FAIR TRADING COMMISSION

DECISION

On

Feed-in-Tariffs for Renewable Energy Technologies Above 1MW and up to 10MW

Document No.: FTCUR/DECFIT1-10MW/2022-14 **Date of Issue: December 31, 2022**

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DOCUMENT TITLE: Decision on Feed in Tariffs for Renewable Energy Technologies above 1MW and up to 10MW

ANTECEDENT DOCUMENTS

Document Number	Description	Issue Date
FTC/URD/CONFIT - 2019-03	Consultation Paper on Feed-in-Tariffs for Renewable Energy Sources	29 May, 2019
FTCUR/DECFIT/2019- 04	Decision on Feed in Tariffs for Renewable Energy Technologies up to and Including 1MW	24 August, 2019
FTCUR/CONS/FIT1-10MW/2022-07	Feed in Tariffs for Renewable Energy Technologies Above 1MW and up to 10 MW	13 July, 2022
FTCUR/DECFIT/2022-02	Decision on Feed in Tariffs for Renewable Energy Technologies between 1MW and 10MW	September 30, 2022

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LIST OF ABBREVIATIONS

AC	Alternating Current
BLPC	Barbados Light & Power Company Limited
BNEP	Barbados National Energy Policy
COD	Commercial Operation Date
ELPA	Electric Light and Power Act, 2013-21
FCA	Fuel Clause Adjustment
FIT	Feed-in-Tariff
FTC	Fair Trading Commission
FTCA	Fair Trading Commission Act CAP. 326C of the Laws of Barbados (as amended)
GoB	Government of Barbados
IPP	Independent Power Producer
KV	Kilovolt
KWh	Kilowatt Hour
KWp	Kilowatt Peak
LCOE	Levelised Cost of Energy
MW	Megawatt
NDC	National Determined Contributions
PV	Photovoltaic
RE	Renewable Energy
REC	Renewable Energy Credit
The Commission	The Fair Trading Commission
URA	Utilities Regulation Act CAP. 282 (as amended)

SECTION 1 DECISION SUMMARY

The GoB expects an economy driven by 100% RE by 2030. This thrust towards the exploitation of RE indigenous resources is set out in the BNEP. FIT programmes were adopted as a vehicle to accelerate the deployment of RE projects and expand the RE sector. The targeting of utility scale RE projects sized above 1 MW and up to 10 MW under a FIT regime was accepted by stakeholders as an approach to achieve cost effective electricity prices and provide investment opportunities. In light of the current volatility in prices and market conditions observed during the review process and based on the FITs determined for new participants in the RE market and the impact of these rates on customer electricity prices, the FITs herein shall remain in place for one year with respect to this 2023 FIT programme:

I **The dates of the commencement and termination of the FIT programme shall be January 1, 2023 and December 31, 2023, respectively. All applicable technology project categories, rates, and assigned capacity for systems sized above 1 MW and up to 5 MW as set out in paragraph IV, shall remain in place for a full 12 months of the programme. A review of this segment of the programme shall be undertaken at least 3 months before the expected termination date or when the allocated capacity of 40 MW is exhausted. For RE technologies over 5 MW and up to 10 MW in size, the rates, terms and conditions for this segment of the programme shall remain in place for seven (7) months from the January 1, 2023 and conclude on July 31, 2023 or until a competitive procurement framework is established.**

II **All terms for FITs procured under this decision shall remain constant for the duration of the 20-year contract.**

III **The FIT determined for the technology classes were derived via the LCOE methodology and utilised the multi-criteria approach expressed in the BNEP document. Rates are differentiated by technology and size and shall be based on a fixed 20-year term with no front-loading. These details are captured in the Table following.**

Fit Policy Design

FIT Policy Element	RE Systems above 1 MW up to and including 10 MW
Proposed Effective Date	January 1, 2023
Rate: Fixed, Tiered or Variable Options	Fixed
Rate: Differentiated by Technology & Size	Yes
Tariff Duration	20 years
Administratively-Determined or Competitively-Bid	Administratively-Determined
Presumed Off-taker	BLPC
Quantity Covered by FIT	100% of output

IV The applicable categories, rates and capacity allocation shall be as outlined below:

Technology, Size Category	January 1, 2023 – December 31, 2023 FIT (BDS cents/kWh)	January 1, 2023 – December 31, 2023 FIT (BDS cents/kWh) Allocation (MW)
Solar PV, above 1 MW and up to 5 MW	**26.75**	
Land-based Wind, above 1 MW and up to 5 MW	**26.25**	
Solar PV, above 5 MW and up to 10 MW	**25.25**	
Land-based Wind, above 5 MW and up to 10 MW	**24.25**	
Total Allocation		40

V References to capacity in this Decision means alternating current - AC. Where allocated capacity for any technology category remains unutilised, said capacity shall be transferred from one technology to the other, where applicable.

VI The revenue metering configuration shall be applied in accordance with established prudent industry practice. The billing arrangement adopted shall be applied according to the specificity of the project. Where it is practical to utilise either "Buy all/Sell all" or "Sale of Excess" billing modalities, the appropriate option shall be adopted.

VII **RE procured under this programme shall be purchased at the rates determined herein and shall apply to the applicable FIT agreement.**

VIII **All future and existing RE generators connecting to the 24.9 KV transmission system shall pay the full interconnection cost estimated in the FIT and the cost incurred pursuant to the interconnection agreement.**

IX **Interconnection cost outside of the cost covered in the FIT shall be shared between the IPP and BLPC according to the ratio of 25% / 75% of this cost. This cost includes the cost of the substation, switchgear, cabling, and poles required to interconnect the project. Where a substation facilitates the interconnection of an additional RE generator, the IPP is required to contribute 25% of the cost associated with that interconnection.**

X **All prudent costs of interconnection of transmission RE equipment incurred by the BLPC shall be recovered through an approved appropriate recovery mechanism.**

XI **At the end of the 20-year FIT contract period, a new contract will need to be negotiated based on the existing value of the assets, the avoided cost of fuel or such other factors as may be determined by the Commission, in its sole discretion, at that time.**

SECTION 2 TRANSITIONING TO RENEWABLE ENERGY

2.1 Introduction

The evolving renewable energy sector has been recognised by the GoB as a crucial vehicle to facilitate the transition from a fossil fuel dominated economy to one driven mostly by indigenous RE sources. This thrust towards the target of 100% RE consumption by 2030 is set out in the BNEP. One of the tools which has been implemented to accelerate RE deployment towards the target envisioned is the FIT programmes.

