



Analysis of Return on Investment for Small Renewable Energy Systems

Statement of Results and Final Decision

ES 29/2026

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1. Introduction

The Utilities Regulation and Competition Authority ("URCA") is the independent regulator of the electricity sector in The Bahamas under the Electricity Act, 2024 ("EA"). In accordance with sections 13 and 14 of the EA, URCA is responsible for regulating the electricity sector in a manner that promotes the objectives of the National Energy Policy ("NEP"), including facilitating the increased adoption of renewable energy technologies.

On 19 May 2026, URCA published the Consultation Document Analysis of Return on Investment for Small Renewable Energy Systems (ES 15/2026)¹. The consultation sought stakeholder views on URCA's analysis of the financial performance of small-scale renewable energy systems operating under the existing regulatory framework, including whether the findings should inform future regulatory or policy measures. Interested parties were invited to submit written comments by 19 June 2026. No submissions were received by the close of the consultation period.

Having allowed interested parties a reasonable opportunity to respond to the consultation, this Statement of Results and Final Decision sets out the outcome of the consultation process and URCA's final conclusions regarding the analysis of return on investment for small renewable energy systems.

The study that was conducted as part of the consultation provides empirical evidence on the financial performance of residential and commercial solar photovoltaic (PV) systems in The Bahamas using customer survey data, electricity billing information, and financial modelling. The findings are intended to support evidence-based regulation, improve public understanding of renewable energy investments, and inform future reviews of renewable energy policies and regulatory frameworks.

URCA conducted this study to better understand the costs, benefits, and performance of renewable energy systems currently deployed in The Bahamas. The findings are intended to inform regulatory approaches to encourage sustainable investment and ensure that sector development remains aligned with the Government's NEP 2025–2030, which establishes a target of achieving at least 30% renewable energy generation by 2030.

The move towards renewable energy has been shaped by several key policy and regulatory milestones. In 2017, URCA introduced the Small-Scale Renewable Generation (SSRG) framework, which created a mechanism for residential and small commercial customers to interconnect renewable systems with the grid under a net billing

¹ <https://urcabahamas.bs/wp-content/uploads/2026/05/ES-152026-Consultation-Analysis-of-Return-on-Investment-for-Small-Renewable-Energy-Systems.pdf>

arrangement. This was followed by the establishment of the Renewable Energy Self-Generation (RESG) program in 2019, expanding opportunities for larger customers to self-generate electricity from renewable sources while still maintaining grid reliability and oversight.

The NEP 2025–2030 further strengthens the policy foundation by explicitly identifying renewable energy adoption, particularly distributed solar PV as a national priority. It highlights the importance of creating regulatory conditions that support sustainable investment and consumer participation in energy generation.

1.1 Regulatory Framework

The EA establishes URCA as the independent regulator of the electricity sector, with its role defined in section 13. URCA is required to regulate the sector in accordance with the goals, objectives, and principles of the NEP, to monitor licensee compliance, and to support policy changes articulated by Government.

The specific functions and powers of URCA are set out in section 14, which grant authority to issue determinations, regulations, and technical rules, to approve or amend licensee proposals, and to otherwise take regulatory measures to implement sectoral objectives. These provisions ensure that URCA has both the mandate and the tools to align sector performance with national energy priorities. Complementing this, section 5 of the EA requires the Minister, in consultation with URCA, to revise the NEP and ensure its objectives are implemented through regulatory decisions.

The EA also includes dedicated provisions on renewable energy, particularly in Part V (sections 51–55). These sections require public electricity suppliers to prepare renewable electricity plans for URCA’s approval (section 51), establish permitting requirements for residential renewable systems and grid interconnections (section 54), and set conditions for crediting or purchasing excess generation.

1.2 Structure of the Remainder of the Document

The remainder of the document is structured as follows:

- Section 2 explains URCA’s methodology for the study
- Section 3 contains URCA’s analysis and findings from the study.
- Section 4 contains the conclusion and next steps.
- Annex A shows the questionnaire used in the study.
- Annex B presents the data analysis.

