Cost-Effectiveness Tariff Policy for Renewable Energy Self-Generation Projects

RESG and SSRG

CONSULTATION ON PROPOSED POLICY OPTIONS

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1 INTRODUCTION

In February 2020, the Utilities Regulation and Competition Authority (URCA) issued its, "Guidelines for the Approval of Renewable Energy Self-Generation (RESG) Projects, Small Commercial and Government, Statement of Results and Final Decision[1]." The document defines the rules for small commercial and government entities to participate in renewable energy via the RESG.

URCA also stated in the decision that the Buy-All/Sell-All arrangement is provisional as URCA was committed to completing a cost-based pricing study to ascertain the economic cost of the RESG framework with the view to determine the fair economic price for the exchange of Renewable Energy (RE) from RESG installations and by extension other programs designed or determined by URCA, namely the Small-Scale Renewable Generation (SSRG) program.

Consequently, URCA sought and got technical assistance support for a Cost-based Pricing for Renewable Energy Generation projects under the RESG program and by extension the Small Scale Renewable Energy generation program (SSRG). Through support from the Inter-American Development Bank (IDB), in collaboration with The Cadmus Group LLC and Energynautics, technical assistance was provided to URCA examining economic costs and policy design alternatives to the Renewable Energy Self-Generation programs which encompasses the RESG

This technical assistance has provided the foundation for URCA to take the next steps in revising and implementing the RESG program in a way that balances URCA's obligations with the goals of The Bahamas' National Energy Policy and to fulfil its obligation of establishing a cost-effectiveness pricing policy for for the existing RESG and SSRG programs.

This document sets out for consultation with interested stakeholders proposed revised Economic Cost Based Tariff or Levelized Cost of Energy (LCOE) methodology and policy for RESG projects advanced by the Government and small-scale business or commercial enterprises, as provided for in section 28 of the Electricity Act (EA). Additionally, using the study as the base line, URCA sets out the proposed tariff policy for the Small-Scale Renewable Generation (SSRG) program. The existing approved tariff for the SSRG program was also predicated on URCA examining economic costs and policy design alternatives.

The methodology and policy guidelines for the cost-effectiveness approach may be amended by URCA as Government policy, the underlying technological environment, and operating conditions change from time to time.

1.1 OBJECTIVES OF THIS CONSULTATION

The objectives of the consultation are to -

- Discuss the proposed RESG cost-based rate-setting which includes RE program design process
- Discuss the approaches to RE tariff rate-setting, in particular, references to RESG and SSRG programs
- Discuss the proposed methodology for calculating cost-based rates, the data collection approach and the proposed indicative tariff rates
- Present and discuss the cost-effectiveness analysis, findings to gather feedback from stakeholders

[1]https://www.urcabahamas.bs/decisions/es-03-2020-statement-of-results-and-final-decision-on-renewal-energy-self-generation-projects/

- Discuss policy scenarios around cost-effectiveness results

The main goal and objective of the ESP as stated in the Electricity Act (EA) is the supply of safe, least-cost, reliable and environmentally sustainable electricity throughout The Bahamas[2] . The primary role of URCA is the regulation of the Electricity Sector (ES) in accordance with the goals, policy objectives and principles underpinning the NEP and ESP, of which the incorporation of RE resources in the electricity generation mix in The Bahamas is a key objective. URCA is proposing in this document to address the price point at which the RESG program design will facilitate the goals of the ESP and the NEP.

(a) RESG projects are advanced by –

  (i) the Government, in any place in The Bahamas, in relation to the supply of energy to premises occupied by a ministry department, statutory body, agency, local government council, or other entity of Government.

  (ii) a small-scale business or commercial enterprise within The Bahamas.

(b) such stations meet the requirements of, and are operated in accordance with regulatory or other measures issued by URCA; and

(c) such stations have no adverse impact on the reliability of the electricity supply system.

Additionally, under the SSRG program an owner of property may apply to a public electricity supplier in writing for a permit to install or operate on the property and connect to the grid, for residential purposes only, a generating resource using renewable energy sources of such size and quality as may be prescribed in regulatory or other measures issued by URCA,

1.2 HOW TO RESPOND

URCA invites and welcomes comments from licensees, members of the public and interested parties on the matter set out in this consultation document. Such comments must be received by URCA within thirty (30) calendar days from the publication of this consultation document. The deadline for receiving written comments is 5:00 pm on 18 November 2021. Such written submissions and comments should be submitted to URCA either:

  (i) By hand to: The Director of Utilities and Energy, Utilities Regulation and Competition Authority, Frederick House, Frederick Street, Nassau, Bahamas.

  (ii) By email to: info@urcabahamas.bs;

  (iii) By mail to: P.O. Box N-4860, Nassau, Bahamas; or

  (iv) By facsimile to: (242) 393-0237.

After the period of representation closes, URCA will carefully consider such representations made and shall publish its final decision on the proposed tariff options.

[2] As established under section 6(1) of the EA

1.3 STRUCTURE OF THE REMAINDER OF THIS DOCUMENT

The remainder of this document is structured in the following way:

Section 2: provides the background to this consultation document.

Section 3: sets out the Regulatory Framework for RE Resources.

Section 4: sets out Renewable Energy Rate-Setting: discusses the renewable energy program design process, the approaches to renewable energy tariff rate-setting, the methodology for calculating cost-based rates, the data collection approach and sources, and results of calculating the various tariff rates.

Section 5: Sets Benefit-Cost Effectiveness Tests and propose an overview of the cost-effectiveness analysis and tests, propose the policy scenarios and modeling assumption, presents the results of the cost effectiveness analysis for each policy scenario, and propose conclusions from the analysis.

Section 6: sets out the next steps as it relates to approval of RESG.

Annexes I - IV: provide additional data and information that were used by Cadmus in completing the cost study.

2 BACKGROUND TO THIS CONSULTATION DOCUMENT

Section 28 of the EA completes the structure set out in Part V, by making provision for RESG projects advanced by the Government or small-scale business or commercial enterprises, as follows:

(1) URCA shall approve in writing the installation or operation of generating stations using prescribed renewable energy resources where —

(a) renewable energy self-generation projects are advanced by —

i. the Government, in any place in The Bahamas, in relation to the supply of energy to premises occupied by a ministry, department, statutory body, agency, local government council, or other entity of Government;

ii. a small-scale business or commercial enterprise with The Bahamas

(b) such stations meet the requirements of, and are operated in accordance with regulatory or other measures issued by URCA; and

(c) such stations have no adverse impact on the reliability of the electricity supply system.

(2) URCA shall maintain and publish, in accordance with section 43, a list of the names of the entities granted approval under this section together with the corresponding sizes and aggregate kilowatts of the installed generation stations.

In February 2020, the Utilities Regulation and Competition Authority (URCA) issued its, "Guidelines for the Approval of Renewable Energy Self-Generation (RESG) Projects Small Commercial and Government Statement of Results and Final Decision." The document defines the rules for small commercial and government entities to participate in renewable energy via the RESG. Table 1 summarizes the main elements of the policy.

Policy Design Element	RESG Policy
Eligible Technologies	Solar PV & Wind
Eligible Size Range	101kW – 1MW
Eligible Customers	Commercial and Government
Treatment of Electricity Generated	• 101kW – 500kW: net-billing • 501kW – 1MW: buy-all/sell-all
Payment / Compensation Rate	Compensation at a rate per kWh equivalent to avoided fuel cost of Public Electricity Supplier (PES)

Policy Design Element	RESG Policy
Payment Structure	Variable. Will vary with the PES' cost of fuel.
Program Cap	Total installed capacity no more than 10% of generation capacity of respective Public Electricity Supplier
Interconnection and System Upgrade Costs	Renewable energy generator assumes responsibility for interconnection and system upgrade costs
Contract Duration	15 years
Periodic Review of Rates and Program Cap	Not determined

As illustrated in the table and discussed in URCA's decision[3], small commercial and government customers installing RESG systems 101 kW – 500 kW are under a net billing arrangement and small commercial and government customers installing RESG systems 501 kW – 1000 kW are under a Buy-All/Sell-All arrangement. The compensation rate that Net Billing and Buy-All/Sell-All customers receive for any electricity the RE system produces and is fed into the grid is equal to the avoided cost of generation rate as established by URCA. Customers will receive the compensation in the form of an avoided cost credit on their monthly bill for all electricity produced by the customer's RE system at the applicable monthly fuel charge per kWh during that period.[4]

URCA also stated in the decision that the Buy-All/Sell-All arrangement is provisional as URCA was committed to completing a cost-based pricing study to determine the economic cost of the RESG framework on the electricity delivery system . Hence the objective of the study is to inform URCA understanding of the cost reflective price point that RESG projects should receive under a Buy-All/Sell-All arrangement that is fair to all stakeholders and enhances the desired renewable penetration.[5]

Consequently, the Inter-American Development Bank (IADB), The Cadmus Group LLC and Energynautics provided technical assistance to URCA to support the examination of economic costs and policy design alternatives pertaining to the to the various RE programs.

The technical assistance, provided through the support of the IDB, served to help URCA calculate a cost-based rate for renewable energy projects under a Buy-All/Sell-All scheme, and to understand the benefits and costs of Buy-All/Sell-All and Net-Billing arrangements on different stakeholders in The Bahamas. The main deliverables of this technical assistance included:

[3] https://www.urcabahamas.bs/decisions/es-03-2020-statement-of-results-and-final-decision-on-renewal-energy-self-generation-projects/

[4] Ibid.

[5] Utility Regulation and Competition Authority (URCA). 28 February 2020. "Guidelines for the Approval of Renewable Energy Self-Generation Projects Small Commercial and Government Statement of Results and Final Decision." Available at: https://www.urcabahamas.bs/wp-content/uploads/2020/03/Statement-of-Results-and-Final-Decision-on-Renewal-Energy-Self-Generation-Projects-ES-03-2020.pdf

(1) a renewable energy rate-setting tool to calculate a cost-based rate;

(2) collecting data and calculating the cost-based rate; and

(3) modelling the benefits and costs of alternative policy scenarios for different stakeholders.

This technical assistance has provided the foundation for URCA to take the next steps in revising and implementing the RESG program in a way that balances URCA's obligations with the goals of The Bahamas' National Energy Policy and fulfil its obligation of establishing a cost base pricing policy for the RESG program.

URCA, pursuant to Part V EA, is empowered to provide guidelines for the approval of RESG projects. In so doing, URCA must have due regard to the Government's NEP and ESP objectives, whilst ensuring that the rules and established processes are consistent with applicable legislation. The legal framework for the EA places upon URCA the responsibility to take such action as it may deem necessary to ensure the availability, security and reliability of RE consistent with the NEP.

The RESG and the SSRG programs decisions state that the tariff arrangement is a provisional arrangement, pending revision following a cost-based pricing study, this document sets out for consultation with interested stakeholders proposed alternative program designs and tariff options for the RE programs.

3 REGULATORY FRAMEWORK

As noted previously, the ES is governed by the EA which provides the legal framework for URCA's regulation of the sector. URCA's role is to implement, monitor and enforce this legislation.

Section 6 of the EA sets out the ESP objectives, as follows:

(1) The main goal and objective of the electricity sector policy shall be the creation of a regime for the supply of safe, least cost, reliable and environmentally sustainable electricity throughout The Bahamas.

(2) The principles and objectives governing the sector policy and electricity supply regime, in accordance with the aims and goals of the National Energy Policy, shall be the –

(a) provision of safe, least cost electricity supplies to all consumers.

(b) enhancement of the energy security of The Bahamas.

(c) introduction of a structure for the sector that is overseen by an independent regulator.

(d) employment of practices and technology that are designed to protect the natural environment of The Bahamas.

(e) promotion of energy efficiency in the generation, distribution, and consumption of electricity throughout the economy.

(f) promotion of the use of renewable energy.

