REGULATORY AUTHORITY OF BERMUDA

Fairness • Innovation • Integrity

Retail Tariff Methodology

Final Report
Final Decision and Order
Date: 19 October 2018

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I. INTRODUCTION

1. The purpose of this Final Report, Final Decision and Order (the "Final Report") is for the Regulatory Authority of Bermuda (the "Authority") to: (i) present the Authority's assessment of the responses to the Retail Tariffs Design Consultation Document (the "Consultation Document") and Preliminary Report, Preliminary Decision and Order (the "Preliminary Report"); and (ii) issue the General Determination ("GD") setting the methodology (the "Methodology") for assessing the level of the retail tariff for the electricity sector.

2. The Authority is responsible for the regulation of the electricity sector in Bermuda, and its overarching responsibilities are to:

   (a) regulate tariffs and the quality of service provision to end-users;

   (b) ensure that access to the electricity infrastructure by current and prospective generators in Bermuda is transparent, fair, reasonable and non-discriminatory;

   (c) investigate and respond to complaints from end-users with regards to the provision of electricity.

3. Section 35 of the Electricity Act 2016 ("EA") provides that the Authority shall determine the retail tariff in accordance with the methodology set by general determination and in accordance with the principles set out in the EA.

4. On 8 March 2018, the Authority issued the Consultation Document to consult on the Methodology.

5. The Authority received three responses to the Consultation Document.

6. On 17 September 2018, the Authority issued the Preliminary Report, which summarised the responses received to the Consultation Document and presented a draft GD setting forth the Methodology for assessing the retail tariff in light of the responses, inter alia, to the Consultation Document.

7. The Authority received three responses to the Preliminary Report.

8. This Methodology should be considered in combination with other regulatory tools, such as those listed below.

   a. **Integrated Resource Plan ("IRP")**—an energy plan for the supply of electricity in Bermuda. The IRP defines the requirements for the transmission, distribution and retail ("TD&R") licensee to meet forecasted energy demand using both supply[1]- and demand-side resources to ensure reliable, cost-effective service to customers. The IRP includes a procurement plan that can be used to guide bulk generation licensees' capital expenditure ("CAPEX") forecasting.

   b. **Net benefit test**— which provides the framework for assessing fair network access in Bermuda's electricity sector through balancing the benefits and costs of new generation capacity.

   c. **Power Purchase Agreement ("PPA") guidelines**— which facilitates and aids the negotiation of PPAs between the TD&R licensee and independent power producers ("IPPs"), to encourage efficient procurement of generation.

[1] Supply-side resources is the bulk generation entity

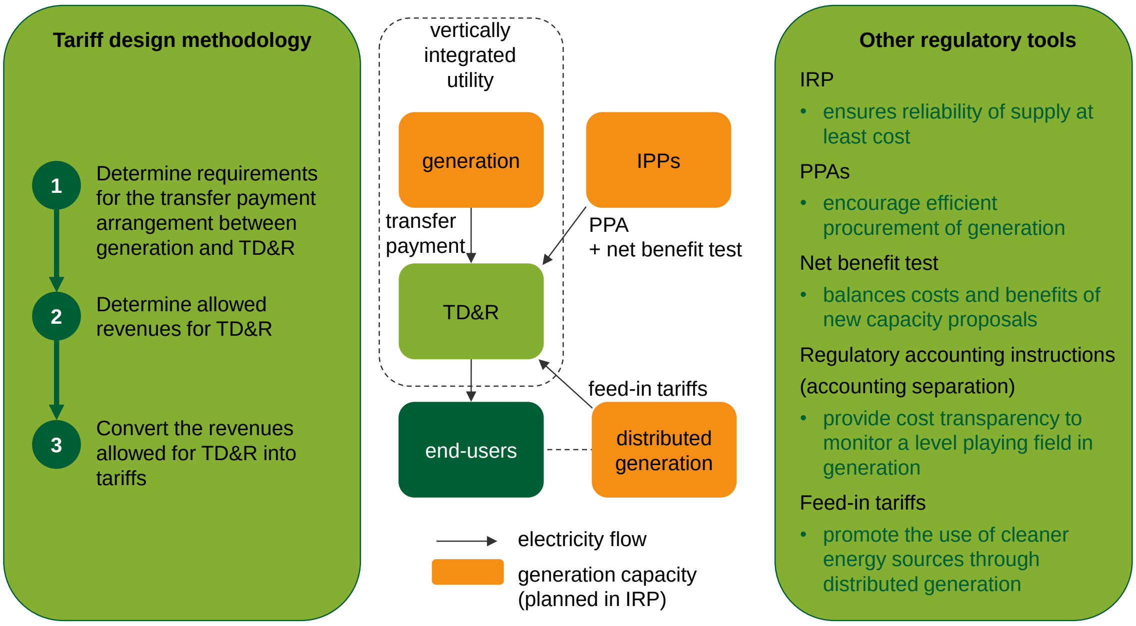
d. **Regulatory accounting instructions**—which require separate regulatory accounts for the bulk generation and TD&R licensees. This informs the tariffs to end-users and provides cost transparency to monitor whether there is a level playing field in generation.

e. **Feed-in tariff methodology**—setting the methodology to define the feed-in tariff — the pre-determined rate at which the TD&R licensee purchases renewable energy from distributed generators. The feed-in tariff methodology ensures that all electricity resources have access to transmission and distribution systems on fair, reasonable and non-discriminatory terms

f. Service Standards— which set key performance indicators for assessing the quality of customer service and the technical performance of the TD&R licensee and bulk generation licensees.

9. Figure 1.1 below illustrates the regulatory regime.

Figure 1.1 Elements of the regulatory regime



Note: IRP - Integrated Resource Plan; PPA - Power Purchase Agreement; IPP - Independent Power Producer and TD&R - Transmission, Distribution and Retail.

10. In particular, the Methodology introduces elements of incentive regulation to promote economic efficiency in the provision of electricity services to the customers of Bermuda. The Methodology determines the allowed revenue for the TD&R licensee, which is subsequently converted into retail tariffs.

11. The allowed revenue of the TD&R licensee is determined using the formula:

Allowed revenue = operating expenditure ("OPEX") + depreciation + (rate base x return on rate base)

12. This regime combines some elements of incentive regulation (i.e. ex ante cost forecasts) and some elements of rate-of-return regulation (cost pass-through allowances). A combination of incentive and rate-of-return regulation is common in international practice.[2] The regulatory

[2] For example, the RIIO (Revenue=Incentives+Innovation+Outputs) regime in the UK (incentive regulation) has some costs that are remunerated on a pass-through basis. On the other hand, some rate-of-return regulation regimes in the US energy sector are moving towards incentive regulation. See Ofgem (2012), "RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas", December; Lowry, M.N., Makos, M.,

regime set by the Authority is specifically tailored to the electricity sector in Bermuda. The aim of this regulatory regime is to balance the provision of incentives to promote cost efficiency with proportionality and practicality of implementation.

13. Table 1.1 below describes the treatment of each component of allowed revenue in turn.

Table I.1 Treatment of the components of the allowed revenue for the TD&R licensee

Element of regulatory regime	Treatment
Rate base	• plant in service and working capital are considered for potential inclusion in the rate base • historical cost accounting approach for the initial valuation of assets and a periodic update of the rate base in accordance with the annual CAPEX (ex ante, subject to an asymmetric CAPEX incentive scheme) and depreciation
Depreciation	• straight-line depreciation, subject to approval of the asset-life assumptions
OPEX	• core network OPEX: ex ante, subject to an asymmetric incentive scheme • power procurement:* cost pass-through allowance • other expenses (fees and taxes): cost pass-through allowance
Return on rate base	• ex ante nominal vanilla WACC estimate, subject to a trigger mechanism[3]

Note: CAPEX, capital expenditure; OPEX, operating expenditure; WACC, weighted average cost of capital.

* This includes a transfer payment to the generation business unit of the vertically integrated utility from the TD&R licensee.

14. The Authority considers that, at this time, the degree of competition in the electricity generation market in Bermuda is not sufficient to ensure that the terms for the procurement of electricity would reflect the best available market terms. Therefore, the Methodology imposes certain requirements regarding terms for the procurement of electricity.

15. In particular, the Methodology requires a transfer pricing arrangement for the vertically integrated utility, i.e. Bermuda Electric Light Company Limited ("BELCO"). Regarding any new generation facilities proposed by IPPs, the Authority will assess PPAs for such IPP entrants on a case-by-case basis and always with the intention of pursuing the purposes of the EA.

16. For both the TD&R licensee's transfer pricing arrangement with its bulk generation business unit and PPAs with IPPs, the charges to the TD&R licensee should be sufficient to recover the sum of the bulk generation licensee's (i) initial investment (including a return on invested capital); (ii) ongoing costs; and (iii) fuel costs. The exact terms of a PPA will be negotiated between the TD&R licensee and an IPP bilaterally, subject to the Authority's approval. The transfer pricing arrangement between the TD&R and bulk generation business units of a vertically integrated utility would be reviewed and approved by the Authority periodically, aligned with the review periods for the TD&R licensee.

17. Once the allowed revenue for the TD&R licensee is established, the total revenue must then be allocated across different customer classes and converted into retail tariffs.

18. This Final Report is structured as follows:

a. section II outlines the background and procedural history;

Deason, J., Schwartz, L. (2017), "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities", July.

[3] Under a trigger mechanism, a return on capital is estimated and allowed ex ante for the duration of a price control. However, it is allowed to vary if there are significant movements (up or down) in capital markets (e.g. changes in the risk-free rate).

b. section III sets out the legislative context and framework that underpin the development of the Methodology;

c. section IV summarises the responses to the Consultation Document;

d. section V summarises the responses to the Preliminary Report;

e. section VI provides the conclusion;

g. Appendix A sets forth the Final Order;

h. Appendix B sets forth the GD.

II. BACKGROUND AND PROCEDURAL HISTORY

II.A. Background

19. The Authority initiated this consultation by publishing a Consultation Document on 8 March 2018 that invited responses from members of the public, including electricity sectoral participants and sectoral providers, as well as other interested parties.

20. The purpose of the Authority's Consultation Document was to consult on the Methodology.

21. The Consultation Document asked the following questions:

Form of control

1. Do you agree that the new regime should include elements of both rate-of-return regulation and incentive regulation?
2. Do you agree that the TD&R licensee should be subject to a revenue-cap regime?
3. Do you agree that the regime should be based on five-year price control periods, with a transitional period consisting of shorter price control periods (i.e. two one-year control periods followed by one three-year control period)?

Building blocks of regulation

4. Do you agree that an annual true-up mechanism for cost pass-through allowances is appropriate for the TD&R licensee (e.g. true-up for capital expenditure ("CAPEX") allowances, wholesale electricity cost under PPAs, fees and taxes)?

Proposed remuneration of operating expenditure ("OPEX") of the TD&R licensee

5. Do you consider it appropriate for the core network OPEX to be remunerated using ex ante allowances derived through a top-down approach?
6. Do you agree that the expenditure incurred on wholesale electricity costs under PPAs by the TD&R licensee should be recovered on a cost pass-through basis?
7. Do you agree that the other expenses incurred by the TD&R licensee, including FAR, fees and taxes, should be recovered on a cost pass-through basis?

Initial asset valuation

8. Do you agree that the historical-cost accounting ("HCA") approach for the initial valuation of the vertically integrated utility's assets—split between the bulk generation and the TD&R business units—is appropriate?

Rate base roll-forward

9. Do you agree that an HCA approach for rate base roll-forward for the TD&R licensee is appropriate?

Depreciation

10. Do you agree that a straight-line depreciation approach should be applied to the TD&R licensee's rate base in order to estimate the depreciation allowance?
11. Do you agree that the Authority should have a right to rebase the allowed revenue calculations on revised asset life assumptions if the Authority considers that current asset life assumptions made by the licensee are unreasonable?

Capital expenditure

12. Do you agree with a cost pass-through approach for remunerating CAPEX?
13. Do you consider that an ex ante regime for capital expenditure would be appropriate in the future?

Return on capital

14. Do you agree that the weighted average cost of capital ("WACC") should be set on a vanilla basis, and that while there is no corporate tax payable, any other taxes or fees should be remunerated within OPEX allowances?
15. Do you agree that the CAPM should be used to estimate cost of equity?
16. Do you agree that the cost of debt estimate should be based on investment grade credit rated debt with no explicit allowance for embedded debt given that the licensee has little to no embedded liabilities?
17. Do you agree with the use of a notional gearing assumption?
18. Do you agree that the cost of capital estimate should be fixed for the duration of a price control, subject to a trigger mechanism in case of 'extreme' market volatility?

Outputs

19. Do you agree that the TD&R licensee should be incentivised to deliver the following outputs—generation reliability, network reliability, network efficiency, safety, customer satisfaction?
20. What metrics would you consider to be appropriate for targeting the outputs outlined above?

Capacity fee—existing generation assets

21. Do you agree that the capacity fee should be based on the HCA values of existing generation assets?
22. Do you consider that the Methodology for setting the return on capital is appropriate for remunerating the existing generation assets?
23. Do you agree that the return on capital for the existing generation assets of the vertically integrated utility should be fixed for the duration of the PPA, with the possibility of this to be reviewed by the Authority periodically?

Capacity fee—new generation assets

24. Do you consider that the proposed CAPEX incentive scheme is appropriate for the bulk generation licensee's investment in new generation assets?
25. Do you consider that the Methodology for setting the return on capital is appropriate for remunerating the new generation assets?
26. Do you agree that the return on capital for the TD&R licensee's new generation investment should be fixed for the duration of the PPA, with the possibility of this to be reviewed by the Authority periodically?

Energy fee

27. Do you agree that the ongoing costs of generation (excluding fuel costs) should be remunerated though an energy fee on a per-unit-of-energy basis?
28. Do you consider that it would be appropriate to adjust the energy fee periodically, in line with the TD&R licensee's price control periods?

Fuel adjustment rate

29. Do you agree that the FAR mechanism should be included within the PPAs and set separately for the existing generation assets and new generation assets?

Outputs

30. Do you agree that the PPAs should include safety, reliability and generation efficiency commitments?

Tariff design

31. What changes would you propose, if any, to the current approach for allocating tariffs?

22. Responses to the Consultation Document were solicited from the public electronically through the Authority’s website at www.rab.bm.

23. The response period commenced on 8 March 2018 and concluded on 29 March 2018.

24. The Authority received three responses to the Consulation Document from:

   (a) Bermuda Alternate Energy Limited (“BAE”);

   (b) Bermuda Electric Light Company Ltd (“BELCO”); and

   (c) SMART Innovations Ltd. Bermuda (“SMART Innovations”).

25. On 17 September 2018, the Authority issued the Preliminary Report. The Authority invited responses from members of the public, including electricity sectoral participants and sectoral providers, as well as other interested parties.

26. Public comments on the Preliminary Report were to be submitted by the extended deadline of 1 October 2018.

27. The Authority received three written response to the Preliminary Report from:

   (a) BAE;

   (b) BELCO; and

   (c) SMART Innovations.

II.B. **Final Decision and Order**

28. The Authority hereby adopts the Order in Appendix A and make the General Determination set out in Appendix B to this Final Report.

III. LEGISLATIVE CONTEXT

29. The core legal framework relevant to the development of the Methodology is based on the RAA, National Electricity Sector Policy and EA.

30. The RAA established a cross-sectoral independent and accountable regulatory body "to protect the rights of consumers, encourage the deployment of innovative and affordable services, promote sustainable competition, foster investment, promote Bermudian ownership and employment and enhance Bermuda's position in the global market."[4]

31. In June 2015, the Ministry of Economic Development of Bermuda published the National Electricity Sector Policy (the "Policy Document"). The Policy Document set out the groundwork for the establishment of the subsequent EA and the desired structure of the electricity sector of Bermuda, and it also outlined four broad policy objectives for the sector. These policy objectives encourage the pursuit of an electricity service that is (i) least cost and high quality, (ii) environmentally sustainable, (iii) secure and (iv) affordable.[5]

32. The EA established an electricity sector regulatory framework within the meaning of the RAA. The EA received Royal Assent on 27 February 2016 and came into operation on 28 October 2016, pursuant to the Electricity Act 2016 Commencement Day Notice 2016 (BR 101/2016). The EA repealed the Energy Act 2009.

33. The Minister responsible for electricity is currently the Minister of Transport and Regulatory Affairs (the "Minister"). The Minster can issue Ministerial declarations that establish policies for the electricity sector[6] and can also issue Ministerial directions to the Authority regarding any matter within his authority with regards to the electricity sector.[7] In formulating Ministerial directions, the Minister shall set priorities and resolve trade-offs or conflicts that arise from the purposes of the EA in a way that he thinks best serves the public interest.[8]

34. The Authority has the powers to supervise, monitor and regulate the electricity sector in Bermuda in accordance with the purposes of the EA. Such purposes, as set forth in section 6 of the EA, are:[9]

(a) "to ensure the adequacy, safety, sustainability and reliability of electricity supply in Bermuda so that Bermuda continues to be well-positioned to compete in the international business and global tourism markets;

(b) to encourage electricity conservation and the efficient use of electricity;

(c) to promote the use of cleaner energy sources and technologies, including alternative energy sources and renewable energy sources;

(d) to provide sectoral participants and end-users with non-discriminatory interconnection to transmission and distribution systems;

(e) to protect the interests of end-users with respect to prices, affordability and the adequacy, reliability and quality of the electricity service;

(f) to promote economic efficiency and sustainability in the generation, transmission, distribution and sale of electricity."

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[4] Regulatory Authority Act 2011, p. 5.
[5] Ministry of Economic Development (2015), "The National Electricity Sector Policy of Bermuda", Bermuda, p. 4.
[6] Electricity Act 2016, section 7(2).
[7] Electricity Act 2016, section 8(3).
[8] Electricity Act 2016, section 9.
[9] Electricity Act 2016, section 6.

35. The principal functions of the Authority set forth in section 12 of the RAA are:

(a) "to promote and preserve competition;

(b) to promote the interests of the residents and consumers of Bermuda;

(c) to promote the development of the Bermudian economy, Bermudian employment and Bermudian ownership;

(d) to promote innovation;

(e) to fulfil any additional functions specified by sectoral legislation."

36. To further the purposes of the EA, the EA grants various functions to the Authority. Section 14(1) of the EA provides that the function of the Authority is generally to monitor and regulate the electricity sector. Additionally, section 14(2)(c)(ii) of the EA provides that the functions of the Authority shall include, among other things, the making of administrative determinations[10] to provide for the control and conduct of the provision of electricity services, including transparency measures and notice requirements relating to the rates, charges and other terms and conditions for the provision of electricity services for the benefit of end-users.