2. Methodology

2.1 Research Design

This study employed a quantitative research approach to assess the cost and performance data of renewable energy projects in The Bahamas. The methodology involved collecting primary data from solar energy customers through a structured questionnaire and analyzing their historical billing information to determine the financial and operational impacts of renewable energy adoption. The study aimed to provide insights into the performance of renewable energy systems and their cost implications for both residential and commercial users.

2.2 Data Collection Procedure

URCA requested and received a comprehensive listing of all renewable energy customers in Bahamas Power and Light (BPL) service territory. The listing provided by BPL included both residential and commercial customers. Upon review of the listing, URCA identified a total of 396 solar energy customers as of August, 2024.

URCA contacted all solar energy customers on the list provided by BPL via email, requesting their participation in the study. The email included detailed information about the study objectives and requested their consent for the release of their BPL billing history for the period January 2016 to August 2024. The participation was voluntary, and URCA emphasized the confidentiality of the data collected.

2.3 Sampling

URCA aimed to recruit a sample size of 196 participants, deemed sufficient to achieve statistical reliability for the study objectives. This was calculated using a 95% confidence level and 5% margin of error and then making a finite population correction. However, out of the total population of 396 customers, 36 agreed to participate, representing a response rate of approximately 9%. The participants who consented formed the basis of the study's sample.

Normal Sampling

$$n = \frac{Z^2 * p (1 - p)}{e^2}$$

n = normal sample size (the minimum number of observations or respondents needed for the study)

Z = Z score for the confidence level (e.g., 1.96 for a 95% confidence level).

p = population (the expected proportion of the population possessing the characteristic being measured)

e = margin of error (the maximum acceptable difference between the sample estimate and the true population value, expressed as a proportion, e.g., 0.05 for ±5%)

$$n = \frac{(1.96)^2 * 0.5 (1 - 0.5)}{0.05^2}$$

$$n = \frac{3.8416 * 0.25}{0.0025^2}$$

$$n = 384.16$$

A finite population correction was applied because the total population size was known and relatively small, allowing the required sample size to be adjusted to reflect the fact that the sample represents a significant proportion of the overall population. This prevents overestimating the number of responses needed while maintaining the desired confidence level and margin of error.

Finite Population Adjustment

$$n_{adj} = \frac{n}{1 + \frac{n-1}{N}}$$

n_{adj} = adjusted sample size based on a finite population

n = normal population size

$$N = \text{Population size} \quad n_{adj} = \frac{385}{1 + \frac{384}{396}}$$

$$\underline{\underline{n_{adj} = 196}}$$

2.4 Survey Administration

After securing consent, URCA sent a structured questionnaire to the 36 participants. The questionnaire was designed to capture detailed information on their renewable energy systems, including:

- Purchase cost
- Installation cost
- System performance and reliability
- Maintenance practices
- Perceived financial benefits
- Challenges encountered

Installation costs, where not included in the purchase price, were included to establish the upfront capital outlay, while system performance and reliability data were necessary to estimate energy generation and potential savings over time. Maintenance practices

were captured to understand recurring operational costs, and perceived financial benefits provided insight into household-level cashflow impacts such as reduced electricity bills or revenue from credits. Finally, challenges encountered were documented to account for risks and barriers that may affect long-term financial returns.

Despite the efforts to engage all 36 participants, only 19 customers completed the survey, resulting in a final response rate of 52.8% of the consenting participants. Moreover, once data analysis of the responses commenced due to certain data gaps only 11 customers projects were fit to use for the purposes of this study resulting in 30.6% of the consenting participants.

2.5 Ethical Considerations

The study adhered to strict ethical guidelines, ensuring participants' confidentiality and voluntary participation. Written consent was obtained from all participants for both the survey and the release of their billing history. All data was anonymized to protect individual identities.

2.6 Scope and Limitations

The primary limitation of this study was the lower-than-anticipated response rate. Based on the total population of registered renewable energy customers, a statistically representative sample would have required approximately 196 participants. Although 36 customers initially expressed interest in participating, only 19 completed the survey process, and after data validation and quality checks, only 11 projects were deemed suitable for detailed financial analysis.