(g) promotion of private investment and innovation in the electricity sector.

(h) creation of incentives for the private sector participants in the electricity sector to continuously improve performance in operations and customer service.

(i) provision of investment and job opportunities for citizens of The Bahamas; and

(j) provision of a regulatory structure that balances the interests of and affords opportunities for input from all stakeholders, honours contractual commitments and encourages investment.

Section 7 provides for URCA to issue regulatory processes that are fair, objective, non-discriminatory, transparent, and that seek to implement the NEP and ESP.

Pursuant to section 9, BPL may enter into contracts with consumers in the Island of New Providence and designated Family Islands for the supply and purchase of electricity on terms and conditions approved by URCA. It allows for BPL to support the Government's NEP, including promoting and facilitating the development and use of renewable electricity generation resources and technology.

Section 27 of the EA describes the legal framework for renewable energy projects advanced by residential owners of property.

Additionally, section 28 describes the legal framework for renewable energy projects advanced by the Government and small-scale business or commercial enterprises, as follows:

(i) URCA shall approve in writing the installation or operation of generating stations using prescribed renewable energy resources where—

(a) renewable energy self-generation projects are advanced by—

i. the Government, in any place in The Bahamas, in relation to the supply of energy to premises occupied by a ministry, department, statutory body, agency, local government council, or other entity of Government;

ii. a small-scale business or commercial enterprise within The Bahamas;

(b) such stations meet the requirements of, and are operated in accordance with regulatory or other measures issued by URCA; and

(c) such stations have no adverse impact on the reliability of the electricity supply system.

(ii) URCA shall maintain and publish, in accordance with section 43, a list of the names of the entities granted approval under this section together with the corresponding sizes and aggregate kilowatts of the installed generation stations.

Under section 41 of the EA, URCA has a duty to consult with the public on matters which, in the determination of URCA, are of public significance.

4 [6]RENEWABLE ENERGY RATE-SETTING

4.1 RENEWABLE ENERGY PROGRAM DESIGN PROCESS

There are two major aspects to the RE program:

(i) the program design; and
(ii) the rate program participants receive for the electricity the renewable energy system feeds into the grid.

The RESG program design choices are informed by the NEP, ESP and EA energy goals and objectives. Policymakers do not have to incorporate all design elements into the program design. However, URCA's view is that it's important to consider and understand the different design choices, the trade-offs with different design choices, and how the different choices may impact the ability of the program to meet The Bahamas' energy goals and objectives.

As discussed below, there are five main steps policymakers often take to develop a renewable energy program including (1) process, (2) design, (3) data, (4) modelling, and (5) evaluation and review. These steps are not necessarily sequential and often happen in parallel.

(1) **Process.** Policymakers should determine the desired levels of stakeholder involvement and transparency in the program design process. Involving more stakeholders and making the program design and rate setting process highly transparent can help ensure confidence in the program and create a more stable market for renewables. However, it can also expose the process to political influences, leading to a program and rates that are reflective of special interests rather than market realities. Therefore, it is important for URCA to balance the various stakeholder interests in the program design and rate setting process.

(2) **Design.** There are many program design choices that policymakers can make when developing a renewable energy program. URCA has developed and issued a consultation, on the required number of design elements envisaged by the EA, namely RESG and SSRG programs. It's also important to note that the rate design process and resulting tariff rates are significantly influenced by program design choices. The process of identifying data needs, developing tariff rate calculation models, and determining appropriate rates can be streamlined if key program design choices are determined prior to tariff rate setting.

(3) **Data.** Collecting data on the cost and performance of renewable energy systems and other inputs required for rate setting is often an inexact process. Particularly in markets where there is limited experience with renewables or limited available data, there is often a range of likely cost and performance data. Selecting within the range of reasonable inputs thus becomes a policy choice: for example, selecting higher costs and lower performance assumptions will lead to higher rates, which will increase participation and accelerate market growth, but it may overcompensate some generators, leading to higher policy costs. The granularity of data is also an important policy choice. More granular data can improve accuracy in the

[6] Source: Draft Final Report Technical Assistance Support to URCA for Cost-Based Pricing for Renewable Energy Generation Projects Under the RESG Program, The Bahamas
December 18, 2020

rate-setting process; however, there are diminishing returns with increased granularity and trade-offs in terms of the data collection process and transparency to the public.

(4) **Modelling**. Once the required inputs and level of data granularity have been determined, constructing a rate-setting model and collecting data can proceed in parallel. Where data is unavailable, certain inputs can be met using appropriate benchmarking data.

(5) **Evaluation and Review.** After program design choices are made and tariff rates are developed, policymakers can evaluate the benefits and costs of the potential program by conducting a cost-effectiveness analysis. The analysis can enhance policymakers understanding of the program and the different impacts it will have on different stakeholders helping policymakers make more informed program design and tariff rate decisions. Once the program design and tariff rates are set, they should be reviewed and evaluated regularly. This will ensure the program and tariff rates are updated to reflect changes in the market such as declines in technology costs.

4.2 Proposed Approaches to Setting a Renewable Energy Tariff Rate

Setting the tariff rate for feeding electricity into the grid is one of the major aspects of designing a renewable energy program. There are different approaches to setting tariff rates, including administrative rate setting and competitive rate setting. Under administrative rate setting, an administrative entity such as an independent electricity regulator sets the payment rate using a rate setting methodology. Under competitive rate setting, tenders or auctions are used where developers typically bid for the right to sell electricity at a given price. In setting the renewable energy rate for The Bahamas, an **administrative rate setting** approach is used since it is generally accepted to be more appropriate for systems of the scale contemplated in the RESG.

Administrative rate setting can generally be categorized in two ways:

- **Cost based** rates establish the payments according to the cost of renewable energy generation, plus a targeted rate of return to the RE system investor.
- **Value based** rates establish the value of energy delivered to the system, which can be pegged to the utility's avoided cost, the retail electricity rate, or other benchmarks.

The RESG program currently uses an administrative and value-based approach for compensating the renewable energy generator for any electricity that is fed into the grid: renewable energy generators receive a credit at the utility's avoided cost for any electricity fed into the grid under a net billing arrangement for systems from 101 kW - 500 kW and under a Buy-All/Sell-All arrangement for systems from 501 kW - 1 MW. Similarly for the current SSRG program, the SSRG renewable energy generators receive a credit at the utility's avoided cost for any electricity fed into the grid under a net billing arrangement for systems up to 100 kW. This avoided cost credit is proposed as the applicable monthly fuel rate charge per kWh during the period when the electricity was produced. The applicable monthly fuel charge rate per kWh will vary with the utility's cost of fuel; therefore, as the utility's fuel cost goes down or up, so will the RESG feed-in rates.

While the administrative, value-based approach is an accepted methodology for setting the compensation rate for renewable energy generators, it pegs the value of the kWh produced by the renewable energy generator to the utility's cost of fuel. There are a few drawbacks associated with this approach including that it does not provide long-term investment certainty because the compensation rate is variable and fluctuates based on the cost of fuel, it only incentivizes investment in renewable energy when the cost of fuel is high and not when the cost of fuel is low, it does not reflect the actual costs of investing and operating a renewable energy system, and it does not reflect the full value a kWh of renewable energy may deliver to the grid.

Compared to a value-based approach, a cost-based approach ensures the compensation amount allows developers to recover all costs and earn a reasonable return on their investment creating an incentive for renewable energy project development by providing investment certainty. However, there are potential drawbacks to the cost-based approach such as providing an excessive compensation rate for renewable energy generators and in turn having a higher electricity rate increase than anticipated for non-participating utility customers. It is possible to mitigate these drawbacks through thoughtful program design including a highly consultative process in determining rate inputs, a cost-effectiveness analysis to understand the potential impacts of the tariff rate on different stakeholders, and regular periods of review to adjust the compensation rate to reflect the changes of an evolving market.

URCA herein proposed a cost-based methodology to understand the potential compensation level a renewable energy generator would need to cover the cost of installing a renewable energy system and earning a targeted rate of return under each design option.

Consultation Question 1

Do you agree with the two proposed approaches to setting RE tariff rates? Which approach do you think is most appropriate for estimating RE pricing for exchanging energy to the grid? Please give reason(s) for your answer(s)

4.3 Proposed Methodology: Calculating Cost-Based Rates

URCA is proposing a Renewable Energy Rate-Setting Tool (referred to throughout this document as the Rate-Setting Tool) calculates rates using the Discounted Cash Flow (DCF) methodology. Under the DCF methodology, rates are determined by calculating the Levelized Cost of Energy (LCOE) of various renewable energy technologies, including a targeted rate of return.

To conduct the DCF, annual cash flows are calculated, showing the revenues and expenses that a representative project would incur in each year within the payment period. The individual annual cash flows are subsequently discounted to a single net present value (NPV) and internal rate of return (IRR). The return on equity (ROE) is used as the discount rate. The model then calculates the payment rate by calculating the revenue per kilowatt-hour, which results in an NPV of zero using the project's discount rate, the assumed cost of equity and satisfying any other applicable cash-flow constraints.

By setting payment rates equal to the LCOE, policymakers can ensure that payments to project investors throughout the contract will allow them to recover their costs and generate a reasonable return on their investment. If rates are designed correctly, this method provides an incentive for renewable energy development to realize the RE policy target without providing windfall profits.

4.3.1 RATES MODELLED

4.3.1 Renewable Energy Technologies

The IDB Study developed the methodology and provided the modelling tools, at URCA's request, for calculating cost-based renewable energy rates for the technologies that are currently eligible under the RESG: solar PV and wind. As a point of comparison, it is proposed to use results from the modelling tool to determine cost value tariff for solar PV + battery storage projects separately.

4.3.2 Representative Projects

To avoid calculating a unique rate for every project that applies to participate in a renewable energy program, standard rates are proposed for each category of eligible renewable energy technology. A representative project is used to calculate a rate for each technology and capacity size tier within the program. The size tiers used for the analyses throughout this report are summarized in Table 2.

Table 2. Representative Project Sizes Modelled for Each Technology & Size Tier

Capacity Size Tier	Representative Project Size (kW)
Solar PV	
101kW -250kW	150kW
251kW – 500kW	300kW
501kW- 1MW	750kW
Wind	
101kW – 1 MW	750kW

Annotations on Size Tiers and Representative Project Size Selection

- *Range from 101kW to 1MW* – The capacity size range of 101kw to 1MW was used, as this is the capacity size range of the RESG program currently in place. Solar PV and wind projects below 101kW fall under the Small-Scale Renewable Generation program.
- *Additional Tiers* – The current RESG program has two tiers: 101kW to 500kW and 501kW to 1MW. Through the interview process with stakeholders in the renewable energy sector in The Bahamas, an indication was provided that slightly more granular tiers within the 101kW to 1MW range would better reflect the distinctions in costs between renewable energy project sizes. In an attempt to integrate the need for more granular capacity size tiers, while also balancing the need for simplicity to more effectively communicate and administer the policy, the Cadmus Team divided the 101kW to 500kW tier into two tiers (101kW to 250kW and 251kW to 500kW). This tiered structure also mirrors that of the feed-in tariff adopted in Barbados in 2019 (Feed-in-Tariffs for Renewable Energy Technologies up to and Including 1MW).[7]

[7] Barbados Fair Trading Commission. September 2019. Fair Trading Commission Decision and Order on Feed-in-Tariffs for Renewable Energy Technologies up to and Including 1 MW. Available at: https://www.ftc.gov.bb/library/2019-09-16_commission_decision_final_FIT.pdf

- *Representative Project Sizes* – The representative project sizes (150kW, 300kW, 750kW for solar PV and 750kW for wind) were selected given their relative prevalence as common project sizes in the respective size tier and available data.

4.3.2 Data Collection Approach and Sources

A critical step prior to modelling the cost-based rates was data collection. The objectives of this step were to gather data on key parameters needed to calculate the cost-based rates for solar PV, wind and solar PV + battery storage installations and to consult with renewable energy stakeholders active in The Bahamas to understand the costs of renewable energy installations in The Bahamas.

