generator. The expense

resulting from this calculation has been included in BLPC's revenue requirement.

*Intervenor Positions*

166. In Mr. Went's written submissions dated October 28th, 2022, he has proposed an adjustment to the average service life from twenty-five (25) years to thirty-three (33) years. Mr. Went identified the revenue requirement impact of this change as resulting in a reduction of $1 million.

*Commission's Analysis and Findings*

167. The Depreciation Manual sets out a number of factors which should be taken into account in determining the terminal retirement dates. This includes economic studies, retirement plans, forecasts, technological obsolescence, adequacy of capacity and competitive pressure.[45] Mr. Went's suggested thirty-three (33) year service life for the CEB is based on the historical experience of a number of what Mr. Greaves describes as "low-speed" diesel plants, as opposed to CEB, which is a "medium-speed" diesel plant. This makes the direct comparison to earlier units less than apt.

168. The CEB was put into service at the end of 2021 and given BLPC's requirement to be meeting 100% of its base load with renewables by 2030, and the likelihood of increased technological obsolescence of the CEB, it is not unreasonable to anticipate that the CEB will face a shorter overall economic life than other similar generation units. Mr. Greaves assessment, which he stated was in part based on the engineering estimate of the generator's manufacturer, that twenty-five (25) years is the anticipated useful life of this type of "medium speed" diesel generation units.

169. While the Commission finds it unfortunate that the CEB was included in the BLPC's depreciation expense as a pro forma adjustment without being included in a depreciation study, it is difficult to conclude that BLPC's proposed

[45] NARUC Depreciation Manual, pg. 146.

depreciation expense for the CEB is unreasonable. The Commission approves the inclusion of the CEB depreciation expense as proposed by BLPC. However, the Commission directs BLPC to include the CEB plant in its next depreciation study with full support for an appropriate and reasonable terminal retirement date, interim retirement curve, interim retirement net salvage percentage and terminal net salvage estimate.

*Terminal Net Salvage*

170. Net salvage is defined as the salvage value of the materials being retired ("gross salvage") minus the cost associated with the retirement of that plant ("cost of removal"). As laid out in the Depreciation Manual, and as typically calculated in the industry, net salvage for plant utilising the life span method, as BLPC's generation plant uses, is calculated using two separate components. One is net salvage for interim retirements and the other is net salvage for terminal retirement. BLPC has not followed the life span method as typically applied.

171. BLPC has proposed to estimate future net salvage for its generation units according to a simple future net salvage percentage, which is purportedly based on the experience of other utilities in the industry. BLPC is not proposing to estimate future net salvage for interim retirements and terminal retirement separately.

*Intervenor Positions*

172. No intervenor has articulated a position regarding the estimation of future net salvage for generation plant.

*Commission's Analysis and Findings*

173. Interim retirements are typically recorded as the retirement of components associated with life span units, which do not result in the retirement of the entire unit. For example, a steam generation unit may require the replacement of a turbine. This retired turbine would typically be recorded as an interim retirement and an appropriately allocated portion of the replacement project

would be recorded as the cost of removal. The estimation of future net salvage for interim retirements is typically achieved by tracking the retirement rate of interim retirements, assessing an average service life and Iowa curve[46] for the account, as one would for a typical group depreciation asset. This life and curve are then used to estimate future interim retirements up to the final retirement date, and a net salvage percentage is estimated and applied to the total interim retirement amount.

174. Terminal retirements take place at the final retirement date, and typically involve substantial retirement effort involving the dismantling and removal of the entire unit and the demolition of the site itself. In general, terminal retirement costs are very substantial, and involve a complex set of considerations to properly estimate of costs. Moreover, unlike the case of the replacement of most group utility assets, the retirement of generation or other life span units often involve considerable estimation of the potential salvage value of the unit, including buildings and materials.

175. The process of estimating terminal net salvage is both complicated and important, as the cost of removal associated with generation units in particular can be substantial. In many cases, this is accomplished with what is known as a "decommissioning study", which is performed on behalf of the utility by an outside consultant with engineering expertise in dismantling projects.

176. However, it is also not uncommon for estimates to be arrived at internally. At hearing, it was clarified that BLPC already performs this type of estimate as part of the bidding process for hiring contractors to perform the dismantling projects. Mr. Greaves outlined BLPC's decommissioning estimate process. In lieu of a

[46] Iowa Curves are a set of 31 standard curve shapes which were developed to describe the retirement characteristics of utility plant. The primary purpose of these Iowa curves is to fit historical retirement data to the most appropriate service life and curve shape, and then use the standard Iowa curve to make predictions about the future retirement characteristics of a particular category of plant. These future retirement expectations allow for the calculation of the average remaining life for that category of plant.

complete study, an estimate similar to the one Mr. Greaves discussed can be used to estimate terminal net salvage.

177. The process of properly estimating the dismantlement cost of a generation unit is a time-intensive project, as is the process of properly estimating net salvage for interim retirements. Given the time constraints in the current case, it would not be appropriate to direct BLPC to perform such an analysis for the present Application.

178. The Commission therefore directs BLPC to properly incorporate net salvage estimates for interim and terminal net salvage in accordance with the Depreciation Manual in its next filed depreciation study. In the alternative, BLPC may request and justify approval for an alternative method prior to submitting revised depreciation rates.

## SECTION 6 – ACCOUNTABILITY/CLAWBACK MECHANISM

*Overview of Issue*

179. "Accountability/Clawback Mechanism"[47] is one of the issues set out in the List of Issues. The issue arises partly out of the items required by the Commission in the 2010 Decision, which BLPC failed to implement or comply with, such as BLPC's decision not to retire the steam generating plants by 2012. It also includes other rate issues associated with BLPC's SIF, namely the discontinuance of contributions to the SIF and the withdrawal from the SIF in 2016 and its treatment of excess accumulated deferred income taxes following the 2019 corporate income tax rate change. The question has arisen as to whether the proposed Clawback Accountability Mechanism on these topics constitutes retroactive ratemaking.

*BLPC's Position*

180. BLPC's position on the Accountability/Clawback Mechanism was articulated Dr. Philip Hanser in his oral testimony[48]. He makes a distinction between a clawback mechanism and retroactive ratemaking. Dr. Hanser explained that a claw-back mechanism is an incentive mechanism to induce the utility for a particular behaviour. He provided two examples[49]. In the first example, Dr. Hanser referred to an adjustment to the net capital plant reconciliation which he notes is used in the United States to reclaim unspent portions of a capital budget and the associated earnings, providing an incentive to the utility to spend the full budget. Dr. Hanser explained that such incentive mechanisms are essentially established in advance of a rate mechanism being established so that all parties, (the utility and the Commission), understand the clawback provision to be

[47] Issue 4(iv)(d). In response to BLPC's inquiry on this issue, the Commission clarified:
*"The issue of Accountability/Clawback Mechanism listed at No 4(iv) d refers to those requirements that were set out and approved in the 2010 Rate Review, but either were not implemented or are no longer being incurred by the Application on behalf of the consumer. For clarity, an example of this would be that portion of the tariff that is to be paid into the Self Insurance Fund that is however no longer being paid unto the fund".*

[48] Dr. Hanser's testimony was provided on Day 12 of the Hearing

[49] *Id.*, lines 342-353 and 682-689

implemented and the impact on the utility. The Clawback Mechanism is forward-looking and is by mutual agreement according to Dr. Hanser[50].

181. Dr. Hanser explains retroactive ratemaking as a situation in which the regulator sets future rates to allow the utility to either recoup past losses or to refund consumers any excess profits. He stated that retroactive ratemaking has usually been prohibited in the United States because it involves a kind of modification of the utility ratemaking process which is usually forward-looking, shifting the ratemaking process to being in some sense looking behind and second guessing what had happened with the utility.[51] Dr. Hanser also notes that the courts in the United States, at the state and federal levels, have generally held that retroactive ratemaking is inappropriate.[52] Dr. Hanser expressed the opinion that the clarification provided to BLPC by the Commission on the intent of the "Accountability/Clawback Mechanism" constitutes retroactive ratemaking, rather than a Clawback mechanism. Dr. Hanser's view appears to be on the basis that the 2010 Decision did not specifically layout a mutually agreed upon Clawback procedure, so there cannot be a Clawback Mechanism in place. Consequently, any adjustments stemming from past events must represent retroactive ratemaking.

182. BLPC's Post-Hearing Brief reiterates the discussion by Dr. Hanser on retroactive ratemaking and that the Commission's July 27th, 2022 clarifying letter on the intent of "Accountability/Clawback Mechanism" represents retroactive ratemaking.[53] The Post-Hearing Brief also cites several decided cases in the United States supporting the position that retroactive ratemaking is generally a prohibited practice.[54]

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[50] Id., lines 724-725.
[51] Id., lines 360 – 365 and 690-695.

[52] Id., lines 378-379.
[53] BLPC Post-Hearing Brief at 77-78.

[54] See *Associated Gas Distributers v FERC* (D.C. Cir 1990); *Narragansett Elec Co v Burke* ( R.1 1977); and *Louisiana Power & Light Co. v. Louisiana Pub. Serv. Comm'n* (La. 1979), referred to by BLPC.

183. BLPC's Post-Hearing Brief also discusses retroactive ratemaking in view of the URA sections 3 and 10, stating that the URA requires every rate to be fair and reasonable. BLPC argues that the URA does not provide the Commission with retroactive ratemaking powers. Therefore, to pursue a retroactive course of action would result in a breach of statutory principles. BLPC further argues that retroactive ratemaking may be criticized as a breach of the constitutionally guaranteed right of due process by a deprivation of previously granted and enjoyed property rights without just compensation.[55] BLPC also sought to advance its case against retroactive ratemaking on the basis of policy and equity.[56] BLPC concluded stating that the 2010 Decision does not reference clawback, accountability, or refunds to customers, and it was not given notice by the Commission that the rates determined in 2010 were subject to any mechanism other than rate of return ratemaking. Therefore, BLPC stated that any belated attempt to extract refunds from past rates would be unfair, unjust and unlawful.[57]

*Intervenor Positions*

184. Intervenors did not articulate strong legal positions on the issues of clawback and retroactive ratemaking. However, positions which they advanced may warrant a regulatory response that would fall into the category of clawback or retroactive ratemaking. These issues included the decision not to retire the steam generating plant in 2012 causing excessive fuel costs and reliability concerns; the withdrawal of $99.5 million of SIF monies and net of tax distribution to its sole shareholder; and the treatment of deferred income taxes following the tax rate change.

[55] Id. at 85.

[56] Id. at 86, citing to *Public Utilities Commission of California v FERC* (D.C. Cir 1990), "equity lies in its steady application regardless of what party is seeking to reexamine the past."
[57] Id. at 88.

**URA & FTCA Framework**

185. Neither the URA nor the FTCA specifically authorises or prohibits retroactive ratemaking. It is therefore necessary to examine the framework of both enactments to determine whether retroactive ratemaking is permissible or prohibited. The power of the Commission to engage in retroactive ratemaking may be confined by the legislative aim of the URA and/or the FTCA.[58]

186. The Commission reviewed the general approach to interpreting Acts of Parliament[59], and more specifically, utility regulation legislation[60] in the Interim Rate Decision. The Commission also examined the legal framework of both the URA and the FTCA in the Interim Rate Decision. The Commission restates, without repeating, its review undertaken in the Interim Rate Decision concerning the approach to interpreting legislation and the framework of the URA and FTCA here. None of the statutes specifically states that the power of the Commission to make rates is prospective in nature only. However, the mechanism for rate setting would suggest a general pattern of prospective rate hearing.[61] The statutory pattern of ratemaking under the URA and FTCA is based on the setting of rates for the future to enable the utility to recover the forecast revenue requirements of the utility.

187. The Commission maintains the conclusion reached in the Interim Rate Decision, namely that both enactments, the FTCA and the URA, give the Commission wide powers concerning setting rates to ensure that utility rates are always fair and reasonable to both the utility and customers. The wide powers do not give the Commission unrestrained discretion, and any power which the legislation is silent on can only exist if it is consistent with the aim and objects of the legislation. In *Calgary (City) v. Alberta (Energy and Utilities Board),* 2010 ABCA

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[58] See Calgary (City) v. Alberta (Energy and Utilities Board), 2010 ABCA 132, from para [135], the judgment of Mr. Justice Cote concurring in part with the majority.
[59] See paragraph 41 to paragraph 43 of the Interim Rate Decision.
[60] See paragraph 44 to paragraph 46 of the Interim Rate Decision.
[61] See Calgary (City) v. Alberta (Energy and Utilities Board), 2010 ABCA 132, from para [121], the judgment of Mr. Justice Cote concurring in part with the majority.

132, at para 138, Justice Cote, who delivered a judgment concurring in part with the majority, wrote:

> *"[138] The Supreme Court of Canada says that though Alberta's Alberta Energy and Utilities Board Act and Public Utilities Board Act and Gas Utilities Act contain seemingly broad powers, that legislation must be interpreted within the entire context of the statutes, which balance need for consumer protection against owners' private property rights. The main function of the Commission is to fix just and reasonable rates, so ensuring dependable supply (paras. 7, 60). Therefore, imprecise undefined wide statutory provisions letting the Commission make any order, or impose any condition necessary in the public interest, do not give an unfettered discretion.* ***They must be limited to the purpose of the legislation and the context of the regulatory scheme and principles generally applicable to regulatory matters*** *(paras. 46, 48, 49, 50, 51, 60, 61, 64, 73-77). The "power to supervise the finances of these companies and their operations, although wide, is in practice incidental to fixing rates"* (para. 60)". [Emphasis supplied.]

188. The Commission is of the view, that it cannot be said, based on the framework of these enactments, that the Commission is limited to making prospective determinations only. The Commission thinks that any authority to make an order to have retroactive effect must necessarily flow from the broad powers to set rates under sections 3 and 10 of the URA and section 4 of the FTCA. Whether and under what circumstances the Commission may make an order to have retroactive effect will depend upon policy considerations and whether retrospective ratemaking is consistent, in the particular situation, with the aims and objectives of the URA and FTCA.

*Canadian Authorities*

189. The Commission has also considered the Canadian authorities on the issue and note in *Calgary (City) v. Alberta (Energy and Utilities Board),*[62] the Court of Appeal of Alberta considered the meaning of the words "retroactive ratemaking",

[62] 2010 ABCA 132.