37. Given that there will be one TD&R licensee at any point in time, it therefore would operate as a monopoly provider of transmission, distribution and retail services in the electricity sector. Subsequently, the focus of the Authority will be on, among other things:

(a) regulating end-user tariffs according to the efficient costs of meeting the purposes of the EA;

(b) establishing best-practice criteria and standards with the TD&R licensee;

(c) monitoring the TD&R licensee's quality of service performance; and

(d) incentivising or otherwise enforcing performance improvements where necessary.

38. In accordance with the Policy Document, the reformed electricity sector in Bermuda will facilitate the introduction of competition between existing generation facilities, prospective third-party bulk generators (i.e. IPPs), distributed generators and other demand-side resources. Since the TD&R licensee will occasionally be required to evaluate a diverse set of competing proposals for how to meet future demand, it is important that the Authority ensures that all relevant market participants are treated equally and are able to access the grid on transparent, fair, reasonable and non-discriminatory terms.

39. According to the principles set out in section 35 of the EA[11], the Methodology should allow the TD&R licensee to generate a total revenue that covers the reasonable costs of service required to meet the service standards it stipulates, and in particular the reasonable costs in respect of:

[10] Defined in the RAA as including a General Determination, order, direction, decision or other written determination by which the Authority establishes the legal rights and obligations of one or more Sectoral Participants (i.e. person who provides, uses or seeks to use a good or service in the energy sector but does not include the Authority) but does not include an advisory guideline (i.e. written statement issued by the Authority that provides the Authority's views regarding a specific matter but is not legally binding) or an adjudicative decision and order (which means a decision or order following an adjudication conducted in accordance with Sections 74 to 83 of the RAA). General Determination is defined as a statutory instrument made pursuant to Section 62 of the RAA that is applicable to all Sectoral Participants or categories of Sectoral Participants as fall within the scope of the Statutory Instrument.

[11] Electricity Act 2016, section 35.

(a) investment, if prudently incurred and for which the investment is used and useful; and

(b) a reasonable return on investment, i.e. one that is commensurate with the return on investments in business undertakings with comparable risks and sufficient to attract the needed capital.

40. The Methodology should also seek to enable the TD&R licensee to generate a total revenue that recovers the reasonable costs of service incurred in achieving the stipulated service standards, and in particular the reasonable costs relating to the following efficiently incurred expenditure:

(a) operating expenditure;

(b) fuel procured for generation;

(c) generation procured; and

(d) other expenses, including government authorisation fees, the Authority fee and other statutory fees.

41. Finally, the Methodology should "include information that gives end-users proper information regarding the costs that their demand imposes on the licensee's business".[12]

42. The Authority shall conduct a retail tariff review every five years or less.[13]

43. Pursuant to sections 47 and 48 of the EA, procurement of power by the TD&R licensee from a third party shall be effected under a PPA between the TD&R licensee and a bulk generation licensee. The PPA must be approved by the Authority. In the approval process, the Authority will ensure that:

(a) the PPA is consistent with the IRP, the purposes of the EA, and any Ministerial directions; and

(b) the PPA does not create risks to power quality or reliability, or unreasonable financial risks for the TD&R licensee.

44. The Authority considers that at this time, the degree of competition in the electricity generation market in Bermuda is not sufficient to ensure that the terms for the procurement of electricity would reflect the best available market terms. Therefore, the Methodology includes certain requirements in relation to terms for the procurement of electricity, focusing in particular on the transfer pricing arrangements between the TD&R and bulk generation business units of the vertically integrated utility.

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[12] Electricity Act 2016, section 35 (4) (b).
[13] Electricity Act 2016, section 37.

IV. SUMMARY AND DISCUSSION OF RESPONSES TO THE INITIAL CONSULTATION DOCUMENT

IV.A. Response Method

45. The Consultation Document allowed the public to submit responses commenting on the proposed methodology to determine the retail tariff and to respond to the consultation questions. Three written responses to the Consultation Document were received from:

(a) BAE;

(b) BELCO; and

(c) SMART Innovations.

IV.B. Summary of Responses

46. This section provides an overview of the key themes from the responses to the Consultation Document and the related decisions that the Authority has made, taking into consideration the public responses.

47. The responses have been carefully considered and are summarised and addressed individually below.

IV.B.1 Response from BAE

48. The key points of BAE's response to the Consultation Document were as follows:

(a) **Time of Use ("ToU") billing should be reconsidered for small and large commercial customers.**[14] BAE suggested that ToU billing should be introduced in order to incentivise small commercial and demand customers to become more energy efficient during peak hours, thereby reducing peak demand and the overall generation cost; and

(b) **Efficiency Metrics.** BAE suggested that the Authority should request and monitor efficiency metrics for both the TD&R and bulk generation licensees.

A. Time of Use billing should be reconsidered for small and large commercial customers

49. BAE suggested that the current BELCO rate structure discriminates against certain types and sizes of customer. To illustrate this, the response presented two different scenarios.

(a) **Comparison of charges paid by residential and small commercial users.** The analysis showed that small commercial customers pay more per kWh for electricity than residential customers for usage below 760kWh per month.

(b) **Comparison of charges paid by high-use small commercial customers and high-use demand customers.** The analysis found that there is a large discrepancy in the average cost per kWh between "small commercial" customers and "demand service" customers, where both have high usage 24 hours per day. Specifically, BAE calculated that a large

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[14] It is noted that this is not the first time ToU billing has been proposed for consideration. On 17 February 2012, the Energy Commission instructed BELCO to complete a feasibility study on ToU and present its findings by 31 May 2012. However, this instruction was overturned by the Minister of Environment, Planning and Infrastructure Strategy on 9 May 2012. See Government of Bermuda (2012), "Re: BELCO Rate Filing—October 26, 2011", https://www.gov.bm/sites/default/files/EC%20Directive%20Approval%20of%20Base%20Rates%20270212.pdf; and Government of Bermuda (2012), "RE: In the matter of an Appeal to the Minister by the Bermuda Electric Light Company Limited ("BELCO")", https://www.gov.bm/sites/default/files/Minister%27s%20Response%20to%20BELCO%20Base%20Rate%20Case%20Appeal%20090512.pdf.

guest house ("small commercial" customer) may pay 42% more per kWh than a large hotel ("demand service" customer). Another example of a discrepancy may occur between a small convenience store on the "small commercial" rate and a large supermarket on the "demand service" rate, due to the large refrigeration loads that run 24 hours per day for both customers.

50. Currently, residential and small commercial customers are charged according to an inclining block tariff, while large commercial customers (i.e. the "demand service" customer group) are charged according to a declining block tariff for energy.

51. Overall, the response concluded that the use of inclining block tariffs is appropriate as it encourages larger customers to become more energy efficient and potentially use alternative sources of energy. However, the response suggested that the use of inclining block tariffs is unfair for small commercial customers who require large loads throughout the day.

52. In order to address this potential discrepancy, the response suggested switching both small and large commercial customers to ToU billing.

53. The introduction of ToU billing was promoted by the fact that the cost of producing electricity increases as total electricity consumption also increases. For example, BAE's response stated that gas turbine generators, typically used in periods of high electricity demand, are the most inefficient generation facilities and therefore are the most costly to run in terms of fuel per kWh. BAE argued that ToU billing would incentivise small commercial and demand customers to become more energy efficient during peak hours, thereby reducing peak demand and the overall generation cost.

54. The Authority maintains an open mind about the structure of retail tariffs and considers it appropriate for BELCO to undertake a feasibility study on new candidate tariff structures, including ToU billing, given that BELCO has also expressed an interest in this (see section 5.3.6 of the Preliminary Report). It is important that the feasibility study carefully considers the costs and benefits of different tariff structures, accounting for any investment that would be required (such as the installation of advanced meters), including the costs of any trials or pilot programmes. The Authority will subsequently review any particular alternative tariff structure that is proposed and will decide on whether the proposed tariff structure should be approved. This decision will be made in accordance with the purposes of the EA and the Authority's duties thereunder.

B. Efficiency metrics

55. BAE suggested that the Authority should request and monitor the efficiency metrics for both the TD&R and bulk generation licensees. These efficiency metrics should be provided by a bulk generation licensee and the TD&R licensee with the aim of ensuring the least cost provision of electricity. For example, it is suggested that the Authority may impose penalties if a bulk generation licensee and/or the TD&R licensee fail to meet certain minimum efficiency standards.

56. The Authority considers that it is appropriate to use metrics to aid the monitoring of the performance of a bulk generation licensee and the TD&R licensee. This Final Report outlines specific outputs that a bulk generation licensee and the TD&R licensee should target. Please see sections II.F and III.E of the Preliminary Report (for the TD&R and bulk generation licensees respectively) for discussion on which specific metrics should be used within each output and whether any financial incentives (both rewards and penalties) should be associated with these outputs.

IV.B.2. Response from SMART Innovations

57. The key points of the response submitted by SMART Innovations were as follows:

(a) proposal of an alternative regulatory regime based on the Minimum Revenue Requirements Method (“MRRM”);

(b) components of the rate base;

(c) proposed metrics to measure targeted outputs; and

(d) methodology for estimation of return on capital.

58. The rest of this section provides responses to the points outlined above.

A. Proposal of an alternate regulatory regime based on the Minimum Revenue Requirements Method

59. SMART Innovations proposed an alternative regulatory regime for the electricity sector in Bermuda—namely, a regime based on the MRRM. The Authority understands that, in addition to the current Base-Rate Filings System, which is currently utilised, the MRRM is a type of rate-of-return regulation.

60. For the reasons specified in section 6.1 of the Consultation Document, the Authority does not consider that rate-of-return regulation (and the MRRM in particular) is appropriate for Bermuda. Rate-of-return regulation does not facilitate the achievement of objectives of the EA, such as the protection of the interests of end-users with respect to prices, the affordability of electricity and the promotion of economic efficiency.[15]

61. SMART Innovations also noted that that the Authority has not defined economic efficiency.

62. The Authority understands economic efficiency to represent the efficient achievement of other objectives of the EA with least-cost outcomes. Therefore, economic efficiency promotes the protection of the interests of end-users with respect to prices and the affordability of electricity.[16]

63. To illustrate the Authority’s position regarding rate-of-return regulation, consider a situation under a pure rate-of-return regime, where a utility does not incur its costs efficiently and, as a result, its profitability (i.e. return on capital) is not as high as the allowed rate of return. To achieve its targeted profitability, the utility can either improve its economic efficiency or request the Authority to review retail tariffs upwards. As the latter option is typically available under rate-of-return regulation, the utility would have no incentive to improve its economic efficiency.

64. Under incentive regulation, however, that option is usually unavailable, so the utility is incentivised to reduce its costs. The Authority notes that in this regard, incentive regulation is similar to multi-year rate plans used by regulators in North America. A multi-year rate plan is a modified rate-of-return type of regulation where the allowed revenue is fixed for a multi-year period.

65. Following international practice, and taking into account the proportionality of the regime, the Authority considers it necessary to introduce elements of incentive regulation to achieve such objectives of the EA as promotion of economic efficiency and protection of the interests of end-users with respect to prices and affordability of electricity.

B. Components of the rate base

66. SMART Innovations noted that the components of the rate base are not specified in the Consultation Document. The Authority recognises that the rate base is an important element

[15] Electricity Act (2016), section 6(e)(f).
[16] Electricity Act (2016), section 6(e).

of the allowed revenue and therefore defined the components of the rate base in the Preliminary Report. This was addressed in section 6.4 of the Preliminary Report.

C. Proposed metrics to measure targeted outputs

67. SMART Innovations proposed a number of metrics that could be used to measure the licensees' targeted outputs. The Authority has considered the suggested metrics and included a discussion on which specific metrics could be used within each output and whether any financial incentives (both rewards and penalties) should be associated with these outputs. Please see sections II.F and III.E of the Preliminary Report, for the discussion on the TD&R and bulk generation licensees respectively.

D. Methodology for estimation of return on capital

68. SMART Innovations had a number of comments in relation to the methodology the Authority has proposed for estimating the allowed rate of return. These are discussed below with each comment made by SMART Innovations, followed by the Authority's response in turn.

69. First, SMART Innovations considered that a range of allowed returns on capital should be estimated instead of a single point estimate.

70. The Authority believes that the estimation of the allowed cost of capital is subject to judgement. For example, the cost of equity is unobserved and has to be estimated. Therefore, it is common practice to start with a range of estimates and then select a point estimate within the identified range.

71. Second, SMART Innovations questioned the Authority's statement that the risks of the TD&R and bulk generation business units of the TD&R licensee are likely to be different and that the weighted average cost of capital ("WACC") needs to be estimated separately for each business unit. In particular, SMART Innovations asked whether this is possible for a vertically integrated electricity utility as small as BELCO.

72. The Authority's view is that the risk faced by the two business units (i.e. TD&R and bulk generation) are likely to be different due to the different nature of their activities. Based on an assessment of relative risk, judgement can be exercised to determine a different point estimate of the allowed WACC for each licensee within an evidence-based range. However, it is also possible that for ease of implementation, a single allowed WACC could be determined.

73. Third, SMART Innovations suggested that the Authority should consult a State Public Utilities Commission in the USA or the National Association of Regulatory Utility Commissioners ("NARUC") regarding approaches to the estimation of cost of capital and cost of equity.

74. The Authority's comments are as follows:

(a) The Authority is aware of the approaches to the estimation of cost of capital and cost of equity that are common in the USA and can confirm that the proposed approaches do not contradict the US practice.

(b) In particular, the Capital Asset Pricing Model ("CAPM")[17] is one of the methodologies commonly used to estimate the cost of equity. The Authority, however, finds it appropriate for the licensee to provide the results of other approaches to the cost of equity estimation in addition to the CAPM, as long as these approaches are applied appropriately and are

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[17] is a popular pricing model that describes the relationship between systematic (market) risk and expected return and that is used to calculate the required rate of return for any risky asset.

well justified. Based on the range of evidence, the Authority will make the final decision regarding the point estimate for the cost of equity allowance.

(c) In relation to the Authority's proposal to account for taxes separately (instead of within the rate-of-return allowance), the Authority can also confirm that this is common practice amongst US regulators. This point, however, is not relevant in Bermuda, as there are no corporate taxes.

75. Finally, SMART Innovations specified a number of factors that need to be taken into account when calculating the cost of debt, stating that:

(a) "Regulators cannot choose the cost of debt as this is a function of a BELCO management decision concerning the level of equity verses debt, what debt financing the market will supply and a function of the revenue requirements of the company and finally the financial risk profile BELCO has and will establish.

(b) The cost of debt should be based on BELCO's experience plus the experience of island utilities similar to BELCO in as many aspects as possible and on BELCO's commitment to investors and on BELCO's financial risk profile of debt to equity ratio."

76. The Authority wishes to clarify that its intention is to determine an appropriate cost of debt allowance that would enable a licensee to recover the cost of its debt financing (or interest expense) and incentivise it to choose an optimal capital structure. While the Authority will review the actual cost of debt financing and actual gearing of the licensee, the determination of the allowed cost of debt and allowed capital structure will be on a notional basis. This is because customers should not pay for an inefficient choice of capital structure. The factors mentioned by SMART Innovations, such as experience of comparable utilities and market conditions, are appropriate considerations in determining the notional cost of debt.

IV.B.3 Response from BELCO

77. BELCO submitted a response to the Consultation Document on 19 April 2018. The Authority welcomes BELCO's view that the proposed hybrid approach of regulation is appropriate for Bermuda. The Authority notes the following key points raised by BELCO in response to the Consultation Document.

(a) **Length of the price-control periods**. BELCO argued against the use of the transitional period, suggesting that the regulatory regime should be based on five-year price-control periods.

(b) **TD&R licensee's costs remuneration**. BELCO raised a number of issues with the proposed regulatory regime for the TD&R licensee (e.g. the methodology for remuneration of OPEX).

(c) **Bulk generation licensee's costs remuneration**. BELCO raised a number of issues with the proposed regulatory regime for the bulk generation licensee, in particular in relation to the transfer pricing arrangement between BELCO in its capacity as a bulk generation licensee and BELCO in its capacity as the TD&R licensee.

(d) **Return on capital**. BELCO raised concerns in relation to the use of the CAPM for estimating the cost of equity and notional assumptions for setting the level of gearing and cost of debt.

(e) **Outputs**. BELCO argued that it is too early in the new regulatory regime to have sufficient information concerning appropriate metrics to use in a binding performance plan.

(f) **Tariffs**. BELCO believes that flexibility should be provided to experiment with new rate programs such as real-time pricing, ToU pricing, critical-peak pricing, energy-efficiency programs and low-income programs.

(g) **National Disaster Contingency Fund**. BELCO also noted that pursuant to Condition 17 of BELCO's TD&R licence, BELCO is required to establish the National Disaster Contingency Fund (the "NDC Fund") that should be defined in the retail tariff methodology.

78. The rest of this section provides detailed responses to the points outlined above.

A. Length of the price-control periods

79. The Consultation Document proposed to base the regulatory regime on five-year price-control periods, with a transitional period consisting of shorter price-control periods (i.e. two one-year control periods followed by one three-year control period). In its response, BELCO argued against the use of a transitional period, suggesting that the regime should be based on five-year price-control periods. BELCO contends that this would lead to greater stability and predictability of the regulatory process.

80. The Authority considers that five-year price-control periods are important for promoting efficiency throughout the electricity sector in Bermuda. However, as the proposed methodology is in its infancy, the Authority believes that the transitional period is essential to fine-tuning the regulatory framework with the aim of improving future utility performance and enhancing the benefits to customers.

81. Therefore, the Authority considers that the regulatory regime should continue to be based on five-year price-control periods, with a transitional period consisting of shorter price-control periods (i.e. two one-year control periods followed by one three-year control period).

B. Responses to the proposed principles of the regulatory design for the TD&R licensee

82. In the Consultation Document, the Authority proposed to remunerate OPEX through ex ante allowances that would be determined using a top-down benchmarking approach. In its response, BELCO suggested a system for the remuneration of operating expenditure that is similar to the methodology proposed by the Authority. However, BELCO's proposals differ in the following two areas.

(a) BELCO suggested establishing the ex ante allowance at the level of OPEX that is consistent with the "Test Year", which may be the latest year for which data is available.

(b) BELCO proposed the application of an asymmetric incentive mechanism for the actual OPEX incurred by the TD&R licensee—i.e. should the TD&R licensee reduce its costs below the costs identified from the "Test Year", the outperformance would be shared with the customers in the form of reduced rates. On the other hand, should the actual costs exceed the costs identified from "Test Year", the cost increase would be absorbed by BELCO.

