JPS | RE-IMAGINING ENERGY... TOGETHER

THE JAMAICA PUBLIC SERVICE COMPANY LIMITED

ANNUAL TARIFF ADJUSTMENT SUBMISSION FOR 2018

&

EXTRAORDINARY RATE REVIEW

May 2, 2018

Executive Summary

Introduction

This is an overview of Jamaica Public Service Company Limited's (JPS) 2018 Annual Adjustment Submission to the Office of Utilities Regulation (OUR) (the "2018 Annual Adjustment"), provided in accordance with Electricity Licence 2016 (the Licence), Schedule 3, Paragraph 43, which states:

> *"The Licensee shall make annual filings to the Office at least sixty (60) days prior to the Adjustment Date. These filings shall include the support for the performance indices, the inflation and the proposed Non-Fuel Base Rates for electricity, and other information as may be necessary to support such filings…."*

This is the filing by JPS under the Licence for an annual adjustment under the Performance Based Rate-making Mechanism (PBRM) and will be the Company's last annual adjustment submission within the last Five Year Rate Review process 2014 – 2019 Rate Case Determination and before its first filing under the Five Year Rate Review Process in the Licence. JPS has in accordance with the terms of the Licence filed two other applications for Annual Adjustment under the Licence being the May 3, 2016 and the May 5, 2017 filings, respectively.

The Rate Determination process (including Annual Tariff Adjustment) provides an opportunity to implement business strategies that are consistent with the National Energy Policy, meet the evolving needs of the customers, improve JPS' financial performance and ensure a reasonable return is provided to shareholders.

As the sole integrated electric utility in Jamaica, JPS owns and operates 4 power stations, 9 hydroelectric plants, 1 wind farm, 53 substations and approximately 14,000 kilometres of distribution and transmission lines. JPS is also the sole distributor of electricity in Jamaica with over 600,000 customers served by a workforce of approximately 1,600 employees. JPS is a key partner in national development with an active corporate social responsibility portfolio, contributing significantly to the areas of education, and community development.

The generation of electricity in Jamaica is very dependent on fossil fuels and petroleum imports account for over 80% of electricity production costs. JPS actively supports the diversification of generation supply with renewable sources, such as solar and wind, or alternate fuels such as Liquefied Natural Gas (LNG) as a means of enhancing Jamaica's energy security.

Since the implementation of the 2014-2019 Rate Determination, JPS has made significant strides in executing on its mandate to modernise Jamaica's electricity sector, improve its overall efficiency and enhance service delivery. In this regard, the Company has successfully implemented a range of projects and far-reaching initiatives across its operations, including: generation, transmission and distribution, and customer service delivery.

The strategic objectives of JPS are closely aligned with Jamaica's National Energy Policy goals and include continued fuel diversification to achieve more affordable rates; reducing system losses and increasing productivity; improving reliability; increasing the availability of options to address the changing needs of customers; and improving service quality.

JPS maintains a central role in the development of Jamaica's energy landscape and is committed to supporting the national energy policy goals with improvement to the electrical system and provision of safe, reliable, and affordable service. The Company has been leading this improvement through important initiatives such as bringing LNG to Jamaica through the Bogue Combined Cycle Plant conversion, and supporting the development of renewable supply. These initiatives have produced tangible benefits for customers. Supply reliability has improved as a result of fewer and shorter outages, and faster response times with the installation of Distribution Automated (DA) switches, and along with other technology-based initiatives to improve the performance of the grid. Changes in the generation fuel supply (increasing use of LNG and renewables) has resulted in cleaner energy and reduced environmental impact of generation. This diversity in energy sources has also contributed to more stable energy pricing as Jamaicans become less exposed to oil price volatility. Finally, customers have considerably more options today to help manage usage as a result of JPS' investment in the prepaid infrastructure. These improvements require ongoing and sustained investment in the system.

The Jamaican electrical system continues to be significantly impacted by the high level of system losses. System losses in 2017 was 26.45% of the total power generated, of which 8.6% were attributed to technical losses (TL) and the other 17.85% attributable to non-technical losses (NTL). Of the reported NTL, approximately 80% of the system losses were related to illegal consumers. JPS continues to work along with number of critical stakeholders in its many attempts to address this challenge. Reducing systems losses is an important contributor to lowering rates in the medium term.

The 2018 Annual Tariff Adjustment

The 2018 Annual Tariff Adjustment provides the Regulator with an opportunity to appreciate the Company's operational performance in 2017, and, in accordance with the Licence, make certain adjustments required as a result of its 2017 performance to the schedule of rates for implementation as of July 1, 2018. As permitted, JPS has also included in its submission this year, certain proposed items which the Company has identified it requires for prudent utility functionality which requires the review and determination by the OUR to support the provision of electrical service in Jamaica to the benefit of all rate customers. With the support of these activities, resources and investments, JPS is confident that it will continue to improve its performance and provide safe, reliable and affordable electrical power to its customers.

The 2018 Annual Tariff Adjustment is consistent with the strategic objectives of JPS and focuses on meeting the balanced needs of the electrical system and customers. JPS has in this submission been particularly attentive to customer interests. The Company has reduced expenses wherever reasonable and appropriate, while protecting initiatives and programmes that provide direct benefit to customers. Where clearly known future expenses exist, JPS has considered how to mitigate the impacts of these future rate requirements by proposing appropriate and reasonable costs be included in this submission to provide gradualism and help prevent a balloon effect to rates. Finally, JPS acknowledges the financial challenges faced by all customers and has taken steps to provide rate stability by limiting or capping the maximum rate increase sought for non-fuel customer bills.

These objectives are reflected in the 2018 Annual Tariff Adjustment and focus on:

- Securing sufficient revenues to support the continued investment in the systems including reducing system losses;

- Managing rate impacts to customers; and

- Resolving outstanding matters with the OUR and move forward collaboratively to work on key items including Losses interface.

2018 Initiatives

JPS continues to aggressively pursue stretched initiatives to manage the electrical system to enhance affordability, reliability and quality of service. Many of these initiatives are intended to create a smooth tariff ramp for customers through the next regulatory period and provide continued support to the Company's grid investment strategy. Within the 2018 Annual Tariff Adjustment this includes:

- Reducing 2018 operating and maintenance expenses by approximately US$14M ($1,792M), 10% lower than 2017, to reduce rates by 3%;

- Completing a depreciation study to review asset lives, class and realign depreciation expenses where necessary ;

- Lowering financing costs through debt refinancing and proactively pursing the lowering of the costs of debt by taking advantage of market conditions that could result in annual savings in excess of US$5M ($640M) and reduce rates by 1.2%;

- Adopting a more aggressive approach to reducing system losses starting with a 0.75% reduction target in 2018 which is greater than the combined reduction for the prior two years; and

- Reducing the impact on rates by proposing that the System Benefit Fund (SBF) directly support the implementation of the LED Street Light Programme to help continue the advancement of this important initiative.

Return on Equity Shortfall

In preparing this annual adjustment filing, JPS completed an assessment of its performance in terms of achieving the approved regulatory Return on Equity (ROE). Based on the assessment, the company is achieving a ROE on the financial results, adjusted to remove the effects of non-Licenced activities and Regulatory required reserves, of approximately 6.35%. While JPS recognizes its right under the Licence to pursue a claim for the 5.9% ROE shortfall, the Company has decided to forego the claim at this time to avoid a large increase in customer tariffs.
It should be further noted that capital employed is at historic highs with 0.38cents of every dollar of margin producing revenues being reinvested in key capital projects.

2019 Rate Review

Notwithstanding the efforts outlined above that are expected to reduce costs to customers, there remain factors that support the requirement for a tariff increase in 2019. Key factors that create pressure on non-fuel rates in 2019 include the following:

- Plant decommissioning expenses;
- Continuing system investment;
- Commissioning new generation capacity:
    - Project Renaissance – Old Harbour 190 MW (South Jamaica Power Company);
    - JAMALCO – 94 MW CHP Plant (New Fortress Energy);
    - Eight Rivers – 37 MW solar (Eight Rivers Energy Company); and
- Incorporating the full provisions of the Licence to incorporate some items excluded from the 2014-19 Determination including the impact of the CWIP and an increased current portion of long-term debt.

A new 190MW combined cycle plant is being constructed and is expected to be commissioned in July 2019. This will result in JPS retiring four steam plants at two generating stations (3 units at Old Harbour and 1 unit at Hunts Bay). All of these plants are over 40 years. Costs associated with retirement of these assets are significant and include decommissioning expenses, unamortized depreciation expenses and redundancy costs for staff being separated. These costs are projected to be in excess of US$45M ($5,760M). To help mitigate the rate impacts to customers, JPS is proposing to allocate the recovery of these costs across the 2018 Annual Tariff Adjustment and the 2019 Rate Determination periods. The request for 2018 is US$14.6M ($1,869M) with an additional US$30M ($3,840M) expected to be recovered during the 2019 Rate review period.

Continued system investment is another primary focus. Over the past period, JPS has continued to increase its investment in the system each year. JPS investment in key initiatives including Conversion of Bogue Combined Cycle Plant to Operate on Natural Gas, Retooling of GT 11, Expansion of New Spur Tree Substation, Upgrade of Old Spur Tree Substation, Reconfiguration (LILO) of Oracabessa Substation, Major Distribution and Inter Bus Transformer Replacements, Voltage Standardization along the North Coast (Duncans, Martha Brea, Greenwood, Roaring River) and Gordon Town, Introduction of Enterprise Asset Management, Structural Improvement on the T&D network to include replacement and rehabilitation in excess of 15,000 degraded Poles and supporting Equipment, Lightning Mitigation systems, Installation of 198 Distribution Automation switches, 202 Trip Savers, Reclosers, Fault Circuit Indicators, upgrades to SCADA/ADMS, SMART meter installation, SMART streetlight installations, the development of the MESH network, and commence the installation of a hybrid storage system. These initiatives have contributed to further enhance the reliability, stability, and efficiency of the electric grid.

- Improved system reliability with a reduction in the number of outages per customer by 28% since 2014 and a reduction in the length of outages by 26% since 2014;
- Reduced system losses by 0.74% since 2016; and

- Enhanced fuel diversity with the conversion of Bogue Combined Cycle Plant to LNG and the restoration of GT 11.

The 2014-2019 Rate Determination was based on a test-year approach with December 2013 being the applicable Rate base. Since then, JPS has invested approximately US$307M ($39,296M) in capital improvements while depreciating US$266M ($34,048M), with the rate base grown by approximately $40M ($5,120M). Further increases in the rate base are anticipated in the 2019-2024 period, with JPS forecasting a further US$116M ($14,848M) in 2018. JPS' medium term plan projects annual capital expenditure in excess of $100M ($12,800M) for the five-year period 2019-2024. The inclusion of CWIP in the rate base will also cause an increase in the revenue target. As a reference point, the CWIP at December 2017 was US$86M ($11,008M).

The investment in 2018 is expected to provide further improvements in the reliability of the transmission and distribution system and a 0.75% reduction in system losses. Additionally, there will be significant investment in generation reliability improvement with important initiatives such as:

- Implementation of Energy Storage to help secure grid stability and improve reliability of the overall system with the growth in renewable generation.

- Interconnection facility for the SJPC 190MW combined cycle plant to be commissioned in 2019.

Application Summary

This filing for an Annual Review represents the last such filing for both the OUR and the Company; both will have the opportunity for the first time to fully implement the Revenue Cap model of the 2016 Licence (including but not limited to the establishment of a Base Year) since the advent of the new Licence. With the guidance and assistance of the OUR, both JPS and the OUR have sought to navigate a transitionary path to move from Price to Revenue Cap. Bearing in mind what the Licence seeks to achieve through the Five Year Rate Review Process, then practically, what is intended to be accomplished at a 5 year review should (all things being equal) also realise for the most part what an annual adjustment would.

Logically therefore, there should in all likelihood, be no filing for an annual review in 2019 (at least certainly not to provide support for the setting of targets) and therefore no need for target setting before 2019 in the Five Year Rate Review Process. This would allow for the establishment for the first time of a 'Base Year' to support the fixing of a Revenue Cap in keeping with the terms of the Licence. That said, JPS will nevertheless propose targets in the event the OUR should require JPS to do same.

The 2018 Annual Revenue Target reflects changes since 2014 in the value of the Jamaican dollar (JMD) against the US dollar (USD) and changes in the cost of providing electricity products and services related to inflation; as well as JPS' performance against the operational targets established by the OUR for 2017.

For ease of reference, the following table summarizes the major elements of the 2018 Annual Revenue Target and indicates how each element impacts the 2018 Expected Revenue increase. In reviewing same the following points should be noted:

1. Computation of the 2018 Revenue Cap, based on the adjusted revenue cap for 2014 determined by the OUR in the 2017 Annual Tariff Determination Notice, is $39,965,567,027;

2. When adjusted for the changes that have occurred since 2014 with the USD to JMD exchange rates, inflation rates in both Jamaica and the USA, the 2018 Revenue Cap (dI) is adjusted to $47,672,379,772;

3. Key performance drivers compared to 2017 have reduced the Annual Revenue Target by $2,091,418,006 or 4.31% as a result of the following:
    a. Actual sales exceeding targets established in the 2017 Annual Filing Determination have resulted in adjustments for energy, demand and customer charges;
    b. Not achieving the aggressive system losses target in 2017 has resulted in adjustments to the system losses surcharge;
    c. The foreign exchange gain returned during the period has resulted in a refund to customers; and
    d. Greater interest income from commercial and government accounts in 2017 has resulted in adjustments to the interest surcharge (lion share of interest has not been collected).

2018 Annual Tariff Adjustment

Item	**Amount ($'000)**	**Document Reference**
Actual Revenue 2017	48,520,723	
Revenue Cap 2018	39,965,567	Section 1.2.1
Revenue Cap 2018 (Adjusted for Growth – dl)	47,672,379	Section 1.2.2
Performance Adjustments (note 1)		
- Foreign Exchange Surcharge	(287,158)	Section 1.2.4
- Interest Surcharge	(102,614)	Section 1.2.4
- Volumetric kWh	(410,914)	Section 1.2.5
- Volumetric kVa	(80,958)	Section 1.2.5
- Customer Charge	(110,403)	Section 1.2.5
- System Losses	(1,099,371)	Section 1.2.5
	(2,091,418)	
Z-Factor Adjustments		
- Accelerated Depreciation	1,640,529	Section 3.1
- Separation Costs	242,432	Section 3.2
Prior Approval (note 2)		
- CPLTD return	633,454	
Extraordinary Rate Review Item		
- Debt Refinancing Cost Recovery	679,936	Section 4
2018 Annual Revenue Target	**48,777,312**	Section 5
Non - Fuel Bill Impact	+2.40%	
Proposed 2018 JPS Non-Fuel Bill Impact	**+2.00%**	

Note 1: Performance adjustments have been adjusted by the Weighted Average Cost of Capital (WACC) of 13.22%.
Note 2: In the 2017 Annual Tariff Adjustment, JPS filed for and received a determination from the OUR to recover a return on the Current Portion of Long Term Debt (CPLTD)

Quality of Service

JPS continues to improve and enhance the quality of service provided to customers. In 2017, initiatives to improve reliability of the electrical network included deployment of various grid technologies throughout the transmission and distribution network, including the installation of DA switches, smart fault circuit indicators, and smart meters. These ongoing improvements are geared towards developing a self-healing grid through increasing automated grid management, so as to help reduce the number of outages and facilitate faster JPS response times and power restoration when outages occur. This also includes as well the installation of over 100,000 smart meters year to date.