"retrospective ratemaking" and "prospective ratemaking". Madam Justice Hunt also mentioned some arguments made against retroactive ratemaking and for prospective ratemaking. She wrote thus, from paragraph [46] to [49]:

> "[46] *A brief overview of some central principles of ratemaking, including the related concepts of retroactive and retrospective ratemaking, is necessary. Generally, ratemaking and rates must be prospective: Coseka Resources Ltd. v. Saratoga Processing Co. (1981), 31 A.R. 541 at para. 29, 16 Alta. L.R. (2d) 60 (C.A.). A utility's past financial results can be used to forecast future expenses, but a regulator cannot design future rates to recover past revenue deficiencies: Northwestern Utilities Ltd. and al. v. Edmonton, [1979] 1 S.C.R. 684 at 691 and 699 ("Northwestern Utilities").*
>
> *"[47] Retroactive ratemaking "establish[es] rates to replace or be substituted to those which were charged during that period": Bell Canada v. Canada (Canadian Radio-Television and Telecommunications Commission), [1989] 1 S.C.R. 1722 at 1749 ("Bell Canada 1989"). Utility regulators cannot retroactively change rates (Stores Block at para. 71) because it creates a lack of certainty for utility consumers. If a regulator could retroactively change rates, consumers would never be assured of the finality of rates they paid for utility services.*
>
> *"[48] Retrospective ratemaking, in contrast, imposes on the utility's current consumers shortfalls (or surpluses) incurred by previous generations of consumers. It is generally prohibited because it creates inequities or improper subsidizations as between past and present consumers (who may not be the same). "[T]oday's customers ought not to be held responsible for expenses associated with services provided to yesterday's customers": Yvonne Penning, "The 1986 Bell Rate Case: Can Economic Policy and Legal Formalism be Reconciled" (1989), 47(2) U.T. Fac. L. Rev. 607 at 610. This is sometimes referred to as the problem of inter-generational equity (which the Board discusses at p. 12 of the Limitations Decision reproduced at para. 23).*
>
> *"[49] Sometimes retrospective ratemaking is referred to as retroactive ratemaking. This is because rates imposed on a future generation of consumers, while*

*prospective, create obligations in respect of past transactions, and in this sense they are retroactive: City of Edmonton at 402.*

*"[50] In this case, the proposed accounting adjustments had retrospective effect: past costs would be borne by ATCO's present southern Alberta consumers, not the 1999 - 2004 consumers who received gas utility services when ATCO's gas costs were incurred.*

*"[51] In summary, whether termed retrospective or retroactive ratemaking, imposing gas cost shortfalls or surpluses incurred by past consumers on future consumers is generally prohibited. Although this prohibition against retroactive and retrospective ratemaking is relatively clear, how to apply it in practice is less so. A review of key cases illustrates the complexity."*

190. The Canadian authorities seem to suggest (either the authorities suggest or they do not) that, generally, ratemaking is prospective and that there is a general prohibition against retroactive ratemaking.[63] The policy reasons for such are varied. In addition to the reasons given in *Calgary (City) v. Alberta (Energy and Utilities Board,* it is argued that a core principle of ratemaking is that it is based on an *ex-ante* framework. Future rates are designed to create conditions for future behaviour, such as future efficient management of the utility and efficient investment, amongst others[64]. Retroactive rates could undermine incentives for future behaviour. The retroactive application of a rate cannot change the past behaviour of the utility. It is touted that the prohibition against retroactive ratemaking promotes equality and fairness as argued by BLPC. The rule against retroactive ratemaking also provides for rate certainty.

191. The Canadian authorities establish that there are exceptions to the general prohibition against retroactive ratemaking. In Capital Power Corp. v. Alberta

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[63] See *Capital Power Corp. v. Alberta (Utilities Commission)*, [2018] A.J. No. 1539. Also see the case of *Calgary (City) v. Alberta (Energy and Utilities Board),* 2010 ABCA 132, referred to above at paragraph [2].
[64] See Retroactive Rate Setting - A Review of Regulatory Precedent, page 3, by Peter Waters and Geoff Petersen, available at: https://ised-isde.canada.ca/site/spectrum-management-telecommunications/sites/default/files/attachments/2022/CRTC-2019-288-Bell-Canada-Petition-ATT.pdf.

*(Utilities Commission*[65]*)*, a decision of the Alberta Court of Appeal, BK O'Ferrall JA, considered the general principle concerning retroactive ratemaking. He seems to have accepted the Commission's adumbration of some identified exceptions to the general rule. At paragraph 57, O'Ferrall JA wrote, identifying some of the exceptions to the general rule as follows:

> "*In making its decision, the Commission carefully canvassed the jurisprudence governing retroactive ratemaking. In particular, the Commission dealt with some (but not all) the recognized exceptions to the prohibition against retroactive ratemaking:*
>
> 1) *adjustments to rates which may be properly characterized as interim;*[66]
> 2) *the use of deferred accounts to deal with differences between forecast and actual costs and revenues;*
> 3) *changes to rates as a result of the operations of what is known as a negative disallowance scheme (where rates are set and charged by utilities subject to being later changed by the Commission because they were not "just and reasonable" in the first place);*
> 4) *changes to rates when affected parties knew or ought to have known that the rates were subject to change (the so-called "knowledge exception"); and*
> 5) *replacing rates in a tariff that have been determined to be a nullity*."

192. In that case, the Court held that the line loss rule was unlawful in that it did not comply with the Transmission Regulations. Therefore, it appears that a regulator can make an order affecting a rate retrospectively where the rate was unlawful, in the sense that it conflicted with legislation, either primary or subsidiary legislation. A regulator would, in such a case, be permitted to make a retroactive order to remedy the situation. It is arguable that under that principle, a regulator would similarly be justified in reopening a rate where it is made based on some manifest error or reliance on information which was false or misleading.

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[65] [2018] A.J. No. 1539

[66] Interim rates and deferral accounts are generally accepted exceptions to the rule against retroactive ratemaking. See *Newfoundland and Labrador Hydro v. Newfoundland and Labrador (Board of Commissioners of Public Utilities),* [2012] N.J. No. 212, at para 60.

193. At paragraph 64 of *Capital Power Corp. v. Alberta (Utilities Commission)*, the Court observed that there is no blanket prohibition against retroactive rate making and identified some reasons therefor, as follows:

> *"64 The reason that there is no blanket prohibition against retroactive ratemaking is that* ***there are decades of public utility board and judicial decisions variously applying the rule or declining to apply the rule depending on circumstances****. See, for example, Professor Stefan Krieger's article entitled "The Ghost of Regulations Past: Current Applications of the Rule Against Retroactive Ratemaking in Public Utility Proceedings" (1991) 1991 Illinois L Rev 983. Professor Krieger discusses a century of what he characterized as "inconsistent and contradictory application of the traditional rule against retroactive ratemaking." Whether that is a fair characterization of the jurisprudence,* ***no court or public utilities board will ever be able to define precisely the circumstances in which retroactive ratemaking is permissible. Nor is it desirable that they should do so. And, presumably, it has been deemed even less desirable to enact a blanket prohibition****."* [Emphasis supplied.]

194. There is no enumerable list of circumstances where the rule against retroactive ratemaking will be applied. It will apply when considerations of fairness, reliance, rate stability and certainty are engaged and they outweigh the countervailing considerations. In effect, it involves a consideration of factors for and against applying or disapplying the retroactive rule. O'Ferrall JA stated a broad principle that the rule against retroactive ratemaking will apply where it is necessary to "achieve sound utility regulation." What is sound utility regulation is a question for the regulator and not the court. In effect, the court will defer to the judgment of the regulator as to what is sound utility regulation. These principles emerge from the following paragraphs of O'Ferrall JA's judgment, at paras 65 and 66 thus:

> *"65 The rule against retroactive ratemaking is applied when considerations of fairness, reliance, rate stability and certainty are engaged and given more weight than countervailing considerations. By way of examples, the rule is often not*

*applied in the context of regulatory changes to accounting methodology, when obvious mistakes have been made in rate orders, when utilities experience extraordinary losses or gains or other exceptional (novel and complex) circumstances. It is often not applied when rate orders are quashed or reversed following judicial review. And it is often not applied when retroactive relief is granted by the utility regulator following a lengthy tariff proceeding or in cases of interim rates subject to change or in cases of deferral accounts employed to deal with differences between forecast and actual costs and revenues. There are other circumstances as well in which the rule is not applied. The list is not closed.*

*'66The point being made is that the Commission's application of the rule against retroactive ratemaking is not so much a question of law* ***but a question of whether or not a strict application of the rule in the circumstances of the case achieves sound utility regulation. The latter is not a question for this Court."*** [Emphasis Supplied].

*Unites States' Authorities*

195. The Commission has considered cases decided by Courts in some States in the United States of America and note that in some cases the Courts take the strict position that retroactive ratemaking is prohibited, as reflected in the cases cited by BLPC. Other cases establish a general prohibition against ratemaking, while recognising exceptions to the general prohibition[67].

196. One of the common exceptions to the general prohibition against retroactive ratemaking recognised by several courts in the United States of America is for unforeseeable and extraordinary gains and losses. This exception permits the return of certain gains to customers that were not expected during the last rate review. In MCI Telecommunications Corp. v. Pub. Serv. Comm'n of Utah, the Utah Supreme Court stated:

[67] See the extensive discussion of the rule against retroactive ratemaking in the USA and the exceptions to the rule, by Stefan H. Krieger, The Ghost of Regulation Past: Current Applications of the Rule Against Retroactive Ratemaking in Public Utility Proceedings, available at https://scholarlycommons.law.hofstra.edu/cgi/viewcontent.cgi?referer=&httpsredir=1&article=1054&context=faculty_scholarship

*"The extraordinary and unforeseeable nature of the expenses recognized under the exception differentiates them from expenses inaccurately estimated because of a misstep in the rate-making process, such as the inability to predict precisely, or from mismanagement. An increase or decrease in expenses that is unforeseeable at the time of a rate-making proceeding cannot, by hypothesis, be taken into account in fixing just and reasonable rates. Furthermore, because the increase or decrease must have an extraordinary effect on the utility's earnings, the increase or decrease will necessarily be outside the normal range of variance that occurs in projecting future expenses.*

*If a rate-making body were to attempt to make allowance for an unforeseeable and extraordinary increase or decrease in expenses in fixing rates, a task that by definition is impossible, the resulting rates would always be unjust and unreasonable, if not confiscatory or exploitive, as to either ratepayers or stockholders. To achieve fairness, the exception allows recoupment of such expenses either in future rates or in some other appropriate fashion.*[68]

197. In *MCI Telecommunications*, the Utah Supreme Court held, inter alia, that the change in income tax rates was unforeseeable at the time the prior rates were set and were extraordinary due to a cut by more than one-fourth.[69] *MCI Telecommunications Corp. v. Pub. Serv. Comm'n of Utah*, also established that retroactive ratemaking is permissible where there is misconduct on the part of the utility.[70] Further, courts have supported exceptions to the prohibition against

[68] MCI Telecommunications Corp. v. Pub. Serv. Comm'n of Utah, 840 P.2d 765, 771–72 (Utah 1992).

[69] See too Re Narragansett Elec. Co., 40 P.U.R.4th 498, 521 (Nov. 8, 1980), a decision of the Rhode Island Supreme Court reversed the commission's decision regarding the retroactive recovery of unforeseen storm damage costs, holding that no rule-even the rule against retroactive ratemaking should be blindly applied. *"Turning to the prohibition against retroactive rate making, we recognize that the commission justifiably expressed concern over the applicability of this judicially created rule set forth in such decisions… No rule should be blindly applied, however, without prior consideration of the underlying policy that originally precipitated its adoption. Such an approach ensures that the application of the rule in a particular instance will not undermine its original purpose."*

[70] The court stated thus: *"A utility that misleads or fails to disclose information pertinent to whether a rate-making proceeding should be initiated or to the proper resolution of such a proceeding cannot invoke the rule against retroactive rate making to avoid refunding rates improperly collected. The rule against retroactive rate making was not intended to permit a utility to subvert the integrity of rate-making proceedings. See Southwest*

retroactive ratemaking in cases involving changes in accounting practices,[71] and where the regulator has made a clerical or procedural error.[72]

*<u>Conclusion on Retroactive Ratemaking</u>*

198. The Commission is not persuaded that it should follow the line of cases which have sought to establish a strict prohibition against retroactive ratemaking as cited by BLPC. The Commission is of the view, that based on the framework of the URA and FTCA, the Commission is not limited to making prospective determinations only. Accordingly, whether and under what circumstances the Commission may make an order to have retroactive effect will depend upon policy considerations and whether retrospective ratemaking is consistent, in the particular situation, with the aims and objectives of the URA and FTCA. The Commission is persuaded to follow the body of case law emanating out of both Canada and the United States which establishes a general principle that ratemaking is prospective and that there is a general prohibition against retroactive ratemaking; however, that there are exceptions to the general prohibition against retroactive ratemaking. The broad principle against retroactive ratemaking will apply where it is necessary to "achieve sound utility regulation." The Commission accepts the recognized exceptions to the prohibition against retroactive ratemaking mentioned in the cases reviewed above, but also acknowledges the categories are not closed.

199. The Commission is of the view that its decisions concerning the following (i) the withdrawal from the SIF and payment of the same as dividends to shareholders or (ii) the excess accumulated deferred income taxes following the 2019 corporate income tax rate change, do not amount to impermissible retroactive

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*Gas Corp. v. Public Serv. Comm'n, 86 Nev. 662, 474 P.2d 379, 383 (1970). If a utility misleads the Commission or the Division by withholding relevant rate-making information, the rates fixed by the Commission cannot be based on reasonable projections of the utility's revenues and expenses. The rule against retroactive rate making was designed to ensure the integrity of the rate-making process, not to shelter a utility's improperly obtained revenues."*

[71] *Peterson, G. and Waters, P. (2019) Retroactive rate setting; A review of regulatory precedent. Available at: https://ised-isde.canada.ca/site/spectrum-management-telecommunications/sites/default/files/attachments/2022/CRTC-2019-288-Bell-Canada-Petition-ATT.pdf.*
[72] *Mike Little Gas Co. v. Public Service Commission 574 S.W.2d 926 (Ky. Ct. App. 1978)*

ratemaking. Moreover, the decision in respect of the SIF was not prudent in that there is no evidence that an actuarial study guided the decision to make the withdrawal from the fund. Those positions discussed below do not reset rates previously established. Rather, the positions establish the initial treatment of unusual gains to BLPC not expected or considered in the establishment of prior rates.

## SECTION 7 – INCOME TAXES

200. Effective January 1st, 2019, the rates applied to taxes on the income of companies resident in Barbados were reduced from 15% to 2.34%, effectively reducing BLPC's corporation tax rate. The change in the corporation tax rate required BLPC to remeasure its ADIT balances for accounting purposes to reflect the current income tax rates for accounting purposes. The ADIT balances are a result of temporary difference of (i) when expenses are recognized for accounting and ratemaking purposes and (ii) when they are recognized for income tax purposes. Temporary differences may initially create tax reducing effects when expenses are lower for accounting and rate purposes than the associated income tax deductions, which are captured as an ADIT liability for accounting and rate purposes because the initial temporary difference will eventually reverse, and the utility will pay a higher future income tax. The inverse will create an ADIT asset that when reversed, will result in the utility paying a lower income tax in the future. Accordingly, ADIT is a measure of the temporary or timing differences associated with income taxes used for accounting and rate purposes and for income tax purposes, which will eventually reverse, assuming income tax rates remain constant.