83. First, the Authority considers that the OPEX allowance should be based on the forecast of efficient costs submitted by the TD&R licensee. The levels of forecast OPEX put forward should be well justified using either a top-down or bottom-up approach. The Authority previously proposed a top-down approach due to the relative ease of implementation. BELCO, however, believes that it is not practical to use a top-down approach for setting ex ante projections due to lack of experience in benchmarking and other procedures for estimating OPEX. BELCO's concern may be partially addressed through the transitional period consisting of shorter price-control periods, where both BELCO and the Authority would gain knowledge of the cost base and inputs to the regulatory regime. However, since BELCO seems to have

a preference towards a bottom-up approach, the Authority would maintain an open mind about the choice of the OPEX forecast methodology, as long as it is appropriately applied and well justified.

84. The Authority also recognises the difficulty in preparing a well-justified OPEX forecast. Therefore, the Authority considers it acceptable to benchmark the OPEX allowance to the "Test Year", as described by BELCO, for the first price-control period. The Authority will review the elements of this OPEX allowance to ensure that non-recurrent-cost items from the "Test Year" (e.g. inventory write-offs) are not included as allowed expenditure in the subsequent price-control period.

85. Second, the Authority considered the merits of introducing an asymmetric incentive mechanism for the actual OPEX incurred by the TD&R licensee. On the one hand, an asymmetric incentive mechanism reduces the incentive effect of the ex ante allowance and adds an additional layer of complexity to the regime. On the other hand, such a mechanism allows customers to capture the cost savings within a price-control period. On balance, the Authority considers that an asymmetric incentive mechanism for the OPEX allowance should be introduced to the regulatory regime for the TD&R licensee. The Authority also considers that the cost savings should be shared between customers and funding the NDC Fund, the exact proportion of this sharing to be determined by the Authority.

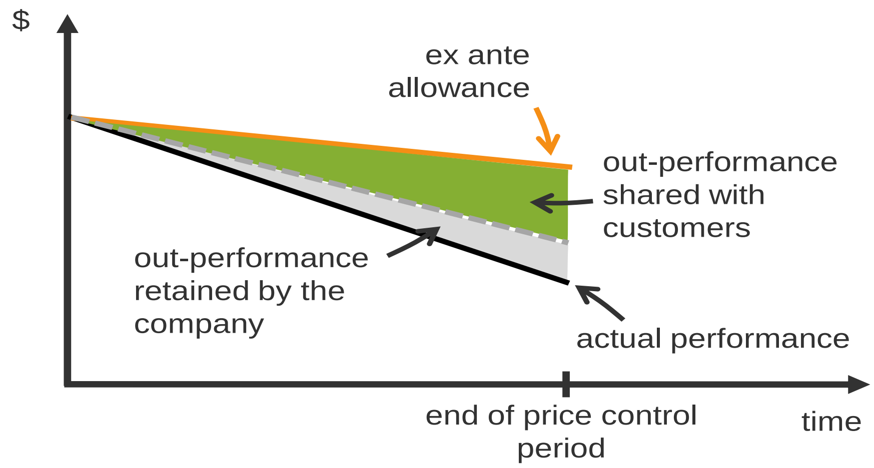
86. As a result, the Authority proposed to set the OPEX allowance for the TD&R licensee on the basis of an ex ante forecast, with an asymmetric incentive mechanism. In particular:

(a) should the TD&R licensee incur OPEX below the ex ante allowance, the outperformance should be shared with customers and/or the NDC Fund on a 20:80 basis (i.e. the majority of the benefit accrues to customers and/or the NDC Fund);

(b) should the TD&R licensee incur OPEX in excess of the ex ante allowance, the cost of the underperformance should be absorbed by the TD&R licensee.

87. This is illustrated in Figure 2.1 below.

88. Figure 2.1: OPEX remuneration mechanisms set by the Authority:



C. Bulk generation licensee's costs remuneration

89. In the Consultation Document, the Authority proposed that the remuneration of bulk generation licensee's costs should be achieved through a PPA. BELCO highlighted that this proposal is legally not feasible vis-à-vis BELCO in its respective capacities as bulk generation and TD&R licensee. Specifically, BELCO stated that as the TD&R licensee it could not enter into an

agreement with itself as a bulk generation licensee. Instead, BELCO suggested that transfer pricing arrangements between its business units should be based on its cost of service and an adequate rate of return.

90. The Authority does not dispute that the legal meaning of a PPA between independent parties and a PPA between two business units of the vertically integrated utility is not the same. A PPA between two business units of a vertically integrated utility would be analogous to a transfer pricing arrangement.

91. In addition, BELCO made some observations with respect to the proposed methodology for setting the remuneration for the bulk generation licensee.

(a) BELCO considered that the return on capital should not be fixed for the duration of the transfer pricing arrangement, subject to a re-opening mechanism. Instead, it suggested to align the review of the return on capital allowed for the bulk generation licensee with the price-control periods for the TD&R licensee.

(b) BELCO emphasised that the transfer pricing arrangements between BELCO in its capacity as the TD&R licensee and BELCO in its capacity as the bulk generation licensee should be the same for both legacy and new generation.

(c) BELCO considered that the fuel adjustment rate (“FAR”) mechanism is appropriate for recovery of the fuel costs. In addition, BELCO suggested that the FAR calculation should reflect the entire cost of fuel instead of the current system, where $30 per barrel is recovered separately from FAR, as part of the base rates. The Authority agrees that BELCO’s suggestion to reflect the entire fuel costs in the proposed FAR mechanism would increase transparency.

(d) BELCO suggested that the transfer pricing arrangement should be based on cost of service.

92. The Authority considers that it is appropriate to update the methodology for remunerating bulk generation licensee’s costs. In particular, the Authority considers that in the interest of transparency, consistency and ease of implementation, the form of remuneration of the bulk generation licensee’s costs may be aligned with the form of remuneration of the TD&R licensee’s costs. The Authority wishes to clarify that the economic principles underlying the methodology for remunerating bulk generation licensee’s costs that was proposed in the Consultation Document are not substantially different from the principles underlying this Final Report. Instead, the Authority has focused on the simplification of the form of the remuneration without substantially revising the principles.

D. Return on capital estimation methodology

93. BELCO disagreed with the methodology that the Authority proposed to apply to the return on capital estimation.

94. First, BELCO believes that it would not be possible to accurately estimate the cost of equity with the CAPM because its parameters cannot be tailored to the specificities of Bermuda. Therefore, BELCO suggested that the “WACC methodology” should be applied similarly to how it was in BELCO’s rate filing submitted to the Energy Commission dated 3 June 2015 (the "2015 Rate Case").

95. The Authority disagrees with the statement that the CAPM cannot be tailored to reflect specificities of the Bermudian market. This methodology is widely used in the regulation of utilities around the world—if the appropriate inputs are used, it allows for the risks of investing

in any specific country to be reflected. The Authority also notes that the CAPM is one of the approaches applied within the “WACC methodology” in BELCO’s 2015 Rate Case.[18]

96. The Authority therefore finds it appropriate to use the CAPM when estimating the cost of equity. However, other approaches to cost of equity estimation in addition to the CAPM may also be acceptable, as long as they are applied appropriately and are justified. For example, these may include discounted cash flow or risk-premium approaches.

97. Second, BELCO disagreed with the Authority’s proposal to employ notional gearing and notional cost of debt assumptions. One of BELCO’s main reasons for the disagreement was a practical challenge of looking for appropriate benchmarks suitable for the unique conditions of Bermuda.

98. The Authority recognises that the circumstances under which the licensee(s) operate are unique. In particular, BELCO has no (or little) debt, and the typical reason for raising debt—an interest payments tax exemption—does not apply in Bermuda.[19] The Authority is also aware that BELCO is planning to use long-term debt to fund the proposed capital plans, which means that BELCO considers it optimal to deviate from the fully equity-funded capital structure.[20]

99. While the Authority will review the actual and expected costs of debt financing and gearing of the licensee, the determination of the allowed cost of debt and allowed capital structure will be on a notional basis. This is because customers should not pay for an inefficient choice of capital structure. To take account of the unique capital market constraints in Bermuda, the Authority considers that it is appropriate for the first price control to be informed, in the determination of the notional gearing and cost of debt, by the expected capital structure and financing options available to the licensee. The Authority notes, however, that the licensee would need to justify the choice of its target capital structure and provide evidence showing that debt, if any, would be raised on market terms.[21] In addition, the Authority proposes to reassess the gearing and cost of debt assumptions when the licensee undertakes significant changes to its capital structure.

E. Outputs

100. In relation to outputs for the TD&R licensee, BELCO argued that it is too early in the new regulatory regime to have sufficient information concerning appropriate metrics to use in a binding performance plan. The Authority disagrees with this statement. As an example, the Authority is aware that BELCO has data on its network efficiency (e.g. a proportion of sold electricity to generated electricity). Therefore, the Authority finds it appropriate for BELCO to commit to, inter alia, a particular network efficiency level.

101. The Authority considers that it is appropriate to use metrics to aid in the monitoring of the performance of the TD&R and bulk generation licensees. This Final Report outlines specific outputs that the TD&R and bulk generation licensees should target. Please see sections II.F and III.E of the Preliminary Report for discussion on which specific metrics should be used

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[18] NERA Economic Consulting (2015), “BELCO Cost of Capital. Exhibit 2.0”, 21 May, p. 8.

[19] Tax benefit is one of the typical reasons that makes debt financing preferable to equity financing in non-zero corporate tax jurisdictions where interest payments reduce the tax base—the higher the debt and the corresponding interest expense, the lower the tax base and the corresponding corporate tax paid by the company.

[20] For example, see BELCO (2017), “Questions and answers. How will BELCO pay for these projects?” http://yourenergyfuture.bm/qa/.

[21] Examples of evidence that the Authority would expect from BELCO include existing financing agreements with evidence of competitive offers, or yields of bonds with a comparable credit rating, if credit rating analysis is undertaken.

within each output, for the TD&R and bulk generation licensees respectively, and whether any financial incentives (both rewards and penalties) should be associated with these outputs.

102. However, the Authority considers that there may be metrics for which it may not be possible to establish binding targets in a timely manner for the purpose of the first price control. Therefore, the Authority suggests that the bulk generation and TD&R licensees should monitor the relevant metrics over the first price-control period with a view to incorporating binding performance thresholds in future price controls.

F. Tariffs

103. BELCO believes that flexibility should be provided to experiment with new rate programmes such as real-time pricing, ToU pricing, critical-peak pricing, energy-efficiency programmes and low-income programmes.

104. The Authority considers it appropriate for BELCO to undertake a feasibility study in relation to the most appropriate tariff structure. It is important that BELCO considers the costs and benefits of a particular rate programme, taking into account the required investment (for example, the installation of advanced meters).

105. The Authority will subsequently review any particular alternative tariff structure that is proposed and will decide on whether the proposed tariff structure should be approved. This decision will be made in accordance with the purposes of the EA and the Authority's duties thereunder.

G. National Disaster Contingency Fund

106. BELCO also noted that pursuant to Condition 17 of BELCO's TD&R licence, BELCO is required to establish the NDC Fund that should be defined in the retail tariff methodology.

107. Currently, the TD&R licensee does not have an NDC Fund. Instead, in order to protect itself against any natural disasters, the licensee has insurance coverage obtained from the market.[22] The cost of insurance coverage, if efficiently incurred, should be part of allowed OPEX, and should therefore be recovered from customers via regulated tariffs. The Authority considers that this approach is in the interest of end-users. However, in accordance with Condition 17 of BELCO's TD&R licence, BELCO shall establish the NDC Fund in order to provide additional protection. The Authority will determine the source and methodology for funding and disbursing the NDC Fund. The Methodology also provides an additional protection against unexpected costs by allowing for the potential use of a 're-opener' mechanism for the tariff review, in the event of significant and uncontrollable deviations (positive or negative) in actual costs relative to allowances.[23]

108. The Authority notes that to the extent possible, the licences and any general determinations shall be construed consistently. However, where any irreconcilable differences between licences and the Retail Tariff Design Methodology General Determination to arise, then the Retail Tariff Design Methodology General Determination would take precedence.

[22] Ascendant group (2018), 'Annual report 2017', p. 15.
[23] Specifically, where the licensee has to incur unexpected costs, or achieves cost savings, that which exceed 20% of its revenue, the price control may be re-opened.

V. SUMMARY AND DISCUSSION OF RESPONSE TO PRELIMINARY REPORT, PRELIMINARY DECISION AND ORDER

V.I Response Method

109. The Authority received three response to the Preliminary Report from:

(a) BELCO;

(b) BAE; and

(c) SMART Innovations.

110. The responses have been carefully considered and are summarised and addressed individually below.

V.II Summary of Responses

111. This section provides an overview of the key themes from the responses to the Preliminary Report and summarizes some of the main decisions that the Authority has made, taking into consideration the public responses.

V.II.A Response from BELCO

112. The key points of BELCO's submission were as follows:

(a) the length of price-control periods;

(b) National Disaster Contingency Fund;

(c) core network OPEX remuneration;

(d) construction work in progress;

(e) capital expenditure remuneration;

(f) TD&R licensee's outputs; and

(g) principles of regulatory design for bulk generation licensee(s).

113. The rest of the section provides detailed comments on the points outlined above.

A. Price-control period

114. BELCO continues to advocate for five-year price-control periods. In addition, BELCO notes that if the Authority decides to proceed with the transitional period, BELCO recommends using two price-control periods (two-year and three-year) instead of three price-control periods (two one-year and one three-year period), as proposed by the Authority. BELCO argues that more frequent price-control periods will increase the resource and cost burden on the Authority and BELCO.

115. The Authority does not dispute that more frequent review periods would be associated with additional costs. However, as before, the Authority considers that the transitional period consisting of shorter review periods is necessary to fine-tune the regulatory framework.

116. BELCO advocates that an additional tariff review one year after the start of the first price-control period will significantly increase the resource and the cost burden on BELCO and the

Authority. The Authority notes the tradeoff between the benefits of more frequent tariff reviews (i.e. to fine tune the regulatory framework) and the additional cost of such tariff reviews, as noted by BELCO. As such, the Authority has amended the Methodology to set an initial transitional period of five years. Within that transitional period, the Authority will determine the frequency and duration of the tariff reviews, taking into account the costs and benefits of such reviews.

B. National Disaster Contingency Fund

117. BELCO notes that it would propose retail rates that fulfil the requirement for the National Disaster Contingency Fund (the "NDC Fund").

118. As explained in the Preliminary Report, the National Disaster Contingency Fund will be accumulated from any outperformance, should the TD&R licensee incur costs below the ex ante allowance. The Authority will determine the exact amount and whether additional funding sources for the NDC Fund would be required at the retail tariff review stage.

C. Core network OPEX remuneration

119. BELCO notes that contrary to the Authority's aim to incentivise cost efficiency, the proposed asymmetric sharing mechanism incentivises BELCO to avoid pursuing any cost efficiency initiatives. Therefore, BELCO proposes the treatment of the core network OPEX as either:

(a) sharing of both the downside and upside cost deviations with a 40:60 split; or

(b) an asymmetric split similar to the one proposed by the Authority, with separate treatment of cost-saving initiatives whereby such costs are fully recoverable in rates and are not part of the sharing calculations.

120. The Authority considers that an asymmetric approach provides strong incentives to BELCO to avoid underperformance. The change to a symmetric approach would expose customers to adversarial price effects in the downside.

121. The Authority also notes that BELCO fails to take into consideration the reward equivalent to 20% of outperformance. BELCO will be incentivised to optimise its costs to keep 20% of any outperformance.

122. With regard to BELCO's proposal of an "asymmetrical split such as that proposed with separate treatment of costs incurred to achieve sustainable costs savings whereby such costs are fully recoverable in rates and not part of the sharing calculations", the Authority contends that the differential treatment of costs incurred to achieve sustainable cost savings through a pass-through mechanism would be undesirable. The Authority considers that this introduces an additional layer of complexity to the Methodology.

123. More generally, however, the Authority does not disagree that recovery of the costs incurred to achieve sustainable cost savings may be allowed. The Authority invites BELCO to propose cost efficiency initiatives at the tariff review stage, specifying the expected savings and investment required. The Authority may then allow the recovery of the corresponding costs.

124. Therefore, the Authority does not consider that BELCO's reasoning is strong enough to motivate a change to the proposed asymmetric mechanism.

125. BELCO also requests specific provisions to recover various legacy costs that were charged to shareholders' equity. These costs include healthcare and worker retirement costs incurred due to the transition to International Financial Reporting Standards. The Authority infers that this comment relates to the treatment of specific cost items, rather than the Methodology, in

relation to a broad category of costs. As such, the Authority proposes to address this issue at the retail tariff review stage.

D. Construction work in progress

126. BELCO does not disagree with the proposed exclusion of the construction work in progress ("CWIP") from the rate base, as long as returns on this invested capital are allowed. BELCO further proposes to use an allowance for funds used during construction ("AFUDC").

127. The Authority acknowledges BELCO's proposal and assures that, as indicated in the Preliminary Report, the Authority will ensure the consistent treatment of the capitalisation of funds used during construction within the Regulatory Accounting Instructions, with the exclusion of CWIP from the rate base.

E. Capital expenditure remuneration

128. BELCO notes that the same issues apply to the CAPEX asymmetric sharing mechanism as those that apply to OPEX (and explained in paragraph 11919 above). However, BELCO argues that the impact of this asymmetric sharing mechanism is more severe for CAPEX due to the higher risks and uncertainties of CAPEX programmes. Moreover, BELCO states that the Authority's proposed sharing mechanism would incentivise BELCO either to build contingencies into its estimates to account for the risks or to outsource work to contractors that would charge substantial risk premiums. Therefore, BELCO proposes two alternative mechanisms for CAPEX remuneration:

(a) sharing both the downside and upside cost deviations with a split of 40:60; or

(b) an asymmetric split similar to the one proposed by the Authority, with allowances for contingencies, calculated in accordance with good engineering practices for the identified risks, entirely assumed by ratepayers.

129. The Authority recognises BELCO's concern in relation to uncertainties and potential overruns of CAPEX programmes. However, as BELCO correctly points out, prudent financial planning and compliance with engineering and economic principles should mitigate uncertainties inherent in CAPEX programmes. Therefore, an asymmetric sharing mechanism would incentivise BELCO to produce high-quality capital plans and manage its contractors in the interests of consumers in Bermuda.