Independent assessment of the level of satisfaction of customers with the service provided by JPS, has revealed a general recognition of the positive impact of the results of the Company's ongoing focus on key areas of its operations. The results of a JPS-commissioned 2017 Customer Satisfaction (CSAT) study revealed improvements in service reliability as one of the areas with which customers are most satisfied. There was a high level of satisfaction with what customers describe as a noticeable decrease in power outages over time. The Company was generally perceived as a reliable and consistent service provider. Customers also indicated that the Company provided good customer service, both in the commercial offices and through its 24-hour Call Centre.

JPS and the OUR continue to work closely to finalize the establishment of a baseline for the measurement of quality of service for our customers. This baseline will be incorporated into the 2019 Rate Case Submission. Consequently, JPS has not filed a Q-Factor adjustment for 2018.

Thermal Efficiency (Heat Rate)

The heat rate efficiency of the JPS thermal plants improved by approximately 2.2% in 2017 compared to 2016. This was largely due to improved efficiency from generation plants returning from major overhauls (Rockfort Diesel Barge, Bogue Combined Cycle Plant), reduced operation of older facilities (Old Harbour Station), increased production from renewables such as wind and solar, and increased availability from new gas generation sources. For 2018/19, JPS proposes a heat rate target of 11,482 kJ/kWh. Though the overall heat rate performance has improved, the period 2018-19 will see JPS having to dispatch a thermal fleet which is a year older amongst aging IPPs units as well. While heat rate performance over the previous three years has averaged 11,414 kJ/kWh, JPS is increasingly aware of how easily this average can be negatively impacted by failures on key baseload units which have passed the major overhaul retirement dates. The proposed heat rate for 2018 is needed to assist JPS at least to partially mitigate negative impacts to JPS thermal assets; to mitigate any hindrance to JPS's ability to fully recover on its fuel costs and ultimately its ability to serve its customers. JPS recognizes its obligation to continue to work diligently to mitigate the outage risk and supply availability associated with these older assets.

System Losses

System losses have remained a significant challenge for JPS since privatization in 2001. Theft-related system losses has reduced rate-related income and has resulted in substantial penalties to the utility since 2009 (US$168M, $21,504). This issue is of critical importance and JPS is committed and motivated to implement mechanisms that reduce system losses, and as a result benefit both JPS and ultimately customers. JPS views the reduction of system losses as a significant opportunity to improve efficiency and lower the costs of electricity. Modest reductions that have been achieved in the previous two years have the opportunity to be accelerated with the aggressive advancement of the SMART AMI technology program.

To be able to accomplish this, JPS is looking to significantly increase investment in the programme and has budgeted the capital budget for losses to US$27M ($3,456M) in 2018 at a time when the Company is looking to implement a record level of capital expenditure (US$116M, $14,848M) to include other important initiatives including energy storage, interconnection of Old Harbour 190 MW, GT11 retrofitting, North Coast voltage standardization (Ocho Rios), grid modernization and transmission and distribution asset management.

JPS agrees that penalties should act as an incentive to achieve a reduction in system losses, but note that penalties also reduce the ability of the company to raise the capital and resources required to help reduce system losses. JPS is unable to fund the significant increase in capital expenditure needed and simultaneously absorb significant increase in penalties and is therefore proposing. An assessment on the impact of on 2018 suggests that any penalty greater than US$6M ($768M) results in an equivalent reduction in EBITDA and debt capacity by US$18M ($2,304M) and the inability for JPS to meet its Debt to EBITDA ratio and associated ability to draw loans to provide the equity contribution necessary to fund its capital expenditure programme for the year. JPS has calculated a system losses penalty of US$8.5M ($64M) for 2018/19 and maintains that a significant increase in the penalty is detrimental to its effort to reduce systems losses.

For 2018/19, JPS is proposing the elimination of the system loss penalty for 2018/19 and acceleration of the SMART Meter programme by increasing the installation objective from 100,000 to 200,000 units. Further, JPS is proposing that the assessment of penalties should consider only the execution of the program rather than system losses such that if JPS fails to deliver on the proposed program then it would be appropriate to apply the penalties.

JPS is also seeking engagement with the OUR to collaboratively develop a basis for establishing reasonable and achievable system losses targets to guide the administration of the system loss incentive mechanism. This will also include development of a fair and objective methodology to measure and report system losses (the Losses Spectrum) including consensus on the allocation and responsibility for causal factors within JPS's complete control, and losses where JPS reasonably does not have complete control.

Plant Decommissioning Costs

The 2018 Annual Tariff Adjustment includes a Z-Factor adjustment to address issues associated with the pending decommissioning of existing steam plants at Old Harbour and Hunts Bay. JPS intends to retire these existing steam plants by December 2020 as new gas fired generation plants are commissioned. Depreciation/impairment of these steam plants will need to be completed by the time of the commissioning of new generation plants to ensure these assets are retired before replacement assets are commissioned. Accelerating this depreciation will advance depreciation costs totalling US$12.8M ($1,640M). The decommissioning of these plants will also result in staff separation. Based on review of staffing requirements through to closure in December 2019, it is appropriate to initiate this process in 2018. The Company expects to separate staff employed to the Old Harbour location progressively over the 12 months to June 2019 and proposes to recover

US$1.89M (J$242M) through the 2018 Annual Tariff Adjustment. JPS believes including these costs in the 2018 tariff adjustment will help mitigate large rate increases anticipated in 2019 as greater decommissioning expenses are incurred.

Extraordinary Rate Review Item – Interest Cost Reduction Opportunity

JPS has included in the 2018 Tariff Rate Adjustment an Extraordinary Rate Review item which it hopes will be favourably considered by the OUR.

JPS currently has certain outstanding 10-year bonds with a principal value of US$179.1M ($22,925M), an attendant coupon rate of 11% per annum and a maturity date on July 6, 2021. Current favourable market conditions indicate that these outstanding bonds could be refinanced at a lower rate of approximately 8% per annum. This refinancing would translate into savings of US$5.37M ($687M) per annum for the remaining three years of the life of the bond or US$16.11M ($2,062M) in total. JPS is prepared to pass on all incremental savings to the customer net of the costs required to complete the refinancing and confirm the magnitude of the savings. JPS is proposing that the refinancing costs of US$5.3M ($678M) be recovered in the 2018-19 regulatory year. The Company acknowledges this request for recovery of debt refinancing costs falls outside of the annual adjustment rate filing. However, JPS believes this initiative provides a real opportunity to substantially reduce the cost of energy for customers through the reduction of interest costs on a sustained basis.

JPS acknowledges that a substantial increase in tariffs may present a challenge for some customers. In considering the needs of customers and their ability to accommodate large rate increases, the Company proposes a saw-off, or a cap, on the increase in the tariffs at 2% on the non-fuel component of the tariff to be applied during the 2018/2019 tariff year. This will provide for a greater level of reception of any increase in the market while permitting JPS to pursue needed investments the sector requires. JPS further proposes that the recovery of the differential between the determined level of increase and the proposed saw-off at 2% be deferred to the 2019/2020 period.

Rate Adjustment and Bill Impacts

The adjusted non-fuel annual revenue target required by JPS will result in limited bill increases for customers. For a typical residential customer increase in the non-fuel bill component will be limited to 2.0% under the rate adjustment proposed by JPS. Assuming no change in current fuel prices, the total bill impact (including Fuel and IPP charges) will be an increase of approximately 1.0% for all customers.

Due to the implementation of the Smart Streetlight Programme (SSP), JPS proposes a forward-looking mechanism to account for the reduction of Rate 60 consumption in the rate design for 2018. The proposed adjustment assumes that the 3,113 GWh sold in 2017 is held constant and the difference in the Rate 60 consumption was redistributed to the other rate classes using a weighted average.

Additional Item – Reconciliation of the EEIF Residual Balance

JPS is proposing that the OUR approves a direct set-off of the total capital expenditure cost of the Smart Streetlight Programme against the determined present and future liability to the Electricity Efficiency Improvement Fund (EEIF). Consistent with JPS' commitment to reducing costs for customers and the interconnection of the EEIF, the System Benefit Fund (SBF) and the Smart Streetlight Programme (SSP), JPS is proposing a comprehensive approach that addresses the requirement for the two funds and best serves customers. The proposal is guided by the following principles:

- Residual obligations to the EEIF by JPS will be honoured;
- Tariff impact on customer from discharging responsibilities to both the EEIF and the SSP (through the SBF) should be minimal;
- The SBF should have a net positive inflow in 2018; and
- The treatment of the EEIF balance and SBF contribution should not negatively impact JPS' capital expenditure capacity for the SSP.

The Electricity Efficiency Improvement Fund (EEIF) was initiated by the OUR in the 2009 five-year rate review to provide a stream of revenue to fund loss reduction capital programmes. The EEIF became the primary financing source for JPS' Residential Automated Metering Infrastructure (RAMI) initiative and by December 2016, the EEIF had funded assets totalling US$60.6M. As customers directly fund these assets, JPS does not earn a return on them due to the fact that they are excluded from the Rate Base.

On August 15, 2017, the Hon. Minister of Science, Energy & Technology, in accordance with the Electricity Act, directed that the SBF be established and initially funded with an amount of US$5M in order to allow JPS to recover the cost of implementing the SSP. This amount would normally be collected through customer tariffs. The OUR requested that JPS initially fund the US$5M for the SBF from the residual amounts due to the EEIF therefore avoiding an initial requirement to collect these funds through customer tariffs. Directing these funds to the SSP avoids any immediate need to adjust tariffs to fund the SBF, sustains the deployment of Smart LED streetlights that benefit customers, and maintains JPS responsibility for management and maintenance responsibilities for streetlight assets. JPS proposes that within the 2018 Annual Tariff Adjustment process, and subject to the EEIF audit and verification of capital expenditure requirements, JPS and the OUR agree on the final reconciliation of the EEIF obligations, the SSP capital expenditure and the SBF funding needs.

Glossary

ABNF	-	Adjusted Non-fuel base rate
CIS	-	Customer Information System
CPI	-	Consumer Price Index
EDF	-	Electricity Disaster Fund
EEIF	-	Energy Efficiency Improvement Fund Electricity
Licence	-	Electricity Licence, 2016
GDP	-	Gross Domestic Product
GOJ	-	Government of Jamaica
GWh	-	Gigawatt-hours
ICDP	-	Integrated Community Development Programme
IPP	-	Independent Power Purchase
JMD	-	Jamaican Dollar
kVA	-	Kilo Volt Amperes
kWh	-	Kilowatt-hours
MVA	-	Mega Volt Amperes
MW	-	Megawatt
MWh	-	Megawatt-hours
NWC	-	National Water Commission
O&M	-	Operating and Maintenance
OCC	-	Opportunity Cost of Capital
PATH	-	Programme of Advancement through Health and Education
PIOJ	-	Planning Institute of Jamaica
PBRM	-	Performance Based Rate-Making Mechanism
RAMI	-	Residential Advanced Metering Infrastructure
REP	-	Rural Electrification Programme Limited
RPD	-	Revenue Protection Department
T&D	-	Transmission & Distribution
TOU	-	Time of Use
USD	-	United States Dollar

Table of Contents

1. PBRM Annual Adjustment 18
   1.1 Overview 18
   1.2 Computation of Exhibit 1 Parameters 25
      1.2.1 The Revenue Cap for 2018 (RC_{2018}) 25
      1.2.2 The Rate of Change of Revenue Cap (dPCI) 26
      1.2.3 Weighted Average Cost of Capital (WACC) 28
      1.2.4 FX and Interest Surcharges 28
      1.2.5 Revenue Surcharge 29
      1.2.6 The 2018 Revenue Target (ART_{2018}) 45
   1.3 Target Setting 45
      1.3.1 JPS' Target Setting 45
      1.3.2 Heat Rate Target Proposal 46
      1.3.3 System Losses Target Proposal 46
2. System Losses Performance and Target Setting Proposal 48
   2.1 Introduction 48
   2.2 JPS Loss Performance and Results 49
   2.3 2017 Performance Drivers 51
   2.4 Socio-Economic Conditions 52
   2.5 JPS Losses Strategy and Plans 2018 53
   2.6 System Losses Penalty 55
   2.7 Conclusion 56
3. Z-Factor Adjustment 58
   3.1 Accelerated Depreciation of JPS Steam Generation Plants at Old Harbour and Hunts Bay 58
      3.1.1 Background 58
      3.1.2 Cost Recovery 59
      3.1.3 IFRS Requirements 60
      3.1.4 Analysis 60
      3.1.5 Ongoing Expenditure Requirements 61
      3.1.6 The Impact on Customers 61
      3.1.7 Conclusion 62
   3.2 Separation Costs 63
4. Extraordinary Rate Review: Debt Refinancing Cost Recovery 64
   4.1 Electricity Licence 64
   4.2 Background 64

4.3 Conclusion 66
5. Proposed 2018 Tariff Basket and Rates 67
5.1 Pre-paid Rates 69
5.1.1 Rate 10 Pre-paid Rates 69
5.1.2 Rate 20 Pre-paid Rates 70
5.2 Forward-looking Model 70
5.3 Community Renewal Rate 72
6. Overview of Fuel Efficiency Mechanism 73
6.1 Introduction 73
6.2 JPS' Heat Rate Performance 74
6.2.1 Thermal Heat Rate Performance vs Target: (January 2016 – March 2018) 76
6.3 Comparing Regulatory Review Periods: July 2016 – June 2019 76
6.4 Heat Rate Forecast for July 2018 to June 2019 77
6.4.1 Model Assumptions 77
6.4.2 System Heat Rate Model Results 79
6.4.3 JPS Thermal and System Heat Rate Forecasts for the 2018/19 Regulatory Period 79
6.5 Proposed Heat Rate Target 79
6.5.1 Key Considerations 80
7. Ensuring Quality of Service – The Q-factor 82
7.1 Introduction 82
7.2 JPS' OMS Data for Reliability Baseline 82
7.3 Q-Factor Reliability Benchmark and Implementation Issues 83
7.4 Reliability Baseline 83
7.5 2017 Reliability Performance 85
7.6 2017- 2018 Reliability Performance Improvement Strategy 86
7.6.1 Automated/Technological Approaches 87
7.6.2 Traditional/ Routine Activities - Reliability Improvement Methods 88
7.7 2018 Reliability Improvement Plan 89
7.8 2018 System Reliability Objectives: 90
8. Other Regulatory Matters 91
8.1 EEIF, Smart Streetlight Programme and the System Benefit Fund 91
8.1.1 Background 91
8.1.2 EEIF & SBF 92
8.1.3 JPS' Proposed Way Forward 93
8.1.4 Offset of EEIF Obligations Against SSP Capital Expenditure 93
8.1.5 SBF Contribution 94

8.1.6 Advantages of JPS' Proposal ... 94
8.2 Rate 70 Interim Rates Continuation ... 95
9. Appendices ... 96

List of Figures

Figure 1-1: Loss Distribution by Mode for Rate 50 ... 37
Figure 1-2: Loss Distribution by Mode for Rate 40 ... 38
Figure 1-3: Loss Distribution by Mode for Medium Rate 20 ... 39
Figure 1-4: Loss Distribution by Mode for Small Rate 20 ... 40
Figure 1-5: Loss Distribution by Mode for Rate 10 ... 42
Figure 2-1: Annual System Losses in MWh and Annual Rolling System Loss Percentage ... 49
Figure 2-2: Losses Performance 2017 ... 51
Figure 6-1: Thermal Heat Rate Performance vs Target, Jan 2016 – Mar 2018 ... 76
Figure 7-1: SAIDI Performance in 2017 – (inclusive of Generation, Transmission and Distribution) ... 85
Figure 7-2: SAIFI Performance in 2017 – (inclusive of Generation, Transmission and Distribution) ... 86