201. Upon an income tax rate change, the ADIT balances are remeasured to reflect the future tax obligations or benefits based on the revised income tax rate. The ADIT remeasurement in 2019 resulted in a lower valuation to BLPC's ADIT obligations due to the lower income tax rate and the excess ADIT was treated as a gain recognized by the BLPC. The excess ADIT (also referred to as "tax gain") represents income taxes previously accrued and recovered in rates based on an expectation of higher income tax rates that ultimately will not need to be paid to the taxing authority because future taxes will be paid at a lower tax rate. At issue in this Application is whether the tax gain should be refunded to customers or retained by BLPC for distribution to its sole shareholder.

202. BLPC explains that it engaged with the Commission on the treatment of the ADIT gain following the corporate income tax rate change. According to BLPC, the final communication was an agreement between BLPC and Commission that instead of setting up a regulatory deferral for the gain, the effect of the tax reduction would be recognised as current year income for 2018 and reflected as such in regulatory reporting. BLPC stated the logic of this outcome is supported by the fact that the Commission has not established a framework for creation of a regulatory account and no guidelines have been issued relative to the details of any such account and its operation.

203. BLPC also notes that a reduction in corporation tax occurred in 2004 and 2006 and on both occasions, it was dealt with in the manner that BLPC applied on this occasion. According to BLPC, the overarching concern for the Commission should be any element of over-earning above the Commission's approved rate of return. To the extent that save for a 1.75% over the approved rate in 2018 there has been on the contrary significant under-earning post the tax change, and the consumers have not been disadvantaged in any way by this treatment.

*Intervenor Positions*

204. During oral hearings, the intervenors generally took positions to decrease rate base to reflect the total ADIT based on the prior income tax rate of 15% and reduce the revenue requirement by the excess taxes collected in rates. On August 5th, 2022, prior to the Hearing Mr. Ralph C. Smith filed an affidavit on behalf of the Ministry of Energy and Business (Business Development Division) wherein he proposed similar adjustments. Specifically, Mr. Smith recommended that ADIT balances included in rates should not be reduced as a result of the income tax rate change. This adjustment increases the ADIT rate base reduction and is intended to represent the amount of income taxes collected in rates that will not become payable to the taxing authority due to the decreased income tax rate. This amount is recommended by Mr. Smith to be refunded to customers over five years.

*The Commission's Analysis and Findings*

205. ADIT balances accumulate on BLPC's books due to differences in the timing of when items of income and deductions are recorded for accounting purposes and included for income tax purpose. For ratemaking purposes, since BLPC's revenue requirement is determined based on its accounting books and records, the timing difference between accounting and tax treatment of income and deductions has ratemaking consequences. Accordingly, the ADIT balances that represent the accumulated tax effect of these timing differences are used as an adjustment to rate base because it represents amounts recovered in rates for income taxes before the tax is actually payable to the taxing authority. This is in the case of an ADIT liability, which reduces rate base. An ADIT asset would arise when timing differences cause a utility to pay taxes to the taxing authority before the amount is included in rates. When a tax rate changes, the ADIT balances are reduced to reflect the fact that future tax liabilities and benefits will be realised at a lower income tax rate. The net reduction to ADIT balances as a result of an income tax rate change is referred to as "Excess ADIT".

206. In the context of ratemaking, Excess ADIT presents several primary issues: the rate base treatment of Excess ADIT, the amount of Excess ADIT that should be refunded to customers, and the amortization period for Excess ADIT refunded to customers. The rate implications of income tax rate changes have not been specifically addressed in prior decisions by the Commission. As the BLPC notes, in 2004 and 2006 the income tax rate changed and the 2010 Decision did not require any refunds for the Excess ADIT. However, the rate implications of these tax rate changes were not issues raised during the last rate review proceeding by the BLPC, intervenors, or the Commission. Therefore, BLPC's statement that the last rate review dealt with Excess ADIT in the manner it proposes in this proceeding is incorrect. The issue of Excess ADIT was not dealt with in prior Commission decisions. It cannot be expected that the Commission will address every possible rate issue during a rate review. Neither can it be expected that

the Commission's silence on a topic in prior rate reviews or Commission decisions represents a policy of approval.

207. The issue of Excess ADIT was first substantially presented to the Commission during the communications between the BLPC and Commission following the income tax rate change, effective January 1st, 2019. The Commission staff's written correspondence to BLPC required BLPC to confirm the final amount of the income tax gain (i.e., excess ADIT), record the amount in a regulatory account, and the amount be taken into account during the upcoming rate review through an adjustment to the Revenue Requirement. The Commission staff concluded that this approach is a more effective means of facilitating the return on these gains to the customer. In response to financial reporting concerns, the BLPC was verbally authorized to record the full amount of the Excess ADIT as current year income in 2018 for regulatory reporting, rather than the deferral and amortization initially requested. This change in accounting and regulatory reporting did not change the written requirements of the April 3rd, 2019 letter order regarding the rate treatment of the Excess ADIT being determined in the next rate review.

208. While the Commission has previously ruled on the rate treatment of certain income tax issues, the Commission has not directly ruled on the rate treatment for changes in the corporate income tax. Now that the issue is directly before the Commission and with the benefit of the record in this Application, the Commission is of the view that changes in income tax rates does give rise to ratemaking consequences and that Excess ADIT should be factored into rates. Similarly, deficient ADIT should be factored into rates as appropriate. In consideration of the fact that prior income tax rate changes have reduced the income tax rates and created Excess ADIT without rate consequence and that future rate changes are likely to result in increases to BLPC's income tax rate, the Commission holds a general policy that excess and deficient ADIT should be factored into rates on a 50/50 sharing basis to customers and BLPC on the basis of equality. The Commission believes this approach can provide a consistent and

equitable rate treatment for Excess and deficient ADIT in situations when income tax rate changes result in refunds to or additional collections from customers.

209. The refund of Excess ADIT is a view supported by other similar retail jurisdictions. The amount and manner of rate refunds varies by jurisdiction, demonstrating flexibility in ratemaking considerations and the application of rate treatments catered to the unique facts and circumstances. Accordingly, BLPC shall record 50% of the 2019 income tax gain in a Regulatory Liability account and amortize the liability to customers over a fifteen (15) year period.[73] Additionally, the rate base will reflect a reduction for 50%of the 2019 income tax gain and the revenue requirement will be adjusted to reflect the annual amortization over the 15-year period.

[73] While the Commission finds that 50/50 sharing of the 2016 income tax gain is appropriate and believes that it will create fair and reasonable results in future tax rate changes, this general policy need not be strictly followed if future facts and circumstances necessitate different rate treatments. Additionally, the Commission may conclude on a different amortization in future rate determinations.

## SECTION 8 – SELF-INSURANCE FUND

210. BLPC's SIF was informally established in 1993 when there was only a limited amount of commercial insurance to cover transmission and distribution ("T&D") assets against hurricanes and the insurance available was expensive.[74] In the initial stages of the SIF, BLPC deposited funds into a bank account and relied on a credit facility for additional liquidity to self-insure. BLPC formally established its SIF following the Insurance (Barbados Light and Power Company Limited) (Self Insurance Fund) Regulations, 1998 (revised in 2005 (the "BLPC Insurance Regulation"), which provided the legislative requirements for self-insurance against losses caused by catastrophic events. The BLPC Insurance Regulation required that the SIF be created by a deed of trust, with the trustee being someone approved by the Supervisor of Insurance (now the Financial Services Commission). The regulations also stipulated that the monetary limit of the fund could not exceed: (1) the total of the replacement cost of the assets which are being self-insured and the self-insured portion of BLPC's commercial insurance programme; or (2) 10% of the total assets of BLPC, where replacement cost is not easily determined.

211. The SIF was established by the Deed of Trust dated December 31st, 1998. The SIF was settled with the sum of $25,504,649 on December 31st, 1998. BLPC continued to contribute monies to the SIF through 2013. Thereafter, BLPC ceased making contributions.

212. By year 2013 the end balance of the SIF increased to $141.5 million as a result of SIF contributions and earnings on investments of the SIF. In April 2016, BLPC indicated by letter that it had an accumulated SIF reserve of $147 million. The letter from BLPC further indicated that in 2014, studies were undertaken by Emera Caribbean Inc. (ECI), Carib RM, and CGM Gallagher to evaluate BLPC's risk and necessary level of reserves to be maintained in the SIF. The Commission was advised by BLPC during the oral hearing that the said studies stated the

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[74] BLPC's 2009 Rate Application, Schedule E – Memorandum on Self Insurance Fund.

prudent level of reserves was USD $22 million. The Commission was not provided with any evidence that an actuarial review of the SIF was undertaken. Accordingly, the BLPC indicated its intention to reduce the SIF to USD $22 million, and remit the excess to its sole shareholder, net of the applicable taxes. The Commission indicated by letter to the BLPC dated May 19th, 2016 that no approval was required from the Commission related to the change in the funding level of the SIF. In July 2016, BLPC withdrew $99.5 million from the SIF, and transferred $99.5 million to its sole shareholder, leaving the fund with a year-end balance of $50.2 million in 2016.

213. BLPC contends that its decision to withdraw funds from the SIF and distribute those funds to its sole shareholder was appropriate and opposes claims that funds withdrawn from the SIF belong to customers. As it pertains to the regulation of the SIF, BLPC stated that the SIF is not regulated by the Commission. BLPC argues that the withdrawal from the SIF was not improper or illegal, noting the BLPC Insurance Regulation expressly permit, at Section 8 (2), utilisation of the SIF for purposes other than replacing or reinstating the self-insured assets.

214. BLPC also contends that there is no regulation that requires BLPC to cover generation plant and equipment under the SIF or prohibit the BLPC from utilising third party insurance coverage for generation or other assets. Nevertheless, BLPC contends that third party commercial insurance is far more attractive generally than self-insurance because the risk of being easily exhausted is lower and the extent of coverage that can be secured by a premium.

215. BLPC stated that the BLPC Insurance Regulation does not provide or otherwise contemplate that the customer retains ownership interest in the return earned on the SIF. Furthermore, BLPC holds the position that once ratepayers receive electric service, they no longer have proprietary interest or ownership of the monies paid for the electric service. BLPC thus argues that customers do not retain ownership of the funds after having paid for the service, otherwise

fundamental principles relating to ownership, consideration and transfer of value is ignored.

216. According to BLPC, its directors determined that there was a need to set up the SIF when insurance was unobtainable for T&D assets and those monies used to set up the SIF came from the profit of the BLPC. BLPC supports this position on the basis that the money set aside to initially fund the SIF well surpassed the amounts included in rate at the time of set up and the money originally set aside would have comprised part of its net income that initial year. Thus, BLPC posits, upon the return of funds paid into the SIF, the monies should accrue to profit.

217. Finally, BLPC argues that it is incorrect to suggest that when the funds from the SIF were transferred to BLPC they should have remained in BLPC to fund operations instead of being paid out as a dividend is a skewed. According to BLPC, this is a siloed point of view that ignores that if earnings are retained, this stymies the ability of BLPC to move closer to the approved notional capital structure. BLPC argues that maintaining high equity in the capital structure, does not benefit the customers as the cost of equity is more expensive than the cost of debt.

*Intervenor Positions*

218. Intervenors expressed several concerns and recommendations concerning the withdrawal of funds from the SIF in 2016 and distribution to BLPC's sole shareholder. Intervenors expressed concerns that the funds withdrawn from the SIF should have been retained by BLPC to cover risks of an unprecedented nature. Intervenors also expressed concerns on whether the funds should have been paid to BLPBC's sole shareholder as a dividend. Intervenors noted that BLPC's sole shareholder, Emera (Caribbean) Inc. was not the shareholder of BLPC at the time the settlement of the trust which constituted the SIF. Intervenors also expressed concerns on whether the funds were in fact paid by the then shareholders of BLPC.

*The Commission's Analysis and Findings*

219. A fundamental issue regarding the appropriate rate determination of SIF withdrawals is the nature and amount of BLPC's contribution to the SIF. To address this issue, it is necessary to understand that insurance costs take the form of insurance payments to commercial insurance providers, and to the SIF. The rate recovery of total insurance cost is set based on forecasted expectations of insurance costs at each rate review. The actual insurance costs following the rate review will change and has demonstrated to be vastly different than the projected costs in the prior two rate reviews.[75] That is, the cost of commercial insurance may increase or decrease, and the appropriate SIF reserve amount and annual funding thereof may change as well. Similarly, other projected costs provided for during the last rate review will both increase and decrease. On this basis, it cannot be stated that cost increases associated with normal operating costs, like insurance, are funded by shareholders nor that cost decreases associated with normal operating costs belong to customers.

220. The Commission is also of the view that BLPC's initial and ongoing contributions to the SIF were not voluntary from a ratemaking perspective in that it is BLPC's responsibility to ensure that all property is insured by commercial insurance or other means. BLPC cannot self-elect to forgo providing insurance for its T&D assets as that would be reckless and imprudent. However, BLPC was required to insure the assets as a necessary cost of providing electric utility service in Barbados, making its decision to pursue the SIF not an act of charity or goodwill but the most appropriate means to secure insurance. This is BLPC's responsibility to its customers.

[75] Since the establishment of the SIF, the amounts factored into rate for insurance costs have generally been disconnected with the amount of monies actually used to fund the SIF. The 1986 Rate Review estimated BLPC's insurance costs to be around $700 thousand annually; however, from following the establishment of the SIF, BLPC made contributions well in excess of the amount estimated in rates. The 2010 Decision set rates based on estimated SIF contributions of approximately $7.6 million. However, BLPC's actual contributions to the fund were reduced to $1.6 million in 2011-2013 and have ceased since.

221. BLPC's current shareholder, Emera (Caribbean) Inc. ("Emera"), did not pay any monies into the fund in excess of rate recoveries, since the date of its acquisition of the shares of BLPC. During the period 1993-2010, BLPC paid more for insurance than what was contemplated during the last rate review in 1983 and during this same period Emera was not the shareholder of BLPC. Following the 2010 Decision, BLPC rates provided for approximately $7.6 million in insurance , but only $1.6 million was actually deposited into the fund during 2011 – 2013. In years following 2013, payments to the SIF ceased. In 2010, Emera became the sole shareholder in BLPC after acquiring ownership of all issued and outstanding shares of BLPC from its then shareholders. These facts further support the position that Emera, no funds were paid into the SIF by Emera. At no time previously, or currently, has Emera been a beneficiary of the SIF Trust. No evidence has been provided to the Commission that during the acquisition of the BLPC shares by Emera, that such acquisition included becoming a beneficiary of the SIF Trust. Accordingly, the monies invested into the SIF Trust prior to Emera's acquisition cannot be said to belong to Emera as BLPC's sole shareholder. While BLPC is the beneficiary of the SIF Trust, the intended purpose of the SIF Trust is not to satisfy the interest of the BLPC's sole shareholder.