130. Finally, the Authority notes that in case of significant cost overruns that may occur outside of BELCOs control, BELCO has the right to request that the Authority re-opens the price control if BELCO incurs unexpected costs that exceed 20% of the revenue.

131. Therefore, the Authority disagrees with BELCO's proposal of "asymmetrical split such as that proposed with allowances for contingencies, calculated in accordance with good engineering practices for the identified risks, entirely assumed by ratepayers". The Authority considers that this proposal exposes customers to unpredictable price increases and thus fails to ensure compliance with the "affordable energy prices" principle of the EA, and it disincentivises BELCO to achieve cost efficiency in delivering its CAPEX programmes.

F. TD&R licensee's outputs

132. BELCO notes that it would be preferable to cross-reference the standards set out in the documentation in relation to the Service Standards consultation process instead of duplicating them in the Retail Tariff Methodology. The Authority acknowledges BELCO's comment and considers it reasonable. As such, the Authority has amended the Methodology to explicitly reference the process set by general determination pursuant to section 34 of the EA.

133. In addition, BELCO suggests that the environmental standards ought to be included in the required outputs. Since the environmental standards are also discussed within the consultation on the Service Standards, the Authority will address the environmental standards as part of that process.

134. Finally, BELCO notes that ex ante cost allowances set for OPEX and CAPEX will need to be aligned with performance targets. The manner by which these targets will be set will need to be carefully considered, with appropriate engineering and operational inputs. The Authority does not disagree with BELCO's observations. Therefore, in the Preliminary Report, the Authority proposed a cautious approach to setting the targets. In particular, the Authority considers that it may not be possible to establish binding targets in a timely manner for the purpose of the first tariff review. Therefore, the Authority suggests that the TD&R licensee should monitor the relevant metrics over the first review period with a view to incorporating binding performance thresholds in future tariff reviews.

G. Principles of regulatory design for bulk generation licensee(s)

135. BELCO asks the Authority to clarify whether section 3 of the Preliminary Report applies only to BELCO in its capacity as a bulk generation licensee, or whether it applies to IPPs as well.

136. Thus, the Authority would like to clarify that, as stated in paragraph 72 of the Preliminary Report, for both the transfer pricing arrangement (the arrangement between BELCO's TD&R and bulk generation business units) and a PPA (an agreement between BELCO as a TD&R licensee and an IPP), the charges to the TD&R licensee should be sufficient to recover the sum of the bulk generation licensee's initial investment (including a return on invested capital), its ongoing costs, and its fuel costs.

137. On the other hand, Table 7.1 and the rest of section 3 of the Preliminary Report apply to BELCO in its capacity as a bulk generation licensee only.

138. BELCO also comments that the proposed price-cap framework is unclear in terms of both its intent and the mechanics. Moreover, BELCO notes that BELCO's generation provides not only energy but also the capacity and ancillary services to the TD&R licensee. Therefore BELCO should be able to recover its fixed costs (including a return on the capital) and its variable costs of producing energy. BELCO suggests that this is typically done by setting a fixed revenue amount to recover fixed costs and setting an energy charge to recover variable costs such as fuel.

139. The mechanics of the price-cap framework are explained in paragraph 237(b) of the Preliminary Report. As stated in paragraph 180 of the Preliminary Report, the Authority considers that the price-cap regime would be in line with a typical charging structure between networks and independent generators. The Authority further considers that a price-cap regime should apply to BELCO's generation business unit in its capacity as a provider of energy generation, capacity and ancillary services due to the challenge to distinctively disaggregate and allocate fixed and variable costs to the above-mentioned categories.

140. The Authority welcomes BELCO's intention to work closely with the Authority to determine a suitable transfer charge.

V.II.B Response from BAE

141. The key points of BAE's response were as follows:

(a) **New tariff types:** BAE provided further comments supporting the introduction of ToU billing for small and large commercial customers. The response also suggested that ToU billing could be supported by a differentiated fuel adjustment rate ("FAR"). Specifically, ToU billing may reflect different fuel costs throughout a day depending on the generation mix used to provide electricity;

(b) **Feed-in tariffs ("FIT"):** BAE raised concerns about the proposed approach to treating the FIT as a pass-through item. BAE argues that this approach would result in residential owners of solar PVs subsidising other BELCO customers. The response also raised queries in relation to the FIT methodology itself; and

(c) **Fuel adjustment rate:** BAE supported the inclusion of the full cost of fuel in the FAR.

142. Detailed responses to the points outlined above are provided below.

A. New tariff types

143. BAE expressed its support for BELCO to experiment with new tariff types, including ToU pricing, which BAE recommended in its previous response. BAE considered, however, that more complex tariff structures, such as real-time pricing and critical-peak pricing, would not be required given BELCO's typical load profile in the near future. In addition, BAE supported, in principle, the introduction of energy efficiency programmes and low-income programmes, noting that the current inclining block tariff structure already provides support to low-income consumers (assuming that these consumers also have low consumption).

144. In particular, BAE argued for the introduction of ToU pricing for "demand service" customers in the first instance, followed by "small commercial" customers, and then residential customers. The reason behind BAE's proposal to introduce ToU pricing is the difference in fuel cost that BELCO would incur throughout the day. Specifically, BAE's response highlighted that the cost of running the gas turbines (typically used to meet the peak demand) is more than double that of the reciprocating HFO generators (typically used for baseload generation). Finally, BAE suggested that BELCO should have the necessary capability for implementing such tariffs through the smart meter programme that BELCO has been rolling out. BAE added that should the relevant infrastructure not be in place, this should be relatively straightforward to deploy since the number of relevant "demand service" customers is fairly small.

145. The Authority considers it appropriate for BELCO to undertake a feasibility study in relation to the most appropriate tariff structure. Such analysis would enable BELCO and the Authority to determine the most appropriate tariff structure.

146. In addition, BAE suggests that ToU pricing could be applied to the FAR rather than the base rates (i.e. retail tariff, excluding FAR), such that FAR could be differentiated to reflect the marginal fuel cost of generation. BAE considers that this solution would be relatively straightforward for BELCO to implement using the smart meters that are capable of ToU pricing.

147. The Authority considers that at this stage the FAR methodology should not be adjusted to reflect different fuel costs based on the time of the day without additional analysis. However, this option may be investigated further by BELCO as part of the feasibility study in relation to the alternative tariff structures.

148. BAE also reiterated its argument that the current tariff structure discriminates between different types of customers and leads to a large discrepancy in the average cost per kWh between "small commercial" customers and "demand service" customers, where both have high usage 24 hours per day. The supporting analysis shows that a "small commercial" customer would be paying a 41% premium for its electricity costs compared to a situation where the same customer was to be charged under the "demand service" rate. BAE adds that a declining-block tariff structure for "demand service" customers discourages energy conservation.

149. The Authority notes that the discrepancy in electricity cost highlighted by BAE may be explained by the fact that this particular customer was not switched to the correct tariff, rather than it indicating an inherent problem with the current tariff structure. Specifically, BAE's response acknowledged that the "small commercial" customer used in BAE's analysis should have been assigned to the "demand service" rate by BELCO.

150. Overall, the Authority considers that similar types of users should be paying similar charges. This principle was outlined in the Tariff Design section of the Preliminary Report. In terms of energy conservation, the Authority has previously noted that one possibility to assist the electricity conservation aims of the EA could be for large commercial customers to move to a flat-rate or inclining block structure. Any proposed tariffs will be assessed in line with the principles outlined in the General Determination.

B. Feed-in tariffs

151. BAE expressed its concern with the Authority's proposal to treat FIT costs on a pass-through basis, where the TD&R licensee allegedly makes no money on the resale of electricity provided by distributed generators. BAE argued that this approach would result in a situation where residential owners of solar PVs are subsidising all other BELCO customers.

152. The Authority disagrees with this statement. The Authority notes that the FIT is set with the reference to the avoided cost methodology, i.e. the remuneration of the electricity produced by distributed generation of renewable energy (e.g. solar PVs) is linked to the costs that BELCO would otherwise have incurred if BELCO did not purchase energy from those residential owners. Since a decrease in BELCO's costs would be offset by the FIT payments, the total cost to customers would not change at the level of the overall electricity network.[24] Therefore, residential owners of solar PVs would not be subsidising all other BELCO customers.[25] The avoided cost methodology also ensures that BELCO would not profit from purchasing electricity from distributed generators of renewable energy.

153. BAE also raised questions in relation to the FIT methodology. While the FIT methodology is not the focus of this report, the Authority considers it appropriate to answer BAE's questions in this Final Report.

(a) BAE stated that a long-term FIT based on renewable CAPEX costs would be more appropriate than a FIT based on the avoided cost methodology. The Authority acknowledges BAE's position. However, according to the EA, the FIT has to be calculated using an avoided cost methodology. Therefore, deviating from this approach would be in direct conflict with the EA.

(b) BAE also queried whether the Authority would audit the total amount of energy that BELCO would purchase from distributed generators of renewable energy and whether the quantification of the avoided costs for the TD&R licensee would be available for scrutiny. The Authority expects that the information on the tariff review process would be publicly available and therefore open for industry review.[26]

C. Fuel adjustment rate

154. BAE supported the inclusion of the full cost of fuel in the FAR.

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[24] Assuming that no economic benefit of the distributed generation of renewable energy is included in the FIT estimate. Should the economic benefit be added to the FIT, BELCO's costs are likely to increase. However, this increase would be offset by the wider economic benefits of distributed generation of renewable energy (e.g. the environmental benefits from reduced pollution).

[25] While the total cost to customers would not change at the level of the overall electricity system, the level of FIT may have distributional consequences between the customers that do own solar PVs and those who do not.

[26] Subject to any confidentiality requirements, as appropriate.

155. However, BAE asserts that BELCO used a pass-through approach to the FAR to support increased reliance on inefficient gas turbine generation in the near future. The Authority considers that this comment is not of direct relevance to the retail tariffs and should be expressed as part of the engagement on BELCO's IRP Proposal.

V.II.B Response from SMART Innovations

156. SMART Innovations expressed its agreement with a number of points included in BELCO's response to the Consultation Document.[27]

157. SMART Innovations provided additional commentary in relation to the following key points:

(a) "Proposal of an alternative regulatory regime based on the Minimum Revenue Requirements Method";

(b) "A proposed alteration to the methodology for estimates of return on capital";

(c) "A proposed alteration to the form of control"; and

(d) "Outputs required by the authority".

158. Responses to the points outlined above are provided below.

A. Proposal for an alternative regulatory regime based on the Minimum Revenue Requirements Method

159. SMART Innovations did not agree that a hybrid of the two forms of control, i.e. a combination of rate-of-return and incentive regulation, is the most appropriate regulatory regime for the TD&R licensee in Bermuda. Similar to SMART Innovations' comments to the Consultation Document, SMART Innovations proposed an approach based on the MRRM for the electricity sector in Bermuda. SMART Innovations argued that this form of rate-of-return regulation is in line with the objectives of the EA. For example, the response highlighted that MRRP would promote the protection of the interests of end-users with respect to prices, the affordability of electricity and the promotion of economic efficiency.

160. While the Authority understands that MRRM is a type of rate-of-return regulation, the Authority does not consider that this regulation in its pure form (and the MRRM in particular) is appropriate for Bermuda. In particular, instead of using pure rate-of-return cost pass-through for all elements of the allowed revenue, the suggested approach includes some elements that are fixed ex ante at the level of the efficient cost forecast, making the proposed approach more similar to incentive regulation.

B. Methodology for estimates of return on capital

161. SMART Innovations disagreed with the proposed approach for setting the cost of capital, stressing that the CAPM approach is less widespread among US utilities and state utility commissions than the "WACC" approach.

162. First, the Authority notes that the CAPM is one of the methods for estimating the cost of equity, which in turn is a component of the WACC.

163. As discussed in the Preliminary Report, the CAPM is one of the methodologies commonly used to estimate the cost of equity.[28] However, the Authority finds it appropriate for the licensee to provide the results from other approaches to the cost of equity estimation in

[27] In particular, SMART Innovations expressed its agreement with BELCO on the points such as BELCO's position on return of capital methodology, the use of outputs required, the TD&R licensee's OPEX remuneration mechanism, the bulk generation licensee's cost remuneration mechanism and the length of price-control periods.
[28] California Public Utilities Commission (2017), 'Utility General Rate Case – A Manual for Regulatory Analysts', 13 November, p. 30.

addition to the CAPM, as long as these approaches are applied appropriately and are well justified. Based on the range of evidence, the Authority will make the final decision regarding the point estimate for the cost of equity allowance.

164. Once the Authority makes the decision in relation to the cost of equity, the cost of debt and the gearing estimates, a mechanical calculation would lead to the WACC estimate.

C. Duration of the price control

165. SMART Innovations proposed that the regulatory regime be based on five-year price-control periods only, expressing its opposition to shorter price-control periods during the transitional period. SMART Innovations based its view on the following arguments:

(a) Longer price-control periods encourage stability for the electric utility capital markets.

(b) Longer price-control periods are better aligned with the planning horizon of utility companies (typically five years or longer).

(c) Shorter price-control periods would lead to higher expected cost for compliance with the shorter periods.

166. The Authority considers these arguments reasonable. Moreover, the Authority considers that five-year review periods are important for promoting efficiency throughout the electricity sector in Bermuda. Therefore, five-year review periods are proposed in the long term. However, as the Methodology is in its infancy, the Authority believes that the transitional period is essential in order to fine-tune the regulatory framework with the aim of improving future utility performance and enhancing the benefits to customers.

D. Outputs required

167. SMART Innovations acknowledged that the required outputs, such as the efficiency metrics, are appropriate and necessary for internal and external benchmarking. However, its response highlights that the outputs should be carefully selected and be consistent with the IRP Proposal prepared by BELCO in February 2018. In particular, SMART Innovations stressed that the selection of the target Forced Outage Rate for peaking versus baseload plant is complicated and must conform with international best industry practice. Moreover, it was claimed that a period of less than five years is too short for data collection, analysis and benchmarking.

168. The Authority agrees with SMART Innovations and acknowledges the complexity of setting appropriate metrics. Therefore, the Authority will seek to work with the TD&R licensee to develop the final list of metrics, and, where relevant, establish binding target values for those metrics in the future. The Authority encourages SMART Innovations to refer to the Service Standards consultation process.

VI. CONCLUSION

169. In furtherance of the proposals set forth above, the Authority hereby adopts the Order set forth in Appendix A to this Final Report, and makes the General Determination set forth in Appendix B.

APPENDIX A: ORDER

Order:
Retail Tariff Methodology

Order
Date: 19 October 2018

I The Regulatory Authority, pursuant to Sections 12, 13 and 62 of the Regulatory Authority Act 2011 and Sections 6, 14, 17 and 35 of the Electricity Act 2016, hereby:

(a) Adopts the General Determination attached hereto, setting forth the methodology for calculating the retail tariff for the electricity sector;

(b) Directs the Chief Executive of the Regulatory Authority to forward the General Determination to the Cabinet Secretary; and

(c) Authorises the General Determination to be effected on the date of its publication in the Royal Gazette.

II So Ordered this 19 day of October 2018

APPENDIX B: GENERAL DETERMINATION

BERMUDA

Regulatory Authority (Retail Tariff Methodology) General Determination

BR /2018

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The Regulatory Authority, in the exercise of the power conferred by section 62 of the Regulatory Authority Act 2011, as read with sections 12 and 13 of that Act and sections 6, 14, 17 and 35 of the Electricity Act 2016, makes the following General Determination:

Citation

1 This General Determination may be cited as the Regulatory Authority (Retail Tariff Methodology) General Determination.

Interpretation

2 In this General Determination, unless the context otherwise requires, terms shall have the meaning given in the Regulatory Authority Act 2011, the Electricity Act 2016, and the Schedule to this General Determination.

General Purpose

3 This General Determination establishes the methodology for calculating the electricity retail tariff.

Determination

4 (1) This General Determination is made pursuant to the Consultation Document entitled "Retail Tariffs Design Public Consultation" dated 8 March 2018 and the Regulatory Authority's Decision on it.

(2) Taking into account the received responses to the Consultation Document and for the reasons given in the Decision, the Authority determines that the retail tariff methodology set forth in the Schedule is consistent with the purposes of the Electricity Act 2016, including to seek to:

(a) ensure the adequacy, safety, sustainability and reliability of electricity supply in Bermuda;

(b) encourage electricity conservation and the efficient use of electricity;

(c) promote the use of cleaner energy solutions and technologies;

(d) provide sectoral participants and end-users with non-discriminatory interconnection to transmission and distribution systems;

(e) protect the interests of end-users with respect to prices and affordability, and the adequacy, reliability and quality of electricity service; and

(f) promote economic efficiency and sustainability in the generation, transmission, distribution and sale of electricity.

Terms and conditions of General Determination

5 (1) The Schedule to this General Determination has effect.

(2) The Schedule is also published on the Regulatory Authority's website (www.rab.bm) and is also available for inspection at the offices of the Authority (1st Floor, Craig Appin House, 8 Wesley Street, Hamilton HM 11) during ordinary business hours.

Effective Date of General Determination

6 This General Determination shall become effective on the day it is published in the Official Gazette.

REGULATORY AUTHORITY

Bermuda

Schedule to Regulatory Authority (Retail Tariff Methodology) General Determination

General Determination

Date: 19 October 2018

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This General Determination is made by the Regulatory Authority of Bermuda pursuant to Section 62(1) of the Regulatory Authority Act 2011 ("**RAA**") and in accordance with Sections 6, 14, 17 and 35 of the Electricity Act 2016 ("**EA**") and establishes the methodology for calculating the retail tariff for the electricity sector.

1 Definitions

"Allowed revenue" means the amount of money an entity is allowed to earn in undertaking its regulated business activities, typically on an annual basis.

"Asset life" in regulated tariff setting is the basis for a depreciation calculation.

"Asymmetric incentive scheme" is a regulatory scheme which provides incentives for least-cost provision of services, where the impact of cost outperformance and underperformance, relative to a benchmark, are different.

"Authority" means the Regulatory Authority of Bermuda established under the Regulatory Authority Act 2011 (as defined by the Electricity Act 2016).

"Barrel" is a unit of volume equal to 42 US gallons, or 159 litres.

"Base-rate filings system" means a methodology to determine retail tariffs, which is currently used in the regulation of the electricity sector of Bermuda.

"Bulk generation" means generation using a system with an installed capacity at or above the licence threshold (as defined by the Electricity Act 2016).

"Bulk generation licence" means a licence granted under section 25 of the Electricity Act 2016.

"CAPEX" means capital expenditure, i.e. expenditure related to the acquisition or upgrade of fixed assets.