To achieve this objective, IDB Study deployed a three-pronged approach:

1) Primary Sources from The Bahamas

- A survey was developed to collect relevant data on solar PV, wind, and solar PV + storage installations. URCA shared this survey directly with a range of stakeholders involved in the renewable energy sector in The Bahamas – including renewable energy installers, developers, owners, as well as utilities and relevant ministries. Furthermore, the Bahamas' Chamber of Commerce & Employer's Confederation shared this survey more broadly with an additional 40+ stakeholders.
- Follow-on interviews and data collection calls were conducted with survey recipients who were responsive to outreach.
- Relevant raw data was collected from primary written sources specific to The Bahamas.

While there were no direct responses via the survey form, Cadmus on behalf of IDB collected relevant primary data via interviews and subsequent data files shared. Cadmus also collected relevant raw data from other primary written sources, such as reports conducted in the context of the IDB's "Conditional Credit Line Proposal/ Reconstruction with Resilience in the Energy Sector in The Bahamas".

2) Regional Data and Benchmarks

Cadmus subsequently leveraged regional data both as a cross-reference and benchmark for the primary data sources, as well as a first-choice supplement where primary data from The Bahamas was not available. The most frequently cited regional source of data on solar PV and wind installations was the CREF-Castalia Renewable Islands Index and Marketplace from 2019.

3) International Sources and Benchmarks

International reports and data on solar PV, wind and battery storage installations were subsequently used to fill gaps where data specific to The Bahamas and/or to the Caribbean were not available, as well as to provide an additional benchmark on cost and performance assumptions.

BPL and GBPC

While this scope of work incorporates two utilities (BPL and GBPC), and the subsequent benefit-cost assessment (Section 2) provides detailed assessments for BPL and GBPC separately, Cadmus did not differentiate between utility service territory in developing the input assumptions on costs of generation for solar PV, wind and battery storage. While some costs may differ between utility service territories (e.g., interconnection fees), this level of granularity was not available in the data received, and the distinctions in cost of generation for solar PV and wind are assumed to be minimal between BPL and GBPC. As a result, the input assumptions and results proposed are identical for BPL and GBPC, with the exception of data used for Modelling Net-Billing Rates, which requires input assumptions on the utility's electricity rate structure.

Consultation Question 2

Stakeholders are asked to provide comments on Data collection approach and sources. Do you believe that the data collection approach is adequate? If not, explain why not? Provide alternative and/or additional data where possible

4.3.3 BUY-ALL/SELL-ALL RATE-SETTING ASSUMPTIONS

This section summarizes all input assumptions proposed to model alternative rates under a Buy-All/Sell-All arrangement for all participants in the RESG program. It includes annotations on the considerations and sources for input assumptions. The annotations are intended to serve as a point of reference should further public review or revision be necessary for forthcoming steps in updating the RESG program. Modelling assumptions are segmented into the following categories:

- Installed Cost Input Assumptions
- Operating Cost Input Assumptions
- Technical and System Input Assumptions
- Financing Input Assumptions
- Other Input Assumptions

Under the Buy-All/Sell-All arrangement, the RESG customers will purchase all power that they consume from the utility as usual, and all power that the customer's renewable energy system produces will be sold back to the utility. As such, assumptions on customer demand profiles and utility rate structures have no impact on the Buy-All/Sell-All modelling and are not incorporated within this section but are instead included in subsequent Net-Billing section.

1.1.1 Installed Cost Input Assumptions

Table 3. Installed Cost Input Assumptions

Capacity Size Tier	Base Capital Costs ($/kW)	Additional Storm Hardening Measure Costs ($/kW)	System Upgrade Costs ($)	Permitting & Licensing Costs ($)	Interconnection Fees ($/kW)	Total Installed Costs / kW ($/kW)
Solar						
101kW – 250kW	$2,210	$180	$7,000	$250	$1	**~$2,439**
251kW – 500kW	$1,960	$180	$7,000	$250	$1	**~$2,165**
501kW – 1MW	$1,960	$540	$7,000	$250	$1	**~$2,510**
Wind						
101kW – 1MW	$2,362	$0	$7,000	$250	$1	**~2,372**

Base Capital Costs

Solar PV – The estimates on solar PV capital costs for various project size tiers are based primarily on Bahamas-specific data. Average installed cost data was provided by one renewable energy developer in The Bahamas for projects in the respective project tiers, alongside detailed data inputs for one 500kW solar PV system. Additional storm hardening measure costs were extrapolated from averages for continuity purposes. Estimated additional costs of structural elements (e.g., carport structural costs) were subtracted and not considered as part of the average capital cost for this analysis. The resulting base capital costs used for this analysis (Table 3. Installed Cost Input Assumptions) are slightly lower than the average capital costs reported for all distributed solar PV projects listed in the CREF-Castalia database published in 2019 (average: $2,698 for solar PV projects since 2013),[8] and are higher than the average installed cost for commercial-scale solar PV systems in the U.S. within the 10kW to 2MW size range as reported by NREL in Q1 of 2018.[9]

Wind – Cadmus therefore used the average capital cost reported for all wind projects in the CREF-Castalia Renewable Energy Marketplace 2019.[10] This capital cost assumption is slightly lower than the reported capital cost for three wind installations in The Bahamas in the 100kW to 1MW size range reported in the CREF-Castalia Renewable Energy Marketplace 2017 (ranging from $2,425 to $3,500/kW).[11] These values were not used given that all three were installed 5+ years ago.

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[8] Ibid

[9] R. Fu, D. Feldman, R. Marglos. NREL. November 2018. U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018. Available at: https://www.nrel.gov/docs/fy19osti/72399.pdf

[10] Castalia. 2019. CREF-Castalia 8th Annual Renewable Energy Islands Index and Marketplace. Available for download at: https://castalia-advisors.com/castalia-presents-8th-annual-renewable-islands-index-and-marketplace-at-cref

[11] Castalia. 2017. CREF-Castalia 6th Annual Renewable Energy Islands Index and Marketplace. Available for download at: https://castalia-advisors.com/castalia-presents-at-cref-2/

Additional Storm Hardening Measure Costs

Solar PV – Storm hardening costs for solar PV systems were incorporated. Secondary research indicated that an estimated additional ~$0.18/W in costs are required for a 100kW roof mount system, while an additional ~$0.54/kW in costs are required for a 1MW ground mount system for storm hardening measures. These cost estimates draw from Rocky Mountain Institute's (RMI) Caribbean-based research and report series "Solar Under Storm: Solar Best Practices for Resiliency PV Systems for Small Island

Developing States",[12] which are reported in NREL's study on "Solar PV in Severe Weather: Cost Considerations for Storm Hardening PV Systems for Resilience". [13]

Wind – No information on costs for storm hardening measures for wind installations was received or identified; Cadmus, therefore, did not incorporate costs in this category for wind projects.

System Upgrade Costs

The current RESG program decision indicates that "a grid-tied RESG customer shall be responsible for the total cost of any upgrades such as transformer changeouts or primary/secondary line rebuilds that are required due to the connection of the approved RE facility."[14] System upgrade costs are highly site-specific. Although no Bahamas-specific data was received, Cadmus drew from interviews with renewable energy developers in previous projects in the region (St. Lucia), indicating $7,000 in system and structural upgrade costs as a lower range for 200kW commercial and industrial solar PV projects. No data was received or identified on system upgrade costs for wind. Given the lack of Bahamas-specific data, the upfront cost of $7,000 was applied to all projects.

Permitting & Licensing Fees

An application fee of $250 is required for all eligible projects applying to the RESG program.[15] No other permitting or licensing fees were identified for solar PV or wind projects in The Bahamas.

Interconnection Fees

BPL charges a $100 interconnection fee for all projects greater than 100kW, as well as $1 for each kW above 100. No data on interconnection fees were provided for other Public Electricity Suppliers in The Bahamas; this assumption was used across all rates modelled.

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[12] L. Stone, C. Burgess, J. Locke. 2020. Rocky Mountain Institute. Solar Under Storm for Policymakers: Solar Best Practices for Resilient Photovoltaic Systems for Small Island Developing States. Available for download at: https://rmi.org/insight/solar-under-storm/

[13] J. Elsworth, O Van Geet. NREL. June 2020. Solar Photovoltaics in Severe Weather: Cost Considerations for Storm Hardening PV Systems for Resilience. Available at: https://www.nrel.gov/docs/fy20osti/75804.pdf

[14] URCA. February 2020. Guidelines for the Approval of Renewable Energy Self-Generation Projects, Small Commercial and Government. Statement of Results and Final Decision. Available at: https://www.urcabahamas.bs/wp-content/uploads/2020/03/Statement-of-Results-and-Final-Decision-on-Renewal-Energy-Self-Generation-Projects-ES-03-2020.pdf

[15] Ibid.

4.3.1 Operating Cost Input Assumptions

Table 4. Operating Cost Input Assumptions

Capacity Size Tier	O&M ($/kW/year)	Insurance (%)
Solar		
101kW – 250kW	$16	1%
251kw – 500kW	$16	1%
501kW – 1MW	$16	1%
Wind		
101kW – 1MW	$57	1%

Operation & Maintenance (O&M) Costs

Solar PV – $16/kW/year was quoted as the cost of O&M ($/kW/year) for a 500kW ground-mount solar PV system. This value is nearly identical to the estimated cost of O&M used for the Barbados Feed-In Tariff Decision in 2019 (equivalent to ~$USD17/kW/year).[16]

Wind – No Bahamas-specific data on wind was identified or received. Cadmus used O&M cost estimate used for the Barbados Renewable Energy Rider LCOE calculation (equivalent to ~$USD57/kW/year).[17]

Insurance

The RESG program decision states that "RESG facility owners are required to establish and maintain full insurance coverage for loss and damage from the operation of the RESG facility… to mitigate shock hazards, damage to utility or customers' equipment, interference with automated distribution system protection function systems."

Solar PV – Very little data was identified on available insurance products for renewable energy systems in The Bahamas. One renewable energy developer quoted $15/kW/year for the cost of insurance for a 500kW solar PV system, which correlates to ~1% of total CAPEX. No corresponding data on insurance coverage at this cost was identified.

[16] Barbados Fair Trading Commission. September 2019. Fair Trading Commission Decision and Order on Feed-in-Tariffs for Renewable Energy Technologies up to and Including 1 MW. Available at: https://www.ftc.gov.bb/library/2019-09-16_commission_decision_final_FIT.pdf

[17] Barbados Fair Trading Commission. 2016. Motion to Review the Renewable Energy Rider Decision. Available at: https://www.ftc.gov.bb/index.php?option=com_content&task=view&id=303

Wind – No data was received specific to wind installations. Cadmus, therefore, assumed 1% for wind projects as well.

Consultation Question 3

Stakeholders are asked to provide comments on the Operation & Maintenance (O&M) Costs assumptions. Do you agree with the assumptions, if no explain why not and provide alternative and or additional data?