The limited sample size reduces the ability to generalize the findings across the broader population of renewable energy users in The Bahamas and increases the possibility of non-response bias, whereby participants who responded may differ systematically from those who did not. In addition, portions of the study relied on self-reported cost and operational data, which may contain inaccuracies or omissions despite validation efforts using BPL billing information.

Further limitations include variability in system design, installation quality, customer consumption patterns, financing arrangements, and site-specific conditions such as shading and panel orientation, all of which may materially affect financial performance outcomes. Accordingly, the should be interpreted as indicative rather than definitive measures of renewable energy investment performance in The Bahamas.

2.7 Results

Definitions:

- Case: An alphabetical letter was assigned to each participant to identify them as an individual case study.
- Class: refers to the different categories of customers to which BPL assigns its consumers for tariff purposes. Each tariff class is subject to a distinct base rate and may also incur other applicable charges, such as a demand rate. The fuel charge component of the bill is treated as a pass-through cost and remains the same regardless of class assignment. Participants fell into one of two classes – Residential (R) or Commercial (C).
- System Size (kW): The total installed capacity of a solar photovoltaic (PV) system, expressed in kilowatts, which indicates the maximum amount of electricity the system can generate under standard conditions.
- Discounted Payback Period (yrs): The length of time measured in years that it takes for the cumulative savings and revenues from the renewable energy system to equal the initial investment cost. The values used to determine this period are discounted to factor in the time value of money.
- Internal Rate of Return (IRR): A financial metric that represents the discount rate at which the net present value (NPV) of future cashflows from an investment equals zero. It is used to evaluate the profitability of the system. This metric is important as it also factors in the time value of money of the investment over its lifespan. This is why IRR can differ greatly from ROI for the same project even when they both are positive.
- Return on Investment (ROI %): The ratio of net financial benefits (savings and revenues minus costs) to total investment costs, expressed as a percentage, which measures the overall financial efficiency of the system.

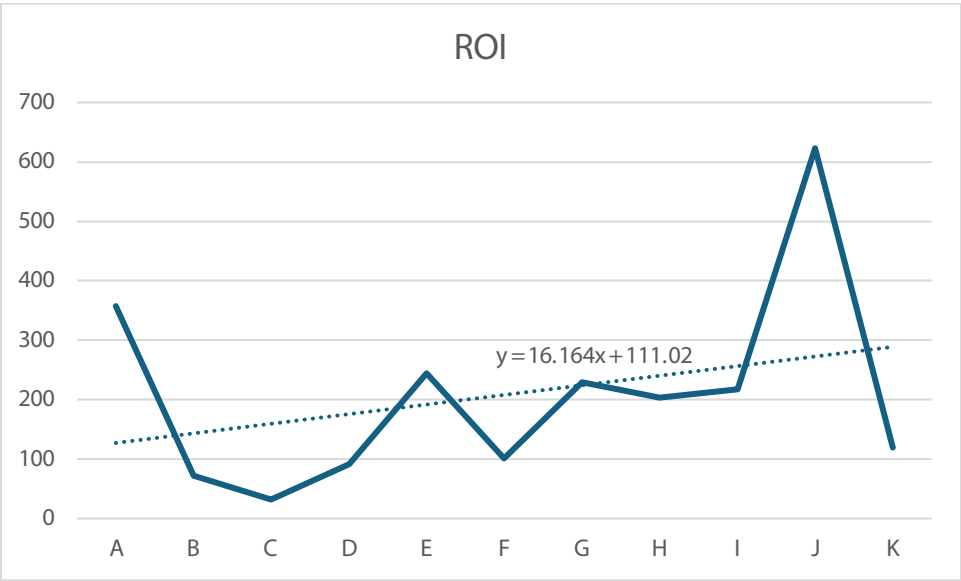
The table below presents the financial performance results of the assessed renewable energy systems, including discounted payback period, internal rate of return (IRR), return on investment (ROI), and net present value (NPV). The analysis evaluates the economic viability of each system based on its upfront investment costs, expected energy savings, operating assumptions, and a 5% discount rate applied over the project life. The results demonstrate variation in investment outcomes across residential and commercial systems, with some cases generating positive financial returns and others indicating limited or negative economic benefits under the assumptions applied.