"Capital structure" means the proportion of debt and equity that an entity uses to finance its activities.

"CAPM" means capital asset pricing model, a methodology commonly used to estimate the cost of equity for an entity.

"Competitive market" means an idealised market in which a large number of firms compete to provide goods and services for a large number of customers.

"Core network OPEX" means operating expenditure related to the regulated activities of the TD&R licensee, excluding the expense of power procurement and "other expenses" as defined in section 35(3)(d) of the Electricity Act 2016.

"Cost allowance" means the amount of money an entity is allowed to earn within its allowed revenue, to recover corresponding costs.

"Cost of capital" means the return on investment required by investors providing funding for an entity's activities.

"Cost of debt" means the return on investment required by an entity's debt holders.

"Cost of equity" means the return on investment required by an entity's equity holders.

“Cost pass-through allowance” means a cost allowance within regulated tariff setting, such that there is no deviation between allowed costs and costs actually borne by an entity.

“CWIP” means Construction Work in Progress, an asset account in which the value of assets under construction is recorded.

“Demand side resources” means the reduced demand for electricity resulting from demand side management (as defined by the Electricity Act 2016);

“Depreciation” means the gradual decrease in the value of an asset through time due to use, wear and tear or obsolescence; within regulatory tariff setting, depreciation also refers to a cost allowance (as a component of allowed revenue) that is determined to allow an entity to recover its capital expenditure.

“Distributed generation” means generation using a system with an installed capacity below the licence threshold (as defined by the Electricity Act 2016).

“Distributed generator” means a person that has a Standard Contract (as defined by the Electricity Act 2016).

“Distribution” means conveying electric power below 22 kilovolts (kV) (as defined by the Electricity Act 2016).

“EA” means the Electricity Act 2016.

“Efficiency” means achieving maximum benefits with minimum resources.

“Economic life” means the estimated lifespan over which an asset is expected to be able to serve its intended purpose.

“Electricity sector” means the regulated industry sector involving the supply, transmission, distribution and consumption of electricity (as defined by the Electricity Act 2016).

“End user” means a person or entity that uses electric power provided by the TD&R licensee on a retail basis (as defined by the Electricity Act 2016).

“Ex ante” means before the event, i.e. this refers to items that are defined before actual results are known.

“Ex post” means after the event, i.e. this refers to items that are based on actual rather than forecast data.

“Facility” means a site where electrical equipment is located to provide some form of electrical service (as defined by the Electricity Act 2016).

“FAR mechanism” means the fuel adjustment rate mechanism designed to recover the cost of fuel used to produce electricity.

“Feed-in tariff” means the pre-determined rate at which renewable energy is purchased by the TD&R licensee from a distributed generator, for a pre-determined period, and under pre-determined conditions in accordance with Part 6 of the Electricity Act 2016

“Fixed Assets” means tangible assets that are not readily convertible to cash (as opposed to liquid assets); this typically refers to plant, property and equipment, which is in service.

“Gearing” is a measure of the extent of debt that an entity has raised; within this report, gearing refers to the ratio of an entity’s net debt to the rate base.

“Generation capacity” means the maximum electrical output that an electricity plant can produce (typically measured in megawatts).

“Generation” means the process of producing electric power. This includes generation of renewable energy (as defined by the Electricity Act 2016).

“Government authorisation fees” means the fees established under section 52 of the Regulatory Authority Act 2011 (as defined by the Electricity Act 2016).

“HCA Approach” means historical cost accounting approach, whereby the value of an asset is based on the original acquisition or construction cost of the asset. Typically, financial statements containing HCA estimates of the book value of assets are stated on a ‘net’ basis, i.e. less accumulated depreciation.

“Incentive regulation” refers to a form of regulation, which involves setting either price or revenue caps linked to an efficient cost forecast. These caps are in place for a fixed period, thereby providing an incentive to outperform .

“Interconnection” means the electrical connection of a generating station of a licensee, or of a distributed generation unit, to the TD&R licensee (as defined by the Electricity Act 2016).

“IPP” means an independent power producer. This is an entity that provides energy, capacity, and ancillary services for commercial purposes at a bulk scale to the electric utility under long-term contracts.

“IRP” means integrated resource plan, an energy plan for the supply of electricity in Bermuda approved by the Authority in accordance with, and set out in the matters required by, Part 8 of the Electricity Act 2016.

“kWh” means kilowatt-hour, a unit of electrical energy equal to one kilowatt of power expended for one hour; the standard unit of measure used for electrical billing.

“kW” means kilowatt, a standard unit of electrical power equal to 1,000 watts.

“Licence” means a valid licence granted by the Authority under the Electricity Act 2016.

“Licensee” means a person that holds a valid licence in accordance with the Electricity Act 2016.

“MRRM” means Minimum Revenue Requirements Method, a form of rate-of-return regulation.

“MW” means megawatt, one million watts, or one thousand kilowatts of electrical power.

“NDC Fund” means National Disaster Contingency Fund, of which the amount is to be determined by the Authority and which must be available at any time during the term of the TD&R licence.

“OPEX” means operating expenditure. This is expenditure incurred in the day to day running of a business.

“Outputs” means measurable characteristics of a licensee’s activities.

“PPA” means power purchase agreement. This is an agreement entered into under section 48 of the Electricity Act 2016 between the TD&R licensee and a bulk generation licensee, approved by the Authority, whereby the TD&R licensee contracts to purchase or acquire electricity generated by the bulk generation licensee as specified in the agreement (as defined by the Electricity Act 2016).

“Price-cap regime” is a type of incentives-based regime where no adjustments to prices due to deviations from volume forecasts are allowed, i.e. volume risk is borne by the regulated entity .

“Review period” means a period for which retail tariffs are determined by the Authority.

“RAA” means the Regulatory Authority Act (2011).

“Rate base roll-forward” means the process by which the value of a rate base is updated over time.

“Rate base” means the total value of assets on which a utility is permitted to earn a return.

“Rate-of-return regulation” means a type of regulation, where tariffs are set at a level that reflects the actual cost of service .

“Regulatory accounts” means accounts that have to be prepared in line with the Regulatory Accounting Instructions.

“Re-opener” means a mechanism which facilitates a change in allowed revenues before the next review period.

“Return on capital” or “return on rate base” means a cost allowance determined to allow a company to recover its cost of capital, as a component of regulatory allowed revenue.

“Revenue-cap regime” is a type of incentives-based regime where the prices can be adjusted to recover any difference between the expected and realised volumes, i.e. volume risk is borne by customers .

“Risk-free rate” is a return required by an investor for an investment in a risk-free asset.

“Straight-line depreciation” refers to a depreciation profile whereby the annual depreciation expense is constant, typically over the lifespan of an asset.

“Sunk cost” means a cost that has already been incurred and is not recoverable.

“TD&R” means transmission, distribution and retail.

“TD&R licence” means a licence granted under section 25 of the Electricity Act 2016.

“Test Year” refers to a year, in the past, for which data is available, and is used to define future cost allowances.

“ToU” means time of use pricing or billing, whereby charges are based on how much energy is used and when the usage occurs.

“Transfer pricing arrangement” refers to an arrangement pursuant to which the TD&R business unit of a vertically integrated utility procures power from the generation business unit of a vertically integrated utility.

“True-up mechanism” means a mechanism which adjusts the cost allowances such that they align with the actual costs borne by a company.

“TSF” means tariff stabilisation fund, as described in paragraph 21 hereof.

“Vertically integrated utility” means a company that engages in bulk generation and transmission, distribution, and sale (retailing) of electricity.

“Vanilla WACC” means the weighted average cost of capital using a pre-tax cost of debt and a post-tax cost of equity, as set forth in paragraph 55 of the Retail Tariff Methodology.

“Volume risk” means the risk that sold units of electricity deviate from the forecast.

“WACC” means weighted average cost of capital.

2 INTERPRETATION

(1) For purposes of interpreting this General Determination:

(a) unless the context otherwise requires, words or expressions shall have the meaning assigned to them by the RAA and the EA;

(b) where there is any conflict between the provisions of this General Determination and the EA or RAA, the provisions of the EA or RAA, as the case may be (and subject to sections 3(2) and 3(3) of the EA), shall prevail;

(c) terms defined herein and in the EA and RAA have been capitalised;

(d) headings and titles used herein are for reference only and shall not affect the interpretation or construction of this General Determination;

(e) references to any law or statutory instrument include any modification, re-enactment or legislative provisions substituted for the same;

(f) a document referred to herein shall be incorporated into and form part of this General Determination and a reference to such document is to the document as modified from time to time;

(g) expressions cognate with those used herein shall be construed accordingly;

(h) use of the word "include" or "including" is to be construed as being without limitation; and

(i) words importing the singular shall include the plural and vice versa, and words importing the whole shall be treated as including a reference to any part unless explicitly limited.

3 LEGISLATIVE AND PROCEDURAL BACKGROUND

(1) This General Determination has been undertaken in accordance with section 62 of the RAA and the exercise by the Authority of its powers under sections 6, 14, 17 and 35 of the EA.

(2) The Authority initiated the consultation by publishing a Consultation Document on 8 March 2018 that invited responses from members of the public, including electricity sectoral participants and sectoral providers, as well as other interested parties. The purpose of the Authority's initial Consultation Document was to consult on the proposed Retail Tariff Methodology.

(3) The Consultation Document asked questions on the following topics:

TD&R licensee

- Tariff design
- Form of control
- Building blocks of regulation
- Proposed remuneration of operation expenditure ("OPEX") of the TD&R licensee
- Initial asset valuation
- Rate base roll-forward
- Depreciation
- Capital expenditure
- Return of capital
- Outputs

Bulk Generation licensees

- Capacity fee-existing generation assets
- Capacity fee-new generation assets
- Energy fee
- Fuel adjustment rate
- Outputs

(4) The Consultation Document also invited respondents to comment on the structure of the proposed retail tariff methodology.

(5) Responses to the Consultation Document were solicited from the public electronically through the Authority's website at rab.bm.

(6) The response period commenced on 8 March 2018 and concluded on 19 April 2018.

(7) The Authority received three responses from the public.

(8) The Authority issued a Preliminary Report, Preliminary Decision and Order on 10 September 2018 that invited responses from members of the public, including electricity sectoral participants and sectoral providers, as well as other interested parties.

(9) The Authority received three responses from the public for the Preliminary Report, Preliminary Decision and Order.

4 FINAL DETERMINATION

(1) Pursuant to section 62 of the RAA and in accordance with sections 6, 14, 17 and 35 of the EA using the general powers granted to the Authority under section 13 of the RAA and in accordance with the procedures established for this purpose in section 62 of the RAA, the Authority hereby determines that:

(2) The adoption and implementation of the Retail Tariff Methodology as set forth in Annex 1 of this Schedule below is consistent with the purposes of the EA, including to seek to: (a) ensure the adequacy, safety, sustainability and reliability of electricity supply in Bermuda; (b) encourage electricity conservation and the efficient use of electricity; (c) promote the use of cleaner energy solutions and technologies; (d) provide sectoral participants and end-users with non-discriminatory interconnection to transmission and distribution systems; (e) protect the interests of end-users with respect to prices and affordability, and the adequacy, reliability and quality of electricity service; and (f) promote economic efficiency and sustainability in the generation, transmission, distribution and sale of electricity.

ANNEX 1 – RETAIL TARIFF METHODOLOGY

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1. INTRODUCTION

1. The Regulatory Authority of Bermuda (the "Authority") is issuing this General Determination to establish the methodology for setting the Retail Tariff (the "Methodology") charged by the TD&R licensee to the electricity consumers in Bermuda.

2. This Methodology should be considered in combination with other regulatory tools, such as those listed below.

   a. **Integrated Resource Plan**—an energy plan for the supply of electricity in Bermuda. The IRP defines the requirements for the transmission, distribution and retail ("TD&R") licensee to meet forecasted energy demand using both supply- and demand-side resources to ensure reliable, cost-effective service to customers. The IRP includes a procurement plan that can be used to guide bulk generation licensees' capital expenditure ("CAPEX") forecast.

   a. **Net benefit test**—which provides the framework for assessing fair network access in Bermuda's electricity sector through balancing the benefits and costs of new generation capacity.

   b. **Power Purchase Agreement ("PPA") guidelines**—which facilitates and aids the negotiation of PPAs between the TD&R licensee and IPPs, to encourage efficient procurement of generation.

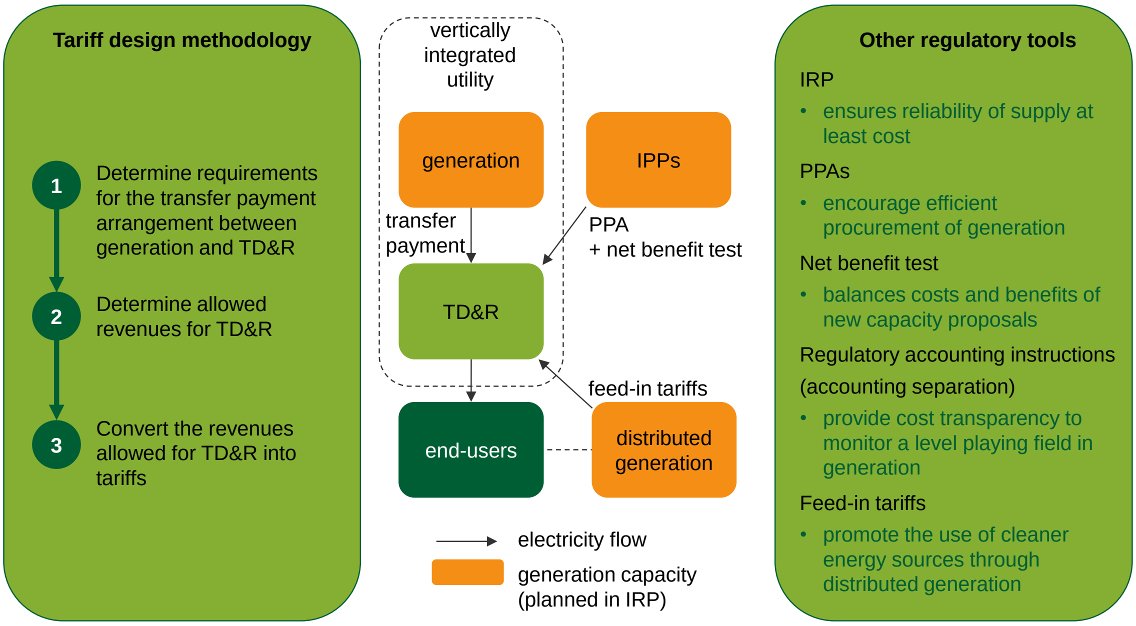
   c. **Regulatory accounting instructions**—which require separate regulatory accounts for the bulk generation and TD&R licensees. This informs the tariffs to end-users and provides cost transparency to monitor whether there is a level playing field in generation.

   d. **Feed-in tariff methodology**—setting the methodology to define the feed-in tariff — the pre-determined rate at which the TD&R licensee purchases renewable energy from distributed generators. The feed-in tariff methodology ensures that all electricity resources have access to transmission and distribution systems on fair, reasonable and non-discriminatory terms.

   e. **Service Standards**— which set key performance indicators for assessing the quality of customer service and the technical performance of the TD&R licensee and bulk generation licensees.

3. Figure 1.1 below illustrates the regulatory regime.

Figure 1.1 Elements of the regulatory regime



Note: IRP - Integrated Resource Plan; PPA - Power Purchase Agreement; IPP - Independent Power Pproducer and TD&R - Transmission, Distribution and Retail.

4. In particular, the Methodology introduces elements of incentive regulation to promote economic efficiency in the provision of electricity services to the customers of Bermuda. The Methodology determines the allowed revenue for the TD&R licensee, which is subsequently converted into retail tariffs.

5. The allowed revenue of the TD&R licensee is determined using the formula:

Allowed revenue = operating expenditure (“OPEX”) + depreciation + rate base x return on rate base

6. The Methodology combines some elements of incentive regulation (i.e. ex ante cost forecasts) and some elements of rate-of-return regulation (cost pass-through allowances).

7. Table 1.1 below describes the treatment of each component of allowed revenue in turn.

Table 1.1 Treatment of the components of the allowed revenue for the TD&R licensee

Element of regulatory regime	Treatment
Rate base	• the components of the rate base are plant in service and working capital; construction work in progress is not included in the rate base • historical cost accounting approach for the initial valuation of assets and a periodic update of the rate base in accordance with the annual CAPEX (ex ante, subject to an asymmetric CAPEX incentive scheme) and depreciation
Depreciation	• straight-line depreciation, subject to approval of the asset-life assumptions
OPEX	• core network OPEX: ex ante, subject to an asymmetric incentive scheme • power procurement:* cost pass-through allowance • other expenses (fees and taxes): cost pass-through allowance
Return on rate base	• ex ante nominal vanilla WACC estimate, subject to a trigger mechanism[29]

Note: CAPEX, capital expenditure; OPEX, operating expenditure; WACC, weighted average cost of capital. * This includes a transfer payment to the generation business unit of the vertically integrated utility from the TD&R licensee.

8. The Authority considers that at this time, in the regulation of electricity, the degree of competition in the electricity generation market in Bermuda is not sufficient to ensure that the terms for the procurement of electricity would reflect the best available market terms. Therefore, the Methodology places certain requirements in relation to terms for the procurement of electricity.

9. In particular, the Authority provides a methodology for a transfer pricing arrangement for the vertically integrated utility, i.e. Bermuda Electric Light Company Limited ("BELCO"). Regarding any new generation facilities proposed by IPPs, the Authority will assess PPAs for such IPP entrants on a case-by-case basis and always with the intention of pursuing the purposes of the Electricity Act 2016 ("EA").

10. For both the TD&R licensee's transfer pricing arrangement with its bulk generation business unit and PPAs with IPPs, the Authority concludes that the charges to the TD&R licensee shall be sufficient to recover the sum of the bulk generation licensee's initial investment (including a return on invested capital), bulk generation licensee's ongoing costs, and its fuel costs. The exact terms of a PPA will be negotiated between the TD&R licensee and an IPP bilaterally, subject to the Authority's approval. The transfer pricing arrangement between the TD&R and bulk generation business units of a vertically integrated utility will be reviewed and approved by the Authority periodically, aligned with the review periods for the TD&R licensee.

11. Once the allowed revenue for the TD&R licensee is established, the total revenue must then be allocated across different customer classes and converted into retail tariffs.