4.3.2 Technical and System Performance Input Assumptions

Table 5. Technical and Performance Input Assumptions

Capacity Size Tier	Capacity Factor	Analysis Term/ Project Lifetime	Annual Degradation
Solar			
101kW – 250kW	19%	15 years	0.5%
251kW – 500kW	19%	15 years	0.5%
501kW – 1MW	19%	15 years	0.5%
Wind			
101kW – 750kW	28%	15 years	0.5%

Capacity Factor

Solar PV – A capacity factor of 19% was quoted by a renewable energy developer for a 500kW solar PV project in The Bahamas. No further primary data from The Bahamas was received. Although the net capacity factor can be site-specific, the capacity factor range of 18% - 20% for solar PV is also used for the Feed-In Tariff analysis for solar PV systems in Barbados.[18]

[18] Barbados Fair Trading Commission. September 2019. Fair Trading Commission Decision and Order on Feed-in-Tariffs for Renewable Energy Technologies up to and Including 1 MW. Available at: https://www.ftc.gov.bb/library/2019-09-16_commission_decision_final_FIT.pdf

Wind – 28% is the capacity factor quoted within the CREF-Castalia Renewable Energy Marketplace published in 2017 for a 1MW wind installation in The Bahamas.[19] This capacity factor assumption is also just below the capacity factor input for wind installations in the same project size range for the Barbados Feed-In Tariff analysis (30%).[20]

Analysis Term / Project Lifetime

The lifetime of the project is set to be equal to the duration of the contract under the RESG program (15 years) for all projects.[21]

Annual Degradation

An annual degradation of 0.5% is a typical assumption used for analyses on solar PV and wind projects. This same value was also quoted by a renewable energy developer for a 500kW solar PV project in The Bahamas and was used as an assumption for all solar PV and wind installations within the Feed-in-Tariff analysis in Barbados.[22]

4.3.3 Proposed Financing Input Assumptions

Table 6. Key Financing Input Assumptions

Capacity Size Tier	Discount Rate*	Loan Percentage	Loan Term	Loan Interest Rate
Solar				
101kW – 250kW	12%	50%	15 years	7.5%
251kW – 500kW	12%	30%	15 years	7.5%
501kW – 1MW	12%	10%	15 years	7.5%
Wind				
101kW - 750kW	12%	10%	15 years	7.5%

[19] Castalia. 2017. CREF-Castalia 6th Annual Renewable Energy Islands Index and Marketplace. Available for download at: https://castalia-advisors.com/castalia-presents-at-cref-2/

[20] Barbados Fair Trading Commission. September 2019. Fair Trading Commission Decision and Order on Feed-in-Tariffs for Renewable Energy Technologies up to and Including 1 MW. Available at: https://www.ftc.gov.bb/library/2019-09-16_commission_decision_final_FIT.pdf

[21] URCA. February 2020. Guidelines for the Approval of Renewable Energy Self-Generation Projects, Small Commercial and Government. Statement of Results and Final Decision. Available at: https://www.urcabahamas.bs/wp-content/uploads/2020/03/Statement-of-Results-and-Final-Decision-on-Renewal-Energy-Self-Generation-Projects-ES-03-2020.pdf

[22] Barbados Fair Trading Commission. September 2019. Fair Trading Commission Decision and Order on Feed-in-Tariffs for Renewable Energy Technologies up to and Including 1 MW. Available at: https://www.ftc.gov.bb/library/2019-09-16_commission_decision_final_FIT.pdf

Consultation Question 4

Stakeholders are asked to provide comments on the Technical System input assumptions. Do you agree with the assumptions, if no explain why not?

4.3.4 Targeted Rate of Return: The Discount Rate

The model calculates an LCOE that allows all project costs to be covered and achieves a target rate of return (the discount rate) over the full duration of the contract (15 years). A target rate of return of 12% was quoted by a renewable energy developer in The Bahamas as the expected rate of return on a 500kW solar PV project. The interviews and conversations Cadmus had with renewable energy developers in the Caribbean region (in the context of previous projects in the region) have indicated that a rate of return of 10% to 15% would typically be needed to attract private-sector investment. As a regional benchmark, the rate of return (cost of equity) used for the Feed-in-Tariff analysis in Barbados in 2019 was 14%.[23]

<u>Loan Percentage, Term and Interest Rate</u>

Very little Bahamas-specific data was received on typical loan products available for renewable energy projects. As such, Cadmus relied on research from previous projects on renewable energy loan products available in the

Consultation Question 5

Stakeholders are asked to provide comments on the targeted rate of return for RE investors. Do you agree with the assumptions, if no explain why not?

Caribbean region. This research identified loan products available for up to $200,000 from the Caribbean Development Bank (as of 2018). The assumptions on loan percentages (a percentage of the total capital costs) reflect manually input percentages that result in a loan amount not exceeding $200,000 for all projects. The loan term of 15 years and a loan interest rate of 7.5% were both quoted by a renewable energy developer for a commercial-scale solar PV project in The Bahamas. These terms fall within the range of loan terms identified via prior research on loan products in the Caribbean – including loans from the CAFF, Grenada Development Bank and the CDB – which included loan terms ranging from 7.5 to 10 years, and interest rates ranging from 4.5 to 14%. Note that the report referenced is not publicly available, and these loan products identified may have expired since the date of publication.

4.3.5 Other Input Assumptions

Other input assumptions include:

<u>Depreciation</u>

Depreciation is modelled on a straight-line basis for all projects. Based on stakeholder feedback, accelerated depreciation incentives are not applicable and were therefore not included.

[23] Ibid.

Taxes

Per data gathered, the model assumes that no taxes are applied to solar PV and wind projects owned by commercial or governmental customers.

Costs not included in the model:

Some of the costs not included separately are costs related to site leasing, land taxes, project management, or decommissioning, as there are varied approaches to incorporating these costs with an LCOE methodology to rate-setting, and the tool did not include separate fields for these inputs.

Consultation Question 6

Stakeholders are asked to provide comments on the URCA proposed other Input assumptions. Do you agree with the assumptions, if no explain why not?

4.3.4 BUY-ALL/SELL-ALL RATE-SETTING RESULTS

Using the Rate-Setting Tool (as described in Section 2.2 "Methodology: Calculating Cost-Based Tariff Rates") and all assumptions detailed in Section 2.4 "Buy-All/Sell-All Rate-Setting Assumptions", the Consultant Team calculated the following potential payment rates under a Buy-All/Sell-all RESG policy, as detailed in Table 7.

Table 7. Calculated Cost-Based Rates for Solar PV and Wind under a Buy-All/Sell-All RESG Program

Technology	Capacity Size Tier	Calculated Cost-Based Rate[24]
Solar PV	**101kW – 250kW**	**$0.22**
	251kW – 500kW	**$0.21**
	501kW – 1MW	**$0.25**
Wind	**101kW – 1MW**	**$0.18**

These calculated rates are subsequently used for benefit-cost effectiveness of the Buy-All/Sell-All policy scenario. The calculated rates under a Buy-All/Sell-All policy assume that all modelling assumptions detailed in "Buy-All/Sell-All Rate-Setting Assumptions" do not vary between utilities; the resulting rates under a Buy-All/Sell-All policy, therefore, do not vary between utilities.

[24] All calculated rates are rounded to the nearest cent.

4.4 BENCHMARKING RATES AGAINST BUY-ALL/SELL-ALL RATES IN THE CARIBBEAN

The results of the Buy-All/Sell-All rate-modelling ranged from \$0.21 to \$0.25 per kWh for solar PV projects, and \$0.18 per kWh for wind. This section provides a brief comparison of these results with the results from the Barbados "Decision and Order on Feed-in-Tariffs for Renewable Energy Technologies up to and Including 1MW", adopted by the Barbados Fair Trading Commission in September 2019.[25] Both the Barbados FiT modelling and the Buy-All/Sell-All rate-modelling within this study used a cost-of-generation approach via an LCOE tool to calculate the rates. The distinctions between the results largely reflect distinctions in the cost of generation input assumptions, including installed cost assumptions. It should also be noted that while both studies used Barbados-specific or Bahamas-specific data where available, the Barbados study benefited from a larger data pool collected via a public consultation issued by the Commission.

Solar PV

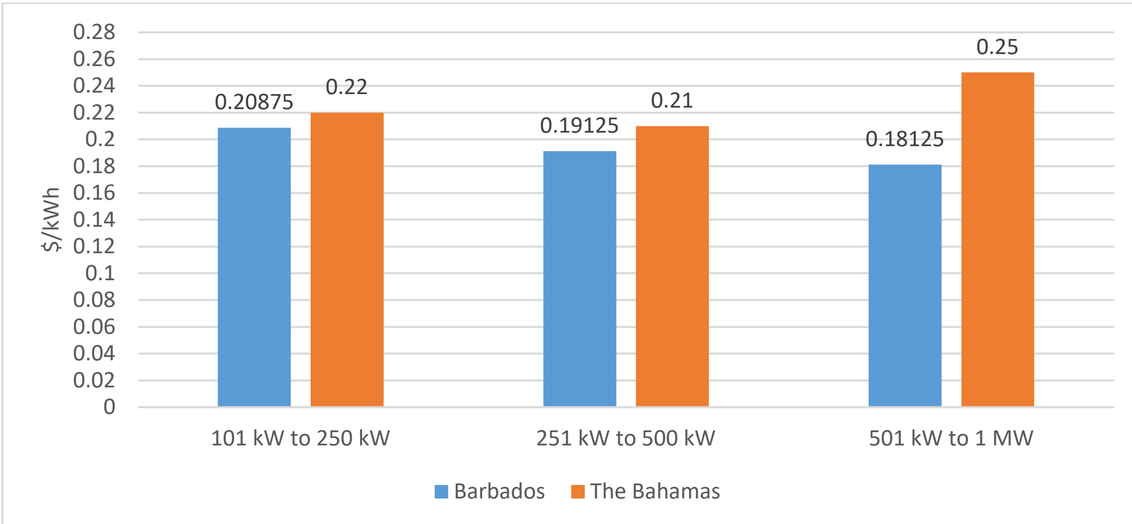
Figure 2 depicts the Buy-All/Sell-All results from this study for solar PV projects next to the Barbados FiT Decisions solar PV rates. In the *lower two capacity tier ranges* (101kW to 250kW and 251kW to 500kW), the difference between the rates are within ~0.02 cents; this difference largely reflects the higher installed cost input assumptions within The Bahamas rate-modelling, which are most likely attributable to the relatively smaller data pool available for the Bahamas rate-modelling.

The difference in the results within the *largest capacity size tier* (501kW to 1MW) is considerably larger (a ~\$0.07 per kWh difference). This difference is likely attributable to the generally higher costs of ground-mounted PV versus roof-mounted PV – the Bahamas-specific data within the 501kW to 1MW tier reflects cost data collected from ground-mounted projects in The Bahamas.

An additional, potential factor contributing to the cost differences in all capacity size tiers is the incorporation of "storm hardening measure costs"; while this study for the Bahamas explicitly includes the costs of additional storm hardening measures, it is unclear if or to what extent this is reflected within the Barbados FiT Decision.