Figure 1

Case	Class	System Size, kW	Discounted Payback Period, yrs	Internal Rate of Return, %	Return on Investment, %	Net Present Value
A	R	5	4.50	20	357	16,724
B	R	14	>20	-3	72	-27,061
C	R	3	>20	-10	32	-20,485
D	R	5	>20	-1	91	-2,486
E	C	240	6.80	12	244	857,803
F	R	7	19.80	0	101	138
G	R	7	7.00	11	229	20,660
H	R	15	8.20	9	203	53,716
I	R	9	7.60	10	217	46,733
J	R	5	2.50	38	623	26,144
K	C	25	15.90	2	119	33,978

The graph below in figure 2 illustrates the variation in Return on Investment (ROI) across the sampled renewable energy projects (A–K). While the results show significant fluctuations between individual projects, the overall trendline indicates a positive upward trajectory, suggesting that ROI generally increases across the sample. The highest ROI is observed in Scenario J, which significantly exceeds the other results, while the lowest returns are observed in Scenarios C and B. Despite the variability, the positive slope of the trendline ($y = 16.164x + 111.02$) indicates an overall improvement in investment returns across the evaluated cases. The fluctuations highlight that ROI outcomes are influenced by specific underlying assumptions and conditions, such as system costs, energy production, electricity savings, or other project-specific variables, rather than following a uniform pattern.

Figure 2 – Return on Investment by Project



3. Analysis

URCA did have concerns about some of the data supplied by the participants. Some values appeared outside the range expected (outliers). This is of particular concern with a small data set which lacks sufficient data points to produce a normalized distribution. Notwithstanding the discussions on the sample size in Section 2.3 and the scope and limitations in Section 2.6, URCA was able to draw interesting observations from the analysis. These are discussed below.

Residential system sizes ranged from 5 to 15 kW with the average size being 7.8kW which was consistent with the BPL's SSRG framework. Applying the framework² to the annual use before the PV system was installed yields and expected system size of 8 kW. This means systems are being sized in accordance with the framework, which is designed for self-use, i.e. to avoid excessive units sent back to the grid.

Over half of the systems studied are projected to be a good investment for the individuals. These systems are likely to beat inflation. Eight out of eleven systems also had a positive net present value over their expected useful life of 20 years, applying a discount factor of 5%. This compares favorably with the available return on a Bahamas Government bond over a similar period. Hence, if a government bond is the next best alternative installing a PV system can be an attractive option. On average, people can expect to make their money back within 10 years after installation.

There was no strong correlation between system size and financial return (i.e., discounted payback, internal rate of return, return on investment, or net present value). There was a strong correlation between the upfront system cost and financial return, discussed later. The billing data showed that survey respondents paid about 31 cents, on average, for the electricity they consumed. This is the gross charge made up of approximately 14 cents per kWh for the base charge and 17 cents per kWh for the fuel charge. Having determined this, for the economic analysis, the kWh that the PV system produced and was consumed by the customer was valued at 31 cents per kWh and any units that were fed to the grid were valued at 17 cents per kWh.

According to the US Energy Information Administration, residential customers in the United States typically use about 25–35% of their total daily electricity between 11 a.m. and 4 p.m., depending on season and climate. This midday period often coincides with

² [https://www.bplco.com/wp-content/uploads/2020/02/Level_1_SSRG_Requirements_for_Grid_Interconnection - 4.0 Final-1.pdf](https://www.bplco.com/wp-content/uploads/2020/02/Level_1_SSRG_Requirements_for_Grid_Interconnection_-_4.0_Final-1.pdf)

peak cooling demand in summer and moderate appliance use in winter which is also the time when PV systems are expected to produce their output.