12. The rest of this General Determination is structured as follows:

    a. Section 2 describes the approach to setting the allowed revenue for the TD&R licensee;

    b. Section 3 describes the requirements in relation to the transfer pricing arrangement between the TD&R and bulk generation business units of the vertically integrated utility;

    c. Section 4 describes the approach for converting the allowed revenue into appropriate retail tariffs; and

[29] Under the trigger mechanism, the return on capital for the TD&R licensee is estimated and allowed ex ante for the duration of a review periodbut allowed to vary if there are significant movements (up or down) in capital markets (e.g. changes in the risk-free rate).

d. Section 5 summarises the Methodology.

2. PRINCIPLES OF THE REGULATORY DESIGN FOR THE TD&R LICENSEE

13. This section described the Methodology for setting the allowed revenue for the TD&R licensee.

II.A. **Form of Tariff Review**

14. The Authority considers that a hybrid of the two forms of tariff review, rate-of-return and incentive regulation, is the most appropriate regulatory regime for the TD&R licensee in Bermuda. This is to balance the provision of incentives to promote cost efficiency with proportionality and practicality of implementation. In particular, instead of using pure rate-of-return cost pass-through for all elements of the allowed revenue, the Methodology also includes some elements that are fixed ex ante at the level of the efficient cost forecast, i.e. similar to incentive regulation.

15. In addition, the Authority concludes that the TD&R licensee should be subject to a revenue-cap regime (where applicable).

16. The regime should be based on five-year review periods.[30] However, as the energy market in Bermuda is going through a period of change, the Authority considers that a transitional period with shorter review periods is appropriate. In particular, there will be a transitional period of up to five years. During this transitional period, the frequency and duration of tariff reviews will be determined by the Authority. After the initial transitional period, the Authority expects that the regulatory regime would be mature enough to support longer, five-year review periods. The TD&R licensee will also maintain the right to request that the Authority re-opens the tariff review if it has to incur unexpected costs that exceed 20% of the licensee's revenue. Similarly, the Authority maintains the right to re-open a tariff review if the TD&R licensee achieves a cost outperformance of at least 20% of its revenue.

17. In the rest of this section, the regulatory regime is described in detail.

II.B. **Building Blocks of Regulation**

18. Pursuant to the EA, the allowed revenue under both rate-of-return and incentive regulation regimes is set such that the TD&R licensee recovers reasonable costs in respect of efficiently incurred OPEX and CAPEX as well as the cost of capital.[31] This would be realised through the allowance of OPEX, depreciation and a return on capital (rate base x return on rate base). In broad terms, the allowed revenue is calculated in accordance with the following formula:

Allowed revenue = OPEX + depreciation + (rate base x return on rate base)

19. As such, the intention of the allowed revenue is to align the revenues of a regulated company with those that the company would expect to earn in a competitive market. Table 2.1 provides a summary of the Methodology. The rest of this section describes the treatment of each component in detail.

[30] The EA requires the retail tariff review to happen every five years or less. See Electricity Act 2016, section 37(1)(a).
[31] See Electricity Act 2016, section 35.

Table 2.1 Treatment of each component of allowed revenue for the TD&R licensee

Element of regulatory regime	Treatment
Rate base	• the components of the rate base are plant in service and working capital; construction work in progress is not included in the rate base • historical cost accounting approach for the initial valuation of assets and a periodic update of the rate base in accordance with the annual CAPEX (ex ante, subject to an asymmetric CAPEX incentive scheme) and depreciation
Depreciation	• straight-line depreciation, subject to approval of the asset-life assumptions
OPEX	• core network OPEX: ex ante, subject to an asymmetric incentive scheme • power procurement:* cost pass-through allowance • other expenses (fees and taxes): cost pass-through allowance
Return on rate base	• ex ante nominal vanilla WACC estimate, subject to a trigger mechanism[32]

Note: CAPEX, capital expenditure; OPEX, operating expenditure; WACC, weighted average cost of capital. * This includes a transfer payment from the TD&R licensee to the generation business unit of the vertically integrated utility.

20. As outlined above, the regime will be based on five-year review periods. However, a number of cost categories are subject to cost pass-through treatment—i.e. if actual costs incurred by the licensee are different from the ex ante allowance, then the regulatory regime would provide an adjustment to the allowed revenue in future periods such that the licensee recovers its costs in full. The Authority considers that such adjustments should be made on an annual basis, i.e. an annual true-up mechanism should be used. This approach allows a closer alignment between the revenues recovered and costs incurred by the licensee, and therefore helps to promote the economic sustainability of the electricity sector. In addition, an element of a frequent true-up mechanism should be maintained in the form of the fuel adjustment rate ("FAR"), which adjusts the total tariffs intra-year in order to reflect the changes in the fuel costs.

21. Under the previous regime, there is a different mechanism that ensures that the company's recoverable revenues are in line with costs that have been incurred. In particular, where actual profit is above the targeted level of profit, the difference accumulates within a fund, i.e. the TSF. The TSF is then used to defer tariff increases or to make up revenue requirement shortfalls similar to the FAR balancing account.[33]

22. Under the Methodology, the Authority concludes that the retention of the TSF mechanism is not necessary. Instead, for ease of implementation, adjustments for discrepancies between allowed expenditure and actual expenditure can be directly incorporated as an adjustment within regulatory allowed revenues in future periods. This is as per a true-up mechanism where the TD&R licensee would share the company's outperformance with customers. Moreover, the TSF mechanism constrains the level of actual profit that the company can achieve, and thereby lowers incentives to reduce costs.

23. Another fund, the National Disaster Contingency Fund (the "NDC Fund"), is required under Condition 17 of the TD&R license granted to BELCO.

24. The TD&R licensee does not currently have an NDC Fund. Instead, in order to protect itself against any natural disasters, the licensee has insurance coverage obtained from the market.[34] The cost of insurance coverage, if efficiently incurred, should be part of allowed OPEX and should therefore be recovered from customers via regulated tariffs. In order to provide additional protection against costs related to a national disaster, the TD&R licensee shall establish an NDC Fund. The source and methodology for funding and disbursing the

[32] Under the trigger mechanism, the return on capital for the TD&R licensee is estimated and allowed ex ante for the duration of a review periodbut allowed to vary if there are significant movements (up or down) in capital markets (e.g. changes in the risk-free rate).
[33] Energy Commission (2016), "Re: BELCO Base Rate Filings—June 3, 2015", 31 March, para. XXVII (b).
[34] Ascendant group (2018), 'Annual report 2017', p. 15.

NDC Fund shall be established by the Authority. Moreover, an additional protection against unexpected costs is provided by allowing for the potential use of a 're-opener' mechanism for the tariff review, in the event of significant and uncontrollable deviations (positive or negative) in actual costs relative to allowances. (see section II.C.).[35]

25. To the extent possible, the licenses and any general determinations shall be construed consistently. However, where any irreconcilable differences between licences and the Retail Tariff Design Methodology General Determination arise, the Retail Tariff Design Methodology General Determination would take precedence.

II.C. Operating Expenditure

26. In this section, the approach for remunerating OPEX for the TD&R licensee is described.

27. Previously, OPEX is remunerated on a cost pass-through basis, i.e. OPEX that is allowed to be recovered through tariffs is based on the actual costs incurred by the TD&R licensee. While this approach was transparent in its implementation, it did not provide sufficiently strong incentives for the licensed company to improve efficiency and deliver electricity services for the least cost.

28. In order to incentivise the TD&R licensee to improve efficiency, it would be appropriate to introduce ex ante OPEX allowances. The Authority distinguishes two potential approaches for remunerating OPEX on an ex ante basis:

    e. **a top-down approach**—this would project the allowed OPEX over a review period based on the *aggregate* level of expenditure, i.e. the efficient level of overall OPEX for the company is assessed;

    f. **a bottom-up approach**—this would project the allowed OPEX over a review period based on a more *disaggregated* level of expenditure, i.e. overall OPEX is built up from line-by-line cost projections.

29. Both approaches would require comprehensive engineering and benchmarking studies in order to project the efficient levels of OPEX.

30. Overall, the Authority expects that the TD&R licensee will use one of these approaches to prepare a well-justified OPEX forecast.

31. The Authority will divide the approach for remuneration of OPEX for the TD&R licensee across three distinct categories of expenditure—core network OPEX, procurement of power and other expenses (fees and taxes).

Core network OPEX

32. The Authority concludes that the OPEX allowance should be based on the forecast of the efficient costs submitted by the TD&R licensee and that the levels of forecast OPEX put forward by the TD&R licensee should be well justified.

33. The Authority recognises the difficulty in preparing a well-justified OPEX forecast. Therefore, the Authority considers it acceptable to benchmark the OPEX allowance to the "Test Year", being the latest year for which data is available, for the first review period.

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[35] Specifically, where the licensee has to incur unexpected costs, or achieves cost savings, which exceed 20% of its revenue, the tariff may be re-opened.

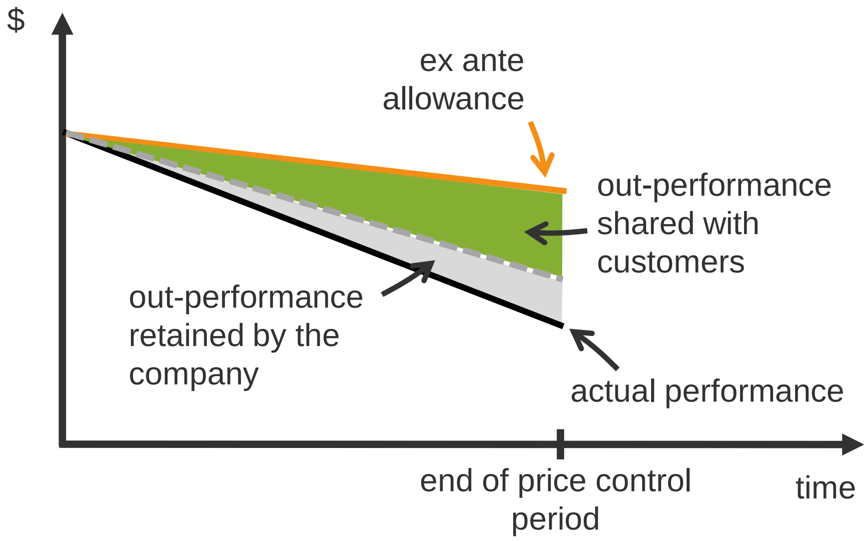
34. In addition, an asymmetric incentive mechanism for the actual OPEX incurred by the TD&R licensee should be used, such that:

g. should the TD&R licensee incur OPEX below the ex ante allowance, the outperformance should be shared by the TD&R licensee with the customers and/or the NDC Fund on a 20:80 basis (i.e. the majority of the benefit accrues to customers and/or the NDC Fund, the proportional split to be determined by the Authority); and

h. should the TD&R licensee incur OPEX in excess of the ex ante allowance, the cost of the underperformance should be absorbed by the TD&R licensee.

35. This illustrated in Figure 2.1 below.

Figure 2.1 OPEX remuneration mechanisms



Power procurement

36. Pursuant to sections 47 and 48 of the EA and condition 24 of the TD&R license, procurement of power by the TD&R licensee shall be effected under:

i. an Authority approved PPA between the TD&R licensee and an IPP;[36] and

j. a power purchase arrangement ("transfer pricing arrangement") between the TD&R license and the generation business unit of the vertically integrated utility.

37. In the short term, the TD&R licensee will procure most of the power from its bulk generation business unit under a transfer pricing arrangement.

38. The cost of power procured should be remunerated within the TD&R licensee's allowed revenue on a cost pass-through basis.

Other Expenses (fees and taxes)

[36] A PPA secures the payment stream and specifies agreed terms and conditions for a project undertaken by an IPP. It is usually agreed between the purchaser ("offtaker") and a privately-owned power producer. In addition to obligations relating to the sale and purchase of the power generated, the PPA also sets out the required design and outputs and operation and maintenance specifications for the power plant. Source: World Bank (2017), Power Purchase Agreements (PPAs) and Energy Purchase Agreements (EPAs), https://ppp.worldbank.org/public-private-partnership/sector/energy/energy-power-agreements/power-purchase-agreements.

39. Compensation for any fees, charges or taxes that the TD&R licensee is obliged to pay to public authorities (except for fines and penalties) should be compensated on a cost pass-through basis.

40. The approach for the remuneration of OPEX is summarised in Table 3.1.

Table 3.1 OPEX remuneration summary

Type of TD&R costs	Approach
Core network OPEX	• ex ante, subject to an asymmetric incentive scheme
Power procurement*	• cost pass-through allowance
Other expenses (fees and taxes)	• cost pass-through allowance

Note: * This includes the transfer pricing arrangement for the vertically integrated utility.

II.D. Rate Base

41. Rate base is a driver of the return *on* capital (i.e. allowed profit), and the return *of* capital (i.e. depreciation). The rate base shall be determined using the following principles.

a. **Components of the rate base**—plant in service and working capital are the components of the rate base. Construction work in progress ("CWIP") is not included in the rate base.[37] This is discussed in section II.D.1.

b. **Initial asset valuation**—the assets should be valued using historical cost accounting ("HCA") approach.

c. **Rate base roll-forward**—the rate base should be updated using HCA values of CAPEX and depreciation that will be directly observable in the regulatory accounts.

d. **Depreciation**—a straight-line depreciation approach should be applied to the TD&R licensee's rate base in order to estimate the depreciation allowance. The Authority will approve the asset-life assumptions used in regulation and, where assumptions change, may disagree with a change and base the allowed revenue calculations on the asset-life assumptions that the Authority considers appropriate.

e. **CAPEX**—introduce an asymmetric CAPEX incentive scheme for the TD&R licensee. This is discussed in section II.D.2.

42. The rest of the section defines the components of the rate base (section II.D.1) and treatment of CAPEX (section II.D.2).

II.D.1 Components of the rate base

43. The rate base is the value of the assets on which investors earn a return. The rate base will include:

f. plant in service—typically equivalent to the fixed assets that are used and useful to generate revenue;

g. working capital—typically including materials and supplies, fuels and lubricants (these items are applicable to a bulk generation licensee only) and cash working capital (i.e. cash requirements for a timing lag between cash inflows and outflows);

[37] The Authority notes that adjustments may be required to the book values of the above components for the purpose of assessing regulatory allowed revenues.

44. It is important that there is no double counting in regulatory allowed revenues; for example, if an unspent OPEX allowance is recorded as a current asset (e.g. as excess cash or excess inventory stock) within the calculation of working capital and then included in the rate base, then the allowance would be double counted. To avoid double counting, as part of the tariff review, the Authority will review the allowance for working capital carefully. In any case, working capital that is included in the rate base will not earn a depreciation component of allowed revenue. The Authority will also consider whether it would be appropriate to allow a differentiated rate of return on capital to be earned, on the working capital component of the rate base.

45. The CWIP should not be included in the rate base to ensure consistency of the Methodology with section 35 (2) (a) of the EA where the EA states that the investment cost should be recovered only where it is used and useful.

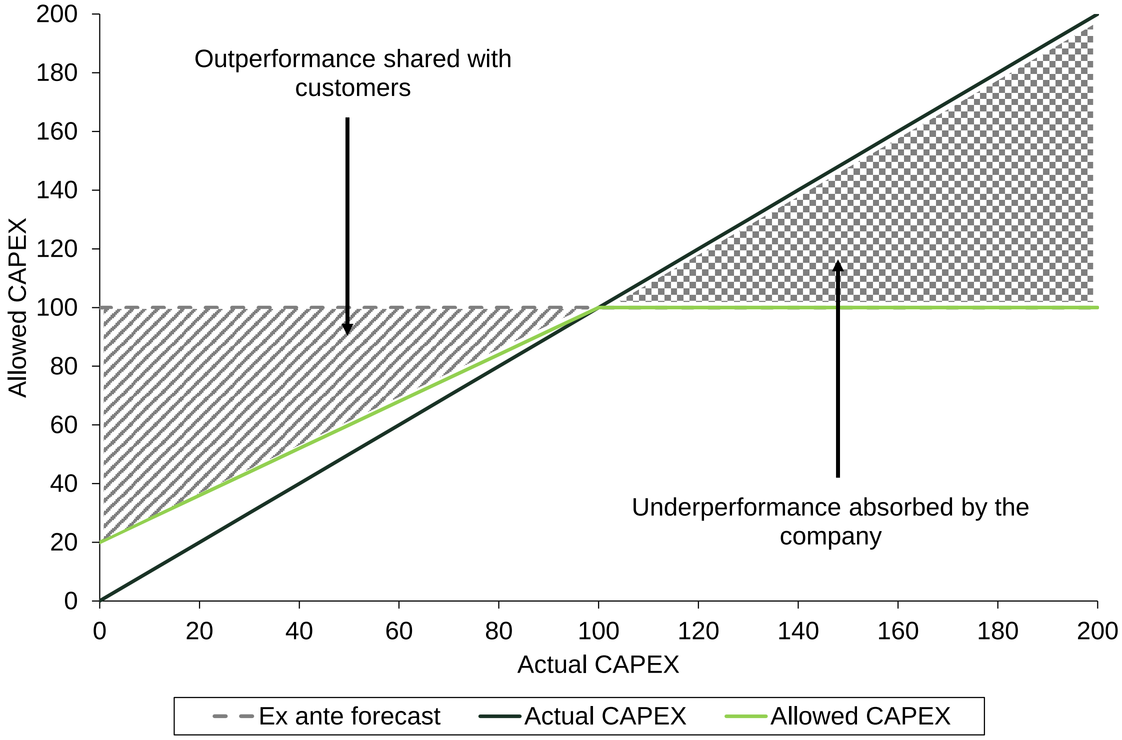
II.D.2. Capital expenditure

46. CAPEX plans of the TD&R licensee shall be subject to scrutiny, whereby, inter alia, the TD&R licensee will be required to commit to the amount, timing, scope and specification of the proposed capital programme. As a result, CAPEX shall be subject to an ex ante incentive scheme.

47. An incentive scheme would be structured in such a way that it encourages the TD&R licensee to become more efficient and reveal its best estimates of the costs. This will be achieved through an asymmetric incentive, where the TD&R licensee bears the cost of CAPEX overspend relative to the ex ante allowance but shares the benefit of outperformance with its customers. The investment and financing plans will be used to determine the ex ante allowance. Should the TD&R licensee not achieve any of the timing, scope or specification commitments, a penalty and reward scheme can be applied.

48. Such an incentive scheme is illustrated in Figure 3..

Figure 3.1 Asymmetric CAPEX incentive scheme



Note: The TD&R licensee is assumed to bear the full cost of overspend relative to the ex ante allowance and to share any outperformance with its customers and/or the NDC Fund on a 20:80 basis (i.e. the majority of the benefit accrues to customers and/or the NDC Fund).