[25] https://www.ftc.gov.bb/library/2019-09-16_commission_decision_final_FIT.pdf

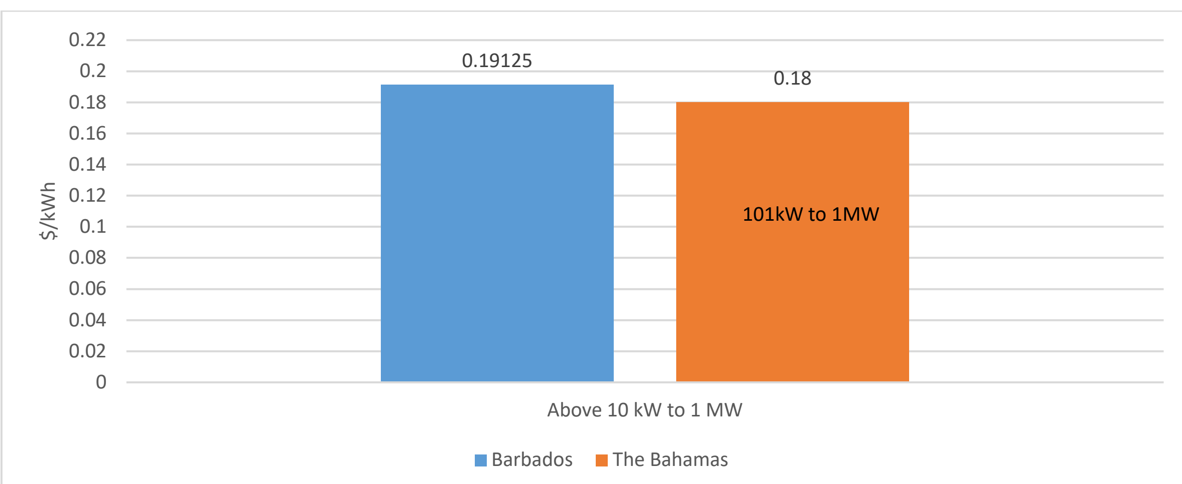
Figure 2. Solar PV - Comparison of Buy-All/Sell-All Modelling Results to the Barbados FiT Decision



Wind

Figure 3 depicts Buy-All/Sell-All results from this study for wind projects next to the Barbados FiT Decisions wind rate. The ~$0.01 per kWh difference between the results largely reflects the higher installed cost assumptions for wind in the Barbados FiT Decision than in this study ($2,829 per kW in the Barbados FiT modelling versus $2,362 per kW within this study). One potential factor contributing to this difference is the distinction in capacity size tiers: the Barbados FiT includes one size tier for wind, *10kW* to 1MW, while eligible capacity size under the Bahamas RESG program ranges from *101kW* to 1MW**.**

Figure 3. Wind - Comparison of Buy-All/Sell-All Modelling Results to the Barbados FiT Decision



4.5 MODELLING NET-BILLING RATES

The current RESG program offers a net-billing arrangement for renewable energy installations in the 101kW – 500kW capacity size range. This arrangement mirrors the Small-Scale Renewable Generation compensation scheme in the SSRG program: the customer exports excess electricity generated to the grid and the utility credits the customer for the value of the amount of kWh at the prevailing fuel charge rate for the month in which the customer is billed.

The compensation rate under a Net-Billing arrangement can be set via a variety of methods, including avoided cost of electricity from the utility (e.g., avoided fuel charge), as well as time-of-use or time-varying rates.[26] A Net-Billing compensation rate is not typically set via a cost of generation approach. Nonetheless, upon request and to provide a point of comparison on the financials for a customer-sited renewable energy installation under Net-Billing, URCA is proposing to use the Rate-Setting Tool to model the compensation rates for solar PV and wind projects under a Net-Billing scheme that would enable the developer to recover all costs and achieve the targeted discount rate. As it relates to the SSRG program, URCA takes the view that the benefit/cost to the Residential consumer ought to be the positive net gain on the customer electricity bill and not so much to achieve a target discount rate. URCA, therefore, is proposing that the SSRG compensation rate under a Net-Billing be set at the avoided fuel charge.

Consultation Question 7

Do you agree with

(i) the proposed modelling of the RESG compensation rate under the proposed Net-Billing arrangement?

(ii)* the proposed modelling of the SSRG compensation rate under the proposed Net-Billing *arrangement?

If no, why not? Please explain and provide the reasons and alternative proposal

4.5.1 ADDITIONAL MODELLING ASSUMPTIONS UNDER NET-BILLING

To model a compensation rate under a Net-Billing scheme, additional input assumptions must be made on customer electricity demand, load profiles, as well as the cost of electricity from the applicable utility or public electricity supplier. URCA has proposed these assumptions which were developed as follows:

Customer electricity demand – Cadmus used the electricity consumption profiles from small to mid-sized hotels in The Bahamas (sources and assumptions detailed in Annex 2: Customer Electricity Consumption Input Assumptions)

C&I load profiles – With a lack of adequate Bahamas-specific data on load profiles, Cadmus used load profiles from commercial-scale customers sourced from HOMER Energy.

[26] IRENA. 2019. Net Billing Schemes Innovation Landscape Briefs. Available at: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Feb/IRENA_Net_billing_2019.pdf?la=en&hash=DD239111CB0649A9A9018BAE77B9AC06B9EA0D25#:~:text=Under%20the%20NEM%20mechanism%2C%20the,the%20consumer%20into%20the%20grid.&text=FiTs%20can%20be%20higher%20than,install%20distributed%20renewable%20generation%20capacity.

Utility rate structure – The cost of electricity, applicable rate structures and prevailing fuel rates were sourced directly from the two utilities (BPL and Grand Bahama Power Company) assessed in the Benefit-Cost Effectiveness portion of this study, as detailed in Annex 1: BPL and Grand Bahama Power Company Rate Structure.

All other assumptions on solar PV and wind installations are identical to those laid out in Section 4

Net-Billing compensation rate is not typically set via an LCOE calculation, but rather via a value-based approach as discussed in Section 4.5 above, such as the avoided cost of generation to the utility (e.g., the avoided fuel rate, as is currently in place under the 101kW – 500kW tier of the RESG program and the (1kW – 100 kW) SSRG program. URCA proposed not to model this tier further within the benefit-cost policy tool.

4.5.2 RESULTS: MODELLING COMPENSATION RATES UNDER NET-BILLING

Using the Rate-Setting Tool, Cadmus modelled rates under a Net-Billing scenario with the following results:

Representative Project	150kW solar PV	300kW solar PV	750kW solar PV	750kW wind
RE Project Installed Capacity (kW)	150	300	750	750
RE Project Annual Electricity Yield (kWh)	249,660	499,320	1,248,300	1,839,600
Customer Annual Electricity Demand (kWh)	529,427	529,427	2,507,326	2,507,326
Calculated % Self-Consumption	**96.4%**	**71.12%**	**95.47%**	**52.52%**
Rate-Setting Tool Result	**$0.0**	**$0.07**	**$0.0**	**$0.12**

The results from the rate-setting tool generally indicate: the higher the percentage of electricity generated that is consumed on-site, the lower the rate per kWh exported to the grid that the renewable energy system owner would need to recover costs. On the other hand, renewable energy systems sized such that they export a lower percentage of electricity to the grid require a higher rate per kWh to recover costs. These results reflect that, under the assumptions modelled, the cost per kWh of generating electricity on-site via solar PV or wind is lower than the cost per kWh of purchasing electricity from BPL.

These results are intended to provide insights into the financials of a solar PV or wind system under a Net-Billing compensation scheme (consuming on-site and exporting excess). Net-Billing compensation rate is not typically set via an LCOE calculation, but rather via a value-based approach such as the avoided cost of generation to the utility (e.g., the avoided fuel rate, as is currently in place under the 101kW – 500kW tier of the RESG program). These results are therefore not modelled further within the benefit-cost assessment portion of this study.

4.5.3 ADDITIONAL MODELLING ASSUMPTIONS UNDER SOLAR PV + BATTERY STORAGE

To model a compensation rate of a solar PV system including battery energy storage, additional input assumptions must be made on battery energy system size. URCA is proposing these assumptions that were developed as follows:

Battery sizes were calculated assuming the primary purpose of the battery energy storage system is to serve as a backup in the case of power outages. Under this assumption, the battery sizes were calculated to match the parameters of the given representative project sizes (150kW, 300kW and 750KW) in combination with the annual electricity demand profiles of the three representative projects (see Annex 3: Customer Electricity Consumption Input Assumptions). Using the total annual electricity demand profiles an average daily electricity consumption for three representative projects was calculated. Assuming a daily critical load of 10%, a daily priority load ratio of 15%, and the potential for outages of 18 hours or more, the battery sizes calculated represent the estimated battery size that would be needed for minimum continuous power between typical solar generation periods. The resulting battery energy storage size assumptions are summarized in Annex 4: Battery Energy Storage System Input Assumptions.

All other input assumptions on solar PV and wind installations are identical to those laid out in Section 3

Consultation Question 8

Stakeholders are asked to provide comments on the URCA proposed assumptions in regard to Solar PV + Battery Storage. Do you agree with the assumptions outlined in Annexes 4, if no explain why not?

4.6 URCA PROPOSED BENEFIT-COST EFFECTIVENESS TESTS

URCA is proposing to conduct Benefit-Cost effectiveness Tests centered around the data gathered and the assumptions proposed. URCA is proposing to rely on the policy-cost tool developed by Cadmus for URCA. The purpose of the tool is to allow URCA to analyze the cost effectiveness of various design options for the Renewable Energy Self-Generation (RESG) program, and by extension the SSRG program, which was designed in 2018, within the footprint of The Bahamas' individual utility service areas. The tool allows the user to adjust program options, including whether the program allows for self-consumption (Net-Billing) or requires that customers export all self-generated energy to their utility (Buy-all/Sell-All). Additionally, URCA will be able to adjust if the customer rate is based on the utility customer fuel charge or a cost-based rate. Users are also able to adjust various parameters impacting the cost-effectiveness of the program design, including various cost based RESG rates and/or customer fuel charges, utility electricity rates, renewable system performance and cost metrics, customer diesel generator usage metrics, discount rates, and utility customer characteristics.

This policy-cost tool was developed in conjunction with a separate Renewable Energy Rate-Setting Tool, which was developed by Energynautics on behalf of URCA. The Rate-Setting Tool can produce various rate options that can serve as inputs for this tool. Utility-area specific data for Bahamas Power and Light (BPL) and Grand Bahamas Power Company (GBPC) was incorporated to run six (6) cost-effectiveness calculation scenarios for URCA.

The tool's cost-effectiveness and cost impacts results are presented in alignment with guidance from the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources (NSPM), which provides guidance on how to estimate the cost-effectiveness of distributed energy resources policies[27]. The tool presents cost-effectiveness outputs from the perspectives of the regulator, society, and the utility. Additionally, the policy-cost tool presents cost-effectiveness from the perspective of the participants, showing the impact of policy designs on customer cash flows, and calculates what, if any, customer rate increase is needed to recover fixed utility cost. Table 1 below shows what each of these tests considers as a cost or benefit.

Table 11. Utility Cost Tests Analyzed

Test	Perspective	Costs	Benefits
Jurisdiction-Specific Cost Test	Regulators or decision-makers	Administrative costs, tariff rate payments, applicable policy goal impacts	Energy-related and capacity/transmission and distribution (T&D)-related costs avoided by the utility, applicable policy goal impacts
Utility Cost Test	The utility[a]	Administrative costs	Energy-related and capacity/T&D-related costs avoided by the utility
Societal Cost Test	Society	Administrative costs, installation costs, incremental measure costs (O&M, replacement, etc.)	Energy-related and capacity/T&D-related costs avoided by the utility, non-monetized benefits (such as cost of carbon)
Participant Cost Test	Participants	Installation costs, incremental measure costs (O&M, replacement, etc.)	Tariff rate payments, avoided retail payments
Ratepayer Impact Test	Non-participating ratepayers	Administrative costs, tariff rate payments, lost revenue to utility due to reduced consumption	Energy-related and capacity/T&D-related costs avoided by the utility

[a] The Utility Cost Test does not include utility revenue impacts such as tariff rate payments or avoided fuel charges, since these revenue impacts are passed through to utility customers through increased rates. Rather, the test focuses on direct costs and benefits experienced immediately by the utility.

URCA is proposing the Jurisdiction-Specific Test, which is intended to provide cost-effectiveness results from the perspective of the regulator. This test shall include the cost and benefits necessary to understand if policy design options are cost-effective when considering the policy objectives and URCA remit

Costs and benefits are assigned differently for each test, according to the various perspectives. For example, while benefits associated with avoided carbon emissions are important from the regulator and societal perspectives, these are not considered benefits from the utility, ratepayer, or participant perspective. Similarly, the cost associated with developing renewable systems may not be costs for the utility but are important cost considerations from the participant's perspective. Therefore, users of this tool must consider carefully which costs and benefits are included in each test. Discount rates are also determined based on the test's perspective. For example, the appropriate discount rate from the participant perspective is the project's expected rate of return, whereas for the utility it is the utility's cost of borrowing (utility weighted average cost of capital [WACC]). Cost-

[27] *National Standards Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources. Energy Screening Project. August 2020.

effectiveness results can be impacted by utility-specific parameters, such as fuel costs, line losses, customer electric rates, and WACC. Users should consider that results reflect only outputs for a specific utility, and not for the entirety of The Bahamas.