On September 24, 2019, the Commission issued its first Decision on Feed-in-Tariffs for Renewable Energy Technologies up to and including 1MW. This was considered a key step towards expanding the RE sector locally. Given the policy objectives identified in the BNEP, a FIT programme which catered to utility scale[1] type projects was issued to the public on September 29, 2020. The implementation of this programme for solar PV and land-based wind technologies above 1 MW and up to 10 MW was pivotal to further promote RE deployment and obtain cost effective benefits from economies of scale. This FIT programme was scheduled to conclude on March 31, 2022 but was later extended until December 31, 2022 following negative price impacts due to the enduring COVID-19 pandemic.

From July 12 to August 5, 2022 the Commission conducted a public consultation on the above 1MW and up to 10 MW FIT programme. In total the following seven (7) organisations responded to the consultation:

- Barbados Light and Power Company Limited (BLPC)
- Barbados Renewable Energy Association (BREA)
- Blackstone Megawatt Energy
- Haymans Solar Inc
- Pavana Energy Ltd
- Williams Caribbean Capital
- Williams Solar

A summary of responses from the aforementioned organisations is presented in Appendix 1.

The Commission thanks all respondents for their contributions to the Consultation.

[1] Utility scale projects in the local contexts refers to RE technologies 1 MW-AC and above in size.

2.1 Economic Regulator's Role In The Energy Transition

One of the key functions of the economic regulator is to design balanced rates for the RE sector. This task is multifaceted in that the regulator must develop rates that will allow private RE investment to continue to evolve, while ensuring the utility remains financially viable and able to support the energy transition. At the same time, these rates must be such that their impact on the charge consumers are expected to pay for their electricity service will be minimal. The economic regulator's role also includes assisting with the integration of RE to the grid and ensuring that the electricity service provided is safe and reliable. Under the FTCA and URA the Commission is responsible for establishing principles for arriving at rates to be charged by service providers and RE producers as well as determining the maximum rate applicable and set guidelines for any agreements which are entered by RE producers. These tenets are set out in section 4(3) (a) and (b) of the FTCA and section 24B (1)(a) through (d) of the URA, of the Laws of Barbados.

Following is the Commission's determination on RE systems above 1 MW and up to and including 10 MW, taking into the account the capability of the national grid. The objective of this Decision mirrors the multi-criteria approach expressed in the BNEP.

The Commission notes that the adjustments made under this programme took into account the impact of the COVID-19 pandemic on technology prices and it is hoped that the initiatives made under this programme will promote greater uptake of RE online while providing investors with price certainty.

The above 1 MW and up to 5 MW component of the FIT programme shall commence on January 1, 2023 and conclude on December 31, 2023 or conditional on market response to the allocated capacity of 20 MW, while the above 5 MW and up to 10 MW capacity segment of the programme shall continue to be in place until July 30, 2023 or until a competitive procurement framework is in place.

FITs as determined herein were developed based on information from the consultation process and the Commission's own research.

2.2 Submission of RE Project Information to the Commission

The Utilities Regulation Act, CAP 282 (URA) was recently amended to confirm the Commission's authority to set RE rates. The determination of appropriate RE rates is partly influenced by the level of incentive needed to stimulate investment in the sector. The provision of technical and financial project data is expected to play a critical role in price discovery. Under Sections 3 (2A) and 24B (5) of the URA, the Commission is empowered to request information from service providers and RE producers, on their operational, financial, or any information which advances the function of the Commission. During the consultation, information was received from a number of local RE installers and project investors.

SECTION 3 LEGISLATIVE FRAMEWORK

3.1 Legislative Framework

Power to Set Rates

The URA and the FTCA together empower the Commission to set and monitor rates for the supply and distribution of electricity in the RE sector of Barbados. More particularly, pursuant to section 4(3) of the FTCA, the Commission has the responsibility to, inter alia:

> *(a) establish principles for arriving at rates to be charged by service providers and renewable energy producers;*
> *(b) set the maximum rates to be charged by service providers and renewable energy producers;*
> *(c) monitor the rates charged by service providers and renewable energy providers to ensure compliance;*
> *(d) …*

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

> *"The functions of the Commission under this Act are, in relation to service providers, to*
> *(a) Establish principles for arriving at the rates to be charged;*
> *(b) Set the maximum rates to be charged;*
> *(c) Monitor the rates charged to ensure compliance*
> *(d) …."*.

Principles and Rates

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

> *(a) every rate, fare, toll, charge, rental or other compensation of a service provider or renewable energy producer;*
> *(b) a rule, practice, measurement, classification or contract of a service provider or renewable energy producer relating to a rate; and*
> *(c) a schedule or tariff respecting a rate.*

Interconnection Agreements and Agreements to Supply Electricity

Section 24B(1) of the URA sets out the functions of the Commission in relation to a renewable energy producer entering into an interconnection agreement or other agreement to supply electricity to the public grid. These functions are as follows:

(a) establish principles for arriving at the rates to be charged;
(b) set the terms and conditions of the agreements;
(c) set the maximum rates to be charged under the agreements; and
(d) direct renewable energy producers to submit the proposals for the rates and terms and conditions relating to their agreements.

The Commission also has rate-setting functions in relation to the RE producers storing energy produced from RE plants. Section 24B(4) of the URA stipulates that the Commission is required to:

(a) set the maximum rates to be charged; and
(b) establish guidelines for interconnection.