This analysis assumed that for a newly installed solar system in 30% of the historical consumption would now be satisfied by that PV system. This assumption was selected to represent a conservative estimate of the proportion of PV generation that would be consumed on-site by a typical residential customer, while recognizing that actual self-consumption levels vary depending on customer load profiles, system size, occupancy patterns, and the timing of electricity usage relative to solar generation. A check was made, using PV Watts³, (*Estimates the energy production of grid-connected photovoltaic (PV) energy systems throughout the world. It allows homeowners, small building owners, installers and manufacturers to easily develop estimates of the performance of potential PV installations.*) to confirm that the size of the PV system installed could meet this demand. The excess production from the PV system was then considered to be fed back to the grid. To validate this, a comparison was made between the units billed before the PV system was installed and the units billed after the PV system was installed. The expectation would be that the units billed would drop by the amount being produced by the PV system. This turned out to be the case. On average, the units billed after the PV system was installed were 34% lower than before. Hence, survey respondents were saving about a third on their electricity bill compared with before.

The study then turned to look at units sent to the grid. For approved SSRG and RESG systems, any units that are produced by the PV system and not consumed by the property are fed into the electricity grid. BPL compensates customers at the prevailing fuel charge for these units. As mentioned above, these units were valued at 17 cents per kWh for the study. The units exported to (fed into) the grid are shown on the customer's bill. A check was made to see if the numbers lined up with what was expected. To do this the ideal system output was compared to the number of units (kWh) BPL recorded being fed into the grid. The ideal system output was calculated by subtracting 30% (the amount consumed internally) from the total possible system output calculated using PV Watts. The results showed that the actual system output was 40% lower than expected. This result is not necessarily surprising because most systems are not installed under ideal conditions, i.e. south facing at the right angle with no shading. It does show that persons should pay attention to how the system is installed to maximize its output and their financial return.

There was significant variation in how much people reported paying for their systems. It ranged from \$1.00 per W to \$10.00 per W and was the deciding factor on a systems return

³ PVWatts: <https://PVWatts Calculator>

on investment. The two graphs below (figures 3 and 4) summarize these findings. Both graphs show the negative impact of paying more per W for a PV system.

Figure 3 – Graph of PV System Cost vs Internal Rate of Return

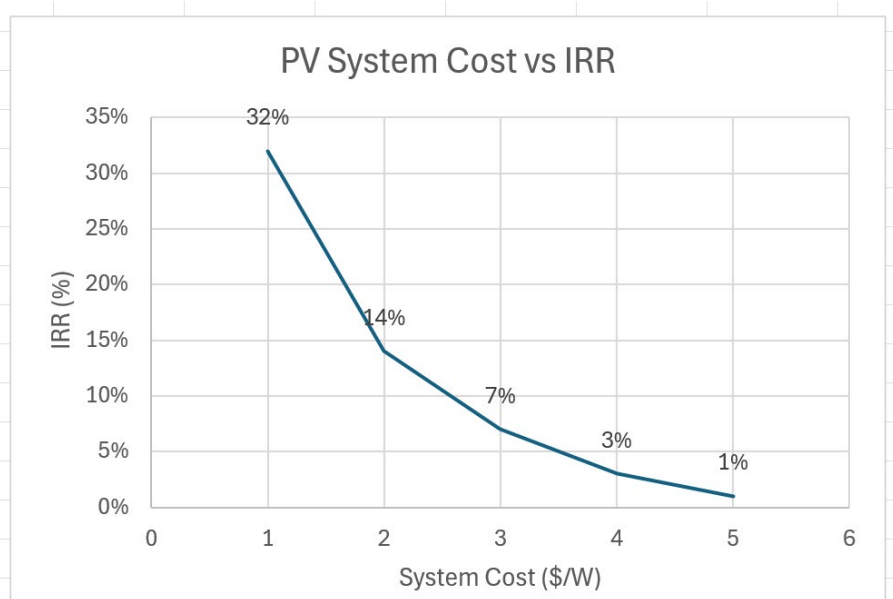
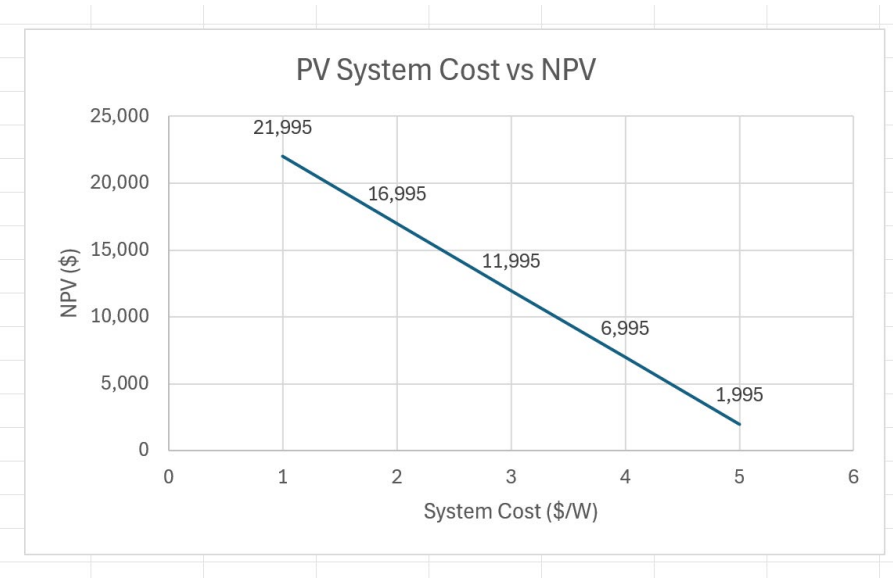