List of Tables

Table 1-1: Escalation Factor ... 27
Table 1-2: 2018 Revenue Cap Adjustment ... 28
Table 1-3: Computation of FX and Interest Surcharges\ ... 29
Table 1-4: Corrected Approved Annual Revenue Target: 2017 – 2018 ... 31
Table 1-5: Computation of Volumetric Adjustment ... 32
Table 1-6: 2017 System Losses ... 33
Table 1-7: Allocation of 2017 Non-Technical System Losses ... 34
Table 1-8: Computation of TULos2017 ... 34
Table 1-9: Description of the Modes of Loss ... 36
Table 1-10: Loss Distribution Data for Medium Rate 40 and 50 ... 38
Table 1-11: Loss Distribution Data for Medium Rate 20 ... 39
Table 1-12: Loss Distribution Data for Small Rate 20 ... 41
Table 1-13: Loss Distribution Data for Rate 10 ... 43
Table 1-14: 2018 Annual Revenue Target Calculation ... 45
Table 2-1: System Loss Strike Rates ... 52
Table 2-2: 2018 Capital Expenditure Plan ... 54
Table 3-1: Incremental Depreciation Charges ... 61
Table 3-2: Total incremental Depreciation Charges ... 61
Table 4-1: Debt Refinance Costs ... 65
Table 5-1: 2017 Approved Non-Fuel Tariff Basket ... 67
Table 5-2: Actual 2017 Revenues ... 67
Table 5-3: 2017 Billing Determinants ... 68
Table 5-4: Approved Non-Fuel Tariffs for 2017 ... 68
Table 5-5: Proposed Revenues for 2018/2019 ... 68
Table 5-6: Proposed 2018/2019 Tariff ... 69
Table 5-7: Analysis of JPS Proposed Prepaid Rate for Rate 10 Customers ... 70
Table 5-8: Analysis of JPS Proposed Pre-paid Rate for Rate 20 Customers ... 70
Table 5-9: Proposed Tariff for 2018/2019 (Forward-looking Model) ... 71
Table 5-10: Analysis of JPS Proposed Pre-paid Rate for Rate 20 Customers (Forward-looking Model) ... 71
Table 5-11: Analysis of JPS Proposed Pre-paid Rate for Rate 10 Customers (Forward-looking Model) ... 71
Table 6-1: JPS Thermal Heat Rate Performance ... 75
Table 6-2: 2018/2019 JPS Thermal Heat Rate Forecast ... 79
Table 7-1: Summary of Reliability Performance in 2017 ... 86

Table 8-1: SSP Schedule and Capital Expenditure 92

List of Appendices

Appendix A: STATIN CPI New Release – CPI Index for Jamaica, March 2018
Appendix B: US Bureau of Labour CPI Index for March 2018
Appendix C: Loss Initiatives
Appendix D: CAPEX Requirement Overview 2017 – 2010
Appendix E: Bill Impact
Appendix F: 2018 Reliability Statistics Dataset (Excel workbook provided separately)
Appendix G: Rule Base Data Dictionary

1. PBRM Annual Adjustment

1.1 Overview

The Electricity Licence 2016 dated January 27, 2016 was gazetted in February, 2016. It includes several amendments to the Amended and Restated All Island Electric Licence (2011) and moves the Performance-Based Rate-Making (PBRM) from a price cap to a revenue cap regime. The amended Licence shall hereafter be cited as the "Electricity Licence".

Paragraphs 1 and 2 of Condition 15 of the Electricity Licence which governs Price Controls, states:

1. *"The Licensee is subject to the conditions in Schedule 3.*

2. *The rates to be charged by the Licensee in respect of the Supply of electricity shall be subject to such limitation as may be imposed from time to time by the Office."*

Schedule 3 of the Electricity Licence prescribes that "*the basis of rate setting shall be the revenue cap principle which looks forward at five (5) year intervals and involves the de-coupling of kilowatt hour sales and the approved revenue requirement.*"

Paragraphs 1 to 5 of Schedule 3 states as follows:

1. *"The rates shall be charged to customers in accordance with rate classes approved by the Office.*

2. *The rates are comprised of the following:*
   a. *Non-fuel rate; and*
   b. *Fuel rate.*

3. *The fuel rate shall be adjusted by the Office monthly in accordance with the Fuel Cost Adjustment Mechanism.*

4. *The non-fuel rate shall be reviewed by the Office:*
   a. *In rate reviews that are customarily done every five years;*
   b. *In extra-ordinary rate reviews which may be conducted in between rate reviews; and*
   c. *Annually under the Performance Based Rate-making Mechanism ("**PBRM**") adjustment.*

5. *All rates shall be determined by the Office."*

Paragraphs 42 to 56 of Schedule 3 describes the methodology to be used in making an Annual Performance-Based Rate-Making Filing for Rates under the mechanism. Paragraphs 42 to 46 provides as follows:

42. *The methodology to be utilised by the Office in computing the PBRM is set out in detail in **Exhibit 1**.*

43. *The Licensee shall make annual filings to the Office at least sixty (60) days prior to the Adjustment Date. These filings shall include the support for the performance indices, the inflation, and the proposed non-fuel rates for electricity and other information as may be necessary to support such filings.*

44. *These filings shall also propose the non-fuel rates scheduled to take effect on the Adjustment Date for each of the rate categories. These rates shall be set to recover the annual revenue requirement for the same year in which the proposed rates take effect, given the target billing determinants.*

45. *The target billing determinants shall be based on the actual billing determinants for the immediately preceding calendar year. The Office is empowered to adjust the target billing determinants for known and measurable changes anticipated in relation to the following year.*

46. *The Office shall apply the following adjustment factors to the non-fuel rate at each PBRM:*
    a. *The **Q-Factor**, which is the annual allowed price adjustment to reflect changes in the quality of service provided by the Licensee to its customers. The Office shall measure the quality of service versus the annual target set in the 5 year rate review determination.*
    b. *The **H-Factor**, if applicable, will reflect the heat rate as defined by the Office of the power generated in Jamaica versus a pre-established yearly target in the 5 year rate setting determination by the Office.*
    c. *The **Y-Factor** reflects the achieved results versus the long-term overall system losses target.*
    d. *The **Z-Factor** reflects the adjustment to the non-fuel rate due to special circumstances. The Z factor is the allowed percentage increase in the Revenue Cap due to any of the following special circumstances:*

        (i) Any special circumstances that satisfy all of the following:

            a) affect the Licensee's costs or the recovery of such costs, including asset impairment adjustments;
            b) are not due to the Licensee's managerial decisions;
            c) have an aggregate impact on the Licensed Business of more than $50 million in any given year; and

            d) are not captured by the other elements of the revenue cap mechanism.

        (ii) where the Licensee's rate of return with respect to the Licensed Business is one (1) percentage point higher or three (3) percentage points lower than the approved regulatory target (after taking into consideration the allowed true-up annual adjustments, special purpose funds included in the Revenue Requirement, awards of the Tribinal (sic) and determiantions (sic) of the Office and adjustments related to prior accounting periods). This adjustment may be requested by the Licensee or the Minister or may be applied by the Office;

(iii) where the Licensee's capital & special program expenditure are delayed and such delay results in a variation of 5% or more of the annual expenditure, the Z-factor adjustment will take into consideration the over–recovery of such expenditures plus a surcharge at the WACC;

(iv) Government Imposed Actions;

(v) where the Licensee demonstrates and the Office agrees that an extra-ordinary level of capital expenditure or a special programme is required (i.e. greater than 10% for any given year relative to the previously agreed five year Business Plan); or

(vi) where the Licensee is required to make a change to the Guaranteed Standards in Condition 17(5) and such change will have a financial impact on the Licensee in an amount greater than Fifty Million Jamaican dollars (J$50,000,000.00) during any rate review period.

Paragraph 47 lays out the conditions under which Government Imposed Actions may trigger a Z factor claim and paragraph 48 prescribes the necessary rate adjustment that will result from a failure on the part of the Licensee to undertake the investment activities stated in the Business Plan on an annual basis subject to a variation of 5% of the annual expenditure. Paragraphs 49 to 54 captures the provisions relating to the right of the Licensee to charge interest on overdue balances to the GOJ and customers, other than residential customers, who do not pay their bills in full by the due date. In relation to residential customers, the Electricity Licence permits the Licensee to charge a late payment fee and offer an early payment incentive to residential customers for payments made on time and in full by the due date but prohibits the charging of interest charges on overdue balances.

The methodology to be utilised in computing the PBRM is set out in detail in Exhibit 1 to Schedule 3 of the Electricity which states:

The Annual Revenue Target shall be adjusted on an annual basis, commencing July 1, 2016, *(Adjustment Date)*, pursuant to the following formulae:

$$\mathrm{ART_y} = \mathrm{RCy}(1 + \mathrm{dPCI}) + \left(\mathrm{RS_{y-1}} + \mathrm{SFX_{y-1}} - \mathrm{SIC_{y-1}}\right) \times (1 + \mathrm{WACC})$$

where:

$$\mathrm{RS_{y-1}} = \mathrm{TUVol}_{y-1} + \mathrm{TULos_{y-1}}$$

$$\mathrm{SFX_{y-1}} = \mathrm{AFX_{y-1}} - \mathrm{TFX}$$

$$\mathrm{SIC_{y-1}} = \mathrm{AIC_{y-1}} - \mathrm{TIC}$$

and

$\mathrm{ART_y}$	=	Annual Revenue Target for Year "y"
RCy	=	Revenue Cap for the current tariff adjustment year "y" as established in the last Rate Review Process
$\mathrm{RS_{y-1}}$	=	Revenue surcharge for Year "y-1"
$\mathrm{TUVol_{y-1}}$	=	$\left\{\frac{\mathrm{kWh\ Target_{y-1}} - \mathrm{kWh\ Sold_{y-1}}}{\mathrm{kWh\ Target_{y-1}}}\right\} \times \mathrm{Non\ Fuel\ Rev\ Target\ for\ Energy}$

$$+\left\{\frac{\text{kVA Target}_{y-1}-\text{kVA Sold}_{y-1}}{\text{kVA Target}_{y-1}}\right\}\times \text{Non Fuel Rev Target for Demand}$$
$$+\left\{\frac{\text{\#Customer Charges Billed Target}_{y-1}-\text{\#Customer Charges Billed}_{y-1}}{\text{\# Customer Charges Billed Target}_{y-1}}\right\}\times$$
$$\text{Non Fuel Rev Target for Customer Charges}$$

Given that all tariffs charged to customers can be broadly allocated to three primary revenue buckets, namely, Energy, Demand and Customer Charge, the true-up mechanism will be operated on that basis. The revenue target for each year will be allocated to each bucket with the target quantities estimated to achieve each revenue bucket forming the basis for the true-up adjustment for each revenue bucket as outlined in the formulae above.

For the purpose of administering the system losses component of the Annual revenue target Paragraph 38 of Schedule 3 of the Electricity Licence describes the losses targets as follows:

The target set by the Office for losses shall normally be done at the Rate Review and be for a "rolling"[1] ten (10) year period and broken out year by year over the following three (3) categories:

a. Technical losses;
b. The aspect of non-technical losses that are within the control of the Licensee; and
c. The aspect of the non-technical losses that are not totally within the control of the Licensee.

$$TULos_{y-1} = Y_{y-1} * ART_{y-1}$$
$$Y_{y-1} = Ya_{y-1} + Yb_{y-1} + Yc_{y-1}$$

Ya_{y-1} = Target System Loss "a" Rate$\%_{y-1}$ – Actual System Loss "a" Rate$\%_{y-1}$

Yb_{y-1} = Target System Loss "b" Rate$\%_{y-1}$ – Actual System Loss "b" Rate$\%_{y-1}$

Yc_{y-1} = (Target System Loss "c" Rate$\%_{y-1}$ – Actual System Loss "c" Rate$\%_{y-1}$) * RF

where:

Ya = System losses that fall under subsection "a" of paragraph 38.

Yb = System losses that fall under subsection "b" of paragraph 38.

Yc = System Losses that fall under subsection "c" of paragraph 38.

RF = The responsibility factor determined by the Office, which is a percentage from 0% to 100%. This responsibility factor shall be determined by the Office, in consultation with the Licensee, having regard to the (i) nature and root cause of losses; (ii) roles of the Licensee and Government to reduce losses; (iii) actions that were supposed to be taken and resources that were

[1] The rolling nature assures a clear long term focus for Loss mitigation, incentivizing the Licensee to go beyond what might have been agreed in the 5-Year Business Plan, because the benefit will be accrued over a longer period. The breakdown of the individual elements of the loss targets will assure a linkage to the reductions targeted and the actions taken and/or funded in the 5-Year Business Plan; it also supports a potential "Z-factor" adjustment in case the non-technical losses that are not totally within the control of the Licensee are strongly influenced by matters unforeseen during the rate review process.

allocated in the Business Plan; (iv) actual actions undertaken and resources spent by the Licensee; (v) actual cooperation by the Government; and (vi) change in external environment that affected losses.

SFX_{y-1} = Annual foreign exchange result loss/(gain) surcharge for year "y-1". This represents the annual true-up adjustment for variations between the foreign exchange result loss/(gain) included in the Base Year revenue requirement and the foreign exchange result loss/(gain) incurred in a subsequent year during the rate review period.

AFX_{y-1} = Foreign exchange result loss/(gain) incurred in year "y-1".

TFX = The amount of foreign exchange result loss/(gain) included in the revenue requirement of the Base Year

SIC_{y-1} = Annual net interest expense/(income) surcharge for year "y-1".

This represents the annual true-up adjustment for variations between the net interest expense/(income) included in the Base Year revenue requirement and the net interest expense/(income) incurred in a subsequent year during the rate review period. The net interest income shall be deducted from the revenue requirement while net interest expense shall be added to the revenue requirement.

AIC_{y-1} = Actual net interest expense/(income) in relation to interest charged to customers and late payments per paragraph 49 to 52 of Schedule 3 in year "y-1".

TIC = The amount of net interest expense/(income) in relation to interest charged to customers and late payments included in the revenue requirement of the Base Year.

dPCI = Annual rate of change in non-fuel electricity revenues as defined below

WACC = The Weighted Average Cost of Capital determined in the Rate Review process.

The annual PBRM filing will follow the general framework where the rate of change in the Revenue Cap will be determined through the following formula:

$$dPCI = dI \pm Q \pm Z$$

where:

dI = the growth rate in the inflation and JMD to USD exchange rate measures;

Q = the allowed price adjustment to reflect changes in the quality of service provided to the customers versus the target for the prior year;

Z = the allowed rate of price adjustment for special reasons, not under the control of the Licensee and not captured by the other elements of the formulae.

Each of these essential components of the PBRM framework is described below:

The Growth Rate (dI)

The rate of change of the Revenue Target (dPCI) applied annually is the adjustment to the annual Revenue Cap as established during the 5-year rate review process.

The growth rate (dI) represents the changes in the value of the JMD against the USD and the inflation in the cost of providing electricity products and services.

Specifically, dI is set as:

$$dI = (EX_n - EX_b)/EX_b \, \{USP_b + INF_{US}(USP_b - USDS_b)\} + INF_{us}(USP_b - USDS_b) + (1 - USP_b)INFJ$$

where:

EX_b = Base US exchange rate at the start of the Rate Review period.
EX_n = Applicable US exchange rate at Adjustment Date.
INF_{US} = Change in the agreed US inflation index as at 60 days prior to the Adjustment Date and the US inflation index at the start of the Rate Review period.
INF_J = Change in the agreed Jamaican inflation index as at 60 days prior to the *Adjustment Date* and the Jamaican inflation index at the start of the Rate Review period.
USP_b = US portion of the total non-fuel expenses as determined from the Base Year.
$USDS_b$ = US debt service portion of the non-fuel expenses as determined from financials in the Base Year of the rate setting period.