222. The Commission also finds that the difference between the estimated insurance costs included in prior rate reviews and the actual cost spent for insurance purposes will not be considered an amount attributable to its sole shareholder nor customers. Indeed, if the Commission were to conclude that the SIF was initially funded by shareholders of BLPC, it would also have to rule in the opposite direction for the period 2011 – 2022 where the no funds allocated for insurance during the previous rate review were paid into the SIF. It cannot be one-sided. Accordingly, the funds paid into the SIF shall be considered as funded by customer rates for the purpose of responding to future catastrophic events. This position also does not negate the need for rate scrutiny of funds paid into the SIF when those funds are not used for their intended purpose.

223. BLPC argues that once customers receive electric service, they no longer have proprietary interest or ownership of the monies paid for the electric service. However, in the case of the SIF, the future restoration of T&D assets in response to a catastrophic event is directly related to the electricity service to be provided. Accordingly, the reserves of the SIF have not been used to provide any electric service to customers.

224. The Commission holds that the monies set aside in the SIF, in addition to being funded by customer rates, ensure the continued provision of electric utility service in the event of a catastrophic event. In view of the determination made by BLPC to no longer fund the SIF, for ratemaking purposes the funds in the SIF at the date of withdrawal should not be considered retained by BLPC's sole shareholder. It is a fair and reasonable outcome that the funds withdrawn in 2016 be considered retained by the BLPC for the benefit of utility operations or refunded to customers. This avoids a perverse outcome of use of funds devoted to future electric utility service and funded by customer rates being used for the benefit of shareholders. Accordingly, the Commission has determined that it is prudent for a fund such as the SIF to obtain an actuarial review prior to the withdrawal of any funds and that in instances where funds are not withdrawn for the purpose of the restoration of utility services, a ratemaking consequence is warranted on such amounts.

225. The Commission also recognises that BLPC made the voluntary election to remove monies from the SIF in 2016. Although, BLPC performed analysis to determine the minimum balance needed in the SIF, it was not mandated to withdraw any funds or given approval to retain the funds for the sole benefit of shareholders. The Commission notes that the regulation of insurance entities is the purview of the Financial Services Commission, however, it is clearly within its jurisdiction to regulate the rate recoveries for monies that support insurance and a SIF as well as the rate treatments of monies removed from the SIF for non-utility purposes.

226. The Commission finds that BLPC's contention, that it was appropriate for its sole shareholder to retain the funds withdrawn from the SIF because it was not reaching its authorised rate of return is without merit. Upon Emera's 2013 acquisition of the ownership interest in BLPC, it did so under BLPC's existing stated rate of return and it is assumed to have factored the current and expected returns in the arms-length transaction to acquire the BLPC. In addition, BLPC is provided with an opportunity to earn its authorised rate of return and has the ability to seek rate increases where existing rates are not sufficient. However, the use of monies set aside for future expenditures of the utility and paid by customer rates is not a fair and reasonable method to satisfy shareholder returns. BLPC always had the right to seek a rate increase if it does not meet its desired return. Such a rate proceeding would be before stakeholders and the Commission and afford due process to all interested parties to achieve a rate that is fair and reasonable.

227. The Commission also finds that in the event of a future need to increase the funding level of the SIF, those monies should not be borne by customers up to the amount of the funds withdrawn from the SIF that have not been refunded. It would not be fair and reasonable to expect customers to pay for such amounts that were previously held in the SIF.

228. For the reasons discussed above, the Commission will require $99.5 million SIF withdrawal to be made available by BLPC to be deployed consistent with the initial intent for the funds and treated as a rate base reduction as the funds represent a source cost-free capital. For regulatory reporting purposes, these monies are to be recorded as a separately identifiable regulatory liability. In the event of a catastrophic event that is eligible to be covered by the SIF, BLPC will first deploy the monies recorded in the regulatory liability account. The BLPC may also re-deposit monies into the SIF as may be determined appropriate by the Commission in the future. Furthermore, BLPC must refund to customers the amount withdrawn from the SIF that are not re-deposited into the SIF over a thirty (30) year period as a reduction to insurance expense that shall be shown as

a separately identifiable amount for regulatory reporting purposes. The thirty (30) year amortization period is reasonable to avoid the flow-back of funds too rapidly in the event additional monies are needed to fund the SIF or respond to a catastrophic event, while allowing a gradual return of monies to customers.[76]

229. In addition, the Commission is directing the BLPC to conduct an actuarial review no later than the end of 2023 to assess the reserves required and the amount to be paid into the SIF annually by an independent actuary approved by the Commission. An actuarial review of the SIF must occur every three (3) years and the actuarial review submitted to the Commission within fifteen (15) days of the issuance of the actuarial report by the actuary. The original actuarial report and the BLPC's intended actions as a result of the independent actuarial review must be submitted to the Commission no later than January 31st, 2024, and subsequently on June 1st in three-year intervals, starting June 1st, 2027. To the extent the reserves in the SIF are insufficient to meet the claims liability as determined by the independent actuary, BLPC will be required to fund the SIF to meet the required levels and may reduce the regulatory liability balance established herein. Finally, BLPC will be required to notify the Commission in writing of any future withdrawals from the SIF for purposes other than the restoration of assets following a catastrophic event or the deposit of funds previously withdrawn and obtain authorisation from the Commission regarding the regulatory accounting impact.

[76] This treatment is also similar to the treatment of pension plan assets that are over-funded. Generally, the over-funded amounts are not returned to customers at once but gradually treated as a reduction to future pension expense.

## SECTION 9 – RATE OF RETURN

230. BLPC has requested a Rate of Return of 8.79%. This is based on BLPC's Weighted Average Cost of Capital ("WACC") stated on a regulatory basis and includes investor-supplied funds of common equity and long-term debt together with customer security deposits, deferred investment tax credits and deferred manufacturing tax credits.

231. The legislative authority used by the Commission for Rate of Return determination is Section 3(2) of the URA which states that in establishing the principles for arriving at the rates to be charged by the Commission shall have regard to:

> "*(c) the promotion of efficiency on the part of service providers;*
>
> *(d) ensuring that an efficient service provider will be able to finance its functions by earning a reasonable return on capital.*"

232. This authority is consistent with principles and standards set forth in the landmark Supreme Court decisions of Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) and Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944) for regulatory determinations of the Rate of Return. These standards recognize that ratemaking requires a balance between the interests of equity investors and customers. The equity investor's interest is met if the return to the equity owner is comparable to the returns earned by making investments in entities of similar risk and that the rate of return is sufficient to ensure confidence in the financial integrity of the regulated company so as to maintain its credit and to attract capital necessary to perform its public duties. The consumer interest is described in *Hope* as including protection from "exploitation at the hands of" the utility.

233. The Commission is of the view that these principles and standards should guide its Rate of Return determination in order to satisfy the requirements set out in the URA. The sections below provide the Commission's findings in respect of each component of the Rate of Return.

## CAPITAL STRUCTURE

234. The capital structure refers to the type of financing used by a company to underwrite its physical capital and other assets. As part of the Rate of Return determination, BLPC has requested that a notional financial capital structure of 65% common equity and 35% long-term debt be utilized for ratemaking purposes. In the Application, the financial capital structure, which represents investor-supplied funds, is combined with other sources of funds, namely, customer security deposits, deferred investment tax credits and deferred manufacturing tax credits to arrive at the overall regulatory capital structure.

235. In support of its request, BLPC explained that as part of the 2010 Decision, the Commission approved the use of a notional financial capital structure of 65% equity and 35% debt for ratemaking purposes and that BLPC considers this still to be reasonable. BLPC added that the actual equity ratio was 74% at the end of 2020, that this falls to 71% if the $33.1M debt related to the CEB were to be incorporated, and the use of lower notional equity ratio is to the benefit of customers. In both the written and oral evidence, BLPC explained that it intends on transitioning its actual capital structure towards the requested notional capital structure and that this would be achieved through the payment of dividends and securing additional debt to support investment.

*Intervenor Positions*

236. Intervenors primarily engaged with the concept of retained earnings as part of BLPC's common equity balance and questioned the interplay between the payment of dividends and obtaining new debt and how those factors lead to a reduction from BLPC's current equity balance down towards the requested financial equity ratio. Additionally, the Ministry of Energy and Business Development filed an Affidavit of Mr. Ralph Smith on July 28th, 2022. Mr. Smith put forward a Rate of Return number that incorporated a capital structure of 65% equity and 35% debt but he noted that the Rate of Return number should be viewed as a placeholder and that it may require further adjustment as additional information is received from BLPC. Mr. Smith did not discuss the merits of this

capital structure in his affidavit. No further affidavits by Mr. Smith were filed and, as previously noted, he was not made available for cross-examination during the oral hearings.

*The Commission's Analysis and Findings*

237. The Commission considers that the inclusion of customer deposits, deferred investment tax credits and deferred manufacturing tax credits as part of a regulatory capital structure to be acceptable for rate-making purposes. This continues the practice adopted in the 2010 Decision.

238. The Commission places no weight on Mr. Smith's placeholder Rate of Return, including the capital structure used, as it was apparently not his final recommendation, and it is further noted that there was no opportunity to cross-examine Mr. Smith during the oral hearings.

239. The Commission is of the view that employing a notional financial capital structure can be appropriate in circumstances where BLPC's actual common equity proportion of the financial capital structure is deemed to be unreasonably high. Indeed, in the 2010 Decision, the Commission approved the use of a notional financial capital structure. Here, there is little dispute as to whether BLPC's actual equity ratio is appropriate to use, with BLPC requesting the use of a lower financial equity ratio together with BLPC's expert witness, Dr. Villadsen, expressing the view during the Hearing that the actual financial equity ratio is "higher than what we normally see." Therefore, the Commission finds the use of a notional financial capital structure to be appropriate.

240. In the 2010 Decision, the Commission notes that the notional financial capital structure found to be appropriate in that determination of 65% common equity and 35% long-term debt represented the average capital structure of electric utilities in the Caribbean during the 2004 and 2006 years. During the oral hearing, Dr. Villadsen was questioned whether she had examined any Caribbean regional data and she explained that she examined the most recent

decision reached in Jamaica where the electric utility was allowed a 50% common equity and 50% long-term debt financial capital structure. The Application also provided regional data in the Performance Benchmarking Study 2014-2019.[77] This study reported that the average equity ratio for Caribbean utilities was approximately 54% during the 2014 through 2018 period and in 2019 it was on average 42%. BLPC's request for a 65% financial equity ratio is comfortably greater that the equity ratios seen across the Caribbean region.

241. The Commission also compared BLPC's request to the accounting book-based capital structures of the companies included in the electricity utility proxy used by Dr. Villadsen's as part of return on equity analysis. This information was made available in Dr. Villadsen's workpapers, provided through the interrogatory process. A wide range of equity ratios are evident, ranging from 29% to 64%, and the average equity ratio for the electric utility was approximately 43%. It is noteworthy that only two electric utilities, out of the thirty proxy group members, have an equity ratio that is greater than 55%.

242. The Commission therefore concludes that the requested financial equity ratio should be reduced. Based on this determination the notional financial capital structure to be used in the calculation of the Rate of Return is set at 55% common equity and 45% long-term debt.

## RETURN ON EQUITY

243. In the Application, BLPC requests a Return on Equity ("ROE") of 12.50%. The ROE request is supported by BLPC's expert witness Dr. Villadsen. Dr. Villadsen relies on three analytical models: (1) Capital Asset Pricing Model (CAPM) (2) Discounted Cash Flow (DCF) model and (3) Risk Premium method. To apply the models, Dr. Villadsen relied on United States based financial and regulatory data and converted this data to the Barbadian environment by adding a country risk premium ("CRP"). Additionally, Dr. Villadsen purports that BLPC's

[77] Application, Volume 1, Appendix V., Page 250.

business risk is greater than average and she stated her recommendation reflects this alleged heightened risk. Lastly, Dr. Villadsen stated her recommendation is based on the Clean Energy Transition Rider ("CETR") being approved.

*Intervenor Positions*

244. During the Hearing, several topics related to the ROE were discussed by intervenors and a particular focus was put on several facets of risk, namely, business risk, industry risk and the country risk premium. The questions covered, whether the country risk premium for Barbados had declined in recent years, the regulatory risk from licence changes and the impact of the CETR. Intervenors also queried the appropriateness of using US based financial data and transferring it to the Barbadian environment. A further discussion related to the change in BLPC's cost of capital from the 2010 Decision to present.

*The Commission's Analysis and Findings*

*Proxy Group*

245. The implementation of the CAPM and DCF models requires the development of a proxy group comprised of companies with similar risk profiles to the subject utility and the availability of appropriate financial data for the proxy group companies. Dr. Villadsen's primary proxy group was based on US publicly-traded companies which are classified by Value Line, an investment research and publishing company, as electric utilities and the candidate companies were screened to identify electric utilities that, according to Dr. Villadsen, were risk comparable to BLPC. A group of 30 electric utilities were selected.

246. The appropriateness of utilising United Stated based stock market data for the risk comparable proxy group, together with a country risk premium, was raised by intervenors during the Hearing. During cross-examination Dr. Villadsen explained the selection of the US based data was a pragmatic issue. Dr. Villadsen said she examined whether a suitable group of comparator companies could be identified in the Caribbean and in Latin America but could not identify such a group. Dr. Villadsen explained she did not want to use companies that

had gone through bankruptcy or that did not have investment grade credit ratings or otherwise did not have representative market data. Dr. Villadsen also raised a concern with certain Caribbean companies having extreme growth rates from one year to the next which is not representative of the cost of capital.

247. Based on this reasoning, the Commission accepts the pragmatic approach of utilizing financial data from the US, a mature and stable market, and the incorporation a country risk premium to estimate a ROE for BLPC.

*Country Risk Premium*

248. The CRP refers to risk differences of committing investor funds across various countries. Dr. Villadsen analysis added a purported low and high CRP to each ROE's model's results. The CRP estimate was based, in part, on data for the Caribbean region produced by Dr. Damodaran covering the period January 2017 through July 2021. During the Hearing Dr. Villadsen explained that she did not use Dr. Damodaran's data that is specific to Barbados because "*it's too high probably going forward*." Using the Caribbean dataset, a range of 1.91% to 4.19% was determined based on Caribbean countries with investment grade and non-investment grade credit ratings, respectively. However, Dr. Villadsen did not use the low-end datapoint of 1.91% based on the underlying data source, rather, she based the low-end CRP on BLPC's weighted average cost of debt which was measured as 2.78%.