Performance of the Commission's Functions

The Commission, in performing the above functions in respect of agreements to supply electricity (section 24B (1) of the URA) is mandated to consult with interested parties and have regard to certain policies and requirements. Section 24B (2) of the URA in particular states that:

"the Commission shall consult with renewable energy producers, representatives of consumer interest groups and other interested parties and shall have regard to

(a) the national energy policy;
(b) the national environmental policy;
(c) the requirement to promote renewable energy and to enhance the security, affordability, safety and reliability of the supply of electricity."

Subsection 24B(3) of the URA further outlines the Commission's functions as it pertains to the establishment of principles for arriving at the rates to be charged under section 24B(1) of the URA. This section states that the Commission shall have regard to:

(a) the promotion of efficiency on the part of renewable energy producers;
(b) ensuring that an efficient renewable energy producer will be able to finance its

functions by earning a reasonable return on capital;

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

In performing its rate-setting functions under 24B(1) (agreements to supply electricity) and 24B(4) (storage of energy) of the URA, the Commission shall request a renewable energy producer to provide the Commission with information relating to its operations, finances or such other information as the Commission may consider necessary to perform its functions.

The Electric Light & Power Act

The ELPA elaborates on the Commission's functions with respect to interconnection, particularly where agreements are concerned. Section 13(2) (a) (ii) and (iii) of the ELPA stipulates that:

"Interconnection services referred to in subsection (1) shall be

(a) offered at points along the public grid subject to

(ii) such agreement between the parties as may be approved by the Commission for the purpose; and

(iii) the payment of such fee as may be specified by the public utility and approved by the Commission in respect of interconnection; "

Further, section 13(3) of the ELPA states that:

"The public utility shall purchase electricity from a licensee or other person referred to in subsection (1) at such rate as may be agreed by the parties and approved by the Commission".

Additionally, subsection (4) states that:

"Where parties fail to agree on the terms and conditions of an agreement referred to in this section or a dispute arises in respect of such an agreement, any party may, in writing, refer the matter to the Commission for determination".

SECTION 4 FEED-IN-TARIFF DESIGN AND ASSUMPTIONS

4.1 Development of Tariffs

Ratemaking for RE based technologies under this FIT programme was developed from modelling resource based input assumptions in the FTC FIT Model 2019 software. The conceptulisation of tariffs derived for project categories above 1 MW and up to 10 MW relied on a LCOE methodology. Outputs from the FTC Model 2019 were assessed to ensure investors were in a position to meet financial commitments for loans and earn a reasonable return on investments.

The policy objectives and multi-criteria approach as outlined in the BNEP were considered in the ratemaking process. The rationale for applying these concepts is intended to achieve balanced rates for each capacity category of the programme. The following considerations were explored during the ratemaking process:

- Technology, size and application diversity;
- Maximising local participation;
- Affordable energy for consumers;
- Sufficient deployment to meet the 100% RE by 2030 goal; and
- Facilitating effective competition in the market.

The rates as determined also considered the impact of the COVID-19 pandemic on the price movements of RE technologies. RE equipment and transportation prices were monitored periodically to determine when instability in these price movements would improve and an appropriate time to develop new rates that will stimulate the RE sector.

The role of the Commission in the energy transition towards a 100% RE goal remains a more crucial one in balancing the interests of all key actors (customers, investors, Government policy, fuel suppliers, technology suppliers, installers, and the utility) in the evolving RE economy and the attainment of cost effective rates. Additionally, the integration of intermittent RE to the grid and the sustainability of a reliable and resilient electricity service are also important roles for the regulator under the transition. Having considered the aforementioned inputs and objectives applicable to the ratemaking process, the rates depicted in Table 1 are as follows:

Table 1 - Derived FIT

Technology, Size Category	FIT BDS cents/kWh	Term
Solar PV, above 1 MW and up to 5 MW	**26.75**	20 Years
Land-based Wind, above 1 and up to 5 MW	**26.25**	20 Years
Solar PV, above 5 MW and up to 10 MW	**25.25**	20 Years
Land-based Wind, above 5 MW and up to 10 MW	**24.25**	20 Years
Cumulative Cash Flow turns positive for all above systems (payback year) in	Year 7	

4.2 FIT Policy Design Features

The following section outlines the specific characteristics of the FIT design.

Official Commencement and Duration

The effective date of commencement for FITs prescribed to project categories 1 MW and up to 10 MW shall be January 1, 2023. All projects which are eligible for these rates following the issuance of this decision shall be:

- Solar PV and land-based wind projects sized above 1 MW and up to 5 MW for an initial period of 12 months until December 31, 2023. The Commission will monitor the operation of this programme category on a monthly basis to collect appropriate data. At least three (3) months prior to the December 31, 2023 termination date, a full review of the FIT programme shall be undertaken. If the level of RE uptake results in depletion of the FIT programme allocated capacity (40 MW) sooner than the initial 12 months, a review of rates will be conducted by the Commission.
- Solar PV and land-based wind projects sized above 5 MW up to an including 10 MW on programme cycle of seven (7) months up to July 31, 2023 or until such time as a competitive procurement framework is established. Monitoring of the price movements within this segment of the programme will also be ongoing on a monthly basis. Review of this programme category will be contingent on the status of the aforementioned framework or capacity depletion.

The rationale for including this above 5 MW and up to 10 MW category is to promote investment opportunities which will result in cost effective rates that tend to accrue from the economies of scale inherent in projects of this size. Additionally, the retention of the existing capacity bands was considered to be prudent in order to cushion customers from higher prices.

Eligibility Parameters

The acquisition of a licence from the Ministry with responsibility for energy qualifies a project to participate under the FIT programme and benefit from the applicable FIT. This is achieved when a potential candidate submits a complete licence application form via the said Ministry's online portal facility provided for such purposes. Once the submission is accredited, capacity will be allocated to projects on a first come, first served basis until the total allocated capacity (40 MW) has been exhausted.

The determination of the period required from the time of licence to the specific project's COD and extension of licence shall be the stipulated by the said Ministry.