The Z-Factor

Z = (Government Imposed Action + Impaired Assets + Funding of Special Programs)$_{y-1}$ – (Government Imposed Action + Impaired Assets + Funding of Special Programs)$_{RC\text{-}Base\text{-}year}$ + approved excessive variation in ROE catch-up + any variation in any other special circumstances as defined in clause 46d and not covered before.

The Q-Factor

The Q-factor should be based on three quality indices until revised by the Office and agreed between the Office and the Licensee:

- SAIFI—this index is designed to give information about the average frequency of sustained interruptions per customer over a predefined area.

$$SAIFI = \frac{\text{Total number of customer interruptions}}{\text{Total number of customers served}}$$

(Expressed in number of interruptions (Duration >5 minutes) per year)

- SAIDI—this index is referred to as customer minutes of interruption and is designed to provide information about the average time that customers are interrupted.

SAIDI = (<u>Σ Customer interruption durations</u>)

Total number of customers served
(Expressed in minutes)

- CAIDI— this index represents the average time required to restore service to the average customer per sustained interruption. It is the result of dividing the duration of the average customer's sustained outages (SAIDI) by the frequency of outages for that average customer (SAIFI).

$$\text{CAIDI} = \frac{(\Sigma \text{ Customer interruption durations})}{\text{Total number of interruptions}} \text{ or } \frac{\text{SAIDI}}{\text{SAIFI}}$$

(Expressed in minutes per interruption *(Duration >5 minutes)*)

Until revision by the Office the quality of service performance should be classified into three categories, with the following point system:

- Above Average Performance (greater than 10% above benchmark) — would be worth 3 Quality Points for each of the three quality indices, viz, SAIFI, SAIDI or CAIDI;
- Dead Band Performance (+ or – 10%) — would be worth 0 Quality Points on either SAIFI, SAIDI or CAIDI; and
- Below Average Performance (more than 10% below target) — would be worth -3 Quality Points on SAIFI, SAIDI or CAIDI.

Until revision by the Office the adjustment factors that would be assigned to the cumulative quality points scores for the three reliability indices as follows. If the sum of quality points for:

- SAIFI, SAIDI, and CAIDI is 9, then Q = +0.50%
- SAIFI, SAIDI, and CAIDI is 6, then Q = +0.40%
- SAIFI, SAIDI, and CAIDI is 3, then Q = +0.25%
- SAIFI, SAIDI, and CAIDI is 0, then Q = 0.00%
- SAIFI, SAIDI, and CAIDI is -3, then Q = -0.25%
- SAIFI, SAIDI, and CAIDI is -6 then Q = -0.40%
- SAIFI, SAIDI, and CAIDI is -9 then Q = -0.50%

As stated earlier, this 2018-2019 Annual Review filing immediately precedes the Five Year Rate Review Process scheduled to commence in April 2019 with the filing of JPS' proposal for the Five Year Rate Review. As required by the Electricity Licence (2016), the result of the Rate Review Process are the Revenue Cap and associated non-fuel rate schedules for the period 2019-2024, together with the annual performance for each year within that rate period. As provided in paragraph 38 of Schedule 3 of the Electricity Licence, the targets which are normally set during the Rate Review Process, are established following a consideration of the Base Year, historical performance and the agreed resources in the Business Plan, corrected for extraordinary events. These targets which form the basis of the performance incentive mechanism related to the non-fuel components of the tariff, are subsequently applied annually to determine the Annual Revenue Target through the Performance Based Rate-making Mechanism (PBRM) adjustment. The process as outlined in the Electricity Licence would result in the measurement and application of targets to the performance of JPS through the non-fuel rates to take effect in the remainder of the year immediately following the year under assessment.

Accordingly, should an Annual Adjustment filing be made in the same year as a Five Year Rate Review Process, a likely result would be that the measurement of the performance in the year immediately preceding such Five Year Rate Review could result in an adjustment to non-fuel rates which rates could stand to be adjusted by the Base Year performance; being the year immediately preceding the adjustment. That said, given all the elements the filing of an Annual Review, it is entirely conceivable that the filing of an annual review is not mutually exclusive to the filing of a 5 year Rate Review. Nevertheless, JPS will proceed to propose targets which would be established in the 2018-2019 regulatory filing but which would utilized for in any Annual Adjustment filed in 2019-2020.

1.2 Computation of Exhibit 1 Parameters

This section outlines the proposed Annual Revenue Target for 2018 based on the Revenue Cap (RC), revenue surcharge, foreign exchange gain/losses, interest expense/income surcharge, and weighted average cost of capital related adjustments.

The annual adjustment in the Electricity Licence allows JPS to adjust its revenue target to reflect general movements in inflation, changes in service quality, changes in the base foreign exchange rate, and where applicable an adjustment for unforeseen occurrences beyond management control not captured in the other elements of the PBRM. The mechanism also allows for a revenue surcharge which includes a true up for revenues, a system losses incentive mechanism and a FX surcharge, offset by net interest income received from customers.

The Annual Revenue Target parameters in this filing are consistent with the Office of Utility Regulator's (OUR's) determinations as published in the 2017 Annual Tariff Determination Notice.

1.2.1 The Revenue Cap for 2018 (RC_{2018})

The Electricity Licence, describes the parameter RC_y as the revenue cap for year "y" which should be established in the most recent Rate Review. The Electricity Licence contemplates that for each year of the Rate Review period, the parameter RC_y will be established without factoring inflation. In making annual adjustments to the Revenue Cap, the inflation between the Base Year and the current adjustment period would be factored into the dI parameter. Given that the 2014 – 2019 rate determination did not contemplate revenue cap regulation, the Revenue Cap, RC_y, specific to the 2016/2017 Annual Adjustment filing was not established in the 2014-2019 Rate Review Process, and so JPS, in the 2016 Annual Adjustment Filing, proposed that the Revenue Cap for 2016 should be determined by the following formula:

$$\mathrm{RC}_{2016} = (\text{Revenue Requirement Established in } 2014 - 2019 \text{ rate review}) \times (1 - \mathrm{X})^2$$

where X is the efficiency improvement factor - the X factor, which was applicable under the price cap regulation and allows for efficiency improvement over the period from the last rate review to the current adjustment period. With respect to efficiency improvement, JPS proposed that this factor should be incorporated in setting the Revenue Cap target by applying the X factor of 1.10% that was set by the OUR in the 2014-2019 Tariff Determination as a proxy for the remainder of this rate review period since it was explicitly removed from the annual adjustment formula indicated in the Electricity Licence. The Electricity Licence contemplates that the efficiency improvement factor will be incorporated in the Business Plan for each five-year rate review period prospectively.

In its 2016 Annual Tariff Adjustment Determination Notice, the OUR concurred with JPS' position on the setting of RC_{2016} on the basis that it represents a simple and straight forward approach. The OUR argued that the alternative would be the derivation of a 5-year revenue cap which would be complex and time-consuming and therefore it should be reserved for a full Rate Review Process. Using the same rationale as established in 2016, the revenue cap for 2018 would have been determined by the application of the following formula:

$$\mathrm{RC}_{2018} = (\text{Revenue Requirement for the } 2014 - 2019 \text{ Rate Review period revised in } 2017) \times (1 - \mathrm{X})^4$$

It should be noted that in the 2017 Annual Review Determination Notice, the OUR established a revised 2014-2019 revenue requirement. The revised revenue requirement in 2014 Jamaican dollars was set at J$41,773,495,042 based on the changes to JPS' rate of return on investment and depreciation expenditure arising from modifications to the depreciable lives of JPS' fixed assets (Determination 6).

Based on this approach, the revenue cap for 2018 is J$39,965,567,027.[2]

1.2.2 The Rate of Change of Revenue Cap (dPCI)

In the 2016 Annual Tariff Adjustment Filing, JPS outlined its proposal for setting the parameters in the formula for dI described in Exhibit 1 of Schedule 3 of the Electricity Licence. JPS argued that this formula represents a reformulation of the formula for the growth rate, dI, that was included in the OUR's 2014 – 2019 Tariff Determination Notice. In its response to the 2016 Annual Tariff Adjustment Filing, the OUR accepted JPS' analysis and the parameters proposed by JPS were used as the basis for computing dI and consequently the adjustment factor, dPCI.

The agreed values of the parameters were:

- USP_b =80%;
- $USDS_b$ = 6.88%; and
- EX_b =J$112:US$1.

The application of the adjustment factor dPCI will result in an increase of 19.28% to the base non-fuel Revenue Requirement in Jamaica dollar terms, derived using the following factors:

- Jamaican point-to-point inflation (INF_J) between March 2018 and March 2014 of 15.83%, derived from the CPI data[3] published by STATIN (see Appendix A);

[2] The revenue cap for 2018 is calculated as follows: J$41,773,495,042 x $(1\text{-}1.10\%)^4$ = J$39,965,567,027.
[3] Obtained from the Statistical Institute of Jamaica.

- U.S. point-to-point inflation rate (INF_{US}) between March 2018 and March 2014 of 5.61%, derived from the U.S. Department of Labor statistical data[4] (see Appendix B);

- The 14.29% increase in the Base Exchange Rate $\left(\frac{EX_n - EX_b}{EX_b}\right)$ from J$112: US$1 to J$128.00: US$1;

- The Q-factor is set to zero; and

- The computed value of the Z-factor is 4.71% for the accelerated depreciation of assets and separations costs discussed in Chapter 3.

The table below sets out the details of the computation of the growth rate, dI. The adjustment factor, dPCI, which amounts to 24.00% is computed by adding the Z-factor to dI.

Table 1-1: Escalation Factor

Annual Adjustment Clause Calculation			
ESCALATION FACTOR (dPCI) based on point to point data as at March 2018			
Line	Description	Formula	Value
L1	Base Exchange Rate		112.00
L2	Proposed Exchange Rate		128.00
L3	Jamaican Inflation Index		
L4	CPI @ Mar 2018		248.1
L5	CPI @ Mar 2014		214.2
L6	US Inflation Index		
L7	CPI @ Mar 2018		249.6
L8	CPI @ Mar 2014		236.3
L9	Exchange Rate Factor	(L2-L1)/L1	14.29%
L10	Jamaican Inflation Factor	(L4-L5)/L5	15.83%
L11	US Inflation Factor	(L7-L8)/L8	5.61%
L12	Escalation Factor (dI)	L9*{0.8+(0.8-0.0688)*L11}+(0.8-0.0688)*L11+(1-0.8)*L10	19.28%
L13	Q-factor		0.00%
L14	Z-factor	4.10% + 0.61%	4.71%
L13	**dPCI**	**dI + Q + Z**	24.00%

It should be noted that the 24.00% increase represents the adjustment between 2014 and 2018 and does not represent an annual increase.

Table 1-2 shows the 2018 revenue cap adjustment for dPCI escalation factor.

[4] Obtained from U.S. Bureau of Labor Statistics website, http://data.bls.gov/cgi-bin/surveymost.

Table 1-2: 2018 Revenue Cap Adjustment

2018 Revenue Cap Adjustment			
Line	Description	Formula	Value
L1	2018 Revenue Cap (RC_{2018})		39,965,567,027
L2	dPCI (dI - Q + Z)		24.00%
L3	**Adjusted RC_{2018}**	L1x(1+L2)	**49,555,339,962**

1.2.3 Weighted Average Cost of Capital (WACC)

JPS is not proposing an adjustment to the WACC at this time and as such the WACC that will be used in this filing is the pre-tax WACC that was set in the 2014 – 2019 Tariff Determination Notice.

1.2.4 FX and Interest Surcharges

Foreign Exchange (FX) losses and interest charges were not included in the revenue requirement that was set by the OUR in the 2014 – 2019 Tariff Determination Notice however, Schedule 3, paragraph 31 of the Electricity Licence makes provision for the inclusion of FX losses in the revenue requirement to be set at the time of a Rate Review. The annual adjustment mechanism described in Exhibit 1, includes a true-up for FX losses (FX surcharge) which is offset by interest surcharge on customer arrears. At the time of an annual adjustment, the FX surcharge is computed as the actual FX loss incurred during the previous year less the target for FX loss set at the last Rate Review. Similarly, the interest surcharge is calculated as the actual interest income (including net late payment fee) less the provisions made for interest income in the revenue requirement. Since no provisions were made in the previous Rate Review for FX losses in the revenue requirement, the true-up will be computed as though the target was set at zero.

The actual net interest expense in relation to interest charged to customers in 2017 reflects the realised interest income. The realized income is based on the distribution of the payments made and credit balances applied to the interest charge for commercial and government accounts created in Customer Suite. Based on this assumption the true-ups for 2017 are computed as illustrated in Table 1-3.

Table 1-3: Computation of FX and Interest Surcharges

FX and Interest Surcharge for 2017 (SFX_{2017} - SIC_{2017})			
Line	**Description**	**Formula**	**Value**
	FX Surcharge		
L1	TFX		-
L2	AFX_{2017}		(253,628,288)
L3	**SFX_{2017}**	**L2-L1**	**(253,628,288)**
	Interest Surcharge		
L4	Actual net interest expense/(income) in relation to interest charged to customers for 2017		16,929,720
L5	Actual Net Late Payment fees for 2017		73,702,400
L6	AIC_{2016}	L4+L5	90,632,120
L7	TIC_{2016}		-
L8	**SIC_{2017}**	**L6-L7**	**90,632,120**
L9	**SFX_{2017} - SIC_{2017}**	**L3-L8**	**(344,260,408)**

1.2.5 Revenue Surcharge

The revenue surcharge is comprised of: (1) the true-up for volume adjustments; and (2) the true-up for system losses, the targets of which are required under paragraph 37 of Schedule 3 to be reasonable and achievable. These true-ups reconcile JPS' actual performance during 2017 against the targets set for that year, and result in a $1,503 million deduction from the Annual Revenue Target (ART) for 2018. This is due to JPS exceeding the sales quantities targeted in 2017, and not achieving the system losses target to varying degrees in each subcomponent. The calculation for the volume adjustment and system losses true-ups is detailed in Section 1.2.5.1 and 1.2.5.2.