249. In reviewing the manner in which Dr. Damodaran constructs the Caribbean region CRP data selected by Dr. Villadsen, the Commission observes that country specific bond issuances are not used to estimate the CRP for any of the Caribbean countries. Instead, the estimates are based on the Caribbean countries' credit rating and the average credit default swap spread for countries from across the globe with an equivalent credit rating, together with an emerging market equity volatility multiplier. To cross-check the reliability of the data, the Commission compared the estimated CRP for Jamaica with the CRP relied upon by the Jamaica regulator in its December 2020 decision for the

Jamaica Public Service Company. In that decision, the regulator determined that a 2.53% CRP was appropriate. This value was computed by comparing the average 2018 bond yield spread of the 10-year Jamaican USD denominated sovereign bond to the US 10-year Treasury bond. In contrast, the Commission notes that Dr. Damodaran's 2018 estimate for the Jamaica was 7.50%. The large delta between the two values is a concern.

250. In justifying the use of BLPC's weighted average cost of debt of 2.78% to set the low end of the CRP range used in the analysis, Dr. Villadsen explained during the Hearing that this metric represents the spread between the cost BLPC pays for its debt and US risk-free rate at the time of her analysis, which she stated was close to zero. Taking the framework advanced by Dr. Villadsen a step further, the Commission observes that using the cost of BLPC's 2021 loan rather than the weighted average cost of all outstanding debt on BLPC's books would indicate a CRP of 2.05%. Indeed, this revised metric is close to the low-end of 1.91% derived from Dr. Damodaran's dataset.

251. These observations are considered as part of the Commission's overall ROE determination.

<u>*ROE Analytical Models*</u>

252. The Commission undertook an assessment of the specific ROE models employed by Dr. Villadsen and following that review several factors, in particular, merit further discussion. First, addressing the CAPM analysis, it is noted that Dr. Villadsen employed two CAPM analyses, a standard CAPM and a method known as the empirical CAPM ("ECAPM"). After cross-examination during the Hearing, it is evident that the specific ECAPM model is no longer considered current in the academic community, with Dr. Villadsen acknowledging that most of the supporting research papers she referenced are 30 or more years old. Moreover, while the ECAPM is used by a limited number of regulatory authorities it is indeed not widely utilized. In fact, of the few examples mentioned by Dr. Villladsen she noted the California Public Service

Commission no longer relied on the method. Additionally, the Commission notes that FERC recently rejected placing any reliance on the ECAPM and determined that "*we do not find, based on the record evidence in this proceeding, that the empirical CAPM is widely used by investors*."[78] Taken together, the Commission is not persuaded to rely on the results produced by the ECAPM.

253. Second, Dr. Villadsen put forward two (2) specific DCF analyses which were termed a single-stage DCF model and a multi-stage DCF model. Dr. Villadsen expressed a concern in her written affidavit regarding the multi-stage model's use of US based GDP growth rate because "*it is plausible that the GDP growth rate in Barbados is higher than that of the U.S. either because real growth is higher or because inflation is higher*." Additionally, in a response to an interrogatory she explained that she considered this limitation when reviewing the model's estimates. However, upon oral cross-examination, it became clear that the differences in GDP growth rates did not give Dr. Villadsen "a huge amount of heartburn" as the GDP forecast she reviewed at the time of her analysis for Barbados was 4.0% and the US GDP forecast was 3.9%. Following this clarification, the Commission is of the view that Dr. Villadsen' stated concern has been addressed and there is no need to limit the value of the estimates produced by the multi-stage DCF model.

254. Third, turning to the Risk Premium analysis, the Commission finds the method's core reliance on past US state commission decisions to be problematic and that through this reliance the method suffers from a form of circularity. It is also noteworthy that Dr. Villadsen, upon cross-examination, described the method as a book-based method and not market-based method. The standard regulatory practice for many decades has been to rely on market-based measures of the ROE.

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[78] *Entergy Arkansas et. al*, FERC Docket No: ER13-1508-001 et al., Opinion No. 575 at P 162 (May 20, 2021).

255. These observations are considered as part of the Commission's overall ROE determination.

*Financial Risk Adjustment*

256. As part of her analysis, Dr. Villadsen performed a financial risk adjustment to the underlying ROE results produced by the models. Financial risk is focused on whether the utility can meet its fixed interest charges and principal repayments in a reliable and timely manner. Generally speaking, the risk is increased when the utility has a greater portion of debt as part of its capital structure. The Commission concurs with the general premise of Dr. Villadsen's financial risk adjustment which seeks to account for differences between the equity and debt ratios of the electric utilities included in the proxy group, and the utilities included in the Risk Premium's supporting dataset, to that of BLPC. However, the Commission finds the specific formulaic adjustments undertaken by Dr. Villadsen to be problematic and declines to adopt use of the adjustments.

257. Dr. Villadsen performs two financial risk adjustment approaches. One method, which is applied as part of the DCF, CAPM and Risk Premium analyses, is described by Dr. Villadsen as the "overall cost of capital approach" and the second method uses what is known as the Hamada beta as part of the CAPM analysis.

258. Both approaches suffer from the same core flaw, whereby the calculation relies on market-based capital structure data of the proxy group and treats this data as directly comparable to the book-based capital structure of BLPC.[79] This is internally inconsistent because, as acknowledged by Dr. Villadsen during cross-examination, for most electric utilities the market value for equity is greater than the book value of equity. This creates an imbalance in the formulaic financial risk adjustment, rendering the result unreliable.

[79] Regarding the Risk Premium method, Dr. Villadsen utilized book-based capital structure data in respect of the ROE decision dataset.

259. A further difficulty with the specific financial risk calculations is the assumption that the after-tax WACC estimates for the US electric utilities in the proxy group are intended to represent the electric utility's cost of capital as if it were based in Barbados, through the use of an estimated Barbados corporation income tax rate. The Commission finds this conversion approach to be deficient. As acknowledged by Dr. Villadsen during cross-examination, the US based proxy group companies' market value is impacted by the actual income tax rate it faces and a utility management's decision regarding its capital structure may also be influenced by the applicable tax rate. Therefore, a financial risk calculation that combines the US proxy group companies' market valuation and capital structures with the Barbados tax rate is not appropriate and calls into question the reliability of the results produced by the method.

260. The Commission believes that alternative approaches to managing financial risk discrepancies between the proxy group and the subject utility are preferable. One such approach is to provide for greater alignment between the regulated utility's capital structure used for ratemaking purposes and the proxy group's capital structures. The Commission's decision to use a notional financial capital structure, described earlier, provides for greater alignment with the proxy group.

*BLPC's Relative Risk to the Proxy Group*

261. Dr. Villadsen's recommended ROE of 12.50% is based, in part, on her view that BLPC has higher business risk due to its small size, the scale of the projected capital investments and island environment in which BLPC operates as compared to the average risk of the proxy group. During the oral cross-examination Dr. Villadsen explained that she increased the ROE value by 25 basis points, from 12.25% to 12.50%, to account for these risks. Additionally, Dr. Villadsen says her recommendation is based on the CETR being approved and without the rider a higher ROE would be warranted.

262. The Commission is not persuaded that the support relied upon by Dr. Villadsen adequately justifies the need for an upward adjustment to the ROE. The Commission's view is based, in part, on several factors that bear noting. First, the Commission finds the impact on the ROE if the CETR is not approved to be ambiguously defined, with Dr. Villadsen confirming under cross-examination that she has not studied how much more risk there would be for BLPC if the CETR was not approved.

263. Second, Dr. Villadsen failed to compare the relative scale of BLPC's planned capital expenditure to the projected expenditures of the electric utilities included in the proxy group. This omission means that the Commission does not have the information necessary to assess BLPC's capital expenditure risk relative to the average risk of the proxy group. Additionally, Dr. Villadsen admitted that she did not study the topic of quantifying the increase in fixed costs resulting from BLPC's capital investment plans.

264. Third, the specific support used to justify a greater ROE to account for BLPC's small size is not directly applicable to a regulated utility like BLPC with Dr. Villadsen confirming under cross-examination that the companies included in the underlying study are not risk comparable to the BLPC. Moreover, Dr. Villadsen expressed the view during the Hearing that BLPC's cost of debt does not currently reflect any small company size premium.

265. Fourth, regarding the risk of operating in an island environment, an intervenor questioned Dr. Villadsen as to how the risks associated with the cost of imported fuel was impacted by the FCA. Dr. Villadsen noted the risk was not significant given the pass-through adjustment and added that BLPC faced a time lag between incurring the cost of the fuel and rate recovery but was unable to specify the specific timing of the lag.

266. As a result of these factors, the Commission concludes that the burden to justify the position that BLPC has above-average risk as compared to the proxy group has not been met.

*ROE Recommendation*

267. Having considered the evidence and based on legal authority, judgement and analysis, the Commission finds that the requested ROE should be lowered by 75 basis points from 12.50% to 11.75%.

## COST OF DEBT AND COST OF OTHER COMPONENTS OF REGULATORY CAPITAL STRUCTURE

268. BLPC requests a cost of debt rate of 2.78%. The requested cost rates for the non-traditional components of the capital structure are: (a) customer security deposits at 3.50%; (b) deferred investment tax credits at 9.10%; and (c) deferred manufacturing tax credit at 9.10%.

269. BLPC based its cost of debt rate on the year-end 2020 weighted average cost of debt. This includes its committed but undrawn debt (at the time of the application) of $33.1M which is related to the CEB. BLPC stated that the customer deposit rate of 3.50% was previously approved by the Commission. The other two deferred credit components are costed by BLPC using the financial WACC (i.e., debt and equity only) at the requested hypothetical capital structure of 35% debt and 65% equity, together with the requested ROE of 12.50% and cost of debt of 2.78%.

*Intervenor Positions*

270. Intervenors did not challenge these requested cost rates.

*The Commission's Analysis and Findings*

271. The Commission accepts the use of the year-end 2020 weighted average cost of debt and deems it reasonable to include the estimated draw down of borrowings to support the CEB which is incorporated as a known and measurable change by BLPC.

272. The Commission confirmed that BLPC's request relied on the currently approved customer security deposit rate.

273. The Commission does not agree with BLPC's cost rate for the deferred investment tax credits and deferred manufacturing tax credit. These components should be assigned a cost rate equal to the weighted average cost of capital on all other sources of capital, namely, long-term debt, common equity and customer deposits. This continues the practice adopted in the 2010 Decision.[80]

## RATE OF RETURN

274. Having considered the evidence and based on legal authority, its judgement and analysis, the Commission approves a rate of return of 7.47% to be used in the computation of the revenue requirement. A rate of return of 7.47% will allow BLPC a reasonable opportunity to earn a reasonable return on its invested capital.

[80] 2010 Decision at P 138.

## SECTION 10 – DIVIDEND POLICY

275. BLPC did not make a specific request regarding the payment of dividends. The issue of dividends was raised by intervenors and whether or not BLPC had a corresponding dividend policy. BLPC explained that it does not have a formal dividend policy that identifies the rate of growth of dividends to its shareholders. Additionally, during the Hearing, BLPC explained that while it does not have a formal dividend policy there are certain criteria that govern how dividend payments are determined. These are (1) the solvency of BLPC and ability to pay; (2) prevailing economic conditions and (3) management of the capital structure. Moreover, BLPC has stated that that it intends to bring its actual capital structure closer to the requested capital structure of 65% equity and 35% debt through the "use of dividends and prudent use of debt, without affecting necessary investment for improving service to customers."

*Intervenor Positions*

276. A number of intervenors were concerned regarding the alleged high dividend pay-out since 2010 and that this may be causing BLPC financial strain. Others, discussed the interplay between dividend payments, securing additional debt and the impact on the capital structure.

277. The Barbados Sustainable Energy Cooperative Society Ltd's closing statements stated, among other matters, stated the annual dividend payments since the 2010 Decision should have been no greater than the allowed return on equity set out in the 2010 Decision on capital invested into BLPC. Correspondingly, the intervenor asserted that earnings attributable to shareholder since the 2010 Decision should be limited to $25.5 million per year and dividend payments above this limit should be recovered.

*The Commission's Analysis and Findings*

278. In recent years BLPC's dividend pay-out has varied greatly. The information provided by BLPC indicates that the average pay-out has been 86% since 2009.

More recently, since 2017 it has averaged 54%, with no dividend being paid during 2020. The Commission notes that according to the Edison Electric Institute the average dividend payout percentage for US Investor-Owned Electric Utilities has ranged from 60.4% to 67.0% over the 2012-2021 period.[81] Additionally, the Edison Electric Institute reported that during 2021 certain utilities had pay-out ratios greater than 86%.[82]

279. BLPC has an obligation, under Section 20 of the URA to provide service to the public that is safe, adequate, efficient and reasonable and it must take responsibility to ensure the financial wherewithal of its operations, inclusive of the payment of dividends. Indeed, BLPC described that one of its governing principles applied as part of the decision making process regarding the payment of dividend includes the solvency of BLPC.

280. The payment of dividends is governed by the Companies Act, Chapter 308 of the Laws of Barbados. The Commission does not have the authority to direct BLPPC regarding the declaring and payment of dividends. A contention raised by an intervenor during the proceeding, was that the BLPC is a public utility. This is not the case, rather, the BLPC is private company that provides a public utility service and which does not extend an invitation to the public to subscribe for its shares or debentures.

281. The Commission is authorized, pursuant to Section 16 of the URA, to initiate a review of the rates, principles and standards of service for the supply of utility service. To protect customers and the integrity of the utility the Commission monitors and acts upon instances where a utility may be earning excessive returns and taking actions that are contrary to the utility's financial well-being or undertaking other inefficient actions.

[81] Edison Electric Institute, 2021 Financial Review, Annual Report of the U.S. Investor-Owned Electric Utility Industry at page 14.
[82] *See id.*, at page 15.

## SECTION 11 – FINANCIAL FORECASTING

282. In the Application, BLPC provided a financial forecast for the years 2021 through 2025 and provides its financial performance under two different scenarios. One scenario incorporates the proposed rates, and the other scenarios is based on using the existing rates. According to BLPC, if existing rates are maintained that its revenues would be insufficient to allow it to; (a) fund planned investments (b) insufficient resources to attract capital and (c) insufficient financial resources to respond to financial, economic or environmental shocks. Moreover, according to BLPC, with the proposed rates, it will not be in a position to earn its requested rate of return during the five-(5) year period due to the capital investment that it anticipates it will be making. Therefore, BLPC anticipates it will require additional rate relief during the five-year period. Additionally, during the Hearing BLPC sought to emphasize that the forecast is not determinative regarding the base rate application.