Contract Tenure and Price Structure

All accredited RE projects under this FIT programme shall be eligible for a contract period of 20 years. The propose price of the energy generated from the RE project shall remained fixed for the duration of the contract period. The significance of the long term fixed price seeks to ensure market certainty and investor confidence in the RE sector and achieve sustainability throughout the energy transition.

4.3 Counterparty and Obligation to Purchase

RE systems are expected to be connected to the utility's transmission network. These connections are considered part of the utility's power system and therefore, the BLPC is expected to purchase 100% of all energy that is exported to the national grid i.e. the full amount of the RE generator's output over the life of the 20-year contract.

When RE generators export power to the grid, this produces RECs. These credits represent the environmental and non- power attributes of RE generation for each Megawatt-hour of RE generation delivered to the grid. The GoB being a signatory to the Paris Accord[2], utilises these

[2] This is also known as the Paris Climate Accords which is an international treaty on climate change adopted in 2015. Barbados signed the revised agreement in 22 April, 2016.

RECs in fulfilment of its National Determined Contributions (NDC) under this international treaty. As such, the RECs associated with RE production are therefore the property of the Republic of Barbados and cannot be claimed by any other entity.

4.4 Addressing Counterproductive Issues

Counterproductive issues such as gaming have implications for increasing the cost that customers are expected to pay for the energy consumed as these acts, indirectly shift unequitable power system costs to customers. Given the importance of the transitioning to a 100% RE by 2030, it is the view of the Commission that all stakeholder agencies involved in the decision making processes address the issues of gaming in a collaborative manner. This approach in the Commission's view can be effective in containing power system costs.

4.5 Billing and Compensation Scheme for RE Projects

All revenue metering configurations shall comply with prudent industry practice and where practicable the mode of billing applied shall be in accordance with the specificity of the RE project. The use of either billing regime "Sale of Excess" or "Buy all sell all" modalities for power purchased shall be according to the specificity of the project.

4.6 FIT Agreement

RE purchases for all energy exported to the national grid shall be procured under a Commission approved FIT Agreement between the utility and IPP.

4.7 Interconnection Agreement

Parties (BLPC and IPP) to the FIT Agreement shall comply with the terms and conditions set out by an interconnection agreement. This shall include the responsibilities, access to and ownership of both parties of transmission connection facilities.

4.8 Interconnection Cost Treatment

The FIT for all RE generators connecting to the 24.9 KV transmission system under this programme includes an interconnection cost estimate which covers the cost of the transformer, transformer pads and riser pole, etc. All future and existing RE generators shall pay the full cost estimate captured in the FIT and the cost incurred pursuant to the interconnection agreement.

Substation facilities

Where a substation is required to interconnect a new RE generator to the transmission network, this cost and the cost of the applicable switchgear, lines and poles shall be shared between the BLPC and that IPP. The allocation of this cost shall be applied to the IPP and the BLPC in a 25%/75% ratio. This approach is expected to assist the utility in financing this initiative.

Substation facilities shall be utilised to facilitate the interconnection of other RE generators nearby where it is appropriate to do so. The cost of interconnecting an additional RE generator to the substation shall be borne by the IPP at 25% of the cost of the equipment and material required for said interconnection.

The BLPC shall design the substation and provide a cost estimate to the IPP. The substation shall be built on the IPP's land.

4.9 Cost Recovery

All prudent costs of interconnection of transmission RE equipment incurred by the BLPC or the incumbent utility shall be recovered through an approved appropriate recovery mechanism.

4.10 FIT Impact on Customer Rates

Based on the short term analysis 2023–2028 of the determined FITs on customer electricity rates, an average FCA of $0.2604/KWh is expected within the lower limit of $0.2597/kWh to an upper limit of $0.2613/kWh. The resulting IPP rate throughout the analysis period is expected to be $0.3645/kWh on average. The realisation of this forecast is contingent on the actual deployment and timing of RE projects over the short term and global crude oil prices remaining within the 2021 West Texas Intermediate and Brent benchmarks.

4.11 FIT Model Assumptions

Input assumptions utilised to determine FITs were primarily based on feedback from stakeholders and research on the specific areas. Some of these include interconnection integration strategies, annual degradation rates for solar PV and wind technologies, capacity factors, and installed costs.

Consideration of the climatic impact on technology performance locally resulted in revisions to the degradation rate for solar PV and land-based wind systems.

The impact of the COVID-19 pandemic on technology prices was also a key consideration when adjustments were made in the model. The Commission therefore sought to balance the need for RE deployment with technology price movements, environmental and societal benefits expected, and customer rate pressure impacts.

Having taken the aforementioned into account, the modeling of input assumptions was concentrated on four (4) key thematic groups:

(i) Installed costs and performance statistics;
(ii) Operating costs inputs;
(iii) Financing inputs; and
(iv) Other inputs.

Table 2 below depicts the input assumptions utilised for the installed costs and performance parameters.

Table 2 - Installed Costs & Performance Input Assumptions

Technology, Size Category	Installed Cost BDS cents/kW	Capacity Factor	Annual Degradation	Analysis Term
Solar PV, above 1 MW and up to 5 MW	$2,598.00	20.00 %	0.50%	20 years
Land-based Wind, above 1 MW, and up to 5 MW	$3,849.00	30.00%	0.50%[3]	20 years
Solar PV, above 5 MW, and up to 10 MW	$2,459.00	20.00%	0.50%	20 years
Land – based Wind, above 5 MW, and up to 10 MW	$3,508.00	30.00%	0.50%	20 years

Interconnection Costs

An adjustment was made to the interconnection cost estimate. For RE projects sized above 1 MW and up to 5 MW, and above 5 MW and up to 10 MW, a value of $90/kW was assumed in

[3] New Land Based wind technologies output decreases by less than 0.20% for the first ten (10) years of operation however, this value was upgraded to 0.5% per year in the model. The Commission notes that currently there are no restrictions on the type of drive train associated with wind turbines entering the RE market. Further research is required on degradation to achieve a better estimate.

the model. The value assumed in the model is expected to cover the costs of interconnecting equipment and includes the aggregated cost per KW for material, foundation, and installation prices for the transformer, transformer pads, and riser pole.