49. The asymmetric CAPEX incentive scheme outlined above should provide strong incentives for the TD&R licensee to deliver proposed CAPEX at the least cost.

50. Once the capital programme is delivered and the Authority concludes that the allowed revenue for the future years may be adjusted such that any overspend relative to the initial plan will be subject to a "claw back", i.e.:

h. if actual CAPEX exceeds the ex ante capital plan forecast, the TD&R licensee bears the full cost of overspend;

i. if actual CAPEX is below the ex ante capital plan forecast, the TD&R licensee shares the benefit of the outperformance with customers and/or the NDC Fund on a 20:80 basis (i.e. the majority of the benefit accrues to customers and/or the NDC Fund).

51. In addition, the Authority may consider the use of specific and targeted ex post adjustments in relation to allowed CAPEX, where there is evidence that CAPEX has been inefficiently accrued or specification of the delivered capital programme deviates from the initial plan without appropriate justification.

II.D.3. Summary of the approach for setting the rate base

52. Table summarises the approach for establishing and updating the rate base.

Table 4.1 Summary of the approach for setting the rate base

Issue	Approach
Components of rate base	Plant in service and working capital; CWIP is not included in the rate base
Initial asset valuation	Net book value of the assets based on HCA accounts
Rate base roll-forward	HCA approach for rate base roll-forward
Depreciation	Straight-line depreciation
CAPEX	Ex ante, subject to an asymmetric CAPEX incentive scheme

53. The net book value of the components of the rate base can be used to determine the value of the rate base. However, if the Authority disallows some CAPEX due to an asymmetric CAPEX incentive scheme, then the adjustments would need to be applied to the net book value of the components of the rate base.

II.E. Return on Capital

54. The allowed rate of return on capital needs to be sufficient for the regulated company to recover its cost of capital. In particular, it needs to allow an appropriate return to equity holders—i.e. cost of equity, and to cover the company's interest expense payable to its creditors—i.e. cost of debt. Therefore, an appropriate approach to estimate the allowed rate of return is to calculate the weighted average cost of capital ("WACC") of the licensee(s).

55. The vanilla WACC, which is defined with the following formula, should be used:

WACC = cost of equity * (1 – gearing) + cost of debt * gearing

where gearing is the share of debt in a company's total capital.[38]

56. Where vanilla WACC is used for remuneration of return on capital, all taxes are accounted for as part of OPEX allowances.[39]

57. WACC should be calculated on a nominal basis. This is consistent with the current base-rate filing system requirements.[40]

58. The main components of the WACC—cost of equity, cost of debt, and gearing—are discussed in turn below.

II.E.1. Cost of equity

59. The cost of equity is the return required by a company's shareholders. The Authority concludes it appropriate for the TD&R licensee to apply multiple methodologies to estimate the range for the cost of equity. These may, for example, include the CAPM, the discounted cash flow approach or a risk-premium approach. Based on the range of evidence, the Authority will make the final decision regarding the point estimate for the cost of equity allowance.

II.E.2. Cost of debt and gearing

60. The Authority will choose the cost of debt that strikes the right balance between retaining the incentives for an entity to manage its risks in an efficient manner and to ensure that the entity

[38] Gearing is defined as the ratio of a company's net debt to the rate base. Net debt is a company's total debt and liabilities after subtracting its cash and cash equivalents.
[39] Note that there is no corporate tax in Bermuda. Ascendant Group Limited (2015), Annual report 2015, p. 35.
[40] NERA Economic Consulting (2015), BELCO Cost of Capital. Exhibit 2.0, 21 May, https://www.gov.bm/sites/default/files/BELCO%20Base%20Rate%20Filing%20030615.pdf.

would be able to attract needed capital.[41] Both conditions need to be satisfied to ensure reliability of the provided service.

61. With this in mind, the Authority considers that the cost of debt should be estimated on the basis of a notional, efficiently financed entity. For ease of implementation, the cost of debt of a generation business unit may be allowed to be the same as for the TD&R business unit, as it is likely that the licensee will raise debt at the entity level, i.e. for both TD&R and generation.

62. In line with the cost of debt, the gearing estimate should be set at the notional level. The gearing of a generation business unit may be allowed to be the same as for the TD&R business unit as it is likely that the licensee will raise debt at the entity level, i.e. for both TD&R and generation.

63. To take account of the unique capital market constraints in Bermuda, the Authority concludes that it is appropriate for the first tariff review to be informed, in the determination of the notional gearing and cost of debt, by the expected capital structure and financing options available to the licensee. The Authority notes, however, that the licensee would need to justify the choice of its target capital structure and provide evidence showing that debt, if any, would be raised on market terms.[42]

II.E.3. Other considerations

64. Given the changing market environment, it may be challenging to forecast a cost of capital for the review period. To account for interest-rate uncertainty and to mitigate the risk that an entity will be unable to raise the required capital, the Authority introduces a trigger mechanism. Under the trigger mechanism, the return on capital for the TD&R licensee is estimated and permitted ex ante for the duration of a review period but permitted to vary if there are significant movements (up or down) in capital markets (e.g. changes in the risk-free rate). In addition, the gearing and cost-of-debt assumptions should be reassessed when the licensee undertakes significant changes to its capital structure. This would provide the incentives and simplicity of the ex ante fixed-rate approach while allowing for revision of the allowed return in “extreme” market volatility scenarios and under significant changes in circumstances.

II.E.4. Summary of the approach for setting the return on capital

65. Table summarises the approach for estimating the appropriate return on capital.

Table 5.1 Summary of the approach for setting the return on capital

Component	Approach
Cost of equity	Fixed for the duration of a review period with a trigger mechanism.
Cost of debt	Fixed for the duration of a review periodat a notional level subject to revision when significant changes to capital structure occur. The first tariff reviewto be informed, in the determination of the notional gearing and cost of debt, by the expected financing options available to the licensee.
Gearing	Fixed for the duration of a review periodat a notional level subject to revision when significant changes to capital structure occur. The first tariff review to be informed, in the determination of the notional gearing and cost of debt, by the expected capital structure of the licensee.

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[41] The latter is referred to as a financing duty of a regulator and is required by section 35 (2) (b) of the EA.
[42] Examples of evidence that the Authority would expect from BELCO include existing financing agreements with evidence of competitive offers, or yields of bonds with a comparable credit rating, if credit rating analysis is undertaken.

II.F. **Outputs**

66. A defined set of specific outputs would provide incentives for the TD&R licensee to deliver the services that consumers require. The Authority shall set specific outputs that the TD&R licensee should deliver in accordance with the process set by general determination pursuant to section 34 of the EA. These outputs may include generation availability of generation capacity, network reliability and efficiency, customer satisfaction and safety. The Authority considers that some of these metrics may be monitored both on an average basis as well as on "worst-served customer" basis. The latter would facilitate an understanding of the distribution of outcomes across customers and create an incentive to target improvement for the worst-served customers.

67. In addition, the Authority will consider that financial penalties could be associated with some of the outputs (and the relevant metrics). Specifically, if the TD&R licensee does not achieve a predefined level of performance, then it will face a reduction in the levels of its allowed revenue.

68. However, it may not be possible to establish binding targets in a timely manner for the purpose of the first tariff review. Therefore, the TD&R licensee should monitor the relevant metrics over the first review period with a view to incorporating binding performance thresholds in future tariff reviews.

3. PRINCIPLES OF THE REGULATORY DESIGN FOR THE BULK GENERATION LICENSEE(S)

69. Pursuant to sections 47 and 48 of the EA and condition 24 of the TD&R license, procurement of power by the TD&R licensee shall be effected under:

   a. an Authority approved PPA between the TD&R licensee and an IPP;[43] and

   b. a power purchase arrangement ("transfer pricing arrangement") between the TD&R license and the generation business unit of the vertically integrated utility.

70. Any PPA should be consistent with the IRP, the purposes of the EA and any Ministerial directions, and that it "does not create risks to power quality or reliability, or unreasonable financial risks for the TD&R licensee", as required by sections 47 and 48 of the EA.[44] In addition, the terms of the transfer pricing arrangement between the TD&R licensee and its bulk generation business unit should be substantially similar to the terms of a PPA between the TD&R licensee and an IPP.

71. For both the transfer pricing arrangement and a PPA, the charges to the TD&R licensee should be sufficient to recover the sum of the bulk generation licensee's initial investment (including a return on invested capital), bulk generation licensee's ongoing costs, and its fuel costs.

72. While the exact terms of a PPA will be negotiated between the TD&R licensee and an IPP bilaterally, subject to the Authority's approval, the transfer pricing arrangement between the TD&R licensee and its generation business unit shall be subject to economic regulation. In particular, the approach to the economic regulation is summarised in Table 7.1 below.

[43] A PPA secures the payment stream and specifies agreed terms and conditions for a project undertaken by an IPP. It is usually agreed between the purchaser ("offtaker") and a privately-owned power producer. In addition to obligations relating to the sale and purchase of the power generated, the PPA also sets out the required design and outputs and operation and maintenance specifications for the power plant. Source: World Bank (2017), Power Purchase Agreements (PPAs) and Energy Purchase Agreements (EPAs), https://ppp.worldbank.org/public-private-partnership/sector/energy/energy-power-agreements/power-purchase-agreements.

[44] Electricity Act 2016, section 48 (3).

Table 7.1 Bulk generation licensee's costs remuneration summary

Element of regulatory regime	Approach
Volume risk	• price-cap regime
Duration of the review period	• aligned with the review periods for the TD&R licensee
Re-opener	• if the licensee has to incur unexpected costs or achieves cost savings that exceed 20% of its revenue, the tariff review can be re-opened
Components of transfer payment	• total transfer payment would be calculated as OPEX (excluding fuel) + fuel adjustment rate + depreciation + rate base x return on capital
Rate base	• the components of the rate base are plant in service and working capital; construction work in progress is not included in the rate base • historical cost accounting approach for the initial valuation of assets and a periodic update of the rate base in accordance with the annual CAPEX (ex ante, subject to an asymmetric CAPEX incentive scheme) and depreciation
Depreciation	• straight-line depreciation, subject to approval of the asset-life assumptions
Operating expenditure (excluding fuel)	• ex ante, subject to an asymmetric incentive scheme
Fuel adjustment rate	• retain the FAR mechanism, subject to a number of changes (section III.D)
Return on capital	• consistent with the methodology used for the TD&R licensee (section II.E).
Outputs	• metrics to monitor safety, reliability and generation efficiency

Note: Although the FAR mechanism is specified as part of the Methodology, the TD&R licensee is required to reflect the FAR separately on a customer bill.

73. The transfer pricing arrangement shall be reviewed periodically, aligned with the review periods for the TD&R licensee.

74. Additionally, the overall charges under the transfer pricing arrangement shall be based on a price-cap regime.

75. The rest of this section discusses the elements of the transfer pricing arrangement.

III.A. Rate base

76. The rate base shall be determined using the following principles.

a. **Components of rate base**—the rate base for the bulk generation licensee shall cover the same components as the rate base for the TD&R licensee. See section II.D.1 for further discussion.

b. **Initial asset valuation**—the assets shall be valued using the historical cost accounting ("HCA") approach.

c. **Rate base roll-forward**—the rate base shall be updated using HCA values of CAPEX and depreciation that will be directly observable in the regulatory accounts.

d. **Depreciation**—a straight-line depreciation approach shall be applied to the bulk generation licensee's rate base in order to estimate the depreciation allowance. The Authority will approve the asset-life assumptions used in regulation and, where assumptions change, may disagree with a change and base the allowed revenue calculations on the asset-life assumptions that the Authority considers appropriate.

e. **CAPEX**—the same asymmetric CAPEX incentive scheme shall be introduced for the bulk generation licensee as for the TD&R licensee. This is to achieve one of the purpose of the

EA to encourage economic efficiency in the generation, transmission, distribution and sale of electricity.[45]

III.B. Return on capital

77. The return on capital shall be based on the methodology described in section II.E hereto. The return on capital shall be reviewed by the Authority periodically, aligned with the review periods for the TD&R licensee.

III.C. Operating expenditure

78. The same asymmetric OPEX incentive scheme shall apply to the bulk generation licensee as for the TD&R licensee.

III.D. Fuel Adjustment Rate

79. The FAR adjusts the total tariffs in order to reflect the cost of fuel.

80. The FAR mechanism shall be retained in the tariff-setting methodology, i.e. the tariffs should be adjusted periodically to reflect the changes in the fuel costs.[46] The mechanism is as follows:

   a. **Review the FAR quarterly rather than monthly**

   b. **Exclude the "Electricity Purchased" component from the FAR mechanism.** Under the Methodology, the FAR shall be a component of a PPA between the TD&R licensee and a bulk generation licensee, so the "Electricity Purchased" component is excluded from the FAR mechanism and subject to a separate cost pass-through by the TD&R licensee.

   c. **Remunerate entire fuel cost through FAR mechanism.** Rather than setting the FAR as an allowance for incremental costs that are incurred in line with moving wholesale costs in excess of $30 per barrel, the TD&R licensee shall recover the entire fuel cost through the FAR mechanism.

III.E. Outputs

81. Bulk generation licensee(s) shall be required to ensure safety, reliability and efficiency of generation. The Authority shall set the metrics that should be used to target individual outputs in accordance with the process set by general determination pursuant to section 34 of the EA.The Authority considers that different generation plants of the vertically integrated utility may target different values for these metrics, e.g. to account for different expected performance.

82. In addition, the Authority will consider that financial penalties could be associated with some of the outputs (and the relevant metrics). Specifically, if a bulk generation licensee does not achieve a predefined level of performance, then it will face a reduction in the levels of the allowed revenue.

83. However, the Authority considers that it may not be possible to establish binding targets in a timely manner for the purpose of the first tariff review. Therefore, bulk generation licensee(s) should monitor the relevant metrics over the first review period with a view to incorporating binding performance thresholds in future tariff reviews.

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[45] See Electricity Act 2016, section 6(f).

[46] Although the FAR mechanism is specified as part of the Methodology, the TD&R licensee is required to reflect the FAR separately on a customer bill.

4. TARIFF DESIGN

84. Section 2 outlines a framework to calculate the allowed revenue for the TD&R licensee, including the recovery of costs in relation to procuring electricity from bulk generation licensee(s).

85. In relation to the methodology to convert the allowed revenue into retail tariffs, the Authority considers that the TD&R licensee shall continue to bear the responsibility for calculating the precise tariff rates, subject to approval by the Authority. The tariff structure will be reviewed by the Authority periodically.

5. SUMMARY

86. The tariffs regime seeks to ensure that the purposes of the EA are met, changes to the regulatory regimes for both the TD&R and bulk generation licensee(s)[47]. Table 9.1 summarises the regime.

Table 9.1 Overview of the retail tariffs methodology

Element of the Methodology	Regulatory treatment
Form of review of the TD&R licensee	
1. Form of review	**Combination of rate-of-return and incentives regulation.** This approach balances the provision of incentives to promote cost efficiency with proportionality and practicality of implementation.
2. Volume risk	**Revenue-cap regime.** Under a revenue-cap regime, the TD&R licensee does not bear volume risk (i.e. the volume risk is borne by consumers). An alternative price-cap regime would incentivise the TD&R licensee to sell more electricity, which may be considered to be against the purposes of the EA.
3. Duration of the review period	**Five-year review periods, with a transitional period.** Five-year review periods provide the licensee enough time to improve efficiency over the period of the tariff review. Since the energy market in Bermuda is going through a period of change, the duration of the review periods should be increased gradually over several price-review cycles.
Building blocks of regulation for TD&R licensee	
4. Treatment of cost pass-through allowances	**Annual true-up mechanism for cost pass-through allowances.** This approach allows a closer alignment between the revenues recovered and costs incurred by a licensee, and therefore helps to achieve the economic sustainability of the electricity sector.
5. Core network OPEX	**Ex ante allowance subject to asymmetric incentive mechanism.** The Authority expects that the TD&R licensee will use either top-down or bottom-up approaches to prepare a well-justified OPEX forecast. In addition, an incentive scheme where the TD&R licensee bears the cost of OPEX overspend relative to the ex ante allowance but shares the benefit of outperformance with its customers should be used.
6. Power procurement	**Cost pass-through allowances.**
7. Other expenses incurred by the TD&R licensee	**Cost pass-through allowances.** Compensation for any fees, charges or taxes that the licensees are obliged to pay to public authorities should be compensated on a cost pass-through basis (excluding fines or penalties).
8. Components of rate base	Plant in service (typically equivalent to the fixed assets that are used and useful to generate revenue) and working capital (typically includes materials and supplies, fuels and lubricants—applicable to the bulk generation licensee only—and cash working capital); CWIP (construction work in progress) is not included in the rate base.
9. Initial asset valuation	**HCA approach.** Retaining the HCA approach for the initial valuation of the vertically integrated utility's assets—split between the bulk generation and TD&R business units—in the interests of transparency and consistency with the current approach.
10. Rate base roll-forward	**HCA approach.** This approach is preferred due its transparency and consistency with the current approach.
11. Depreciation	**Straight-line depreciation.** A straight-line depreciation approach should be applied to the TD&R licensee's rate base in order to estimate the depreciation allowance.

[47] See Electricity Act 2016, section 6 for the purpose of the Electricity Act.