*Intervenor Positions*

283. The primary focus of intervenors was on the projection of sales included as part of the financial forecast and how it compared with the 2020 Test Year. BREA expressed a concern about the staleness of the financial forecast given the passage of time since the application was filed.

*The Commission's Analysis and Findings*

284. The matter of the projected sales and the interaction with the appropriate sales to use when determining base rates in this proceeding is dealt with in section 4 of this Decision.

285. First, following the passage of time since the Application was filed, the Commission finds that the value of the financial forecast to be generally limited. For instance, it was noted in the Interim Rate Decision that the projected capital spend for 2022 of $161.7 million was revised downwards to $108.89 million due to several factors. Additionally, comparing the 2021 actuals to the projection for

that year, raises several additional concerns in respect of the reasonableness of non-fuel and purchase power expenses. While the overall amount of actual and projected expenses is comparable, the component-by-component differences are noteworthy, especially when considering the projection for 2021 was developed during the 2021 year. For example, the projected depreciation expense was $2.6 million greater than actual. Also, insurance costs for 2021 projections, which are shown at $11.2 million exceed actuals by over 8% and general expenses were projected to be $4 million lower than the actual outturn. In the Commission's view, these aspects compromise the value that can be gathered from the financial forecast at this time.

286. Second regarding BLPC's ability to manage debt covenants, BLPC clarified during the Hearing that its current credit facilities, require that a minimum equity to debt ratio of 50:50 is maintained together with an Earnings Coverage minimum of 1.25. Company witness, Mr. Jennings, stated that based on his calculations, the Earning Coverage ratio would be 1.35 in 2025. He added that at the end of 2020, the Earnings Coverage ratio was 4.4, at end of 2021 it was 3.03 and presently it is approaching 2.2. BLPC has stated the intention that it would file for a review of electricity rates by the end of the five-year forecast. Additionally, BLPC's application for CETR remains outstanding. These are options that can be utilized to manage BLPC's alleged decline in the latter years of the forecast period.

287. Based on the above, the Commission accepts the financial forecast data for the purpose of the rate making process.

## SECTION 12 – COST OF SERVICE STUDY

288. The purpose of the Cost of Service Study ("COSS") is to determine the cost of serving specific rate classes. This determination is made through a three-stage process in which the utility's investment and expenses are functionalized, classified, and then allocated between customer classes.

289. The assignment of costs is achieved through the use of ratios typically referred to as functionalization factors, classification factors, and allocation factors. These factors can be developed internally within the COSS or can be input from external sources.

290. In order for the results of the cost of service to be accurate, functionalization, classification, and allocation factors must be used which accurately reflect the nature of the cost or investment to which the factor is assigned. Use of unrepresentative factors at any of the stages will result in incorrect results.

291. These incorrect results will occur both in the total revenue requirement assigned to customer classes and the portion of costs that are assigned as customer, demand, or energy-related.

292. During the Hearing the following problems were identified with BLPC's as filed COSS:
    a. Property Insurance should be functionalized on the basis of total Generation, Transmission, and Distribution plant;
    b. Meter -related expenses should not be allocated to streetlight customers, who do not have meters; and
    c. Administrative and General ("A&G") expenses should be functionalized to Generation, Transmission, and Distribution areas as they support all aspects of BLPC's operations, not only the Distribution function.

*Intervenor Positions*

293. No Intervenor groups addressed the COSS during the Hearing or in writing.

*The Commission's Analysis and Findings*

*Property Insurance*

294. BLPC's filed COSS functionalized FERC Account 924 Property Insurance entirely to the Distribution function. Property insurance is incurred on all of BLPC's assets, including Generation plant. Entirely allocating the costs to the distribution function results in no costs being assigned to the generation or transmission functions.

295. Under questioning from the Commission, BLPC's expert witness, Dr. Phillip Hanser of Brattle Consulting, agreed that the functionalization for FERC Account 924 should be corrected to recognize that insurance was incurred on all utility assets.[83]

296. The Commission orders the use of the "PT_Total" functionalisation factor for functionalising property insurance, as opposed to the "Distribution" functionalisation factor used in BLPC's as filed COSS.

297. Use of the "PT_Total" as a functionalization factor will more fairly apportion the costs of insurance expense to all functions of the utility.

*Meter Reading Expense*

298. FERC Account 902 Meter Reading Expenses contains expenses incurred in the process of reading customers meters and determining consumption.

299. Street Lighting customers are unmetered and therefore do not cause BLPC to incur costs related to meter reading.

[83] Transcript Day 12 at 1870

300. During the Hearing, Dr. Hanser stated a revision to the COSS was necessary in order to remove the allocation of FERC 902 expenses from street light customers[84].

301. The Commission orders revision of the "Meter Reading" allocation factor to exclude Street Lighting customers.

*Labor-Related Administrative and General Expense*

302. As labour-related A&G Expenses in FERC Accounts 920, 921, 923, and 926 are incurred to support all aspects of BLPC's operations and are ultimately allocated to customer classes on the Basis of Salaries and Wages, assigning these costs directly to the Distribution function is improper and results in overstatement of the portion of the costs that is output by the COSS as being customer-related.

303. Consistent with BLPC's use of the "Salaries and Wages" allocation factor, the Commission orders the development and use of a "Salaries and Wages" functionalization factor based on the salaries expense incurred in the Generation (FERC Accounts 500-557), Transmission (FERC Accounts 560-574), and Distribution (FERC Accounts 580-598 and Customer Accounts, Customer Service and Informational Salaries in FERC Accounts 901-917) functions. This functionalization factor is to be used for the functionalization of expenses in FERC accounts 920, 921, 923 and 926 and will provide a more fair and accurate distribution of the labour-related A&G costs within the COSS.

304. The Commission further finds that BLPC's proposed "Salaries and Wages" allocation factor, which is used to allocate the costs of labour-related A&G expense in FERC Accounts 920, 921, 923, and 926, is not appropriate for assigning costs as it only includes the costs of labour in FERC Accounts 901-909, which are expenses related to Customer Account Expenses and Customer Service and Informational Expenses.

[84] Transcript Day 12 at line 2012-2013

305. Salaries related to Customer Account Expenses and Customer Service and Informational Expenses are functionalized directly to Demand, classified as Customer-related, and are allocated between classes on the distribution of metering-related or customer-related costs. The functionalization, classification, and allocation of these costs are not representative of BLPC's operations as a whole.

306. BLPC's proposed "Salaries and Wages" allocation factor does not recognize that the expenses in FERC Accounts 920, 921, 923 and 926 are incurred to support all functions of the BLPC's operations, including Generation.

307. The Commission orders the use of a "Salaries and Wages" allocation factor based on the ultimate functionalization, classification, and allocation of all salary expense incurred in FERC Accounts 500 through 909.

308. Dr. Hanser agreed this change should be made during the Hearing.[85]

*BLPC's Proposed Assignment of Certain Expense and Investment as Customer-Related*

309. Within the COSS, BLPC proposes to classify a larger portion of costs as customer-related than in previous COSS accepted by the Commission.

310. BLPC stated that this methodology would more accurately reflect the amount incurred to provide service to a customer, as these costs vary in proportion to the number of customers served[86].

311. Under questioning by the Commission Dr. Phillip Hanser stated that no testing had been done to confirm the impact of the methodology change on rate model outputs[87].

[85] Transcript Day 12 at line 2078-2081
[86] Application, Page 1262
[87] Transcript Day 12 at line 1639-1644

312. The resulting outputs of the COSS model indicate that a significant increase in customer charges would be needed for all classes in order to recover the customer-related cost of service entirely through customer charges.

313. BLPC stated that this change in classification is appropriate for several reasons.

314. First, BLPC stated that a minimum system study was performed that supports the splits between customer-related and demand-related plant and expense within the COSS.

315. A minimum system study is used to determine the "minimum" system that would be required to serve customers, assuming all customers exhibited the same minimum loading requirements. The portion of investment associated with this minimum system is classified as customer-related, while the remaining system is assumed to be put in place to respond to additional demand above the minimum loading requirements and as classified as demand-related.

316. The Commission recognizes that this approach is one that has been approved by a number of regulatory bodies and is outlined in the NARUC Electric Cost Allocation Manual as a method of determining what portion of plant is customer-related.

317. Other widely-accepted methodologies used include the Basic Customer Charge and the Zero-Intercept method.

318. Second, BLPC claims that the change will help it maintain revenues that would otherwise be deteriorated as renewable energy resources are introduced, resulting in lower energy consumption[88].

319. Third, with respect to the instant case, the factors that drive the cost of service have changed compared to the COSS performed in the last rate case[89]. However, when questioned at the Hearing, the change in factors was linked to future

[88] Transcript, Day 12 at line 1097-1108
[89] Application page 1256.

changes in consumption patterns as a result of the transition to renewable energy[90], not any actual changes in the underlying processes or investment needed to provide service.

320. BLPC has the responsibility of providing sufficient evidence to support its proposed approach to classification of plant.

321. No evidence of the existence of the minimum-system study, the underlying calculations or methodology, assumptions made, or results have been produced by BLPC.

322. The Commission and Intervenors have not had the opportunity to review the minimum-system study for accuracy, errors, or reasonableness.

323. The Commission rejects BLPC's argument that usage will drop with the transition to renewable resources for two reasons. First, the argument is speculatory and unsupported by any analysis of future sales or studies showing drops in revenues and is in fact contradicted by the increasing sales shown in BLPC's own forecasts. Secondly, customers with self-owned generation who are connected to the grid through the "buy all/sell all" billing arrangement would still be billed for all consumption and therefore would not be able to avoid consumption charges as stated by Dr. Hanser.

324. The Commission further believes that any changes in consumption due to the adoption of renewables will take place over a timespan that does not require the Commission to act prospectively to address, as the resulting deterioration in revenues can be addressed through the filing of rate review applications.

325. If deterioration in revenues due to the adoption of renewable resources is determined to be a threat to the economic livelihood of BLPC, the Commission believes that a more focused proceeding to identify the root causes of the deterioration and ensure that customers with distributed generation are not

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90 Transcript, Day 12 at line 1655-1660

avoiding paying their cost of service is a more appropriate venue than a full rate review. A more focused proceeding would allow the Commission to ensure that all relevant stakeholders participated, and that the method of cost recovery would not be at odds with the goals of the Barbados National Energy Policy ("BNEP").

326. The Commission also expresses concern with the following three facets of BLPC's proposal.

327. First, that higher customer charges resulting from the change in methodology may ultimately cause the adoption of renewable resources to slow.[91]

328. Second, if revenues are reduced as renewable energy resources are introduced to the grid, BLPC's proposed methodology change does not target the customers causing the decline, instead imposing higher fixed costs on all customers. This in turn may result in subsidization of customers able to afford distributed generation by those unable to afford distributed generation.

329. Third, the Commission questions the assumptions commonly inherent in a minimum system study:

  a. that actual facilities (e.g. number of poles, miles of line) installed to serve customers accurately mirrors the system that would be built to serve minimum demand.
  b. that the price of the currently installed minimum-sized unit is representative of one that would be installed in the absence of demand as all units are sized to accommodate certain levels of demand.
  c. that the distribution cost of serving load within a given area varies based on the number of customers served.

[91] See Net Metering and Market Feedback Loops: Exploring the Impact of Retail Rate Design on Distributed PV Deployment, 2015, Darghouth et al., finding that rate structures with higher fixed charges can dramatically erode aggregate customer adoption of PV.

330. Given the lack of support for the change in methodology, the Commission finds that the change in methodology lacks merit.

331. In order to reverse the effect of the change in methodology, changes must be made to the classification of items within the COSS. These changes are set out below.

332. The Commission orders that the following FERC Accounts be classified as demand-related within the COSS:

   a. FERC Account 364 – Poles, Towers and Fixtures
   b. FERC Account 365 – Overhead Conductors and Devices
   c. FERC Account 367 – Underground Conduit, Conductors and Devices
   d. FERC Account 368 – Line Transformers
   e. FERC Account 593 – Maintenance of Overhead Lines
   f. FERC Account 594 – Maintenance of Underground Lines
   g. FERC Account 595 – Maintenance of Line Transformers

333. The Commission orders that the following FERC Accounts be classified as customer-related within the COSS:

   a. FERC Account 369 – Services
   b. FERC Account 370.1 - Meters
   c. FERC Account 370.2 – AMI Meters
   d. FERC Account 597 – Maintenance of Meters

334. The Commission determines and orders that in future rate proceedings, BLPC shall publicly provide the Cost-of-Service model in native format, with all formula and links intact, with its initial application. This would allow intervenors and the Commission to better review the model and is generally required by regulatory bodies of investor-owned utilities.

## SECTION 13 – RATE DESIGN

335. Rate Design is guided, but not entirely dictated, by the results of the COSS. Other factors related to rate design considered in previous rate review proceedings included encouraging energy conservation, minimization of the impact of any increase on lower-usage customers and moving classes toward their cost-of-service.

336. As a result of BLPC's proposed methodology for classifying a larger portion of costs as customer-related, discussed in the previous section, the proposed rate design included large increases to fixed charges.

337. These increases were claimed by BLPC to better align the cost structure and rate structure of the utility.

338. The differences between the revenues being received in base rates from customer classes and the results of the COSS lead to BLPC proposing adjustments to the revenue requirements to limit the impact of the rates on the Domestic Service and Street Lighting customer classes. These target revenue levels were used to develop rates.

339. BLPC further justified the assignment of a 0% return for the Street Lighting customer class as Street Lighting is provided as a public service.

340. The target revenue requirement for Employee customers was reduced so that the class was not paying a return on the investment apportioned to it in the COSS. The result of this adjustment was that the target increase for the Employee rate class was reduced to below the increase for residential customers.

341. The shortfall in revenues resulting from these adjustments result in the General Service, Large Power, Secondary Voltage Power, and Time-of-Use customers being proposed to pay over the revenue requirement assigned to them within the COSS.

342. Revenues are recovered through three base rate components:

a. Customer charge – a fixed amount charged to customers regardless of consumption
b. Demand charge – a charge applied to recover costs associated with investment and expense related to the demand on the electrical system.
c. Base energy charge – a charge that recovers the variable non-fuel energy-related costs.

343. Within the Domestic Service, Employee and General Service rate classes, base charges increase depending on the level of consumption by the customer, with higher charges being applied as usage grows. This rate structure is generally referred to as an inclining block rate structure.

344. Due to the impacts on customer bills from moving the fixed charges to recover all customer-related costs arising from the COSS, BLPC moderated the fixed charges proposed, recovering a portion of the costs it determined as being customer-related through consumption and demand charges.