Cost effectiveness metrics are expressed in three ways: 1) as the ratio of benefits and costs, 2) as a summation of overall net benefits, and 3) as the overall impact on utility customer rates. For the benefit-cost ratio, any ratio of 1 or greater represents a cost effective test result, illustrating that the net-present value of the costs and benefits are at least equal. For the net-present value of benefits and costs, any number test result that is zero or positive, is cost-effective, while a test result with a negative total net-present value of summation of cashflows is not cost-effective.

Lastly, to calculate rate impacts, URCA is proposing to calculate the net present value of the cashflows assigned to the ratepayer impact test, and dividing these by the discounted total projected utility electric sales over the 15-year project lifetime. The $/kWh of projected rate increase represents the average increase in utility rates needed to recover the net impacts on utility revenue over the course of the project lifetime. Due to the complexities of fuel-switching and multiple rate tiers, Cadmus did not estimate impacts on various rates or the impacts on reduced fuel charges and instead provided a rate increase that would apply to all utility customers. Cadmus also provided an estimate of the average percentage increase on a customer's utility bill.

Based on the foregoing analysis URCA proposed Jurisdiction-Specific Test Results as the basis for setting tariff for the RE program participants.

Table 12. Description of Cashflows Analyzed

Cost/Benefit	Description
Utility Total Avoided Fuel Cost	Fuel costs for conventional electricity generation the utility avoids due to increased renewable energy generation, assuming a particular fuel cost scenario. Avoided fuel costs are realized at the point of generation.
Customer Total Avoided Fuel Cost	Utility fuel charges the customer avoids due to increased renewable energy generation, assuming a particular fuel rate scenario. Avoided fuel costs are realized at the customer site.
Customer Avoided Retail Rate Payments	Electric retail payments the customer avoids due to increased renewable energy generation. This model allows the user to define four kWh consumption ranges with specific $/kWh rates. For example, $0.20/kWh for 0-10,000 kWh of consumption, $0.15/kWh for 10,000-100,000 kWh of consumption, etc.
Customer Avoided Demand Charges	Demand charges the customer avoids due to decreased peak customer demand resulting from renewable energy self-consumption.
Lost Customer Minimum Charge	In the event customer's renewable energy systems are able to offset electric purchases completely, the customer must still pay a minimum monthly charge to the utility. In that situation, this is a cost to the customer and a benefit to the utility.
Utility Tariff Rate Payments	Payments made by the utility to the customer to purchase electricity generated by renewable energy systems. Rates for each project type can either be cost-based rates or based on fuel rate scenarios (with three possible scenarios).
Avoided Utility Capacity Investments	Capacity investment costs the utility avoids due to decreased demand resulting from renewable energy generation.

Cost/Benefit	Description
Avoided Utility Transmission and Distribution Investments	Transmission and distribution investment costs the utility avoids due to decreased demand resulting from renewable energy generation.
Other Avoided Utility Generation Costs	Generation costs (such as O&M) the utility avoids due to decreased fossil fuel-based generation.
Rate Reduction Bond Payments	A $/kWh payment to the utility similar to fuel charge. Customers must still pay this charge at pre-project levels after they have installed the project.
Administrative Costs	Administrative costs the utility accrues to develop and manage the RESG program.
Customer Interconnection Fees	Fees the customer pays to the utility to enable connection between the renewable energy system and the grid.
Customer Capital Costs	Capital costs paid by the customer to purchase and install all necessary equipment for the renewable energy system.
Customer Loan Payments	Payments made by program participants to finance the DEG systems.
Customer Replacement Costs	Costs paid by the customer to replace components of the renewable energy system. This model allows for four replacement costs to occur in any single year throughout a system's lifetime.
Customer O&M Costs	O&M costs paid by the customer to maintain the renewable energy system at operating conditions.
Avoided Social Cost of Carbon	The value of the avoided carbon emissions resulting from the offset of electricity generation from the utility's fuel generators with renewable energy generation through renewable energy.
Avoided Customer Generator Use	The avoided cost of running emergency generators in the event of system outages. Renewable energy systems are able to supplement the operation of generators in times of system outages, avoiding generator fuel costs. These avoided costs are only attributed when projects have storage systems.

4.6.1 CASHFLOWS ANALYZED AND ASSIGNED TO COST TESTS

URCA is proposing this cost-effectiveness analysis as analyzed from the various cost and benefit cashflows which was discounted to current dollars through various test specific discount rates. A project is considered cost-effective from a particular perspective when the associated test's benefit-cost ratio is greater than 1 or when the net benefits are positive. The various cashflows analyzed in the policy-cost tool are summarized across the entire project's lifetime. These cashflows are presented in Table 13, below.

Table 13. Cashflows Assigned to Cost-Benefit Tests

Cashflow	Participant Cost Test		Utility Cost Test		Jurisdiction-Specific Cost Test		Ratepayer Impact Cost Test	
	Cost	Benefit	Cost	Benefit	Cost	Benefit	Cost	Benefit
Utility Total Avoided Fuel Cost						X		X
Customer Total Avoided Fuel Cost		X						
Customer Avoided Retail Rate Payments		X					X	

Cashflow	Participant Cost Test		Utility Cost Test		Jurisdiction-Specific Cost Test		Ratepayer Impact Cost Test	
	Cost	Benefit	Cost	Benefit	Cost	Benefit	Cost	Benefit
Customer Avoided Demand Charges		X					X	
Lost Customer Minimum Charge	X							
Utility Tariff Rate Payments		X					X	
Avoided Utility Capacity Investments				X		X		X
Avoided Utility Transmission and Distribution Investments				X		X		X
Other Avoided Utility Generation Costs				X		X		X
Rate Reduction Bond Payments	X							X
Administrative Costs			X		X		X	
Customer Interconnection Fees	X							
Customer Capital Costs	X				X			
Customer Loan Payments	X				X			
Customer Replacement Costs	X				X			
Customer O&M Costs	X				X			
Avoided Social Cost of Carbon						X		
Avoided Customer Generator Use		X				X		

Consultation Question 9

Stakeholders are invited to provide comments on the proposed Benefit-Cost Effectiveness Tests outlined above. Comment on its appropriateness and adequacy

URCA proposed Policy Scenario

The policy-cost tool allowed URCA to test the cost-effectiveness of various policy design options by varying both the customer compensation type and compensation rates. To design policy options, URCA can vary how each project is compensated, either through a Net-Billing or a Buy-All/Sell-All arrangement. Additionally, URCA can define if projects are compensated at prevailing fuel rates or through cost-based rates. To aid URCA in its decision to determine a cost-effective tariff for the RE programs designs, Cadmus modelled six policy scenarios:

1. The current RESG policy design[28]: hybrid compensation arrangement at prevailing fuel rates
2. An adjusted RESG policy design: hybrid compensation arrangement at prevailing fuel rates and a cost-based rate

[28] The RESG policy is currently designed to compensate projects between 100kW and 500kW through a Net-Billing arrangement, and projects over 500kW up to 1,000kW through a Buy-All/Sell-All arrangement. Compensation rates for customer-generated electricity is set at the prevailing fuel rate.

3. Alternate Policy Design Scenario 1: Buy-All/Sell-All arrangement with a cost-based rate and no storage systems
4. Alternate Policy Design Scenario 2: Net-Billing arrangement with compensation at prevailing fuel rates and no storage systems
5. Alternate Policy Design Scenario 3: Net-Billing arrangement with compensation at prevailing fuel rates with storage systems
6. Alternate Policy Design Scenario 4: Buy-All/Sell-All arrangement with a cost-based rate with storage systems

Cadmus modelled the cost effectiveness of the policy options using project-specific cost and performance data, as well as utility-area specific inputs, including fuel rates and electric rates. Other model inputs included the utility system load shape (used to calculate peak impacts), cost of carbon assumptions, utility system outage and avoided generator use costs, inflation rates, utility assumptions about rate increases, fuel cost projections, and others. Information about key data inputs can be found in the Annex I - IV.

While all model inputs are important, some of the most critical model inputs are the utility rates, utility fuel costs, and participation assumptions. Some of these key assumptions are described here, as they are major drivers of the cost-effectiveness results and are the source of some of the differences between the cost effectiveness results for BPL and GBPC.

4.6.1 Fuel Cost Assumptions

Cadmus received historical fuel cost data from BPL and GBPC. Cadmus used this historical data to estimate low, high, and base fuel cost scenarios. For the low-cost scenario, Cadmus used the historical low cost, the historical high for the high-cost scenario, and the most recent cost for the base scenario. To capture year-on-year variability Cadmus used historical data to include the actual changes in fuel price. For BPL, the base scenario was escalated based on BPL's projections, and for GBPC, the base scenario was escalated based on inflation. As shown in Figure 1, below, BPL had higher fuel costs than GBPC. Avoided fuel costs is a key driver of cost effectiveness in all policy scenarios. From the participant perspective, avoided fuel costs are a significant driver of cost-effectiveness in a Net-Billing arrangement, and from a regulator and ratepayer perspective, avoided fuel cost is a major driver of cost-effectiveness in all policy scenarios. The different cost effectiveness outcomes for BPL and GBPC demonstrate the model's sensitivity to the fuel cost input.

4.6.2 Cost-Based Rates

Cadmus used cost-based rates calculated with project-specific data to conduct the cost-effectiveness analysis for various scenarios (details on how these were calculated are included in Section 3 Renewable Energy Rate-Setting.

4.6.3 Electric Rates

Avoided customer electric rates are another key driver of cost-effectiveness outcomes from a participant and ratepayer perspective[29]. Avoided electric rates are a key driver for participant cost-effectiveness (under a Net-Billing arrangement) and for ratepayers.

[29] Other components of electric rates include demand charges and minimum monthly charges. The rate components are not itemized here because they have a smaller cashflow impact than variable electric rates.

4.6.4 Participation Assumption

To model cost effectiveness, Cadmus assumed that the total electric production of participation projects would equal approximately 10% of the total utility load as specified in the RESG[30]. With this target in mind, Cadmus assumed individual project participation as illustrated in Table 17, below.

Table 17. Participation Assumption

Scenarios	Small Solar PV - 150kW	Small Solar PV - 150kW w/ Battery	Medium Solar PV - 300kW	Medium Solar PV - 300kW w/ Battery	Large Solar PV - 750kW	Large Solar PV - 750kW w/ Battery	Onshore Distributed Wind - 750kW
Without storage	20		20		8		2
With Storage	10	10	10	10	4	4	2

While Cadmus assumed the system developments as shown in Table 17, this assumption represents a theoretical maximum participation level. Actual participation levels would increase over time, and likely be lower than the modelled assumption at the onset of any policy regime. Lower participation levels would have lower impacts on customer electric rates.

4.7 URCA PROPOSED POLICY SCENARIOS COST EFFECTIVENESS RESULTS: BPL

Cadmus assessed the cost effectiveness for six policy scenarios from the perspective of the regulator (Jurisdiction-Specific Test), the utility (Utility Cost Test), the project developer (Participant Cost Test), and the ratepayer (Ratepayer Impact Test) for the Bahamas Power and Light Company (BPL). Cadmus also calculated the average rate increase and average bill increases under each policy scenario.

Every scenario is cost-effective from the regulatory perspective, which considers high-level policy goals and a comprehensive list of cost and benefits (as shown in Table 13). The figure does not show the results of the Utility Cost Tests because the results of this test were extremely cost effective (the benefit-cost ratio exceeded 78) because of limited cost that were assessed and favorable benefits regarding avoided operations and maintenance costs of existing generators.

Subsequent tests explore the key drivers impacting cost effectiveness for each test in detail. In summary, key drivers of cost effectiveness include the following:

- If a rate is a cost-based rate, which is higher than the cost of fuel, the policy is more expensive from a ratepayer perspective because the cost of developing distributed renewable energy is more expensive than operating and supplying fuel for existing generators.