Figure 4 – Graph of PV System Cost Vs NPV



3.1 Key Takeaways

The key takeaways from the study include the following.

1. Electricity generated by a PV system and consumed directly by the customer provides a higher economic benefit to the customer, as it offsets electricity that would otherwise have been purchased at the applicable retail tariff (approximately 31 cents/kWh). Conversely, electricity exported to the grid is compensated based on the applicable avoided cost value (approximately 17 cents/kWh), which reflects the value of the avoided fuel-related costs. Therefore, from the individual customer's perspective, maximizing self-consumption generally results in a higher direct financial return; however, exporting excess generation remains economically beneficial as it contributes to reducing the need for conventional generation and provides value to the electricity system.
2. Customers can improve the economic return on their PV investment by ensuring their system is appropriately designed and installed to maximize energy production. Key considerations include optimal panel orientation (e.g., south-facing where feasible), an appropriate tilt angle (approximately 15 degrees to the horizontal based on the conditions in The Bahamas), and minimizing shading from trees, buildings, or other structures. Proper system design and installation practices help maximize electricity generation, increase self-consumption, and improve the overall financial performance of the PV investment.
3. The installed cost of a PV system is a significant factor influencing the economic viability of the investment. Based on the analysis, systems installed at costs exceeding approximately \$5/W are unlikely to generate returns that are competitive with alternative investment opportunities, while systems installed at approximately \$4/W may provide returns that exceed lower-risk alternatives such as inflation or bank deposit rates. Systems installed at approximately \$3/W or below demonstrate stronger economic performance and may provide returns comparable to or exceeding other investment options, such as bonds or equities. It should be noted that customers do not necessarily have full control over the installed cost per watt of a PV system, as pricing is influenced by several factors, including equipment costs, installer pricing, system size, import costs, market competition, and financing arrangements. However, customers may be able to improve the economic attractiveness of their investment by comparing multiple supplier quotations, selecting appropriately sized systems, and considering the total lifecycle cost and performance of the system rather than focusing solely on upfront cost.

4. Conclusion and Next Steps

Following the issuance of this Statement of Results and Final Decision, URCA will proceed with the following next steps:

- **Regulatory application:** The findings of this study will be analyzed by URCA as an evidence base for future regulatory decision making, including but not limited to matters relating to distributed generation, net metering arrangements, and renewable energy policy development. Given the limitations associated with the available sample size and data coverage, URCA recognizes that the findings should be interpreted within the context of the study's scope and methodology. Where appropriate, URCA will supplement the results of this analysis with additional benchmarking, industry data, and comparable international experiences to support a comprehensive assessment of future regulatory measures.
- **Incorporation into ongoing work streams:** URCA will integrate the outcomes of this study into its broader electricity sector work projects, particularly in relation to tariff review processes, renewable energy integration frameworks, and long-term sector planning.
- **Stakeholder engagement:** Where future regulatory developments build on or are informed by this analysis, URCA may undertake further targeted engagement with consumers, licensees, government stakeholders, and other interested parties.