345. BLPC also took steps when designing rates to limit the impact on specific groups of customers within customer classes, for example ensuring the increase for Domestic Service customers using between 0 and 150 kWh, which comprise 35% of Domestic Service customers, did not exceed $6 per month.

346. Despite the adjustments made to the cost-based rates by BLPC, significant increases in bills and rates were proposed. Of note, the proposed customer charge for Large Power customers was set at $1,287, an increase of 429% over the current charge of $300.

*Intervenor Positions*

347. Intervenors generally expressed concern over the impacts that BLPC's proposed rates would have on low-usage customers, such as certain customers within the Secondary Voltage Power rate class.

348. Proposals were made by BREA and echoed by Intervenor Went that separate rate classes could be set up to protect vulnerable customers.

349. In closing statements, the Division of Energy stated that the rate design should follow the Bonbright principles of sound rate structure, including:

a. the practical attributes of simplicity, understandability, public acceptability, and feasibility of application;
b. be free from controversies as to proper interpretation;
c. should effectively yield total revenue requirements under the fair return standard;
d. should provide stability from year to year;
e. rates themselves should be stable, that is rates should experience minimal unexpected changes that are seriously adverse to existing customers;
f. should apportion the total cost of service fairly among different consumers;
g. should avoid undue discrimination; and
h. should promote efficiency.

350. The Division of Energy also expressed concern that the rates as proposed by BLPC are at odds with the goals of the BNEP, specifically making energy affordable and accessible to all.

*The Commission's Analysis and Findings*

*General Analysis*

351. The Commission finds that BLPC's proposed overall revenue requirement overstated the cost of service and should be reduced.

352. The Commission finds that BLPC's proposed COSS methodology is unsupported and cannot be relied upon for ratemaking purposes.

353. As a result, the rate design proposed by BLPC, which anticipated an overall increase in base rate revenues of $46.4 million, or 24.98% when excluding fuel expenses and proportionally larger increases to customer charges is no longer appropriate.

354. Some of the methodology employed by BLPC for purposes of designing rates may no longer be relevant given the changes in overall revenue requirements and the assignment of costs to customer classes.

355. As part of the Compliance Filing, BLPC shall provide recalculated revenue requirement, and COSS as discussed below. The Commission will make a determination as to the final approved rates after review of the Compliance filing and issue an order ("Final Order") at that time.

356. Issues related to specific rate classes will be discussed below.

*Employee Rate Class*

357. Current and former employees of BLPC are provided service under the Employee rate schedule, which provides an automatic discount and allows them to avoid fixed charges.

358. BLPC proposed in Schedules K of the application a rate structure including an inclining block consumption charge which represents a discount from the rates charged to a Domestic Service customer.

359. Section 13 of the Utility Regulation Act states in regards to rate discrimination:

> *(1) No service provider shall supply or furnish to any person any utility services at rates which are unduly preferential or unduly discriminatory.*
>
> *(2) A service provider shall not*
>
> *(a) in respect of a rate or a utility service, subject any person or locality, or a particular description of traffic, to any undue prejudice or undue disadvantage; or*

> *(b) extend to any person any agreement, rule, facility or privilege unless that agreement, rule, facility or privilege is regularly and uniformly extended to all persons under substantially similar circumstances and under conditions of service of the same description.*
>
> *(3) Notwithstanding subsections (1) and (2) a service provider may with the approval of the Commission supply a utility service to any charitable organisation or disadvantaged person at a reduced rate.*

360. Service under the Employee rate class is provided for domestic usage only.

361. Under BLPC's proposed rates, a person taking service under the employee customer class would receive the same level of service as a Domestic customer at substantially lower rates.

362. No difference exists as to the level of service and no evidence exists that BLPC's employees have substantially different usage patterns that would cause the cost of service to be lower than an equivalent Domestic customer.

363. BLPC's COSS, as filed, returned total tariff revenue requirement of $165,049,143 for Domestic customers, or $124.66 per bill, and a total tariff revenue requirement of $827,822 for Employee customers, or $149.97 per bill, indicating that the cost of serving the average Employee customer is higher than the average Domestic customer.

364. The Commission finds that the existence of a discounted rate for the Employee class results in the extension of a privilege which is not uniformly extended to all persons under substantially similar circumstances and under conditions of service of the same description.

365. The Commission finds that the existence of the Employee rate class as a separate rate class from Domestic Service is unsupported and the subsidization of the class by other rate payers is unduly preferential.

366. The Commission therefore determines and orders that customers currently taking service under the Employee tariff be moved to the Domestic Service tariff, to be effective as of a date to be determined in the Final Order.

367. The Commission notes that this decision does not preclude the BLPC from continuing to provide a discount to ratepayers formerly taking service under the Employee tariff. However, for purposes of regulatory reporting and in future rate cases, the BLPC is to show revenues from these customers equivalent to those that would have been collected if no discount were applied. In other words, the discount will be borne by the shareholder instead of being subsidized by other ratepayers.

368. In the case that the BLPC determines it shall continue to provide a discount to ratepayers formerly taking service under the Employee tariff, BLPC is to include in the Compliance Filing a description of the mechanism used to effectuate the discount. As placing these customers on a standalone tariff will no longer be an option, BLPC will need to include the proposed tariff language edits needed to calculate and effectuate the discount to standard Domestic Service rates in the Compliance Filing.

## SECTION 14 - RENEWABLE PURCHASE POWER ADJUSTMENT AND FUEL CLAUSE ADJUSTMENT

369. BLPC proposes to recover costs related to renewable power purchases and costs related to fuel through two separate riders.

370. Currently, all costs of fuel and renewable power are recovered through the FCA factor included on customer bills.

371. BLPC proposes to recover only fuel costs through the FCA, while costs related to purchases of renewable power will be recovered through the RPPA. This process of separating the recovery of costs related to each type of energy source is referred to as "disaggregation".

372. BLPC stated several reasons justified the change.

373. First, the recovery of non-fuel costs through the fuel clause resulted in customer confusion which would be avoided by the adoption of the Renewable Purchase Power Adjustment. Second, BLPC stated that the disaggregation of the costs will allow customers to better understand the progress related to the move to renewables and the associated savings.

*Intervenor Positions*

374. Various intervenors support the disaggregation of the FCA and RPPA, stating that it will improve transparency.

*The Commission's Analysis and Findings*

375. The Commission finds recovery of renewable power through a Renewable Purchase Power Adjustment factor to be beneficial for the reasons cited by Applicant and intervenors.

376. The Commission orders the addition to the formula for calculating the monthly $/kWh to include cumulative under/over recoveries from previous months. This is to be achieved by the modification of the description of the "Cost of

Renewable Power Purchases$_{n-1}$" from "Total cost of renewable power purchased in the previous month" to "Total cost of renewable power purchased in the previous month, including cumulative over/under recovery". This change is intended to allow for BLPC to adjust recovery through the FCA when previous recoveries do not match the amount of cost incurred.

377. BLPC is to report to the Commission monthly by the 15th day of the month:

a. The portion of total energy purchased from renewable resources in previous month.
b. The cost of renewable power purchases in the previous month.
c. Total renewable energy kWh purchased in the previous month.
d. Total revenues recovered through the RPPA mechanism in the previous month.
e. Any cumulative over/under recovery of renewable power purchases and recoveries of renewable power purchase costs through the RPPA.
f. For each source from which renewable power is purchased during the previous month, provide:
    i. The name of the owner of the source
    ii. Source type
    iii. amount of renewable kWh purchased
    iv. total cost of renewable purchases
    v. cost of renewable purchases on a dollar per kWh basis

## SECTION 15 - SERVICE CHARGES

378. BLPC proposed changes to the charges assessed for various services, including shut off of meters, applications for connecting solar generation to the grid, and office appointments outside of business hours.

379. After review of the calculation of BLPC's proposed charges, the Commission approves the proposed charges.

## SECTION 16 - COMPLIANCE FILING

380. The Commission orders BLPC to file a revised Revenue Requirement and COSS which incorporate the Commission's findings and orders within three (3) weeks of the issuance of this decision.

381. Specifically, the Commission orders that BLPC provide copies of the following schedules in the Compliance Filing with adjustments to incorporate the Commission's findings and orders:

a. C-1 Calculation of Rate Base
b. C-2 Utility Plant in Service, Including Accumulated Depreciation
c. C-2-1 Utility Plant not Used and Useful
d. C-3 Construction Work in Progress
e. C-4 Cash Working Capital
f. C-5 Materials and Supplies and Prepayments
g. C-6 Deferred Taxes
h. D-1 Income Statement
i. D-2 Statement of Operating & Maintenance Expenses by Department
j. D-3 Calculation of Deferred Taxes, Investment Tax Credit and Manufacturing Tax Credit
k. D-4 Corporation Tax Computation
l. D-5 Statement of Depreciation Expense
m. D-7 Explanations and Comments on Adjustments
n. G-1 Statement of Revenue Requirements
o. Table K.4
p. Table K.5, using a target parity ratio of 100% for all rate classes
q. PH02 Allocated Class Cost of Service Study

382. These schedules must be produced in their native format with all links and formula intact and shall also be provided in PDF format. For any adjustments not explicitly ordered in this Decision, such as changes in income taxes arising

from the difference between the proposed and final Rate of Return, BLPC must provide the full calculation of the change in Microsoft Excel format.

383. BLPC shall provide a Microsoft Excel file showing the application of the approved depreciation rates to Plant in Service balances as of the Interim Rate Effective Date by account. The resulting depreciation expense total should match that included in the Compliance Filing revenue requirement.

384. BLPC shall provide a Microsoft Excel file linking the results of the revised Allocated Class Cost of Service Study to the revenues to be recovered through base rates shown on the revised Table K.5 (i.e. Customer, Demand and Base Energy Charges) for each class, with each class being assigned a 100% parity ratio.

385. BLPC shall provide a Microsoft Excel file linking the results of the Allocated Class Cost of service study, as presented in the originally filed application, to the values shown on the originally filed Tables K.4 and K.5

386. For purposes of this filing, the BLPC shall reflect the movement of ratepayers currently taking service under the Employee tariff to the Domestic Service tariff.

387. The Proposed Tariffs included in BLPC's Schedules K-1 through K-11, shall be provided to the Commission in Microsoft Word format.

388. In addition to the schedules listed above and information required by other paragraphs, the Commission requests that the following be included in the Compliance Filing:

    a. A Proof-of-Revenue worksheet including the following information for each rate class for the period starting July 1st, 2021 and ending June 30th, 2022. This file is to be provided in native excel format with all formulas intact and hardcoded inputs clearly identified by the use of unique formatting:

        i. Annual Billing determinants by rate component (e.g. number of bills, demand, kWh consumption within usage block)

ii. Contemporaneous current (non-interim) rate by rate component (e.g. Customer Charge, Base Energy Charge).
iii. Annual revenues by rate component produced by multiplying the billing determinants provided in subpart i. with the current (non-interim) rates provided in subpart ii.
iv. Per books annual Basic Revenue produced by current rate component (Customer Charge, Demand Charge, and Base Energy Charge).
v. Annual total revenues produced by summing the revenues associated with each rate component determined in subparts iii and iv.
vi. A reconciliation of the basic revenues produced by current rates in the proof-of-revenue calculation described above and the per book revenues, at the bill component level.
vii. For the BLPC's reference, an example of this worksheet for select customer classes is provided as Attachment B to this decision.
viii. For discrepancies between the calculated and booked amounts exceeding 2% at the total class revenue level must be noted and an explanation for the difference provided along with a calculation in excel format reconciling the difference.
ix. For discrepancies between the calculated and booked revenues occurring due to discounts provided by BLPC for early payment or other reasons, BLPC is to provide the following information by rate class and discount type:
    1. Total ratepayer savings by month
    2. Number of ratepayers receiving the discount by month

b. BLPC shall include a separate file showing the same information requested in subpart a. above for the year ending December 31st, 2020. In addition, BLPC shall include a proof showing that application of the billing determinants for the year ending December 31st, 2020 to the rates proposed by BLPC in the Application result in the base rate revenues shown in Column (8) of Table K.5

c. Examples of the calculation of disaggregated RPPA and FCA using actual expenses incurred three months prior to the issuance of this Decision, including:
    i. The calculation of the actual FCA under the currently approved tariff.
    ii. The calculation of the RPPA and FCA under BLPC's proposed tariffs.
    iii. Example bills showing the proposed presentation of the RPPA and FCA and application of the charges to the total amount collected from the customer.

389. The interim rate order issued September 16th, 2022, included the following language: "These interim rates shall be effective from the date of this Decision until the Commission issues a final determination on BLPC's substantive application for rate review. Additionally, should these interim rates be found excessive after the full rate review, BLPC shall refund its customers the difference between the rates and the final approved rates, with an interest rate equivalent to the return on equity to be approved in the substantive rate review."

390. The issue of refunds to customers, if any, will be addressed in the order approving final rates.

## SECTION - ORDER

**UPON HEARING** Mr. Ramon Alleyne K.C, Attorney-at Law in association with Mr. Kevin Boyce, Attorney-at-Law, Ms. Shena-Ann Ince, Attorney-at-Law and Ms. Zaria Weatherhead, Attorney-at-Law, of the firm Clarke Gittens Farmer for the Applicant;

**AND UPON HEARING** the Applicant's witnesses, Mr. Roger Blackman, Mr. Ricaido Jennings, Mr. Rohan Seale, Mr. Johann Greaves, Dr. Adrian Carter and expert witnesses Dr. Philip Hanser, Mr. Peter Huck and Ms. Bente Villadsen;

**AND UPON HEARING** the Intervenors, the Ministry of Energy and Business (Business Development Division) represented by Ms. Sharon Deane, Public Counsel (ag.) in association with Ms. Jamilla Eastmond, Legal Officer, the Barbados Association of Retired Persons represented by Ms. Sharon Deane, Public Counsel (ag.) in association with Ms. Jamilla Eastmond, Legal Officer and Ms. Marilyn Rice-Bowen, the Barbados Renewable Energy Association represented by Mr. Stephen Worme and Mr. Robert Goodridge, the Energy Division, Ministry of Energy & Business (Energy Division) represented by Ms. Samantha Cummins, Chief Legal Officer and Mr. Alton Best, Economist, the Barbados Sustainable Energy Co-operative Society Ltd represented by Lt. Col. Trevor Browne and Mr. Hally Haynes, Ms. Tricia Watson, Attorney-at-Law, in association with co-intervenor Mr. David Simpson and Mr. Kenneth Went on behalf of the public in association with Mr. Tony Gibbs, Mr. Adlai Stephenson and Dr. Aly Elfar.