[30] Cadmus chose to approximate the total RESG-allowed development, under the current policy framework. Utility Regulation and Competition Authority. 28 February 2020. Guidelines for the Approval of Renewable Energy Self-Generation Projects Small Commercial and Government. Statement of Results and Final Decision. https://www.urcabahamas.bs/wp-content/uploads/2020/03/Statement-of-Results-and-Final-Decision-on-Renewal-Energy-Self-Generation-Projects-ES-03-2020.pdf

- In a Buy-All/Sell- All policy with cost-based rates, the participants cost effectiveness benefit-cost ratio will equal one, because the rates are set to ensure that developers earn exactly a twelve percent return on their investment. This expected return is factored into the cost effectiveness analysis.
- Due to the high level of self-consumption of project-generated energy by participants under Net-Billing policies, projects are cost effective for participants, even when the utility purchases project-generated energy at fuel rates. This occurs because customers can avoid significant utility energy costs under Net-Billing arrangements. However, when projects include energy storage in a Net-Billing arrangement, projects are not cost effective due to the high costs of energy storage.
- From a regulatory perspective, all policies are cost effective, given the multitude of benefits, including avoided fuel costs and avoided costs of carbon.
- From a utility perspective all scenarios are very cost effective. This is because only costs associated with program administration are assigned to the test, whereas the benefits of non-fuel avoided generation variable costs are significant.

4.7.1 BPL BAU[31] Scenario: Current Policy Design

The current RESG policy design was modelled using the policy tool provided by Cadmus. The analysis showed that this policy design was cost effective from the regulator, utility, and ratepayer perspectives, but not cost effective from the participant perspective.

Large, avoided utility fuel costs drove the positive cost effectiveness results for the Jurisdiction-Specific and Ratepayer Impact Tests, while non-fuel avoided generation benefits drove the cost effectiveness of the Utility Cost Test. From a participant perspective the policy design is not cost effective overall, however, because large capital costs cannot be overcome with a rate based on the fuel rate under a Buy-All/Sell-All policy. While the policy design is not cost effective overall for participants, those projects that are able to participate in a Net-Billing policy see cost effective results.

Table 19 shows the benefit-cost ratios for each of the tests, indicating that the current policy design is cost effective from a regulator, utility, and ratepayer perspective. However, the policies are not cost effective from a participant perspective.

Table 19. Benefit-Cost Ratios for Current RESG Policy Scenario (BAU)

Fuel Rate Scenario	Jurisdiction-Specific Test	Utility Cost Test	Participant Cost Test	Ratepayer Impact Test
Low Fuel Rate	1.51	78.10	0.87	1.21
Base Fuel Rate	1.56	78.10	0.90	1.22
High Fuel Rate	1.60	78.10	1.00	1.25

[31] BAU- Business As Usual

4.7.2 BPL BAU Scenario-Adjusted: Current Policy Design with Modification

Cadmus also modelled the cost effectiveness of the current RESG policy design with the modification that a cost-based rate is offered to participants in the Buy-All/Sell-All policy component. The analysis showed that this policy design was cost effective from the regulator, utility, and participant perspectives, but not cost effective from the ratepayer perspective. Table 22 shows the benefit-cost ratios for each of the tests, indicating that the current policy design is cost effective from a regulator, utility, and participant perspective. However, the policies are not cost effective from a ratepayer perspective under low and base fuel rate scenarios.

Table 22. Benefit-Cost Ratios for Modified RESG Policy Scenario (BAU-Adjusted)

Fuel Rate Scenario	Jurisdiction-Specific Test	Utility Cost Test	Participant Cost Test	Ratepayer Impact Test
Low Fuel Rate	1.51	78.10	1.06	0.93
Base Fuel Rate	1.56	78.10	1.07	0.97
High Fuel Rate	1.60	78.10	1.12	1.04

4.7.3 BPL Scenario 1: Buy-All/Sell-All with Cost-Based Rate

Cadmus modelled cost effectiveness of Buy-All/Sell-All policy where the utility would purchase renewable electricity generated by the project and fed into the grid at cost-based rates. The analysis showed that this policy design was cost effective from the regulator, utility, and participant perspectives, but not cost effective from the ratepayer perspective. Table 25 shows the benefit-cost ratios for each of the tests, indicating that the current policy design is cost effective from a regulator, utility, and participant perspective. However, the policy option is not cost effective from a ratepayer perspective.

Table 25. Benefit-Cost Ratios for Scenario 1 (Buy-All/Sell All w Cost-based rate)

Fuel Rate Scenario	Jurisdiction-Specific Test	Utility Cost Test	Participant Cost Test	Ratepayer Impact Test
Low Fuel Rate	1.51	78.10	1.00	0.73
Base Fuel Rate	1.56	78.10	1.00	0.76
High Fuel Rate	1.60	78.10	1.00	0.83

4.7.4 BPL Scenario 2: Net-Billing with Fuel Rate

Cadmus modelled cost effectiveness of Net-Billing arrangement where the utility would purchase the renewable electricity generated by the project and fed into the grid at the utilities fuel rate. The analysis showed that this policy design was cost effective from the regulator, utility, and participant, and ratepayer perspectives. Table 28 shows the benefit-cost ratios for each of the tests, indicating that the current policy design is cost effective from a regulator, utility, participant, and ratepayer perspective.

Table 28. Benefit-Cost Ratios for Scenario 2 (Net-Billing w Fuel Rate)

Fuel Rate Scenario	Jurisdiction-Specific Test	Utility Cost Test	Participant Cost Test	Ratepayer Impact Test
Low Fuel Rate	1.51	78.10	1.08	1.34
Base Fuel Rate	1.56	78.10	1.11	1.39
High Fuel Rate	1.60	78.10	1.20	1.48

4.7.5 BPL Scenario 3: Net-Billing with Fuel Rate and Storage Projects

Cadmus modelled cost effectiveness of Net-Billing policy where the utility would purchase renewable electricity generated by the projects fed into the grid at fuel rates. Whereas this policy as modelled in Scenario 2 did not include battery storage projects, this scenario includes an assumption that some battery storage projects would be deployed. The analysis showed that this policy design was cost effective from the regulator, utility, and ratepayer perspectives. The policy was not, however, cost effective from the participant perspective. Table 31 shows the benefit-cost ratios for each of the tests, indicating that the current policy design is cost effective from a regulator, utility, and ratepayer perspective, but not cost effective from the participant perspective.

Table 31. Benefit-Cost Ratios for Scenario 3 (Net-Billing w Fuel Rate and Storage Projects)

Fuel Rate Scenario	Jurisdiction-Specific Test	Utility Cost Test	Participant Cost Test	Ratepayer Impact Test
Low Fuel Rate	1.15	78.16	0.81	1.37
Base Fuel Rate	1.19	78.16	0.83	1.42
High Fuel Rate	1.22	78.16	0.90	1.52

4.7.6 BPL Scenario 4: Buy-All / Sell-All with Cost-Based Rate and Storage Projects

Cadmus modelled cost effectiveness of Buy/All-Sell/All policy where the utility would purchase renewable electricity generated by the project and fed into the grid at cost-based rates. Whereas this policy as modelled in Scenario 1 did not include battery storage projects, this scenario includes an assumption that some battery storage projects would be deployed. The analysis showed that this policy design was cost effective from the regulator, utility, and participant perspectives. The policy was not, however, cost effective from the ratepayer perspective. Table 34 shows the benefit-cost ratios for each of the tests, indicating that the current policy design is cost effective from a regulator, utility, and ratepayer perspective, but not cost effective from the participant perspective.

Table 34. Benefit-Cost Ratios for Scenario 4 (Buy-All/Sell-All w Cost-Based Rate and Storage Projects)

Fuel Rate Scenario	Jurisdiction-Specific Test	Utility Cost Test	Participant Cost Test	Ratepayer Impact Test
Low Fuel Rate	1.15	78.10	1.00	0.54
Base Fuel Rate	1.19	78.10	1.00	0.57
High Fuel Rate	1.22	78.10	1.00	0.61

4.7.7 URCA's summary from Cost Effectiveness Scenarios

The current RESG policy design is likely not attractive for larger projects that are compensated at fuel rates under a Buy-All/Sell-All arrangement.

While the current RESG policy design is cost effective for smaller projects that can offset significant electric purchases with self-generated energy, the current design is likely insufficient to attract participation for larger projects that are not able to offset electric purchases and are compensated at a fuel rate, which is insufficient to cover project development expenses and provide system owners with the required rate of return.

A Buy-All / Sell-All arrangement with cost-based rates (Scenario 1) trades participant certainty for rate impacts.

A Buy-All / Sell-All arrangement with cost-based rates may offer certainty to project investors that they will cover project expenses and earn a return on investment, but ratepayers will purchase solar PV electricity that is more expensive than the existing generation, which will increase electric rates.

A Net-Billing arrangement with rates based on prevailing fuel rates (Scenario 2) is cost effective for all stakeholders except GBPC ratepayers. However, the cost effectiveness for participants (project investors) is primarily based on considerable offset electric purchases resulting from high self-consumption.

While a Net-billing arrangement at a fuel rate may be attractive for some utilities based on their avoided costs, the cost effectiveness for project participants is heavily dependent on offset electric purchases (high self-consumption). If self-consumption is lower than modelled, cost effectiveness for participants will decrease. Furthermore, project investors may require additional investment security and certainty from a fixed rate to spur investment.

Battery storage costs are likely prohibitively expensive for participants and ratepayers.

The very high capital costs of battery storage systems make their deployment not cost effective for participants under a Net-Billing arrangement with fuel rates. While the cost effectiveness test for battery storage systems includes the benefit of avoided generator usage and cost during outages, this additional benefit is not sufficient to make storage systems cost effective.

If a utility were to cover project development costs through a cost-based rate that guarantees a financial return on battery storage projects, the impact on ratepayers would, however, be significant.

The economics of solar systems with battery storage are highly site and project specific. This analysis includes the additional resiliency benefit of offset generator costs. Other resiliency benefits are likely for investors, the utility system, and society. However, there are no industry accepted methodologies for valuing these additional resiliency benefits within a program cost effectiveness modelling exercise. Valuing these additional resiliency benefits would require a site-specific analysis.

A Buy-All/Sell-All arrangement with a cost-based rate will have some degree of ratepayer impact. However, the magnitude of the impact is dependent on the cost-based rate and level of program participation. To model and compare the cost effectiveness of the different scenarios, Cadmus assumed the RESG program was fully subscribed with all participants receiving the cost-based rate based on the rate-setting results. In more realistic circumstances, it would take time for the RESG program to be fully subscribed and it is possible that the rate may be adjusted in a future review cycle before the program reaches its capacity cap, meaning that the ratepayer impact may be less than the result of the current modelling exercise. URCA can monitor and manage ratepayer impact by tracking program participation and adjusting the rate as market conditions evolve

In moving forward with determining a revised policy design for the RESG, it will be critical to consider which trade-offs are acceptable in order to move forward with the overall policy goals of the RESG. URCA considered the following key questions when assessing policy options: how attractive does the policy have to be for participants to spur development? What level of rate impacts are acceptable and sustainable? And what is the right balance to strike fairness for all stakeholders without negatively impacting ratepayers. This being the case, URCA is proposing the following RE policy design outlined in Table 35.