VAT & Import Duties

Based on the fiscal incentives guidelines offered by the GoB for RE projects, no VAT and import duties are applied in the model[4].

Interest during the Construction Phase

An estimate of 7.75% was used in the model; based on feedback this value remains reasonable. During the construction phase of the project interest is expected to accrue on the construction financing facility associated with RE technologies.

Analysis Term

An analysis term of 20-years was consider adequate to allow investors to recoup the costs expended in the development, financing, and construction of RE projects. Additionally, this contract period allows investors to realise a return on their investment.

Operating Cost Assumptions

Inflation

An inflation adjustment of 3.0%[5] was adopted in line with the forecasted value expected in 2023 and was derived from an assessment of local data. This value is assumed for the full contract period of the project.

Site Lease

A 2.0 % escalation rate is assumed in the model over the contract period and are based on local data.

Insurance

An estimate of $10/thousand was assumed for solar PV and land-based wind technologies since this value continues to be reasonable. As familiarity with projects of this scale increases more accurate estimates will be developed from local data.

[4] Division of Energy and Telecommunications, 2017: Renewable Energy and Energy Efficiency Fiscal Incentives Booklet for Individuals and Companies

[5] Data from the Barbados Statistical Service was utilised to determine this estimate.

Land Taxes

The model assumes land tax rate of 0.95% of the value generated by the RE generation system[6].

Table 3 - Operating Cost Input Assumptions

Technology, Size Category	Fixed O&M BDS cents/kW/Yr	Site Lease BDS cents/kW/Yr	Insurance (BDS$/mille)	Project Management BDS cents/kW/Yr	Land Tax (% of rev)
Solar PV, above 1 MW and up to 5 MW	$32.00	$25	$10/mille	$12.00	0.95%
Land-based Wind, above 1 MW and up to 5 MW	$70.00	$25	$10/mille	$12.00	0.95%
Solar PV, above 5 MW and up to 10 MW	$32.00	$25	$10/mille	$6.00	0.95%
Land-based Wind, above 5 MW and upto 10 MW	$70.00	$25.00	$10/mille	$6.00	0.95%

Financing Assumptions

Financial institutions since the institution of the FIT programme are gaining experience with RE projects. Given this development there are varying financial support options for the RE sector. Banking and financial institutions are establishing diverse RE portfolios in recognition of the demand for RE investment. Access to finance remains an important tenet in order to assist with the transition to RE. The following financial assumptions (Table 4) were utilised in the rate determination for the various project categories

[6] https://www.bra.gov.bb/News/Policy-Notes/Land-Tax-Changes.aspx, Accessed December, 2022

Table 4 - Financing Input Assumptions

Technology, Size Category	% Debt	Debt Term (years)	Interest Rate (%)	Cost of Equity (%)
Solar PV, above 1 MW and up to 5 MW	60.00%	15	6.25%	14.00%
Land-based Wind, above 1 MW and up to 5 MW	70.00%	15	6.25%	14.00%
Solar PV, above 5 MW and up to 10 MW	60.00%	15	6.25%	14.00%
Land-based Wind, above 5 MW and up to 10 MW	70.00%	15	6.25%	14.00%

Debt/ Equity

Given the difficulty expressed by a respondent with acquiring self-financing Solar PV projects, a debt component of 60% was assumed for all capacity categories. Land-based wind projects was assigned a debt component of 70% for all capacity categories. These adjustments were considered necessary to assist with financing proposed projects.

Debt Term

A debt term of 15 years was adopted in the model and is reflective of the typical period that is utilised in the banking sector.

Interest Rates

An interest rate of 6.25% was adopted and this aligns well with the value currently obtains in the financial sector.

Lender Fee

A commitment fee of 1.25% associated with loans was assumed in the model.

Cost of Equity

A targeted rate of return of 14% was adopted over the 20 year contract period. Based on the LCOE pricing outlook for the capacity ranges, this adopted return on equity appears to be reasonable, allowing investors an opportunity to achieve a reasonable return.

Other inputs

Deductions

The GoB provided a number of fiscal incentives to facilitate investment opportunities in the RE sector. One incentive utilised in the modeling of RE rates is a 150% deduction of the RE project cost, with up to a maximum of $25,000 per year deductible applied over the first five (5) years of the RE project.

Depreciation

Straight line depreciation is applied to the RE projects over the 20 year contract period.

Decommissioning

An important feature which was adopted in the model is a reserve fund facility which is intended to cater to decommissioning of the RE project. This activity is essentially funded from the operating cash flow of the project which accumulate over its first 10 years of the project.

SECTION 5 THE DETERMINATION

The Commission having reviewed the terms and conditions of the FIT programme in accordance with its regulatory obligations under the FTCA and URA and in keeping with policy objectives expressed in the BNEP, now determines the following new rates and guidelines for RE technology categories above 1 MW and up to 10 MW:

I **The dates of commencement and termination of the FIT programme shall be January 1, 2023 and December 31, 2023, respectively. All applicable technology project categories, rates, and assigned capacity, for systems sized above 1 MW and up to 5 MW, as set out in paragraph IV, shall remain in place for the full 12 months of the programme. A review of this segment of the programme shall be undertaken at least 3 months before the expected termination date or when the allocated capacity of 40 MW is exhausted. For capacity categories over 5 MW and up to 10 MW, the rates, terms and condition for this segment of the programme shall remain in place for seven (7) months from the initial commencement date and conclude on July 31, 2023 or until a competitive procurement framework is established.**

II **All terms for FITs procured under this decision shall remain constant for the duration of the 20-year contract.**

III **The FITs determined for the technology classes were derived from the LCOE methodology and utilised the multi-criteria approach expressed in the BNEP document. Rates are differentiated by technology and size and shall be based on a fixed 20-year term with no front-loading. These details are captured in the Table following.**