**AND UPON HEARING** the submissions of the Applicant and Intervenors, the oral arguments of the parties during the Hearing, the closing submissions of the Applicant, the Ministry of Energy and Business (Business Development Division), the Barbados Association of Retired Persons, the Barbados Renewable Energy Association, the Ministry of Energy & Business (Energy Division), Mr. Went, the Barbados Sustainable Energy Co-operative Society Ltd and the further written submissions submitted by the Applicant, Mr. Went, the Barbados Renewable Energy Association, and the Barbados Sustainable Energy Co-operative Society Ltd;

**IT IS HEREBY ORDERED AS FOLLOWS:**

391. The request that the proposed tariffs come into effect from April 1st, 2022 is denied. The Commission will make a determination as to the final approved tariff rates and the tariff effective date, after review of the Compliance Filing, as part of the Final Order.

392. Interim rates are to continue to be billed through the date to be determined in the Final Order. The issue of refunds to customers, if any, will be addressed in the Final Order.

393. BLPC is directed to update the rate base valuation related to net utility plant, regulatory asset and liabilities, and the associated plant-related accumulated deferred income tax liabilities as of the Interim Rate Effective Date in accordance with the direction provided in the body of this Decision.

394. Updating rate base valuation will require BLPC to adjust certain expense items included in the calculation of the revenue requirement, including depreciation expense and income tax expense. BLPC is directed to make such adjustments.

395. BLPC's request to recover the undepreciated portion of the 5 MW energy storage device and operating expense in base rates is denied. The costs related to the energy storage device will continue to be recovered through the FCA.

396. The Commission directs that BLPC shall discontinue operation of Steam Plant S1 and place the unit into reserve operation status through its retirement as soon as possible but no later than December 31st, 2023. As such, BLPC will include the Steam Plant S1 operating and maintenance costs in the calculation of costs recovered through the FCA recovery mechanism. The Commission will consider the prudency of and recovery of fuel and operating costs associated with the Steam Plant S1, as part of its review of costs recovered through the FCA.

397. BLPC is directed to provide monthly reports for each generation unit as set out in the body of the Decision and Attachment A.

398. The amount of working capital to be included in the revenue requirement shall be recalculated to account for the Commission's adjustments the O&M expenses determined in this Decision. The Commission further directs BLPC to include as part of its next base rate application, a cash working capital allowance in rate base that is supported by a fully developed and reliable lead/lag study.

399. BLPC is directed to establish a regulatory liability to recognize the difference between the accumulated depreciation recorded using the approved regulatory depreciation rates and the accumulated depreciation recorded based on the depreciation rates the BLPC used for its financial statements. The regulatory liability balance is to be updated as of the effective date of this Decision and shall be amortized over a fifteen-year period.

400. The Commission orders the use of base revenue, customer count, usage and demand values from the period ended June 30th, 2022 for purposes of making an adjustment to test year revenues and within the cost-of-service study.

401. In the development of the revenue requirement, BLPC is directed to modify its as-filed test year expenses in respect of the following items:
   a. Utilize the 2020 reported insurance expense of $8,198,082;
   b. Remove the $252,000 of charitable donations and sponsorship; and
   c. Remove the affiliate expenses of Staff Secondments, Board Fees and Other.

402. BLPC is directed to use the generation depreciation rates listed in Attachment C. Additionally, the Commission accepts BLPC's request to use a 4.0% deprecation rate in respect of the Clean Energy Bridge.

403. BLPC is directed to establish a regulatory asset in respect of the interim additions made to Garrison GT No. 2 and Spring Garden Steam Equipment. The regulatory asset balance is to be updated as of the Interim Rate Effective Date and shall be amortized on a straight-line basis through December 31st, 2030.

404. BLPC is directed to record fifty percent of its 2019 income tax gain as a regulatory liability and amortize the liability over a fifteen-year period.

405. In respect of the SIF, BLPC is direct to establish a record of $99.5 million in a regulatory liability account. In the event of a catastrophic event that is eligible to be covered by the SIF, the BLPC is directed to first deploy the monies recorded in the regulatory liability account. BLPC is further directed to refund to customers the SIF amounts withdrawn that are not re-deposited into the SIF over a 30-year amortization period as a reduction to insurance expense that shall be shown as a separately identifiable amount for regulatory reporting purposes.

406. BLPC is directed to conduct actuarial studies, by an independent actuary, to assess the value of self-insurance needed, in accordance with the timelines set out herein.

407. The financial capital structure of Equity 65% and Debt 35% used by BLPC in the determination of its rate of return is denied. BLPC is granted a financial capital structure of Equity 55% and Debt 45% for ratemaking purposes in the determination of the rate of return.

408. The rate of return on rate base of 8.79% is denied. The Commission approves a rate of return of 7.47% to be used in the computation of the revenue requirement.

409. As set forth above, the existence of the Employee class and the subsidisation of the Employee class is unsupported and creates unduly preferential rates. If BLPC determines that it will continue to provide a discount to Employees, it shall provide the tariff revision information requested above.

**IT IS FURTHER ORDERED THAT:**

410. BLPC is directed to modify its cost-of-service study in respect of the following components:

411. Use of "PT_Total" functionalization factor for functionalizing Property Insurance, as opposed to the "Distribution" functionalization factor used in BLPC's filed COSS.

412. The "Meter Reading" allocation factor shall exclude the Street Lighting customers.

413. The "Salaries and Wages" allocation factor shall be on the ultimate functionalization, classification, and allocation of all salary expense incurred in FERC Accounts 500 through 909.

414. BLPC's use of minimum system study as part of its cost-of-service study is rejected. BLPC is directed to implement the changes identified in the body of the Decision to reverse the use of the minimum system study.

415. The Commission accepts BLPC's request to recover costs related to renewable power purchases and costs related to fuel through two separate riders and requires certain adjustments to formulas proposed by BLPC, together with certain monthly reporting requirements, as set out in the body of the Decision.

416. The Commission accepts BLPC's proposed service charges.

417. BLPC is directed to comply with the Compliance Filing requirements set forth in the Decision.

Dated this 15th day of February, 2023

*Original signed by*

……………………..

Donley Carrington

Hearing Chairman

*Original signed by*

…………………………

John Griffith

Commissioner

*Original signed by*

…………………………..

Ruan Martinez

Commisisoner

*Original signed by*

………………………..

Ankie Scott-Joseph

Commissioner

*Original signed by*

……………………………..

Samuel Wallerson

Commissioner

## ATTACHMENT A

Unit Performance Data

Plant: ______________ Unit: ________

Year:

| | | Jan | Feb | Mar | Apr | May | June | July | Aug | Sep | Oct | Nov | Dec | YTD |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | EAF | | | | | | | | | | | | | |
| 2 | Period Hours | | | | | | | | | | | | | |
| 3 | Plant Operating Hours | | | | | | | | | | | | | |
| 4 | Net MWh Generated | | | | | | | | | | | | | |
| 5 | Forced Outage Lost MWh | | | | | | | | | | | | | |
| 6 | Forced Derate Hours | | | | | | | | | | | | | |
| 7 | Forced Derate Lost MWh | | | | | | | | | | | | | |
| 8 | Maintenance Outage Hours | | | | | | | | | | | | | |
| 9 | Maintenacne Outage Lost MWh | | | | | | | | | | | | | |
| 10 | Effective Forced Outage Rate | | | | | | | | | | | | | |
| 11 | Plant Availability | | | | | | | | | | | | | |
| 12 | Average Heat Rate | | | | | | | | | | | | | |
| 13 | Startup Fuel Costs | | | | | | | | | | | | | |
| 14 | Operating Fuel Cost | | | | | | | | | | | | | |
| 15 | Total Fuel Cost | | | | | | | | | | | | | |

Plant Outage Data

| Date | Outage Type | MWh Affected | Description |
|---|---|---|---|
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |

FFO - FULL FORCED OUTAGE

PPO - PARTIAL PLANNED OUTAGE

PMO - PARTIAL MAINTENANCE OUTAGE

PO - PLANNED OUTAGE

PFO - PARTIAL FORCED OUTAGE

FMO - FULL MAINTENANCE OUTAGE

# ATTACHMENT B

| | | | | EXCLUDING DISCOUNTS | | | |
|---|---|---|---|---|---|---|---|
| **BILL COMPONENT** | **BILLING DETERMINANT** | **UNIT** | **CHARGE** | CALCULATED REVENUE | PER BOOKS REVENUE | DIFFERENCE - $ | DIFFERENCE - % |
| ( a ) | ( b ) | ( c ) | ( d ) | ( e ) = ( b ) x ( d ) | ( f ) | ( g ) = ( f ) - ( e ) | ( h ) = ( g ) / ( f ) |
| **DS-DOMESTIC SERVICE** | | | | | | | |
| ***Customer Charge*** | | | | | | | |
| 0-150 kWh | XXX,XXX | Annual Bills | $ 6.00 | $ X,XXX,XXX | | | |
| 151-500 kWh | XXX,XXX | Annual Bills | 10.00 | XXX,XXX | | | |
| Over 500 kWh | XX,XXX | Annual Bills | 14.00 | XXX,XXX | | | |
| Subtotal | X,XXX,XXX | | | $ X,XXX,XXX | $ X,XXX,XXX | $ X,XXX | X.XX% |
| ***Base Energy Charge*** | | | | | | | |
| 0-150 kWh | XX,XXX,XXX | kWh | $ 0.150 | $ X,XXX,XXX | | | |
| Next 350 kWh | X,XXX,XXX | kWh | 0.176 | XXX,XXX | | | |
| Next 1,000 kWh | XXX,XXX | kWh | 0.200 | XXX,XXX | | | |
| Over 1,500 kWh | XXX,XXX | kWh | 0.224 | XXX,XXX | | | |
| Subtotal | XX,XXX,XXX | | | $ X,XXX,XXX | $ X,XXX,XXX | $ X,XXX | X.XX% |
| **Total** | | | | **$ XX,XXX,XXX** | **$ XX,XXX,XXX** | **$ XX,XXX** | **X.XX%** |
| **EM - EMPLOYEE** | | | | | | | |
| ***Customer Charge*** | | | | | | | |
| 0-150 kWh | XXX,XXX | Annual Bills | - | $ X,XXX,XXX | | | |
| 151-500 kWh | XXX,XXX | Annual Bills | - | XXX,XXX | | | |
| Over 500 kWh | XX,XXX | Annual Bills | - | XXX,XXX | | | |
| Subtotal | X,XXX,XXX | | | $ X,XXX,XXX | $ X,XXX,XXX | $ X,XXX | X.XX% |
| ***Base Energy Charge*** | | | | | | | |
| 0-150 kWh | XXX,XXX | kWh | $ 0.108 | $ XXX,XXX | | | |
| Next 350 kWh | XX,XXX | kWh | 0.127 | XX,XXX | | | |
| Next 1,000 kWh | XX,XXX | kWh | 0.180 | XX,XXX | | | |
| Over 1,500 kWh | XX,XXX | kWh | 0.202 | XX,XXX | | | |
| Subtotal | XX,XXX,XXX | | | $ X,XXX,XXX | $ X,XXX,XXX | $ X,XXX | X.XX% |
| **Total** | | | | **$ XX,XXX,XXX** | **$ XX,XXX,XXX** | **$ XX,XXX** | **X.XX%** |
| **GS - GENERAL SERVICE** | | | | | | | |
| ***Customer Charge*** | | | | | | | |
| 0-150 kWh | XXX,XXX | Annual Bills | $ 8.00 | $ X,XXX,XXX | | | |
| 151-500 kWh | XXX,XXX | Annual Bills | 11.00 | XXX,XXX | | | |
| Over 500 kWh | XX,XXX | Annual Bills | 14.00 | XXX,XXX | | | |
| Subtotal | X,XXX,XXX | | | $ X,XXX,XXX | $ X,XXX,XXX | $ X,XXX | X.XX% |
| ***Base Energy Charge*** | | | | | | | |
| 0-150 kWh | XXX,XXX | kWh | $ 0.184 | $ XXX,XXX | | | |
| Next 350 kWh | XX,XXX | kWh | 0.217 | XX,XXX | | | |
| Next 1,000 kWh | XX,XXX | kWh | 0.259 | XX,XXX | | | |
| Over 1,500 kWh | XX,XXX | kWh | 0.290 | XX,XXX | | | |
| Subtotal | XX,XXX,XXX | | | $ X,XXX,XXX | $ X,XXX,XXX | $ X,XXX | X.XX% |
| **Total** | | | | **$ XX,XXX,XXX** | **$ XX,XXX,XXX** | **$ XX,XXX** | **X.XX%** |
| **SVP - SECONDARY VOLTAGE POWER** | | | | | | | |
| ***Customer Charge*** | | | | | | | |
| All Services | XXX,XXX | Annual Bills | $ 20.00 | $ X,XXX,XXX | | | |
| Subtotal | X,XXX,XXX | | | $ X,XXX,XXX | $ X,XXX,XXX | $ X,XXX | X.XX% |
| ***Demand Charge*** | | | | | | | |
| Billed Demand | XXX,XXX | kVA | $ 24.00 | $ X,XXX,XXX | | | |
| Subtotal | X,XXX,XXX | | | $ X,XXX,XXX | $ X,XXX,XXX | $ X,XXX | X.XX% |
| ***Base Energy Charge*** | | | | | | | |
| Billed Energy | XXX,XXX | kWh | $ 0.138 | $ XXX,XXX | | | |
| Subtotal | XX,XXX,XXX | | | $ X,XXX,XXX | $ X,XXX,XXX | $ X,XXX | X.XX% |
| **Total** | | | | **$ XX,XXX,XXX** | **$ XX,XXX,XXX** | **$ XX,XXX** | **X.XX%** |

## ATTACHMENT C

| Account | Depreciation Rate % |
|---|---|
| **GENERATION PLANT** | |
| **Garrison** | |
| GT No. 2 | 0.43% |
| | |
| **Spring Garden** | |
| Steam Building | 3.57% |
| Steam Equipment | 3.73% |
| Fuel Tank | 3.50% |
| LSD No. 10-13 Building | 0.47% |
| LSD No. 10-13 Equipment | 2.22% |
| LSD No. 14-15 Building | 4.80% |
| LSD No. 14-15 Equipment | 4.89% |
| | |
| **Seawell** | |
| GT No. 3 Building | 3.02% |
| GT No. 3 | 4.10% |
| GT No. 4 | 4.82% |
| GT No. 5 | 4.87% |
| GT No. 6 | 5.01% |
| Fuel Tank | 3.18% |
| | |
| **Spares** | |
| LSD A (No. 10-13) | 1.25% |
| LSD B (No. 14-15) | 5.34% |
| **Trents** | |
| Solar Unit PV01 | 5.14% |
| Battery | 9.41% |
| | |
| **TOTAL GENERATION PLANT** | **3.81%** |