Table 35: Renewable Energy Self-Generation Policy Design Elements

Policy Design Element	SSRG Policy	RESG Policy
Eligible Technologies	Solar PV & Wind	Solar PV & Wind
Eligible Size Range	0kW - 100kW	101kW – 1MW
Eligible Customers	Residential	Commercial and Government
Treatment of Electricity Generated	• 101kW – 500kW: net-billing	• 101kW – 500kW: net-billing • 501kW – 1MW: net-billing
Payment / Compensation Rate	Compensation at a rate per kWh equivalent to avoided fuel cost of Public Electricity Supplier (PES)	Compensation at a rate per kWh equivalent to avoided fuel cost of Public Electricity Supplier (PES)
Payment Structure	Variable. Will vary with the PES' cost of fuel.	Variable. Will vary with the PES' cost of fuel.
Program Cap	Total installed capacity no more than 10% of generation capacity of respective Public Electricity Supplier	Total installed capacity no more than 10% of generation capacity of respective Public Electricity Supplier
Interconnection and System Upgrade Costs	Renewable energy generator assumes responsibility for interconnection and system upgrade costs	Renewable energy generator assumes responsibility for interconnection and system upgrade costs
Contract Duration	15 years	15 years
Periodic Review of Rates and Program Cap	Not determined	Bi-annually or when PES or Utility cost test is less than 1, that is when Benefit-Cost is less than 1

Consultation Question 10

Do you agree with URCA proposed Renewable Energy Self-Generation Policy Design Elements? And do you agree with the proposed policy trade-offs? Provide comments with reasons and explanations

5 CONCLUSION AND NEXT STEPS

1. For this consultation, URCA maintains the view that it is not necessary to revisit or make decisions on all program design elements already determined by URCA, namely the RESG and SSRG. URCA is seeking to determine the best economic cost-effectiveness tariff which balances the interest of all stakeholders and is therefore seeking comments on the alterative tariff proposals outlined herein.

2. **Revise draft proposal** - URCA will revise the tariff proposal based on stakeholder comments and feedback, update the input assumptions and re-run the rate-setting model as well as the cost-effectiveness model.

3. **Final written consultation** – URCA will prepare a final draft of the cost-effectiveness tariff updated with revised assumptions as necessary, for written comment from stakeholders; incorporate final feedback and publish the final decision on the RESG and SSRG program.

Annex I : Data Collection from Stakeholders

Cadmus developed a survey to collect data on costs of generation for solar PV, wind and battery energy storage systems. Cadmus also developed a utility data request memo to collect data needed to conduct the benefit-cost assessment.

URCA shared the survey and/or the utility data request memo was shared with the following institutions:

- Compass Power
- Alternative Power Supplies Limited
- Sustainable Energy Limited
- RBC Royal Bank Limited
- Ministry of Agriculture & Marine Resources
- Bahamas Energy Solar Supplies Limited
- Bahamas Society of Engineers & Flameless Electrical Contracting
- Rocky Mountain Institute
- CARILEC
- Bahamas Chamber of Commerce
- Bahamas Power & Light Company
- Gekabi Chub Cay Utilities Limited
- Grand Bahama Power Company Limited
- RAV Bahamas Limited
- St. George's Cay Power Company Limited

Furthermore, the Bahamas Chamber of Commerce shared the survey with an additional list of institutions (not named).

Cadmus received information directly (via interviews, e-mails, and/or data files) from the following institutions:

- Rocky Mountain Institute
- Bahamas Society of Engineers & Flameless Electrical Contracting
- Bahamas Power & Light Company
- Grand Bahama Power Company Limited

All other data sources were supplemented and/or benchmarked against regional and international data sources, as detailed in Section 1.3.

Annex II: Cost-Effectiveness Input Assumptions

This annex provides information about the various model input assumptions used to estimate the cost effectiveness of various policy scenarios. This annex does not include assumptions for project costs, which are described in Section 1, above.

Table 44. Data for BPL and GBPC Electric Rates

Utility	Rates Class	Participation Assumption	Tier	$/kWh
GBPC	Commercial Service	Small and Medium Projects	Tier 1	$0.196
	Commercial Service	Small and Medium Projects	Tier 2	$0.182
	Commercial Service	Small and Medium Projects	Tier 3	$0.168
	General Service	Large Projects	Tier 4	$0.112
	General Service	Large Projects	Tier 1	$0.168
	General Service	Large Projects	Tier 3	$0.140
	General Service	Large Projects	Tier 2	$0.154
BPL	General Service	All Projects	Tier 1	$0.087
	General Service	All Projects	Tier 2	$0.062

Table 45. Data for BPL and GBPC Demand Charges

Utility	Rates Class	Participation Assumption	$/kVA
GBPC	Commercial Service	Small and Medium Projects	$9.11 (if demand more than 5 kVa)
	General Service	Large Projects	$9.11 (if demand more than 1,000 kVa)
BPL	General Service	All Projects	$6.20

Table 46. Data for BPL and GBPC Minimum Charges

Utility	Rates Class	Participation Assumption	$
GBPC	Commercial Service	Small and Medium Projects	$45.55
	General Service	Large Projects	$9,110
BPL	General Service	All Projects	$568

Data for Utility Avoided Capacity and Transmission and Distribution Investments

Cadmus used the GBPC utility load shape (BPL did not provide a load shape so Cadmus normalized the GBPC load shape for BPL using BPL total electric sales) to assess the benefits of avoided capacity and avoided transmission and distribution system investments.

To assess the benefits, Cadmus calculated the overall system peak reduction resulting from solar production. Because the GBPC system load experiences its annual peak at 8 pm in September, there is no solar PV production that is coincident with this peak, even when including timing offsets from storage projects. Therefore, the overall peak reduction benefits are minimal. If a different load shape provides more significant peak reduction estimates, Cadmus has provided a per MW peak energy-reduced benchmark. This benchmark is sourced from Hawaii, which, as an island grid, has similar generation and transmission and distribution characteristics. These benchmarks are a peak reduction benefit of $85,000 per MW of peak reduced for deferred capacity investments, and $20,000 per MW for deferred transmission and distribution investments. Source: Hawaii Energy Policy Forum. University of Hawaii. Best Practices to Value Benefits of Renewable Energy Development in Hawai'i. June 2015. P. 32.

Data for Other Avoided Utility Generation Costs

To estimate the avoided cost of operating generation plants (non-fuel costs), Cadmus used data from the Jamaica Integrated Resource Plan (IRP). The Jamaica IRP estimated fossil fuel generation operations and maintenance costs at $0.0117/kWh. (Source: Ministry of Science, Energy, and Technology.

Integrated Resource Plan: A 20 Year Roadmap to Sustain and Enable Jamaica's Electricity Future. January 2020. P. 147).

Data for RESG Policy Administrative Costs

To calculate the cost of administering the RESG program, Cadmus used information provided by BPL (GBPC did not provide this information, so Cadmus used BPL data for GBPC). BPL estimated that policy administrative costs were $875 per participant in the first year.

Data for Avoided Cost of Carbon

Cadmus calculated the avoided cost of carbon based on data from BPL and the United States Environmental Protection Agency (EPA). BPL provided an estimate of barrels of fuel per kWh, which Cadmus used to translate avoided kWh generation into avoided barrels of fuel. This estimate was 0.0019 barrels per kWh. To estimate avoided carbon, per barrel of fuel Cadmus used the EPA's estimate of 0.43 metric tons per barrel of fuel oil. (Source: EPA Greenhouse Gases Equivalency Calculator – Calculations and References: www.epa.gov/energy/greenhouse-gases-equivalencies-calculator-calculations-and-references).

To calculate the cost of avoided metric tons of carbon, Cadmus used the EPA's "Carbon Fact Sheet". According to data from this fact sheet, the 2021 cost of carbon was $60.58 per metric ton. (Source: www.epa.gov/sites/production/files/2016-12/documents/social_cost_of_carbon_fact_sheet.pdf)

Data for Avoided Customer Generator Use

Cadmus used several data inputs to estimated avoided generator costs. These included system outage data, the percentage of customers with backup generators, the generator size, and usual operation of the generator, and the cost of diesel fuel. Additionally, several generator performance metrics were used.

System outage data were provided by BPL and GBPC (confidential for GBPC). BPL estimates that the total average customer duration of an outage was 2.5 hours per year. Cadmus assumed that 60% of commercial customers had backup generators (Source: World Bank Enterprise Survey for the Bahamas: www.enterprisesurveys.org/en/data). Cadmus used a per gallon of diesel fuel cost of $1.39 (Source: BPL). Cadmus assumed that generators would be sized to cover an entire customer's load in the event of an outage. To estimate fuel consumption of generators by size Cadmus relied on industry data (Source: www.generatorsource.com/temp/Fuel_Consumption_Chart.pdf)

Annex III : CUSTOMER ELECTRICITY CONSUMPTION INPUT ASSUMPTIONS

To make estimates on customer electricity consumption, Cadmus used data from a study conducted in 2010 by a consultancy company called Fichtner. The analysis was conducted in collaboration with BPL using the electrical demand data of The Bahamas. As a proxy for the commercial sector, the study gathered data on hotel electricity consumption. The data is cited in a secondary feasibility study;[32] the original report from Fichtner was not found.

Table 48. Source Data on Customer Electricity Consumption for Hotels in The Bahamas

Hotel Size Classification	# Of Rooms	Average Annual Electricity Demand per Hotel (MWh)
Large	350+	~19MWh
Mid-Sized	50 - 350	~2.5MWh
Small	<50	~0.5MWh

Representative project sizes were then matched to hotel electricity consumption profiles based on possible, realistic matches between the annual electricity yield of a representative renewable energy project and annual electricity demand from the representative hotel profile.

Table 50. Assumptions on Customer Electricity Consumptions for Representative Project Sizes

Representative Renewable Energy Project Size (kW)	Calculated Annual Project Electricity Yield (MWh)	Hotel Profile Used for Input Assumptions
750kW	**~1.2**	**Mid-Sized Hotel**
300kW	**~0.5**	**Small Hotel**
150kW	**~0.25**	**Small Hotel**

[32] http://www.esru.strath.ac.uk/Documents/MSc_2015/Cassar.pdf

Annex IV BATTERY ENERGY STORAGE SYSTEM INPUT ASSUMPTIONS

Table 51. Battery Energy Storage System Assumptions

Representative Project	150kW solar PV + storage	300kW solar PV + storage	750kW solar PV + storage
RE Project Installed Capacity (kW)	150	300	750
Battery Size (kWh/kW)	318 / 72	318 / 72	1,505/ 227
Round-Trip Efficiency	90%	90%	90%
Battery Cost per Energy Size ($/kWh)	$834	$834	$834
Battery Cost per Power Size/ Inverter ($/kW)	$1,587	$1,587	$1,587
Battery O&M ($/kW/year)	$8	$8	$8
Rate-Setting Tool Result	**~$0.47**	**~$0.32**	**~$0.46**

Annex V RENEWABLE ENERGY POLICY DESIGN ELEMENTS

Design Issue	Description
Policy Targets	Does the policy specifically link to existing renewable energy targets?
Eligibility	Technologies, project sizes, ownership models (e.g., community owned)
Treatment of RE Electricity	Consume on-site, export excess. Buy-all/Sell-all. Hybrid
Tariff Differentiation	Technology, size, location (e.g., ground-mounted, car port, brownfield, floating etc.)
Payment Rate	Administratively or competitively. Value based or Cost based?
Payment Structure	Fixed, tiered, or variable
Payment Duration	Time period of payment. Usually in years.
Cap & Review	Is there a cap on the amount of capacity that can connect to the grid? How often will the policy and tariff rate be reviewed and revised?
Interconnection Standards and Guarantees	What interconnection standards are required?
Interconnection and Metering costs	Who is responsible for the interconnection and metering costs? Upgrades?
Purchase and dispatch	Is the generated power purchased and dispatched by the utility?
Commodities Purchased	Who owns the environmental attributes of the project? Are they purchased? What is the value?
Amount Purchased	How much of the generation is purchased?
Contract Issues	Is there a standard contract?
Payment Currency	What currency is the payment in?
Purchasing Entity	Who is responsible for purchasing the power?
Cost Recovery	How will any costs incurred from implementing the policy be recovered?
Transition	What happens to generators that are already a part of the existing program? Grandfathered or Voluntarily opt-in or both?