Fit Policy Design

FIT Policy Element	RE Systems above 1 MW up to and including 10 MW
Proposed Effective Date	January 1, 2023
Rate: Fixed, Tiered or Variable Options	Fixed
Rate: Differentiated by Technology & Size	Yes
Tariff Duration	20 years
Administratively-Determined or Competitively-Bid	Administratively-Determined
Presumed Off-taker	BLPC
Quantity Covered by FIT	100% of output

IV The applicable categories, rates and capacity allocation shall be as outlined below:

Technology, Size Categories	January 1, 2023 – December 31, 2023 FIT (BDS cents/kWh)	January 1, 2023 – December 31, 2023 FIT (BDS cents/ kWh)Allocation (MW)
Solar PV, above 1 MW and up to 5 MW	**26.75**	
Land-based Wind, above 1 MW and up to 5 MW	**26.25**	
Solar PV, above 5 MW and up to 10 MW	**25.25**	
Land-based Wind, above 5 MW and up to 10 MW	**24.25**	
Total Allocation		40

V Reference to capacity in this Decision means alternating current - AC. Where allocated capacity for any technology category remains unutilised, said capacity shall be transferred from one technology to the other, where applicable.

VI The revenue metering configuration shall be applied in accordance with establish prudent industry practice. The billing arrangement adopted shall be applied according to the specificity of the project. Where it is practical to utilise either "Buy all/Sell all" or "Sale of Excess" billing modalities, the appropriate option shall be adopted.

VII RE procured under this programme shall be purchased at the rates determined herein and shall apply to the applicable FIT agreement.

VIII All future and existing RE generators connecting to the 24.9 KV transmission system shall pay the full interconnection costs estimated in the FIT and the costs incurred pursuant to the interconnection agreement.

IX Interconnection costs outside of the costs covered in the FIT shall be shared between The IPP and BLPC according to the ratio of 25%/75% of this cost. These costs include the cost of the substation, switchgear, cabling, and poles required to interconnect the project. Where a substation facilitates the interconnection of an additional Re generator, the IPP is required to contribute 25% of the cost associated with that interconnection.

X All prudent costs of interconnection of transmission RE equipment incurred by the BLPC shall be recovered through an approved appropriate recovery mechanism.

XI At the end of the 20-year FIT contract period, a new contract will need to be negotiated based on the existing value of the assets, the avoided cost of fuel or such other factors as may be determined by the Commission, in its sole discretion, at that time.

Dated this 31st day of December, 2022

Original signed by
…….
Tammy Bryan
Chairman

Original signed by
…….
John Griffith
Commissioner

Original signed by
……
Ankie Scott-Joseph
Commissioner

Original signed by
……
Samuel Wallerson
Commissioner

APPENDIX 1

Summary of Responses to Consultation Questions Posed

1. **Should the duration of the above 1 MW and up to 5 MW component of the FIT programme be extended to 24 months to allow an accurate assessment of capacity utilization? Please provide a reason for your response.**

   Respondents' Comments

   The majority of respondents agreed with the proposed 24 month duration for the FIT programme and the intended objective. One (1) of these implied that the duration can be longer or shorter depending on the capacity utilisation. Five of (5) of these made referenced to the timelines associated with project financing, equipment procurement, project development, project installations, grid connections and permitting matters as reasons in support of the proposal.

2. **Do you agree that the above 1 MW and up to 5 MW segment of the programme should be reviewed three (3) months before the programme concludes? State a reason for your response.**

   Respondents' Comments

   Respondents had various views on when the programme should be reviewed. Three (3) of these agreed that the programme be reviewed three (3) months prior to its conclusion, while another indicated that reviews should be ongoing for the duration of the programme and changes communicated to developers no later than three (3) months before the programme ends. An alternate view was that the programme be reviewed six (6) months before and changes communicated three (3) months prior to the programme conclusion.

3. **Should capacity allocations be limited and flexibly applied in consideration of the thermal capacity limitation of feeders and feeder congestion status? Please give a reason for your answer.**

   Respondents' Comments

   There was a general consensus amongst respondents that capacity be applied taking into account the capability of the grid. One (1) respondent suggested that capacity be reserved

based on feeder capacity constraints but also allocated in consideration of feeder upgrades. Another support that feeder limitations must be considered. Another was of the view that flexibility on capacity should only be applied on reserved capacity not utilised.

4. **Do you agree with the initiative to create the following project categories, above 1 MW and up to 3 MW, above 3 MW and up to 5 MW, above 5 MW and up to 7.5 MW, and above 7.5 MW and up to 10 MW within the existing capacity bands above 1 MW and up to 5 MW and above 5 MW and up to 10 MW, respectively? Please support your response with a reason.**

   Respondents' Comments

   One (1) respondent was indifferent to the majority view which favours the additional capacity bands proposed. In their opinion the initiative aims to promote gaming opportunities and additional administrative costs. A distinction was made by one (1) respondent in support of the proposals, that wind technologies differ significantly by scale and as a result capacity bands will differ. Another reason for supporting the proposal was that it will allows investors to optimize project designs to suit smaller land sizes.

5. **Do you agree that creating additional categories as proposed at question 4 may provide more opportunities for local participation? Please support your response with a reason.**

   Respondents' Comments

   The general view from most respondents is that the proposal will promote local participation. An opposing view was that the additional categories will encourage gaming opportunities and more cost for electricity customers as a result.

6. **Do you agree that the size of the project should meet a minimum capacity requirement to be eligible to participate under the proposed project caps? Please give a reason for your answer.**

   Respondents' Comments

   Most respondents did not agree with the setting of a minimum capacity criteria. A view raised was that the pricing regime and the market should determine the demand for capacity sizes. Imposing additional criteria would further complicate the process.

7. **Do you agree with the proposal that an increased rate of return may address this issue? Please provide a reason for your response.**

Respondents' Comments

Most respondents were indifferent to the proposal and implied that this may increase the cost of electricity. One (1) of these indicated that having more discrete price bands may mitigate the gaming issue. Two (2) respondents supported the proposal.

8. **What do you think should be done to circumvent the occurrence of this type of gaming issue?**

Respondents' Comments

Respondents expressed the view that guidelines should help identify and address these gaming issues. These could be addressed at the town planning and accreditation stages. One (1) respondent suggested that increasing rate categories promotes greater opportunity for gaming.