Annex A: URCA Renewable Energy Questionnaire

The following questionnaire was circulated to renewable energy customers using Google Forms to gather empirical data on installation costs, system performance, financing, and maintenance.

URCA Renewable Energy Questionnaire

Thank you kindly for your participation in this study to determine the actual return persons are achieving on their renewable energy investment. What follows is a series of short questions to gather the information needed to make that determination.

Answers are required to all the questions.

1. Please state your Name and Meter Number as it appears on your electricity bill.
This information is available on the top left-hand side of your bill (see below).
2. Did you finance all or a portion of your system with a loan?
3. Yes – please answer the next three loan questions below
4. No – please enter 0 as your answer to each of the next three loan questions below.
5. Amount borrowed on the loan, \$
6. Duration of the loan in years
7. Annual percentage rate on the loan, %
8. How much money did you pay to buy your system that was not financed by a loan?
If it was all financed by a loan just put 0 here.
9. Tell us about any routine annual expenses for the system (e.g. maintenance contract, insurance, etc.) State the annual amount in \$, followed by a description.
List all that you can remember. If you don't have any write "None".
10. Tell us about any other out of pocket expenses you have had on the system (e.g. you had to replace a damaged panel). State the Year, Amount in \$, and description. Write down all that come to mind. If you don't have any write "None".
11. Choose the statement that best describes how you feel about the investment in your renewable energy system?
12. I would not do it again
13. I would do it again
14. It was one of the best investments I have made

Annex B: Data Analysis

The data collected from the questionnaires were analyzed using Microsoft Excel to assess quantitative data related to renewable energy costs and performance. The efficiency of the investment was measured by comparing the net financial benefits generated to the initial and ongoing costs incurred. The model captures both the upfront capital expenditure and the long-term effects from reduced electricity bills, net billing credits, and maintenance expenses. In this model, ROI was calculated by estimating annual inflows (savings and revenues) and outflows (installation and maintenance costs) over the system's expected lifespan and then deriving a payback period and overall profitability ratio. Additionally, the billing data provided by BPL was used to validate customer-reported financial impacts and analyze trends in energy consumption before and after the adoption of solar energy systems.

Figure 5

Loan	Factor	Units
Total amount borrowed (inc. down payment)		\$
Down payment	0	\$
Annual percentage rate	0	% per year
Duration of loan	0	years
Initial down payment	0	\$
Annual loan payments	#NUM!	\$

This component of the PV ROI model (Figure 5) sets out the financing assumptions used to estimate the annual loan repayment obligations for a solar PV system. It captures key loan parameters specific to each participant including the total system cost, down payment, annual interest rate, and loan duration which together determine the annual loan repayments. These fixed annual loan payments are made over the life of the financing arrangement.

Figure 6

PV System Details	Factor	Units
System size	3	kW
Array tilt (elevation)	15	Deg. to horizontal
Array azimuth	180	Deg. from south
System losses	10%	%
Inverter efficiency	98%	%
DC to AC size ratio		number
Estimate of system output	5311.845	kWh per year
Estimate of avoided cost		kWh per year
Estimate of units fed-in to grid		kWh per year

This section of the model (Figure 6) outlines the technical characteristics of the proposed solar PV system and uses these parameters to estimate its expected annual energy generation. Key inputs specific to each participant include the system size, panel tilt and orientation, system losses, inverter efficiency, and the DC-to-AC size ratio. These factors reflect the physical and performance attributes that determine how much electricity the system can realistically produce under Bahamian conditions. Based on these inputs, the model calculates an annual system output estimate in this example, approximately 5,312 kWh per year for a 3kW system. This estimated production is then used to determine the customer's avoided electricity costs and the volume of excess energy that may be fed into the grid under net billing. Together, these outputs feed into the broader return-on-investment assessment

Figure 7

Routine Cost		
Maintenance contract	0	\$ per year
Insurance	105	\$ per year
Subtotal	105	
Inflation	3	%
Discount Rate for NPV analysis	5	%

This portion of the model (Figure 7) captures the routine operating costs and the macroeconomic assumptions required to assess the long-term financial performance of a solar PV installation. The routine costs specific to each participant include annual expenses such as system insurance and optional maintenance contracts, which together represent the recurring out-of-pocket costs that a customer must cover each year. In the

example shown, only insurance costs are included, resulting in a total annual routine cost of \$105.