1.2.5.1 True Up for Volumetric Adjustments

Schedule 3, paragraphs 42 to 56 of the Licence outlines the methodology to be used in the annual PBRM filings. Paragraph 42 stipulates that the methodology to be used by the Office of Utility Regulator (OUR) in computing the PBRM is set out in detail in **Exhibit 1**. Exhibit 1 describes the methodology for computing TUVol which is outlined in the following formula:

$$\begin{aligned} \mathrm{TUVol}_{y-1} = {} & \left\{\frac{\text{kWh Target}_{y-1} - \text{kWh Sold}_{y-1}}{\text{kWh Target}_{y-1}}\right\} \times \text{Non Fuel Rev Target for Energy} \\ & + \left\{\frac{\text{kVA Target}_{y-1} - \text{kVA Sold}_{y-1}}{\text{kVA Target}_{y-1}}\right\} \times \text{Non Fuel Rev Target for Demand} \\ & + \left\{\frac{\text{\#Customer Charges Billed Target}_{y-1} - \text{\#Customer Charges Billed}_{y-1}}{\text{\# Customer Charges Billed Target}_{y-1}}\right\} \times \\ & \text{Non Fuel Rev Target for Customer Charges} \end{aligned}$$

The formula indicates that the volumetric adjustment for any year is dependent on the variance between the target billing determinants and those that were actually achieved during that year. Schedule 3, paragraphs 44 and 45 of the Licence clarifies how the target billing determinants should be derived and used to calculate non-fuel rates applicable for each year:

> *"These filings shall also propose the non-fuel rates scheduled to take effect on the Adjustment Date for each of the rate categories. These rates shall be set to recover the annual revenue requirement for the same year in which the proposed rates take effect, given the target billing determinants."*
>
> *"The target billing determinants shall be based on the actual billing determinants for the immediately preceding calendar year. The Office is empowered to adjust the target billing determinants for known and measurable changes anticipated in relation to the following year."*

In Exhibit 1, the index "y" is used to denote the year of the filing (which in this case is 2018). Application of the formula in Exhibit 1 to compute ART_{2018} for the 2018/2019 Annual Adjustment requires the computation of $TUVol_{2017}$ (volumetric adjustment for 2017) which is a function of the billing determinants for 2017, that is:

$$\begin{aligned} \mathrm{TUVol}_{2017} = &\left\{\frac{\text{kWh Target}_{2017} - \text{kWh Sold}_{2017}}{\text{kWh Target}_{2017}}\right\} \times \text{Non Fuel Rev Target for Energy} \\ &+ \left\{\frac{\text{kVA Target}_{2017} - \text{kVA Sold}_{2017}}{\text{kVA Target}_{2017}}\right\} \times \text{Non Fuel Rev Target for Demand} \\ &+ \left\{\frac{\text{\#Customer Charges Billed Target}_{2017} - \text{\#Customer Charges Billed}_{2017}}{\text{\# Customer Charges Billed Target}_{2017}}\right\} \times \\ &\text{Non Fuel Rev Target for Customer Charges} \end{aligned}$$

Consistent with the OUR's approach in the 2017 Annual Tariff Determination Notice, the billing determinant targets for 2017 are as follows:

$$\begin{aligned} \text{kWh}_{\text{Target}_{2017}} &= \text{kWh}_{\text{Sold}_{2016}} \\ \text{kVA}_{\text{Target}_{2017}} &= \text{kVA}_{\text{Sold}_{2016}} \\ \text{\# Customers Charges Billed}_{\text{Target2017}} &= \text{\# Customers Charges Billed}_{2016} \end{aligned}$$

where:

$\text{kWh}_{\text{Sold}_{2016}} = \text{kWh billed in 2016}$
$\text{kVA}_{\text{Sold}_{2016}} = \text{kVA billed in 2016}$
$\text{\# Customers Charges Billed}_{2016} = \text{\# Customers Charges Billed in 2016}$

The non-fuel revenue targets for energy, demand and customer charge should be matched to the respective components of the target billing determinants. Since the billing determinant targets for 2017 are the actual billing determinants for 2016, the non-fuel revenue targets for energy, demand and customer should be the product of the 2017 approved prices and the 2016 quantities for each revenue category. Table 5.7 of the OUR's 2017 Determination Notice captures the 2017 non-fuel revenue targets for energy, demand and customer charge as computed by the OUR using the annual escalation factor computed in 2017. A copy of Table 5.7 is shown below.

Table 5.7 Approved Annual Revenue Target: 2017

Class		Block/Rate Option	Customer Charge	Energy-J$/kWh	Demand-J$/KVA				Total Revenue
					Std.	Off-Peak	Part Peak	On-Peak	
									0
Rate 10	LV	--100	1,144,863,424	5,006,462,258	0	0	0	0	6,151,325,682
Rate 10	LV	> 100	1,814,389,896	12,472,210,805	0	0	0	0	14,286,600,701
Rate 20	LV		757,001,152	11,488,242,407	-	-	-	-	12,245,243,560
Rate 40A			-	-	-	-	-	-	-
Rate 40	LV - Std		138,531,119	3,790,944,729	3,946,711,179	-	-	-	7,876,187,027
Rate 40	LV - TOU		9,746,326	658,847,425	-	23,597,471	238,401,412	242,317,231	1,172,909,865
Rate 50	MV - Std		9,079,911	1,008,617,708	891,986,844	-	-	-	1,909,684,463
Rate 50	MV - TOU		1,582,737	261,230,195	-	12,144,806	106,649,974	105,805,048	487,412,760
Rate 70	MV -STD		1,999,246	938,083,802	1,078,621,965	-	-	-	2,018,705,013
Rate 70	MV -TOU		416,510	174,230,287	-	11,212,806	108,223,789	93,411,610	387,495,002
Rate 60	LV		14,544,266	1,712,902,958	-	-	-	-	3,539,782,385
TOTAL			3,892,154,588	37,511,772,576	5,917,319,987	46,955,083	453,275,175	441,533,889	48,263,011,298

The tariffs approved by the OUR in 2017 multiplied by the billing determinants do not exactly equal to the Revenue Target depicted in Table 5.7 of the OUR's 2017 Determination due to rounding errors.

As revenue targets are set using the tariffs determined by the OUR the corrected and approved revenue target is $48,260,637,539, as illustrated in Table 1-4 below.

Table 1-4: Corrected Approved Annual Revenue Target: 2017 – 2018

	Block/ Rate Option			12 Months 2017 Customer Revenue	Energy Revenue	Demand (KVA) revenue				Total Demand Revenue	Total Revenue
						Std.	Off-Peak	Part Peak	On-Peak		
Rate 10	LV	<100	-	1,144,861,891	5,007,387,075					-	6,152,248,966
Rate 10	LV	>100	-	1,814,387,466	12,473,872,292					-	14,288,259,758
Rate 20	LV		-	756,998,307	11,486,125,671					-	12,243,123,978
Rate 40	LV - Std		-	138,531,159	3,787,828,143	3,946,720,401				3,946,720,401	7,873,079,704
Rate 40	LV - TOU		-	9,746,329	658,305,778		23,598,632	238,400,275	242,316,105	504,315,012	1,172,367,119
Rate 50	MV - Std		-	9,079,914	1,009,384,390	891,987,563				891,987,563	1,910,451,867
Rate 50	MV - TOU		-	1,582,737	261,428,765		12,144,780	106,649,615	105,804,829	224,599,224	487,610,726
Rate 70	MV -STD		-	1,999,247	938,195,349	1,078,623,885				1,078,623,885	2,018,818,481
Rate 70	MV -TOU		-	416,510	174,251,004		11,213,630	108,223,161	93,411,721	212,848,512	387,516,026
Rate 60	LV		-	14,544,279	1,712,616,635					-	1,727,160,915
TOTAL				3,892,147,840	37,509,395,103	5,917,331,849	46,957,042	453,273,051	441,532,655	6,859,094,597	48,260,637,539

Using Table 1-4 as the basis, the Non-fuel Energy, Customer Charge and Demand revenues are calculated as follows:

Component of Revenue	Target Value
Non Fuel Rev Target for Energy	$37,509,395,103
Non Fuel Rev Target for Customer Charges	$3,892,147,840
Non Fuel Rev Target for Demand	$6,859,094,597

As illustrated in Table 1-5, $TUVol_{2017}$ is determined by substituting the values computed in Table 1-4 above.

Table 1-5: Computation of Volumetric Adjustment

Volumetric Adjustment TUVol2017			
Line	**Description**	**Formula**	**Value**
	Energy Surcharge		
L1	kWh Target$_{2017}$		3,083,667,744
L2	kWh Sold$_{2017}$		3,113,504,786
L3	Revenue Target for Energy		37,509,395,103
L4	kWh Surcharge	(L1-L2)/L1*L3	(362,934,505)
	Demand Surcharge		
L5	kVA Target$_{2017}$		5,233,851
L6	kVA Sold$_{2017}$		5,288,413
L7	Revenue Target for Demand		6,859,094,597
L8	kVA Surcharge	(L5-L6)/L5*L7	(71,505,321)
	Customer Count Surcharge		
L9	#Customer Charges Billed Target$_{2017}$		623,982
L10	#Customer Charges Billed$_{2017}$		639,615
L11	Revenue Target for Customer Charges		3,892,147,840
L12	Customer Charges Surcharge	(L9-L10)/L9*L11	(97,511,785)
L13	**TUVol$_{2017}$**	**L4+L8+L12**	**(531,951,610)**

1.2.5.2 System Losses and the Computation of TULos2017

As stated in the Licence the annual non-fuel adjustment clause includes the system losses incentive mechanism. The computation of this adjustment will be described in this section. The system losses true-up, represented as TULos is computed by first disaggregating system losses into three components: TL, JNTL and GNTL where:

TL = Technical Losses

JNTL = Portion of Non-technical losses which is completely within JPS' control

GNTL = Portion of Non-technical losses which is not completely within JPS' control

Each component of system loss is then measured against a target set by the OUR as shown in the following equations.

$$Ya_{y-1} = \text{Target System Loss “a” Rate\%}_{y-1} - \text{Actual System Loss “a” Rate\%}_{y-1}$$

$$Yb_{y-1} = \text{Target System Loss “b” Rate\%}_{y-1} - \text{Actual System Loss “b” Rate\%}_{y-1}$$

$$Yc_{y-1} = (\text{Target System Loss “c” Rate\%}_{y-1} - \text{Actual System Loss “c” Rate\%}_{y-1})^{*}\ \text{RF}$$

where RF = The responsibility factor determined by the Office, is a percentage from 0% to 100%.

The Electricity Licence stipulates that the responsibility factor is to be determined by the Office, in consultation with JPS, having regard to (i) the nature and root cause of losses; (ii) roles of the Licensee and Government to reduce losses; (iii) actions that were supposed to be taken and resources that were allocated in the Business Plan; (iv) actual actions undertaken and resources spent by JPS; (v) actual cooperation by the Government; and (vi) change in the external environment that affected losses.

The variance of the three losses components from target is used to compute a total variance Y_{y-1} in year "y-1" as shown below:

$$Y_{y-1} = Ya_{y-1} + Yb_{y-1} + Yc_{y-1}$$

Finally, $TULos_{y-1}$ for year "y-1" (the year preceding the adjustment year) is computed as:

$$TULos_{y-1} = Y_{y-1} * ART_{y-1}$$

In order to complete the calculations for the losses true-up, $TULos_{2017}$, the actual system losses for the year must be disaggregated into the respective three component stipulated in the Electricity License to enable the comparison against the targets set by the OUR in the 2017 Annual Review Determination Notice. Once disaggregated, the three component parts are computed separately and re aggregated to derive the losses penalty. This disaggregation of the 2017 system losses is shown in Table 1-6 and Table 1-7. Appendix C provides information with respect to the 2018 Loss Reduction Initiatives.

Table 1-6: 2017 System Losses

	MWh	% of Generation
System Losses		
Technical Losses	375,225	8.60%
Non-Technical Losses	778,905	17.85%
Subtotal Losses	1,154,130	26.45%
Billed Energy	3,208,949	73.55%
Net Generation	4,363,079	100.00%

Table 1-7: Allocation of 2017 Non-Technical System Losses

Description	Average Monthly Users	Billed Energy (MWh)	Energy Loss (MWh)	Energy Loss %	JNTL %	GNTL %
Billed Customers						
Streetlight, Stoplight, Interchange (RT60)	432	110,577	3,903	0.09%	0.09%	0.00%
Large Commercial (RT40&50)	1,973	1,432,744	32,435	0.74%	0.74%	0.00%
Medium Commercial (RT20)	5,738	257,825	11,890	0.27%	0.27%	0.00%
Small Commercial (RT20)	59,670	338,459	14,622	0.34%	0.13%	0.21%
Residential (RT10)	569,488	1,069,344	261,224	5.99%	1.53%	4.45%
Subtotal	637,302	3,208,949	324,073	7.43%	2.77%	4.66%
Internal Losses	N/A	N/A	47,110	1.08%	1.08%	0.00%
Illegal Consumers	180,000	N/A	407,722	9.34%	0.00%	9.34%
Grand Total	817,302	3,208,949	778,905	17.85%	3.85%	14.01%

The OUR established the 2017 targets for TL, GNTL, JNTL and RF in its 2017 Annual Review Determination Notice and JPS applied those targets in computing Ya_{y-1}, Yb_{y-1}, Yc_{y-1} and consequently Y_{y-1}.

Using the Losses Spectrum shown in Table 1-6 and Table 1-7, the computation of $TULos_{2016}$ is shown in Table 1-8 below:

Table 1-8: Computation of TULos2017

System Losses Adjustment ($TULos_{2017}$)			
Line	**Description**	**Formula**	**Value**
	Losses Surcharge		
L14	Actual TL_{2017}		8.60%
L15	Target TL_{2017}		8.00%
L16	Ya_{2017}	(L15-L14)	-0.60%
L17	Actual $JNTL_{2017}$		3.85%
L18	Target $JNTL_{2017}$		3.30%
L19	Yb_{2017}	(L18-L17)	-0.55%
L20	Actual $GNTL_{2017}$		14.01%
L21	Target $GNTL_{2017}$		9.70%
L22	RF		20.00%
L23	Yc_{2017}	(L21-L20)*L22	-0.8620%
L24	Y_{2017}	L16+L19+L23	-2.01%
L25	ART_{2017}		48,260,637,539
L25	**$TULos_{2017}$**	**L24*L25**	**(971,004,027)**

1.2.5.3 Justification for System Losses Disaggregation

In the 2016 Annual filing, JPS established a methodology to account for the energy impact of the various modes through which, system losses occur. In summary, both the relative incidence as well as the estimated mean energy loss of each mode is combined to determine the share of energy losses for each mode. This approach was also used for the 2017 submission.

The modes of system losses described in Table 1-9 below are the primary factor considered in determining the allocation between JNTL and GNTL. The way in which losses occur affects JPS' ability to detect, correct and prevent future occurrences. Considering the energy impact of each mode of loss on losses provides a basis for establishing responsibility. However, the following factors that affect JPS' ability to manage and control losses should also be considered:

- The size of the user base influences JPS' ability to control losses. Larger user bases are more difficult to monitor and corrective actions are more difficult to implement.

- The penetration, or coverage, of remote monitoring capability has a significant impact on the visibility and measurement of loss-related activity in each customer category. Visibility refers to JPS' ability to detect activity related to its supply of service at each premises in a timely manner. Automated Metering Infrastructure (AMI) metering samples of energy consumption much more frequently than traditional meter reading and reports on various events that can be analysed to detect potential losses. Customer categories with limited AMI penetration must rely on traditional methods of detection with limited visibility.

- The historical performance of strategies adopted for each category are considered in establishing both responsibility and targets. Cases where strategies adopted have limited success these will be reviewed and revised.

Table 1-9: Description of the Modes of Loss

Mode of Loss	Description
Defective Metering Infrastructure	The metering facilities fail to meet acceptable measurement tolerances arising from: manufacturing errors, environmental stress, fatigue, acts of nature and other circumstances affecting the meter, its socket and any other supporting accessories.
Bypass Connection	An unauthorized connection, or connections, that divert all or part of the energy being used around a JPS revenue meter. This results in under-registering of the energy being consumed.
Direct Connection	Unauthorized consumption of electrical energy via illegal connections without a revenue meter installed to register the energy. Direction connections are made at various points, including at or before the pothead (also called a line tap) and within the meter socket.
Idle Service	This is the continued consumption of electricity after the termination of a commercial contract with JPS.
Open Circuit	A break in the conductor, or conductors, supplying the meter, customer or both that results in the meter under-registering the energy being consumed. Single phasing is a specific type of open circuit where the break occurs on one phase of the two or three phase supply.
Meter Burnt	The meter, meter socket or both is destroyed or damaged by fire resulting in under-registration of energy consumption. The likely cause is either an overload on the circuit or slack/loose joints in the meter circuit.
Tampering	Unauthorized alterations of, or actions performed, that circumvent the normal functioning of the revenue meter and its supporting facilities which introduces errors in the measurement of energy.