9. **Do you agree that "sale of excess" billing can be adopted for utility scale projects under the FIT programme? Please support your response with a reason.**

Respondents' Comments

Most respondents agreed with "sale of excess" metering in power purchase applications since this will be more cost effective. One (1) supporter of the mechanism suggested that compliance with this objective be monitored and if this is being used for internal consumption, the utility be allowed to apply the "*buy all sell all*" mechanism at the particular site. Another respondent suggested that the application of either "*sale of excess*" or "*buy all sell all*" be utilised according to the specificity of the project.

10. **How has the magnitude of the installed cost ($/KW) for solar PV and land-based wind technologies changed for the capacity bands since the institution of the programme? Please provide a reason for your response.**

Respondents' Comments

There was a general view from respondents that associated prices of equipment, materials, logistic costs increased significantly for solar PV projects. Values for land-based wind

projects were suggested by one (1) respondent and these were higher than what is in existence.

11. What strategies should be adopted given the surge in technology prices?

Respondents' Comments

One (1) respondent suggested that it is difficult to control external prices but a reduction in installation cost is expected to decline based on experience. Three (3) respondents indicated that the FIT should reflect the true installed cost of solar systems taking into account any increases. Timely approvals and periodic monitoring of market prices are suggested as options to take. Two (2) respondents believe that a FIT rate adjuster should be considered with one of these suggesting an inflation indexing mechanism.

12. Do you agree with the proposed capacity factors for solar PV and land-based wind technologies? Please provide a reason for your response.

Respondents' Comments

Most respondents agreed with the proposed value for solar PV systems. There was a general view by two (2) respondents that the value for land-based wind systems was too high. A suggested value at a good location locally is around 28.5%.

13. Do you agree with the proposal to amend the existing annual degradation rates for solar PV and land-based wind technologies? Please provide a reason for your response?

Respondents' Comments

One (1) respondent indicated that wind farm degradation rates are in the range of 1.6%+/-0.2%. In terms of solar PV systems in a tropical climate, a respondent expects a rate of 1% would be appropriate. Another support the amendment to 0.5% but based on manufacturers quotes this can be between 0.6% to 0.8%. Another intimated that the rate should be in line with module warranty value of 0.6% to 0.7%. Two (2) respondents agreed with the 0.5% value but one commented that the value does not account for all global climatic variations.

14. What are your views on extending the contract term to 25 years under this FIT programme? Please explain your response.

Respondents' Comments

Most respondents opposed extending the contract period since this can increase uncertainty and the payback period. There was a view that extending the term to 25 years was justified based on product warranties, expected system life and duration for bondholders. One (1) respondent was concerned that extending the contract term to 25 years may not be prudent if their existing contractual arrangements cannot accommodate a longer operating period.

15. **How has this rate changed in the energy sector over the FIT programme duration? Should this value be retained or amended? Please provide a reason for your response.**

Respondents' Comments

The general view expressed by most respondents was that the existing rate appears reasonable. However, another view was that this value has not changed but is expected to increase since other interest rates are increasing.

16. **What in your opinion reflects an adequate estimate of O&M costs for solar and land-based wind projects within the capacity bands since institution of the FIT programme? Explain why the estimate is reasonable.**

Respondents' Comments

Respondents stated diverse views. One (1) suggested that an increase from the existing estimate to $40/KW/Yr. was a reasonable value for solar projects. Another respondent suggested that considering various components of O&M costs, these values range from $76 to $81/KW/yr. for a 10 MW, 5 MW, 2 MW and 1 MW projects. Another opined that $33.50/KWp is the going rate for projects 3-5MW and suggest that if the existing value is $32/KWp this is considered to be reasonable. Another respondent agreed that the estimate for O&M is adequate where vegetation management is not required. Where sheep farming is allowed, the estimate may also be adequate. However, where this is not allowed the O&M costs can be negatively impacted.

17. **What could be a reasonable estimate for site lease to facilitate a RE project? Please give a reason for your estimate.**

Respondents' Comments

One respondent suggested that for 1-3 MW projects site lease ranged 0.75 -0.90/square foot. Another respondent indicated that the existing estimate was reasonable but anticipate that this will increase with renewable energy uptake. Another contribution was that $4,000-$6,000 per acre was a reasonable estimate for land lease related cost for projects.

18. What measures do you consider can be put in place to mitigate against the unnecessary increase in land values?

Respondents' Comments

A number of suggestions were posited by respondents. One (1) view was that Government policies would be needed to prevent land tax increases on renewable energy projects. Another view opined that there is a need to educate land owners on the reasonableness of leases.

19. What level of insurance estimate would be reasonable for solar PV and land-based wind projects? Please explain your answer.

Respondents' Comments

One (1) view raised was that the existing estimates were too low and the operational cost of the projects should be considered as insurance cost. An alternate view by two (2) respondents was that the existing estimate is reasonable.

20. Should the existing estimate for project management be amended? What would be a reasonable estimate for the expense? Please provide a reason for your answer.

Respondents' Comments

A general consensus based on respondents' comments was that the existing value should be amended. One (1) respondent proposed that the project management estimate be 9% of the total project cost. Another view was that the value be increased to $20 and $15, for the 1 – 5 MW and 5-10 MW band, respectively. Another respondent indicated a value of $30/kW/year is currently being used for multiple projects.

21. Given the existing RE market conditions, what is your perspective on retaining or amending the inflation value? State a reason in support of your response.

Respondents' Comments

Most respondents suggested that the value be adjusted. Two (2) respondents believe that an adjustment was required with a 4% level suggested for the future. Another view was that a value of 8-10% should be used for the next two years. An alternate vies was that the FIT be indexed to the CPI and or global PPI with 2022 as a reference while another respondent indicated a value of 3%.