12.	**Asset lives**	**Economic lives.** It is important that only the economic lives of assets are used for their depreciation. The Authority should have a right to rebase the allowed revenue calculations on revised asset-life assumptions if the Authority considers that current asset-life assumptions made by the licensee are unreasonable.
13.	**Capital expenditure**	**Ex ante allowance subject to asymmetric incentive mechanism.** An incentive scheme should be used where the TD&R licensee bears the cost of CAPEX overspend relative to the ex ante allowance but shares the benefit of outperformance with its customers.
14.	**Return on capital**	**Nominal vanilla WACC.** As the HCA approach is used for establishing the rate base, the WACC should be calculated on a nominal basis. This is consistent with the current base-rate filing system requirements. Where vanilla WACC is used for remuneration of return on capital, all taxes (if any) are accounted for as part of OPEX allowances.
	a. Cost of equity	**Multiple methodologies.** TD&R licensee may apply multiple methodologies to estimate the range for the cost of equity. Based on the range of evidence, the Authority will make the final decision regarding the point estimate for the cost of equity allowance.
	b. Cost of debt and gearing	**Notional cost of debt.** The determination of the allowed cost of debt and allowed capital structure will be on a notional basis. This is because customers should not pay for an inefficient choice of capital structure. To take account of the unique capital market constraints in Bermuda, the Authority considers it appropriate for the first tariff review to be informed, in the determination of the notional gearing and cost of debt, by the expected capital structure and financing options available to the licensee.
	c. Interest-rate uncertainty	**Trigger mechanism.** Under the trigger mechanism, the return on capital for the TD&R licensee is estimated and allowed ex ante for the duration of a review periodbut allowed to vary if there are significant movements (up or down) in capital markets (e.g. changes in the risk-free rate).
15.	**Outputs**	A number of metrics should be used to monitor the TD&R licensee's performance in relation to availability of generation capacity, network reliability, network efficiency, safety and customer satisfaction.
Regulatory design for bulk generation licensee(s)		
16.	**Volume risk**	**Price-cap regime.** In line with a typical charging structure between networks and independent generators, the overall charges under the transfer pricing arrangement should be based on a price-cap regime.
17.	**Duration of the review period**	**Five-year review periods, with a transitional period.** The duration of the review periods should be aligned with the review periods for the TD&R licensee.
18.	**Components of transfer payment**	**Building blocks**. The total transfer payment should be determined similarly to the allowed revenue for the TD&R licensee. Specifically, this would consist of OPEX (excluding fuel), fuel adjustment rate, depreciation and rate base multiplied by return on capital. The treatment of the components of the transfer payment with that of the TD&R licensee is aligned.
	a. Fuel adjustment rate	The FAR mechanism is maintained, subject to a number of changes. The TD&R licensee is required to reflect the FAR separately on a customer bill.
19.	**Outputs**	The definition of specific outputs would provide incentives for the bulk generation licensee to deliver the services that consumers require. The required outputs for the bulk generation licensee are **safety, reliability and efficiency** of generation. Metrics that should be used to monitor the bulk generation licensee(s') performance in relation to the required outputs.
Tariff design		

20. Approach to tariff design	TD&R licensee should continue to bear the responsibility for calculating the precise tariff rates, subject to approval by the Authority. The tariff structure will be reviewed by the Authority periodically.

ANNEX 1.1: TARIFF DESIGN

A TARIFF DESIGN

87. This section is structured as follows:

a. section A1 provides an overview of tariff design principles;

b. section A2 outlines different options for tariff design relevant to the electricity retail market in Bermuda.

A1 Principles Of Tariff Design

88. Principles of tariff design have been assessed in academic literature.[48] Specifically, a tariff should be designed such that the tariffs are:

a. yielding total revenue requirements;

b. achieving fairness in allocating total cost of service among different customers;

c. discouraging wasteful use of service;

d. ensuring revenue stability and predictability;

e. ensuring tariff stability and predictability; and

f. promoting simplicity, comprehensibility, public acceptability and feasibility of tariffs.

89. In this section, the Authority describes and evaluates these principles before applying them to the retail tariff design for the electricity sector in Bermuda.

a. Yielding Total Revenue Requirements

90. Ensuring that the tariff design yields the allowed revenue for the TD&R licensee is the primary objective of tariff design. The Authority proposed Methodology to calculate the allowed revenue for the TD&R licensee captures the total costs of the provision of the electricity service. Therefore, its approach is consistent with the EA, which requires the retail tariff to facilitate the recovery of costs for the TD&R licensee.

b. Fairness in allocating total cost of service among different customers

91. There are two main aspects to fairness in the context of tariff setting.

a. The first is cost-related fairness, i.e. ensuring that users pay based on the services they actually use and the costs that they directly impose. Electricity service customers are typically divided into classes, with the intention of grouping customers with broadly similar demand and cost characteristics. Customers within groupings with similar demand characteristics should then pay similar charges.[49]

b. The second is distributional fairness, which may be concerned with ensuring equality of access to electricity, and in particular ensuring that electricity is equally affordable for different customers. This may lead to cross-subsidisation across customers or customer classes. Distributional fairness takes into account considerations other than costs to serve in the tariff-setting process.

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[48] See, for example, Bonbright, J. (1961), *Principles of Public Utility Rates,* New York, Columbia University Press.

[49] It should be noted that pricing customers based on an exact calculation of their individual costs would be an extremely difficult exercise. Supplying electricity to thousands of customers in different locations is essentially the supply of thousands of different *products.* See Bonbright, J. (1961), *Principles of Public Utility Rates,* New York, Columbia University Press, p. 296.

92. Cost-related fairness and distributional fairness, while not mutually exclusive, may conflict to the extent that distributional fairness requires that tariffs are not fully cost-reflective.

c. **Discouraging wasteful use of service**

93. Central to the discouragement of wasteful use of the electricity service is economic efficiency, which is concerned with providing incentives for the efficient use of electricity in terms of the amount used and the timing of use. Efficiency in this case is therefore related to the encouragement of energy conservation. Typically, this will involve creating some disincentive for energy use, for example in the form of high per-unit charges or unit charges that increase with usage. In assessing the relevance of price-based efficiency incentives, it is important to consider how responsive customers are to changes in price. If they are price-insensitive (or have "inelastic" demand), there may be few benefits from price incentives. However, if customers differ in their price sensitivity, this may suggest different tariff structures for different customer types.

94. In economic theory, a key consideration is that the price that is set for electricity is reflective of the cost of producing an extra unit of electricity, that is, the marginal cost ("MC") of an additional unit of electricity.[50] The MC comprises elements such as the marginal cost of fuel, capital and labour, as well as other production costs. The concept of setting prices to reflect MC is fundamental to efficient price signals. By pricing electricity with reference to MC, customers face a price that reflects the cost implications of increasing demand and the cost saving that would arise if they reduced demand. It therefore induces customers to adjust their usage to the point where the benefit to them would be outweighed by the change in costs if they were to further increase their consumption.

95. In practice, while economic efficiency is desirable, there are two crucial caveats. The first is that economic efficiency needs to be balanced with considerations related to fairness: there is nothing inherently fair about an economically efficient state of affairs. The second is that pricing purely to reflect MC will not facilitate full recovery of allowed revenue, because, among other things, there are elements of the allowed revenue that are due to large fixed costs in network businesses.

d. **Ensuring revenue stability and predictability**

96. In the electricity sector, demand from year to year is fairly predictable when compared with many other sectors. An electricity company typically has a high proportion of fixed costs and would therefore prefer to have predictable and stable cash flows. As a result, a company may prefer to have a higher proportion of its revenues generated from fixed charges rather than per-unit charges (higher fixed charges, relative to per-unit charges, result in greater revenue certainty). In addition, capacity or demand charges (discussed in section 0) introduce an element of revenue certainty.

e. **Ensuring tariff stability and predictability**

97. In general, consumers also prefer stability in their bills rather than frequent changes over time. Introducing significant changes to the tariff structure is undesirable on this principle.

f. **Simplicity, comprehensibility, public acceptability and feasibility of tariffs**

98. Tariffs should be simple and easy to understand. This is likely to entail the retention of certain cross-subsidies to a degree, since full cost reflection in all dimensions may result in overly complex tariff structures that are difficult to understand. Moreover, the more complex a tariff structure is, the less feasible its implementation.

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[50] Borenstein, S. (2016), The economics of fixed cost recovery by utilities, *The Electricity Journal*, **29**:7, pp. 5–12.

A2 Tariff Options

99. Based on the principles of tariff design described above, the Authority explores four main options for structuring tariffs in Bermuda:

a. **Peak tariffs** — involving pricing energy consumption differently during well-defined times of high demand and/or low supply;

b. **Two-part tariffs** — comprising both a fixed charge and a per-unit charge. The fixed charge (or "standing charge") may vary according to either consumer peak demand or average electricity usage;[51]

c. **Three-part tariffs** — similar to two-part tariffs, but with the addition of a fixed charge that is the same across all users;

d. **Block tariffs** — per-unit charges depend on the actual consumption.

100. These options are not mutually exclusive and, in practice, are often used in conjunction; the current tariff structure in Bermuda balances these elements.

a. **Peak tariffs**

101. Peak pricing involves pricing energy consumption differently during well-defined times of high demand and/or low supply. Such tariffs are readily justified for customers whose demands for electricity vary greatly by day, hour, week, month or season, and thus impose extra costs on various parts of the electricity supply system.

102. With peak pricing, users are charged a higher per-unit charge for access to the peak period (e.g. during the summer due to air conditioners). There are two main objectives of such a scheme:

a. cost reflection—to ensure that customers, at specified times, are charged for the impact of their high-intensity demand on system costs; and

b. incentives at the margin—to provide customers with high-intensity demand with an incentive to reduce their peak consumption.

103. Peak pricing is, therefore, a form of MC pricing: the per-unit charge levied during peak times should reflect the costs of electricity supply incurred in these time periods. As a result, peak pricing promotes cost-related fairness, since those users who require electricity during peak times (thereby imposing higher costs on the system) are charged higher tariffs for this usage.

b. **Two-part tariffs**

104. Two-part tariffs are a common tariff design used for customer electricity pricing. They are known as "two-part" because they are composed of a per-unit charge and a fixed charge.

105. The per-unit charge typically consists of a per-unit (kWh) charge for energy, intended to reflect the marginal cost of extra units of energy (however, there is some flexibility here—see "block tariffs" below).

106. The fixed charge component is typically intended to capture a customer's share of the fixed costs involved in supplying them with electricity, including the costs of transmission and

[51] There are, in practice, several variants of two-part tariffs. For instance, in the UK, a two-part tariff most commonly comprises an invariant or fixed 'standing charge', charged on a per-day basis (rather than being based on peak demand or average usage as defined above). Each unit of electricity used is then billed on a per-kWh basis. The present definitions are the most relevant to the actual charging structures currently in place in Bermuda.

distribution. By charging a fixed charge, the tariff is better able to recover allowed revenues while the incentive benefits of MC pricing are retained.

107. The fixed charge would usually vary according to either consumer peak demand or average electricity usage (hence, it is sometimes known as a "semi-fixed" charge). Charges based on peak demand are known as capacity charges and are often used for larger electricity users.52

108. From the point of view of cost recovery, a two-part tariff aims to approximately recover the costs that each customer imposes on the energy infrastructure in terms of their share of both the fixed and variable costs of electricity consumption. An appealing property of these tariffs is that they ensure that, regardless of usage, customers pays their share of the fixed costs incurred by the TD&R licensee. In addition, they ensure some revenue stability for the TD&R licensee.

c. **Three-part tariffs**

109. Finally, a three-part tariff could be used for electricity pricing. A three-part tariff is essentially a two-part tariff but with the addition of a flat-rate (or invariant) fixed charge.

d. **Block tariff**

110. A final option for electricity pricing is to price electricity usage on inclining or declining blocks. Under this scheme, the first units of electricity consumption in terms of kWh (first "block") are charged at a certain price, followed by a second category for higher usage charged at a higher price (for inclining blocks) or a lower price (for declining blocks), and so on.

111. The use of inclining blocks can be justified on both distributional and conservational grounds.53 In terms of distributional concerns, low-income households are more likely to consume energy at low-tier rates, and high-income households at high-tier rates, redistributing the revenue burden to the wealthiest households.54 In terms of conservational concerns, by charging additional energy usage at increasing per-unit cost, price-sensitive customers will be incentivised to keep their energy consumption down, thereby promoting energy efficiency. However, while appropriate for some customer classes, inclining blocks can also penalise those who require more electricity, particularly for commercial reasons; in some cases, declining block tariffs may be preferred on the basis that they offer an effective volume discount.

112. With inclining or declining block tariffs, the two major control levers are the level at which the tariffs are set and the rate of change between the tariff blocks. A particularly steep ascent from one block to the next may incentivise greater energy consumption but may also have equity implications since this is likely to have the greatest impact on the most price-inelastic customers. Conversely, tariff blocks that incline less aggressively provide less incentive to conserve energy consumption.

[52] Capacity charges differ from peak tariffs (as outlined in section a) since capacity charges are based on the customer's own peak electricity usage, whenever that peak occurs, as opposed to being based on periods of high overall system demand. Equivalently, peak tariffs are intended to incentivise electricity use at the margin at specific times, whereas capacity charges aim to incentivise the efficient conservation of electricity on a continuous basis.

[53] Borenstein, S. (2016), The economics of fixed cost recovery by utilities, *The Electricity Journal*, **29**:7, p. 9.

[54] Borenstein, S. (2016), The economics of fixed cost recovery by utilities, *The Electricity Journal*, **29**:7, p. 9.

ANNEX 1.2: FORM OF REVIEW

1. FORM OF REVIEW

113. The two most common methods for regulation of an entity's economic performance in a utility context are rate-of-return regulation (also referred to as cost-plus regulation) and incentive regulation—employing either price and/or revenue caps.

a. **Rate-of-return regulation**—under this form of regulation, tariffs are set at a level that reflects the cost of service. For an agreed base period, usually covering the previous 12 months, an entity calculates operating costs, depreciation, the capital base and its cost of capital. The regulator audits these calculations and determines the fair total revenue allowance and the level of tariffs. These tariffs may stand until the realised return on capital differs from the allowed return. This deviation may lead to a tariff review to realign the required and actual rates of return.[55] The current regulatory system in the electricity sector of Bermuda, i.e. the base-rate filing system, is a form of rate-of-return regulation.

b. **Incentive regulation**—this involves setting either price or revenue caps linked to an efficient cost forecast. These caps are in place for a fixed period, thereby providing an incentive to outperform, i.e. firms are allowed to retain the benefits of any cost reductions beyond those expected at the last tariff review. The incentive period typically lasts from three to five years, with the regulator undertaking a review of allowed prices at these intervals.

114. Rate-of-return regulation and incentive regulation imply a difference in risk exposure, incentives and rewards for the regulated companies. The Authority explores the main differences between these two types of regulation methods below.

c. **Cost-efficiency incentives**. Rate-of-return regulation tends to be based on historical data, which provides an assurance that the entity will be able to recover its costs. Incentive regulation is generally more explicitly forward-looking — it relies on the regulator's ability to forecast efficient cost levels with a reasonable degree of certainty at price reviews. On the one hand, it creates incentives for cost efficiency, which may translate into lower tariffs. However, entities also face the risk associated with the possibility of cost forecasts being inaccurate.

d. **Investment incentives**. Since rate-of-return regulation allows pass-through of any CAPEX and ensures a sufficient return on the capital base, there is a risk that the entity will over-invest in its capital, thereby tending to increase customer bills. With incentive regulation, there could be a bias towards either over- or under-investment in network assets based on the allowed rate of return. Specifically, there is risk of over-investment in network assets within incentive regulation if the allowed cost of capital is too high; conversely, there is a risk of under-investment under incentive regulation if the allowed returns are inaccurately forecast and inadequate. This may undermine the quality of the provided service.

e. **Risk to company and cost of capital.** Incentive regulation exposes a company to a higher degree of risk—for example, a company bears the risk of cost under-performance against its OPEX allowances. As a result of this high risk, the allowed cost of capital under incentive regulation may be higher than under rate-of-return regulation.

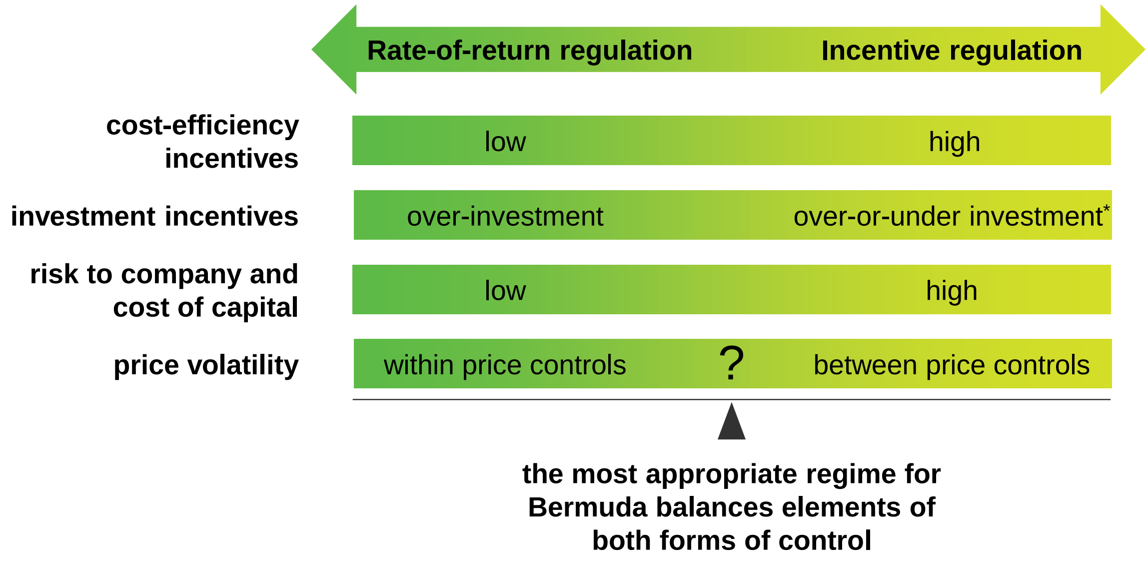
f. **Price volatility.** Consumers bear substantially more risk of cost and revenue shocks being directly passed through into higher prices under rate-of-return regulation. Incentive regulation tends to create a relatively smooth tariff pattern for a review period; however, there is a risk of a substantial movement in tariffs at the end of the review period once all allowances (e.g. OPEX) are reconsidered.

115. Therefore, pure rate-of-return regulation and incentives regulation can be thought of as at opposite ends of the spectrum of possible regulatory regimes. As a result, the differences in

[55] A review of tariffs may be instigated upon the request of the company and/or the regulator.

risk exposure, incentives and reward should be balanced in the design of a regulatory system. These trade-offs are summarised in Figure 5.1.

Figure 5.1 Spectrum of possible regulatory regimes



Note: * If the allowed returns are inaccurately forecast.

116. In addition, the Authority notes that incentive regulation presents a number of methodological choices that would affect both the strengths of incentives and distribution of risks. Specifically, the Authority highlight the duration of the review period and whether the regime operates under a price or revenue cap as characteristics of the incentives-based regime that it is important to consider.

g. **Duration of the review period**. A longer review periodstrengthens incentives, potentially leading to higher risk to the company as allowances are set based on forecasts for longer periods. At the same time, the shorter the review period, the more frequently the regulator will need to undertake the assessment, which increases the burden on the regulator and thereby undermines the overall efficiency of the regulatory regime.

h. **Price cap or revenue cap.** Where a pure revenue cap is used, the prices can be adjusted to recover any difference between the expected and realised volumes, i.e. volume risk is borne by customers. Under a price-cap regime, no adjustments due to deviations from volume forecasts are allowed, i.e. volume risk is borne by the regulated entity.