Losses Associated with Rate 60 Customers

JPS' position on losses related to this rate class has not changed since the 2016 Annual Tariff Adjustment Filing where we stated that:

> *The Ministry of Local Government, MLG, in conjunction with JPS executed a joint streetlight audit, in 2013, which showed that there were 9,150 streetlights that were not being billed by JPS. Subsequent to the audit and without any empirical evidence, the MLG suggested that up to 25% of the street lights being billed by JPS were not working and as such, paying for the entire supply billed by JPS would be unjustified. JPS remains concerned about the growing arrears for streetlight*

service which peaked with the GOJ having an outstanding balance equating 20 months supply.

In this regard, JPS takes full responsibility for this category of losses and will move to bill the MLG for the full cadre of operational street lights.

The losses assigned to this rate class have not changed since this is based on the same data as last year's submission.

Losses Associated with Rate 50 and 40 Customers

Rate 40 and 50 customers account for 0.74% of Net Generation losses based on the Loss Spectrum in Table 1-7. Approximately 2.21% of the energy delivered to these customers was lost in 2017. The distribution of these losses is shown in Figure 1-1 and 1-2 below:

Figure 1-1: Loss Distribution by Mode for Rate 50

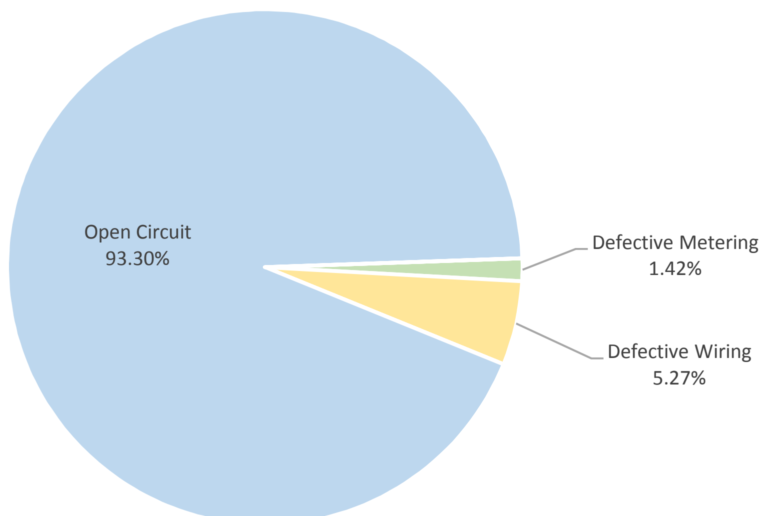
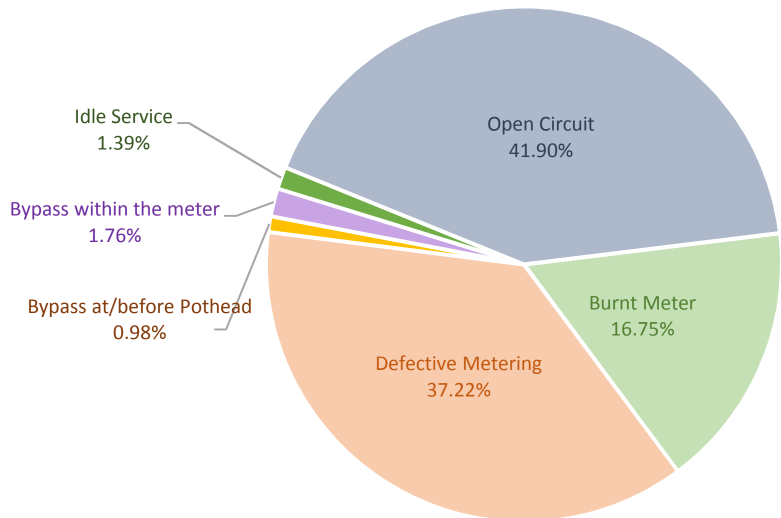


Figure 1-2: Loss Distribution by Mode for Rate 40



The distributions in Figure 1-1 and Figure 1-2 above are derived from weights, which are the product of the relative incident rate and the average recovery for each mode of loss.

Table 1-10: Loss Distribution Data for Medium Rate 40 and 50

Mode of Loss	Rate 40 – % of Energy Lost	Rate 50 – % of Energy Lost
Burnt Meter	16.75%	0.00%
Defective Metering	37.22%	1.42%
Bypass at/before Pothead	0.98%	5.27%
Bypass within the meter	1.76%	0.00%
Idle Service	1.39%	0.00%
Open Circuit	41.90%	93.30%

While Large Commercial customers only total 1,973 accounts, they represented 44% of JPS billed energy in 2017.

JPS considers these accounts very important and employs a number of strategies to increase its visibility into these accounts. Both Large Customer rate classes have full AMI Meter coverage and have a minimum audit requirement of at least one audit annually. The data from the AMI metering is analysed and used to assist in the early detection and arresting of losses in this category.

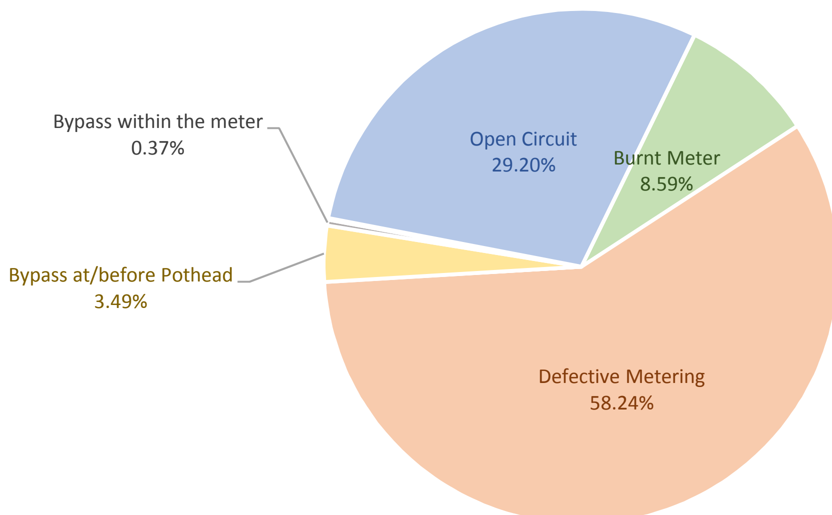
Large Customer rate classes are prioritized due to the relatively small number of customers in each rate class, and the potential for substantial loss due to the sheer significance of the volume of energy consumed by these customers in the normal course of business.

The summary in Table 1-10 suggests that the majority of energy lost in this category relates to various metering defects. JPS notes that customers have employed increasingly sophisticated methods to steal electricity that may appear as defects in the metering infrastructure. Even with modern AMI infrastructure, these methods of theft are often very difficult to detect. However, there is little evidence that the losses in this category relate to unauthorized customer intervention, and consequently all losses in this category are allocated to JNTL.

Losses Associated with Medium Rate 20 Customers

The Medium Rate 20 class captures customers that consume at least 3 MWh of energy per month. Non-technical losses in the Medium Rate 20 class customers account for 0.27% of Net Generation losses in 2017 based on the spectrum in Table 1-11. About 4.41% of the energy delivered to these customers is accounted for as system losses. Figure 1-3 below provides distribution of these losses.

Figure 1-3: Loss Distribution by Mode for Medium Rate 20



The loss distribution in Figure 1-3 above is based on weights derived from the product of the relative incident rate and the average recovery for each mode of loss.

Table 1-11: Loss Distribution Data for Medium Rate 20

Mode of Loss	Relative Incidence
Burnt Meter	8.59%
Defective Metering	58.24%
Bypass at/before Pothead	3.49%
Bypass within the meter	0.37%
Idle Service	0.10%
Open Circuit	29.20%

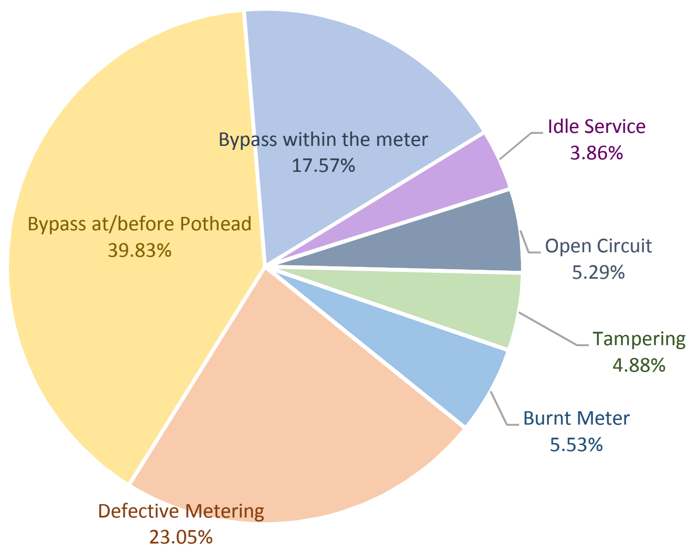
In 2017, there was an average of 5,738 Medium Rate 20 customers, and about 60% of these customers had AMI metering installed. AMI meters capture customers' consumption profiles and, when combined with analytics packages, greatly improve the visibility amongst this customer group. However, these meters have limited capability to detect bypasses.

The data in Table 1-11 suggests that the majority of losses in this class are due to defective metering and open circuit. Consequently, JPS proposes that 100% of the losses in this category be assigned to JNTL.

Losses Associated with Small Rate 20 Customers

Rate 20 accounts that consume less than 3 MWh monthly are classified as Small Rate 20 accounts. Based on the Loss Spectrum in Table 1-11 above, 0.34% of Net Generation was accounted for as non-technical loss due to the Small Rate 20 class. About 4.14% of the energy delivered to customers in this category is lost. The distribution of these losses is shown in Figure 1-4 below:

Figure 1-4: Loss Distribution by Mode for Small Rate 20



The proportions in Figure 1-4 above are based on weights derived from the product of the relative incident rate and the average recovery for each mode of loss.

Table 1-12: Loss Distribution Data for Small Rate 20

Mode of Loss	Relative Incidence
Burnt Meter	5.53%
Defective Metering	23.05%
Bypass at/before Pothead	39.83%
Bypass within the meter	17.57%
Idle Service	3.86%
Open Circuit	5.29%
Tampering	4.88%

In 2017, the average number of Small Rate 20 customers was over 59,000.JPS expended significant resources in containing losses in this category in 2017, and over 17,839 accounts were audited. Many of these accounts were audited multiple times over the year on the basis of intelligence indicating repeated instances of suspected loss at these locations. It is noted that in some instances, theft techniques are elaborate and difficult to detect and require multiple site investigations to identify the losses incidence.

Very few of Small Rate 20 customers have any form of remote metering installed (less than 2% as at December 2017). Consequently, intelligence for these accounts come from analysis of monthly meter readings, historical trends, and other techniques that JPS has developed. While there has been some success with these techniques, the shortcomings limit the efficacy of JPS' monitoring. To help address these shortcomings, JPS is planning for a complete rollout of SMART AMI meters over the next five years which will assist in the intelligence gathering process.

Data suggests that most of the energy losses for this rate class are due to bypasses, particularly inside of the meter socket. As JPS conducts a significant number of field investigations on this group of customers each year, almost 10% (1.3GWh) of the energy lost is recovered. However, the size of the customer base, repeat offenders diverting resources, and lack of significant AMI penetration limits JPS' ability to effectively monitor this category.

While JPS' ability to recover losses in this rate class is better than the residential rate class, this difference is not significant. Ongoing and significant challenges related to understanding where losses in the rate class are being incurred present obstacles to recovery. As there is limited AMI penetration, field investigations remain the most effective tool in detecting losses in these accounts. JPS recovers 11% of the losses from this rate class as summarized in the loss spectrum in Table 1-7.

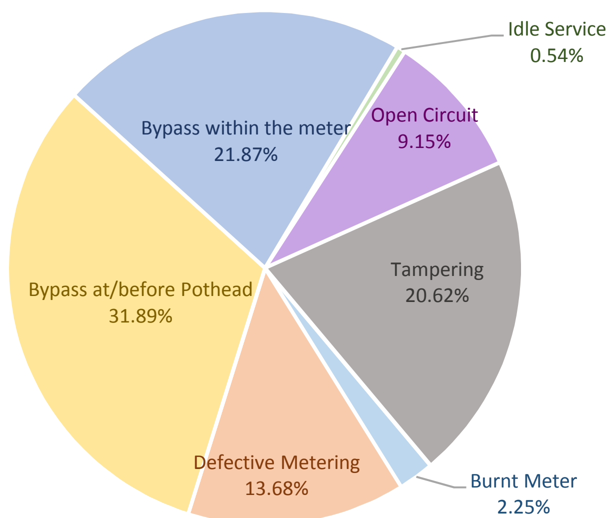
The Smart Grid AMI and Analytical initiatives described for the Small Rate class, are the primary initiatives being advanced to augment JPS' ability to monitor this rate class. The near real-time monitoring and advanced capabilities being deployed through the Smart Meter initiative are expected to significantly improve JPS' capability to detect and control losses in the Small Rate 20 class. The rollout of Smart meters to Small Rate 20 customers has not yet commenced in a concentrated manner, however, the implementation of the program over the next five years will cover these customers.

Based on losses data collected, 62% of the losses identified in this rate class are due to bypasses or tampering in which customers establish unauthorized connections or use contraptions to bypass JPS' energy meters. Consequently, as there is no evidence of customer culpability, JPS accepts responsibility for 38% of the losses sustained from this rate class. This includes losses due to burnt meter, defective metering, defective wiring, idle service, and single phasing. JPS does not accept responsibility for the remaining 62% of losses that relate to customers intentionally bypassing its meters.

Losses Associated with Rate 10 Customers

Based on the spectrum presented in Table 1-7, 5.99% of Net Generation is estimated to be lost to non-technical losses factors related to residential customers. The distribution of modes of loss is shown below:

Figure 1-5: Loss Distribution by Mode for Rate 10



The distribution above is based on weights derived from the product of the relative incident rate and the average recovery for each mode of loss.

Table 1-13: Loss Distribution Data for Rate 10

Mode of Loss	Relative Incidence
Burnt Meter	2.25%
Defective Metering	13.68%
Bypass at/before Pothead	31.89%
Bypass within the meter	21.87%
Idle Service	0.54%
Open Circuit	9.15%
Tampering	20.62%

This customer category has the largest number of electricity users in 2017, with almost 570,000 services. While the rollout of the Smart Meter infrastructure project is still in its early stages, as at December 2017, approximately 40,000 services in this category have Smart Metering. For these services, the real time data and associated analytics platform have played an increasing role in driving intelligence-based audits. This has enabled the Company to deploy resources in a more effective manner.

Limited Smart Meter penetration limits the range of techniques used to detect losses to traditional methods, including monthly consumption profiling, exceptions analysis, payment history, and suspended account analysis. These methods have different business constraints that limit their effectiveness. For example, meters are typically read each month and this provides limited resolution on consumption behaviour. Accordingly, the traditional methods of detection have proven insufficient and somewhat ineffective in containing system losses experienced.

The Company expects that the aggressive rollout of the Smart Meter will meaningfully improve its intelligence capability. Positive outcomes from this project include significantly reduced cycle times for detection, correction and recovery for instances of loss and the improved management of audit resources. Based on the 2018 Capex plan 100,000 of these meters will be installed in 2018.

Over 75,390 premises were audited in 2017 up from about 55,000 in 2016. Despite the large number of audits conducted every year, it is noted that a large number of customers go unaudited each year due to the volume of customers in this category and, to a lesser extent, repeat audits.