22. **Given our specific energy context, should the debt ratio for the RE technologies be amended upward? What range of debt financing would be ideal for this scale of RE projects given the need to increase local participation under the FIT programme? Please provide a reason for your response.**

Respondents' Comments

Two (2) respondents suggested a 60/40 debt to equity ratio and a return on equity capital of 15%. Another view raised by one (1) respondent was that the existing 50% debt ratio does not promote local investment. Another position stated was that as the banking sector gains more experience with solar projects, debt ratios 70%-80% could be realised in the future.

23. **Do you think the existing interest rate is adequate for utility scale projects? Please support your response with a reason.**

Respondents' Comments

The general consensus amongst respondents was that the existing rate continues to be reasonable.

24. **Should this rate be amended given the current economic circumstances? Please support your response with a reason.**

Respondents' Comments

An adjusted value was suggested by most respondents, all being different. The values stated ranged from 1.75% to 3%.

25. **Do you consider this level of return reasonable? Please explain your response.**

Respondents' Comments

Most respondents general agreed that the level of return was not adequate based on forecasted higher interest and inflation levels. One of these suggested that the rate should be 15% - 18%. Two respondents agreed that the level of return was reasonable. One of these suggest it should be closer to 15%. One respondent noted that the return was higher than that of the utility despite its higher risk profile.

26. What are your concerns with the proposed treatment of interconnection costs for existing RE market participants, requiring each IPP to pay the full cost captured in the tariff? Explain your response.

Respondents' Comments

Two (2) respondents agreed with the proposal but one of these only support this view if IPPs can earn a reasonable return. Most respondents preferred that costs beyond the boundary be shared while interconnection cost up to the boundary be included in the FIT. As it relates to the proposal a view was raised that this would introduce complexity where a refund is warranted.

27. What are your views on the proposed sharing of interconnection costs between the BLPC and IPPs as stated above? Please support your response with a reason.

Respondents' Comments

Some respondents agreed with the proposal but suggested that this process be transparent. One to these suggested that the allocation of shared costs should be fair and reasonable. Another indicated that timely cost recovery would be a factor in consideration of the shared cost proposal. Others believed that cost beyond the point of interconnection be shared cost between IPP and the BLPC. One of these suggests that the IPP should pay 20% of this cost, while the BLPC pays 80%. One respondent was concerned that if an IPP is to pay any cost above the interconnection cost estimate, this will impact returns.

28. Do you agree that the BLPC should recoup the portion of interconnection costs through an appropriate cost recovery mechanism once prudently incurred? Please support your response with a reason.

Respondents' Comments

There was a general consensus amongst most respondents that prudently incurred cost by the BLPC be recovered; a cost recovery facility similar to the fuel clause adjustment mechanism or alternative mechanism was suggested.

29. What are your views on the proposed interconnection cost treatment for new RE market participants under the FIT programme? Support your response with a reason.

Respondents' Comments

Two (2) respondents agreed with the proposal but one of these believe the BLPC's requirement for transmission interconnection should be assessed for cost effectiveness. Two (2) others opined that if substation facilities are to be shared, these should be owned and operated by the utility. One of these also felt that the proposal may introduce pricing complexities; RE generator owners could build their own substations and the FIT reflect this cost. Support for shared cost was also expressed by another respondent with the view that the cost of substation facilities be shared between the utility and IPP in a 80/20 ratio and this cost be treated as an external cost to the FIT.

The shared substation facility approach would be designed to facilitate interconnection by other IPPs nearby thus limiting high cost exposure. Another view expressed was that a revision would be required based on current rates.

30. Do you agree that the BLPC be allowed to recovered all prudently incurred costs in a timely manner? State a reason for your response.

Respondents' Comments

The majority of respondents agreed that the BLPC should recover all prudently incurred cost. Five of these recommended a cost recovery mechanism for interconnection cost. Another opined that the utility's portion of cost to be recovered be taken from the rate base since it benefits the transmission and distribution system.

31. What other approaches do you consider would be reasonable to implement for the treatment of interconnection cost? Please explain your answer.

Respondents' Comments

There were mixed views amongst respondents on the treatment of interconnection cost. The Clean Energy Transition Rider (CETR) mechanism was suggested by two respondents as a solution to interconnection cost treatment. Cost allocation be made based on the POI was another perspective; line extensions to this point should be equally shared and the utility pricing on this work be validated. Cost sharing was also expressed by another respondent with respect to the reduction in cost to be borne by the IPP as the value of the infrastructural increases. Another view raised was that the interconnection cost estimate be revised.

32. Do you support the proposal to verify all interconnection costs associated with the FIT programme? State why you agree.

Respondents' Comments

Most respondents support the proposal to verify all interconnection costs. One of these intimated that this is required to give stakeholders greater price visibility and transparency in order to achieve the 2030 goal.

Two asserted that which respect to refunds or rate adjustment, this should be executed by an independent auditor. Two others posited dissenting views, suggesting that the proposal would not be best served by the Commission given its regulatory responsibilities and that the utility has been managing this process reasonably without the Commission's intervention. One of these believe that the proposal would potentially complicate and create delays in the process. However, both agreed that the Commission's involvement was supported where objections to these costs are raised by customers, and the need to periodically audit samples of projects.

33. Should the current FIT programme be further extended until RE technology prices stabilize? Please give a reason for your response.

Respondents' Comments

A general view from respondents was that the programme should not be extended. Two of these suggested that the major cost drivers associated with solar PV be identified, continually monitored for impact on system cost, and identify when adjustments are required.

Two respondents reasoned that the programme should not be stalled or suspended; one of these two intimated that rates should account for current costs. However, one who agreed with the proposal commented that the rates be revised now in order to increase RE uptake.

34. Should the rates be revised based on the proposals in the interim? Please give a reason for your response.

Respondents' Comments

The majority of respondents agreed that rates be revised. Three of these reasoned that revised rates are warranted in order to stimulate RE investment. Another posited that although the rates included interconnection cost, these rates remained inadequate. Another opined that revised rates be indexed to inflation to mitigate risk with RE investments. One respondent disagreed that revisions for land-based wind be done based on the proposals but instead suggested the rate be recalculated to incentivise deployment of these projects.