Figure 8

	A	B	C	D	E	F	G	H
1	Electricity usage before PV system							
2	Month	2019	Jan	Feb	Mar	Apr	May	Jun
3	Units billed	kWh	506	935	1007	1134	1167	1150
4	Electricity charges	\$	\$147.71	\$270.88	\$275.73	\$397.09	\$378.46	\$394.31
5	Average charge per kWh		\$0.29	\$0.29	\$0.27	\$0.35	\$0.32	\$0.34
6	Electricity usage after PV system							
7	Month	2022	Jan	Feb	Mar	Apr	May	Jun
8	Units billed	kWh	501	648	866	875	746	609
9	Units fed to grid	kWh	270	249	245	337	335	320
10	Electricity charges	\$	\$ 39.15	\$ 31.13	\$ 25.73	\$ 35.39	\$ 35.18	\$ 33.60
11	PV Watts estimated ideal monthly output for 1kW system		171.43	173.88	205.53	204.3	194.68	174
14	System size	kW	5					
16	Estimate of ideal PV system output	kWh	857.15	869.4	1027.65	1021.5	973.4	870

Data was gathered for each participant's electricity usage for the full year before and after their PV system was installed (see an excerpt in Figure 8). This included their units billed and electricity charges. After the system was installed, it also included any units fed to the grid. The estimated output of the system was calculated using PV Watts (www.pvwatts.nrel.gov) and the specific system characteristics shown in Figure 6 above. The model also incorporates broader economic assumptions, specifically an inflation rate and a discount rate which are used in calculating the NPV of the investment. The inflation rate adjusts future costs to reflect expected price increases over time, while the discount rate reflects the time value of money and is used to convert future cash flows into today's dollars. These two parameters ensure that the ROI results are expressed in real, economically meaningful terms.

Figure 9

29	Annual Cash Flows			0	1	2	3	4	5
30	Item	Factor	Change	Y0	Y1	Y2	Y3	Y4	Y5
31	Loan payments			0	0	0	0	0	0
32	Routine cost				-150	-150	-150	-150	-150
33	Lumpsum payments not in loan			-6,500					
34	Value of units 0-200kWh @ \$0.00								
35	Value of units 201-800kW @ \$0.00								
36	Value of units generated and consumed @ 31 cents per kWh				1,102	1,102	1,102	1,102	1,102
37	Value of fuel charge								
38	Value of units fed to the grid 17 cents per kWh				609	609	609	609	609
39	Sub-total of cash flow			-6,500	1,561	1,561	1,561	1,561	1,561
40									
41	Present value accounting for inflation			-6,500	1,516	1,471	1,429	1,387	1,347
42	Cumulation of discounted cashflow			-6,500	-4,984	-3,513	-2,084	-697	649

The excerpt from the model above (Figure 9) shows a Discounted Cash Flow (DCF) analysis done of the PV system investment over a 20-year period for one of the participants. The initial Net Cash Outflow of \$6,500 in Year 0 represents the system's capital cost.

Subsequent years show a recurring Net Annual Cash Flow of \$1,561, derived primarily from avoided electricity purchases and fuel charges less routine maintenance costs. The core of the analysis, however, lies in the application of a discount rate to these future cash flows to determine their Present Value, effectively accounting for the time value of money and inflation. The Cumulation of Discounted Cashflow tracks the running balance; the point where this total shifts from negative to positive, occurring between Year 4 and Year 5, defines the project's Payback Period. The final value in Year 20 (not shown but considered the useful life of the system), is \$16,724. This NP, confirms that the project is financially viable, generating a positive return in today's dollars over its expected lifespan.

For each participant the model is used to calculate the Discounted Payback Period, Internal Rate of Return (at the Discount Rate), NPV, and ROI. These are described in Section 2.7 of the Results above.