JPS has demonstrated its commitment to addressing the losses in this category through both the large number of audits, and the investment in new technologies and strategies (Appendix C describes these in greater detail).

While JPS is cognizant of the effectiveness of audits in detecting losses it is noted that audits represent a snapshot of a customer's premises at one point in time, i.e., for the majority of time JPS has no visibility into the consumption patterns of customers with no AMI metering. This prevents the Company from identifying whether the customer has easily observable forms of losses that would be revealed by a consumption profile. Despite auditing about 13% of the customers in this category, only 2% of estimated losses were recovered in 2017. The estimates in Figure 1-5 show that 76% percent of the energy lost in this category relates to unauthorized customer intervention through bypasses and tampering. The energy lost in this category is equivalent to the average energy delivered to over 110,000 residential households.

In summary, while JPS continues to make significant investments in initiatives to improve its ability to detect and prevent losses in the Rate 10 Customer class, the Company's ability to prevent and detect losses in this class is limited to audits which are guided by tips, history and billing analysis. Despite JPS' efforts to monitor and recover from this rate class, the size of the customer base represents a major challenge. The data suggests that for 74% of the losses sustained from this rate class were due to intentional customer interference, namely bypass at/before pothead, bypass within meter, and tampering. Consequently, JPS does not accept responsibility for 74% of the losses sustained from this class; but accepts responsibility for the remaining 26% of losses.

Internal Losses

The internal losses represent JPS' estimate of non-technical losses sustained due to JPS' actions or inactions. It also contains the estimation error for the loss spectrum model. The Internal Process Improvement project is an umbrella of initiatives aimed at reducing internal non-technical loss and improving the efficiency of JPS. JPS accepts full responsibility for this category.

Losses Associated with Illegal Users

Illegal users do not have a commercial relationship with JPS and consume electricity distributed by the Company. As no new information is available since its last submission, JPS' arguments remain the same concerning this category. JPS is actively pursuing the implementation of transformer total metering in high energy loss areas that will help to more accurately identify where losses are originating and as well as the main drivers. This will help the Company to improve the measurement of energy loss and the quality of the system loss spectrum.

Data from the 2011 National Census was compared to the number of customers billed through JPS' Customer Information System. This indicated that over 200,000 households may be connected illegally to JPS' grid. JPS recognizes that a segment of the population resides in tenement housing facilities and cannot say definitively, without further information, that all 200,000 households are illegally connected. A conservative assessment indicates that there are approximately 180,000 illegal consumers.

Responsibility Factor

In a report published in October 2013, Quantum, a consultant retained by JPS, presented the results of the research and analysis that they conducted on multiple electric utilities in different countries with significant system losses. The report concluded that about 90% of the variation in system losses is explained by the poverty level, murder rate and the relative cost of electricity. These are all factors that are largely outside JPS' control. On this basis, JPS asserts that the responsibility factor should be 10%. JPS recognizes that this report may be dated and is open to commissioning a more current report. JPS is willing to partner with the OUR regarding the terms of reference.

1.2.6 The 2018 Revenue Target (ART_{2018})

The application of the computed values of RC_{2018}, $RS_{2017} = TUVol_{2017} + TULos_{2017}$, SFX_{2017} and SIC_{2017} to the annual adjustment formula:

$$ART_y = RCy(1 + dPCI) + \left(RS_{y-1} + SFX_{y-1} - SIC_{y-1}\right) \times (1 + WACC)$$

and including the extraordinary rate review request (debt refinancing cost) results in an annual revenue target of $48,777,312,317 as illustrated in Table 1-14, an increase of 0.53% over the actual 2017 revenue.

Table 1-14: 2018 Annual Revenue Target Calculation[5]

2018 Annual Revenue Target			
Line	**Description**	**Formula**	**Value**
L1	Adjusted RC_{2018} [$RC_{2018}(1 + dPCI)$]		49,555,339,962
L2	Revenue Surcharge 2017 (RS_{2017})		(1,502,955,638)
L3	SFX_{2017}-SIC_{2017}		(344,260,408)
L4	WACC		13.22%
L5	2017 Adjustments	(L2+L3)*(1+L4)	(2,091,418,006)
L6	CPLTD Return (approved in 2017)		633,454,362
L7	Debt Refinance Cost		679,936,000
L8	**2018 Annual Revenue Target (ART_{2018})**	**L1+L5+L6+L7**	**48,777,312,317**

1.3 Target Setting

1.3.1 JPS' Target Setting

The 2018-2019 tariff period immediately precedes the 5-Year Rate Review Process which is scheduled to commence in 2019 with JPS' filing of the 5-Year Rate Review proposal in April 2019. As required by the Electricity Licence (20106), the result of the Rate Review Process are the Revenue Cap and associated non-fuel rate schedules for the tariff period 2019-2024, together with the annual performance targets applicable to each year of that tariff period. As provided in paragraph 38 of Schedule 3 of the Electricity Licence, the targets which are normally set during the Rate Review Process, are established following a consideration of the Base Year, historical performance and the agreed resources in the Business Plan, corrected for extraordinary events. These targets which form the basis of the performance incentive mechanism related to the non-fuel components of the tariff, are subsequently applied annually to determine the Annual Revenue

[5] Based on the precedence of the 2017 Determination, JPS is adjusting the Revenue Cap to include the return on CPLTD for 2018 in the amount of US$4.956M [4956*112*(1+dI)*(1-X)^4].

Target through the Performance Based Rate-making Mechanism (PBRM) adjustment. The process as outlined in the Electricity Licence would result in the measurement and application of targeted performance of JPS in the non-fuel rates for the year immediately following the year under assessment.

Accordingly, if the filing of a 2019 Annual Adjustment proposal was permissible under the Electricity Licence this would result in measurement of the performance in the final year of a 5-Year Rate Review period in the first year of the subsequent 5-Yer Rate Review Process. In the absence of the position of the Office regarding the simultaneous filing of a 2019-2020 Annual Adjustment and the 5-Year Rate Review for the period 2019-2024 prior to the filing of this 2018 Annual Adjustment filing, JPS has proceeded to propose targets which are reasonable and achievable and would be applicable to the operation of the performance incentive mechanism for the tariff period 2018-2019, which would be considered in the filing of an Annual Adjustment proposal in the tariff year 2019-2020, if so required.

1.3.2 Heat Rate Target Proposal

As the heat rate adjustment mechanism operates on a monthly basis in accordance with Schedule 3 of the Electricity Licence and not annually, we have proposed targets for the measurement of the performance of JPS in the tariff period 2018-2019 in Section 6 of this 2018 Annual Adjustment proposal.

1.3.3 System Losses Target Proposal

Non-Technical Losses

The company reported actual non-technical losses of 17.85% in 2017 of which 9.34% was due to illegal users and 8.51% due to customer related losses and internal losses. JPS recognizes that considerable external stakeholder involvement is required for addressing illegal users. Notwithstanding, JPS continues its Community Renewal programme geared towards reducing losses amongst illegal users with the expectation that the returns will be realized over the long term. In the short to medium term JPS' strategy and resources are more aligned around reducing losses in customer related and internal leakages where JPS has greater control. Consequently, JPS has committed and will continue to commit significant capital investment and resources in this area

Based on the 5-year losses strategy and the progress in losses reduction to date, JPS expects to reduce losses by approximately 4 percentage points. At the end of the 2019/2020 tariff period, JPS expects to achieve a 1.1%- 1.4% reduction in the losses over the two year period. **In light of this JPS is proposing a short to medium term target setting process (2019/2020) that is aligned with the loss reduction strategy, resource alignment and expected results. JPS believes that a reasonable and achievable non-technical loss target is 16.55% - 16.75%.**

Technical Losses

The Company recognizes the need to account for technical losses and it has made investments towards improving its measurement and modelling ability in this regard. JPS acquired the DIGSILENT network modelling software in 2016, updated SCADA EMS and implemented the

Automated Distribution Management System (ADMS) in 2017. JPS started the remodelling of its network in DIGSILENT in 2017 and this process continues in 2018.

JPS also acknowledges that the technical loss measurement has not been updated in previous filings and the Company is preparing to address this in the upcoming rate case. This effort is pending the completion of the load flow simulations with DIGSILENT and more precise and frequent measurement of transmission losses**. Consequently, there is no new information available to inform a target for this category and so the company elects not to propose one for the 2019/2020 regulatory period.**

Rationale for Proposed Targets

PS encourages the OUR to strongly consider the level of investment committed over the next five years (US$200M) and the loss performance to date. This level of investment will be significantly impacted either positively or negatively based on the penalties arising from the targets imposed. Restrictive penalties will constrain the company to reduce its capital investment and slow its loss reduction programme. Conversely, with reasonable targets JPS is prepared and committed to increase this level of capital investment to bolster its loss reduction efforts, which will ultimately lower rates for our customers and unlock national growth and development.

The current financial (losses penalty) performance based on JPS' loss performance relative to the 2018/2019 targets as issued in the OUR's 2017 Annual Tariff Adjustment Determination Notice is estimated to be US $8M. It is JPS' view that whilst we embark on our 2018 loss reduction programme and planned capital expenditure (US$26.7M), the financial impact is significant and hinders our progress in containing non-technical losses. If this penalty were to be reduced to nil, JPS would commit to utilising the entirety of the funds to advancing the deployment of additional 100,000 Smart meters within the regulatory year.

2. System Losses Performance and Target Setting Proposal

2.1 Introduction

JPS is aiming to accomplish a 0.75% reduction in system losses in 2018. In order to achieve this objective, the Company will have to implement specific loss reduction projects that will cost the company US$30.2M of which $27.6M is capital in nature. This expenditure will assist in continuing the downward trend we have been experiencing since losses peaked at 27.19% in August 2015 and have since fallen to 26.45% at December 2017, a 0.74% reduction.

The investment in system loss reduction is heavily impacted by the penalties imposed through the current PBRM mechanism. JPS believes that the penalty should incentivise the Company to achieve reduction in system losses but beyond US$6M per annum become damaging to the efforts. A US$6M penalty reduces EBITDA by an equivalent amount and debt capacity by US$18M. JPS also believes that if the adjusted mechanism is not managed in a constructive manner, losses penalties could return to intolerably high levels thereby constraining the level of investment JPS can inject into its losses programme.

The Company proposes that the OUR considers the elimination of the losses penalty for the 2018/2019 regulatory period in order to enable increased levels of investment required to further reduce system losses in a sustainable way. The additional funds from the penalty reduction would be directly invested in the smart meter programme which JPS believes will significantly aid in the reduction of losses going forward.

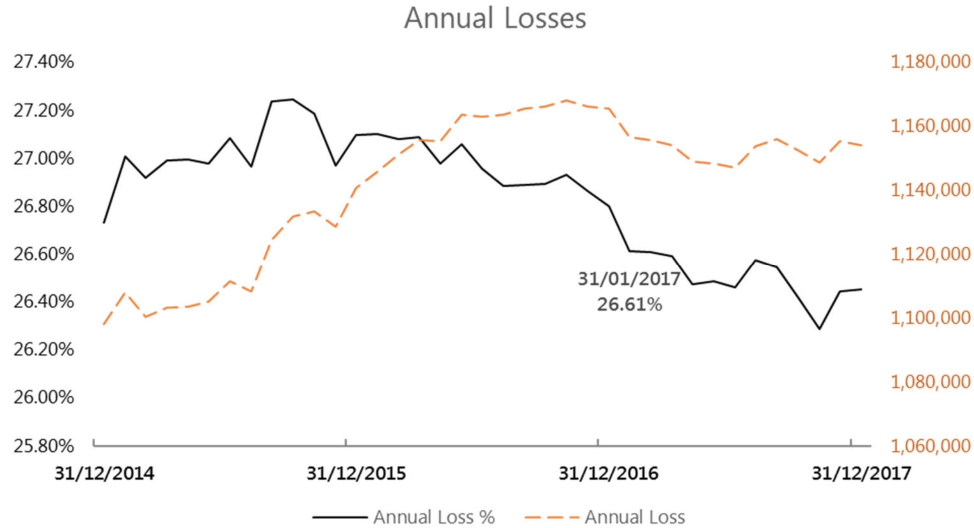
JPS believes Smart AMI Technology is the most significant tool to enable sustainable and significant reduction in system losses. It acknowledges that metering technology has to be used appropriately to detect losses through monitoring, measurement and reconciliation activities and for appropriately raising the necessary service orders to address loss impacting activities. JPS initially centered its metering strategy on preventing losses in red zones but experienced limited success which was difficult to sustain.

JPS has started to see sustainable reduction in system losses and recognizes that in order to increase the rate of this reduction it must accelerate the rate of smart metering installation. With a customer base of just under 640,000 and approximately 40,000 transformers on the system, Smart AMI metering capability currently covers approximately 6% of customers and 8% of transformers. The company rolled out approximately 40,000 smart meters in 2016 and 2017 and plans to install 100,000 during 2018 as a part of a suite of initiatives that will cost the company $30M in 2018. This program is a multi-year program that is expected to be the primary contributor to the 0.75% reduction in system losses in 2018.

Note that if the penalties are eliminated JPS is committed to accelerating this rollout to 200,000 smart meters in 2019.

2.2 JPS Loss Performance and Results

Figure 2-1: Annual System Losses in MWh and Annual Rolling System Loss Percentage



Since 2009, JPS has consistently presented its loss reduction plans to the OUR in both Rate Review and Annual Adjustment filings. While most of the programmes implemented have achieved remarkable success in the short term, as is the case with the implementation of RAMI and CAMI installations in red zones, some programmes have faced considerable challenges given the persistence of persons intent on illegally abstracting electricity. The sustainability of these initiatives is vital to the success of the loss reduction program. JPS has therefore invested considerable time and effort to develop solutions that will address the challenges encountered over the long-run. One significant case in point is the considerable effort surrounding the many attempts to get the communication system on the RAMI project working. This has seen the evolution of Power Line Carrier communication to Mesh communication which is more robust.

In other instances, projects have taken a longer period to return the intended results due to implementation challenges or resource constraints. For example, the community renewal effort has not been implemented at the pace initially desired due to the high capital and O&M cost associated with the programme. The main challenge with this programme is that the implementation of the technical infrastructure is only justified if customers are able to receive power once the implementation is completed. In order to receive power, potential programme participants require wiring that is approved by the GEI. In many instances, participants cannot afford the wiring and so excepting where JPS has identified relevant funding to execute the house wiring aspect of the project the technical electricity supply aspects cannot proceed.

JPS is committed to playing its part to reduce system losses to tolerable levels. Significant efforts have been made in the areas of smart meter installations, transformer metering, energy balance implementation, strike force operations and audits have resulted in the cresting of the system losses in August 2015 at 27.19% with a sustained reduction to 26.80% in December 2016 which further improved to 26.45% in December 2017 as illustrated in Figure 2-1. While this trend is promising, the Company is fully aware of the significant effort required to return system losses to sustainably tolerable levels and we are highly motivated to build on this platform to achieve more significant reductions in this area. It is worth special mention that the Community Renewal initiative, with an entire department dedicated to the effort, was implemented in 2015 to help stem the rising trend in system losses at the time.

JPS has developed considerable insight through experience into how to successfully deploy loss reduction projects. These lessons learnt were comprehensively presented in a recent paper presented by JPS to the Regulator. Based on this knowledge, JPS continues to refine its strategy to ensure that the greatest return can be generated from each dollar spent on loss reduction. Some examples include the following:

1. The energy balance project. This project focuses on the development of the capability to measure the incidence of losses in various sectors of the grid improving the Company's ability to make better decisions about where to deploy capital expenditure.

2. The decision to implement quasi RAMI solutions in Yellow Zones. These projects cost significantly less than full scope RAMI solutions as the pole line infrastructure is already in place and the main requirement is to move the metering point from the customer's residence to the pole and install total meters on the transformers serving customers. These projects stemmed the rate at which losses was growing in the affected areas.

3. The SMART Metering project – This project is the next step up on the base provided by the energy balance project and focuses on identifying losses at the transformer level. Referred to as the transformer energy balance project, the project ultimately seeks to reconcile customer consumption to energy metered as leaving the transformer. The goal will be achieved when all these meters are synchronized to generate and communicate energy consumption information at each metering point to the system so that the Advance Automated Theft Detection Analytical Tool (AATDAT) tool can perform the necessary reconciliation. This application utilizes the smart meter information coupled with circuit mapping formation to provide a circuit energy balance for each transformer circuit. The accuracy of this measurement system is expected to make it considerably easier to identify and control system losses.

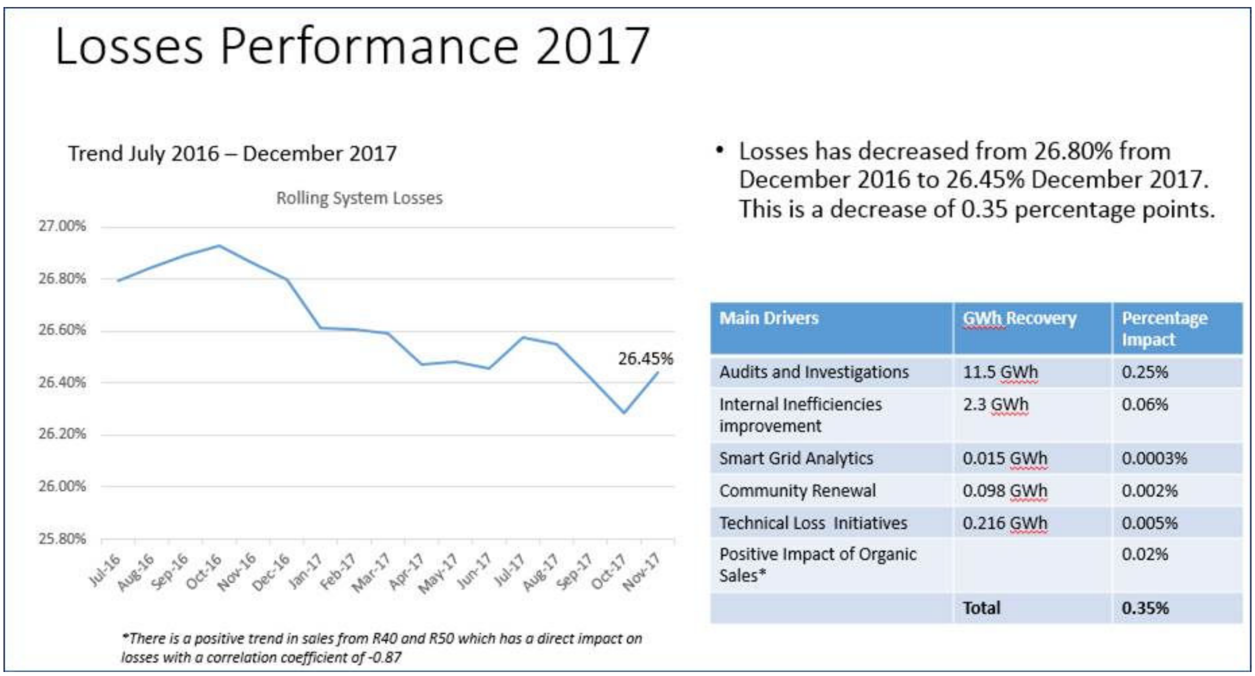
4. Communication issues associated with RAMI indicate that PLC will not work in most high loss communities in Jamaica given the level of interference from illegal encroachment on the distribution infrastructure and as such JPS is pursuing alternate Mesh communication technology to facilitate the efficient and effective operation of these solutions.

5. Being fully aware of the high implementation cost per solution associated with community renewal project, a tempered approach must be adopted at this stage given limited capex and the rate of return available on other higher yielding projects. JPS believes the successful implementation of this project will require tremendous support from the Government, NGOs and civil society. In the interim JPS will perform the groundwork to prove the feasibility of the concept so that when the required support becomes available the deployment can be executed efficiently.

Considerable progress has been achieved with many of the described loss reduction initiatives. 20,419 Smart meters were installed between July and September 2016 and a further 20,000 installed in 2017. The installation of Smart meters is an integral component of the initiatives to address system losses through integration with Advanced Automated Theft Detection Analytical Tool (AATDAT) in the Transformer Total Meters energy balance program. Widespread application of Smart Meter analytics began ramping up only recently (late 2017) and has had only a small impact on losses so far. Notwithstanding this, there were several cases where intelligence from Smart Meters was used to guide audits with positive results. In a sample of 300 accounts investigated using advanced analytics, 40 instances of loss impacting irregularities were discovered, reflecting a strike rate of 13.3% compared to a typical rate of 8% realized without the tool. These investigations have resulted in the recovery of approximately 27 MWh of stolen energy. As the penetration of connectivity mapping between transformer meters and their downstream AMI revenue meters increases, the benefit of smart meter installation in fighting losses will be realized. The greater the penetration of connected and communicating smart metering infrastructure the greater the capability of JPS to fight losses. The planned implementation of a further 100,000 revenue and total meters in 2018 will significantly improve the smart meter penetration and enhance the company's losses fighting capability.

2.3 2017 Performance Drivers

Figure 2-2: Losses Performance 2017



Main Drivers	GWh Recovery	Percentage Impact
Audits and Investigations	11.5 GWh	0.25%
Internal Inefficiencies improvement	2.3 GWh	0.06%
Smart Grid Analytics	0.015 GWh	0.0003%
Community Renewal	0.098 GWh	0.002%
Technical Loss Initiatives	0.216 GWh	0.005%
Positive Impact of Organic Sales*		0.02%
	Total	0.35%

During 2017, a further 1,217 consumers were converted to customers under the RAMI program. Incrementally, the program added 1.2 GWh of sales with collections totalling over J$22M. Work on improving the communication system on the RAMI program continued during the year with varying degrees of success. In some instances, up to 90% communication with the energy guard enclosures were achieved. In others, due to the prevalence of interference on the line, only 30% was achieved. JPS is working with its technology partners to develop a more robust solution for these areas. During the year 1,658 Hexing meters were used to replace malfunctioning Quadlogic meters in various RAMI installations.

A total of 96,518 audits were executed during 2017, including 100% of Rate 40 and 50 customers and a further 4,000 Rate 20 customers utilizing greater than 3 MWh per month, all of whom are equipped with AMI smart meters. As reflected in Table 2-1 below, 7.56% of these accounts were found with irregularities resulting in the recovery of 10.9 GWh of energy, with contributions from the various rate classes as follows: RT 10 – 4.2 GWh, RT20 (Small) – 0.9 GWh, RT20 (Medium C&I) – 1.0 GWh, RT40 – 2.1 GWh and RT50 – 3.3 Gwh.

Table 2-1: System Loss Strike Rates

Rate Class	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg Strike Rate
RT10	10.4%	10.2%	14.0%	16.7%	7.4%	1.4%	6.3%	6.1%	5.2%	6.8%	7.0%	6.0%	8.13%
RT20	6.3%	5.4%	8.8%	8.5%	6.4%	4.0%	5.9%	4.4%	4.4%	6.1%	5.0%	5.0%	5.84%
RT40	5.3%	3.3%	5.0%	2.2%	10.9%	0.0%	4.1%	8.2%	3.0%	0.0%	3.0%	19.0%	5.34%
RT50	4.0%	5.6%	6.1%	10.0%	0.0%	0.0%	7.7%	25.0%	25.0%	0.0%	0.0%	0.0%	6.95%
Total	**9.3%**	**8.8%**	**12.5%**	**14.6%**	**7.1%**	**1.8%**	**6.2%**	**5.7%**	**5.0%**	**6.6%**	**6.8%**	**6.2%**	**7.56%**

2.4 Socio-Economic Conditions

The socio-economic context of system losses cannot be ignored. While one can debate the extent to which there is a cause and effect relationship between poor socio-economic conditions and high system losses, the outcomes experienced in Jamaica are real. The incidence of system losses per person is far greater in zones of lower socio-economic status than experienced in structured communities where mainly middle and high-income customers reside. This is the general conclusion from papers prepared by the World Bank on losses in the electricity sectors of poor and developing states including countries in Latin America and the Caribbean and Africa. According to the IEA report on system losses in 2014, while on average 8% of energy generated is lost in electric transmission and distribution systems worldwide, high income states average 6% while heavily indebted poor countries (HIPC) and low-income countries both average 18%. The Quantum report prepared for JPS in 2013 presents similar findings. The OUR asserts the view that all aspects of system losses are within JPS' control, although some aspects are more difficult to control. In order for JPS to fulfil this expectation there will clearly need to be an assessment of the degree of difficulty associated with the various aspects of system losses and an agreement on the resource requirement to address each segment.

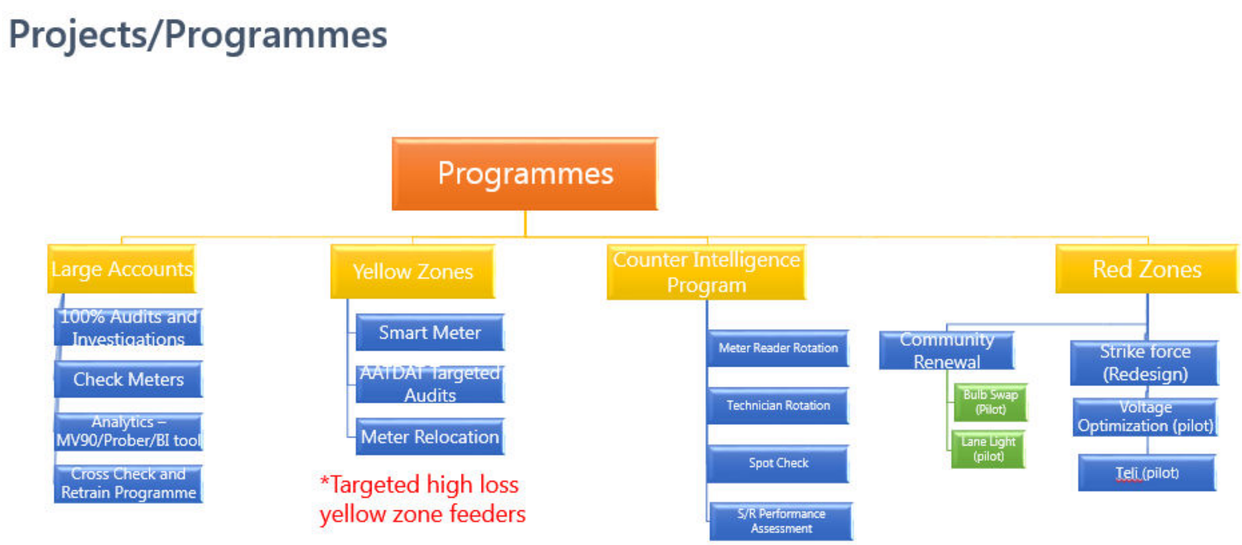
It is reasonable also, to assert that JPS has over-estimated its potential to contain or reduce system losses in prior submissions to the OUR. This is evidenced by the relatively high level of investment and the lengthy periods other countries have invested in achieving success with this challenge. Examples presented in JPS' Lessons Learnt paper to the OUR, dated March 1, 2018 cited a 24% reduction in India over a 12-year period with 40% of capital and O&M expense dedicated to loss reduction efforts while the energy sector grew at an average rate of 6% per annum. The paper also described Columbia achieving a 12% reduction in 16 years with $400M invested in the first three years. Additionally, the Dominican Republic launched a project in 2015 that is slated to reduce losses by 7% by 2020, with an estimated budget of US$800M[6] for the distribution losses

[6] World Bank, Document number PAD1082; paragraph 12 on page 4.

component alone. The program in Jamaica has had less than $200M in investments since 2009, and meaningful legislative support was only enacted in 2015. The enforcement of the law remains a challenge.

JPS wants to maintain a leadership role in facilitating the identification and implementation of system loss programs. It cannot be ignored, however, that the general respect for law and order is certainly very low in Jamaica. The country has been reported by local media as having one of the highest murder rates in the world and this view is confirmed by the World Bank International Homicides report of 2005 and 2015 which cites Jamaica as having the fifth and fourth highest murder rate in the world in both years, respectively. The incidence of crime has been one of the most challenging problems for the Government of Jamaica over the last 30 years. Despite sincere attempts by various governments to curb the problem it remains rampantly out of control. With this general disregard for law and order, the reversal of the attitude toward illegally abstracting electricity, especially in communities where the obligation to pay for utility services was never recognized, is in its mildest form a mammoth undertaking that will require the most effective input from JPS, the Government and law-abiding Jamaicans (civil society). So, while all aspects of losses may be controllable the resource requirement commensurate with the challenge must be considered

2.5 JPS Losses Strategy and Plans 2018



JPS multi-year loss reduction strategy is centred on implementing technology to monitor, detect, measure and eliminate losses and involves:

- Use of check meters for medium and large customers to reconcile the measurement of electricity supplied with consumption billed at the individual customer level;
- Use of transformer meters in conjunction with smart meters for individual customers to measure the level of losses incurred at the transformer circuit level; and
- Use of smart metering capability for instantaneous detection and response to meter tampering.

These strategies will be operated in concert.

JPS plans to invest US$27.6M, almost a third of its capital budget, in these projects supporting loss reduction activities in 2018. This is incremental to the planned US$2.6M operational expenditure for meter audits and strike force operations. The investment is almost three times the previous year's spend, indicating the seriousness of JPS' intent to reduce system losses by 0.75% during the year. Projects earmarked to be implemented are outlined in Table 2-2 below.

Table 2-2: 2018 Capital Expenditure Plan

Projects	**Budget (US$)**
Anti-theft Residential AMI and Special Projects	5,770,000
Smart Meter Initiative	18,540,000
Pilot Projects	263,000
Large Account Check Meters	2,450,000
Community Renewal Programme 2018	600,000
Total	**27,623,000**

As reflected in Table 2-2, the majority of expenditures will go towards implementing 100,000 smart AMI meters, including 90,000 revenue meters and 10,000 transformer totalizing meters. This will provide JPS with greater visibility on losses and will help JPS identify areas where the incidences of system loss are greatest. This will also increase the number of accounts the company can remotely monitor, read and disconnect to 130,000 and the number of totalizing meters to 13,000. It also improves the utilization rate of the AATDAT analytical tool.

JPS is fully cognizant of the potential resident in the smart meter application when used alongside big data analytics to significantly reduce system losses. However, even at the proposed rate of 100,000 meters per annum it will take five years incrementally to achieve full coverage, a period considered way too long given the urgency of the problem. JPS therefore welcomes the Government and other interested parties to the table to provide the necessary funding to accelerate the implementation of the project in Jamaica's national interest. This single project would result in reduced tariffs and have the knock-on effect of fueling growth in the economy as lower energy costs make Jamaican business more competitive.

During 2018 a further 6,229 RAMI solutions are scheduled to be completed, which will result in the recovery of an estimated 2.45 GWh of energy.

A new Check Meter project is being implemented to provide a secondary layer of monitoring for large accounts (RT40 and 50 classes). This project will have the effect of eradicating losses related to this customer group by measuring the amount of electricity leaving the network to supply these customers on an ongoing basis. The installation of 1800 meters in 2018 is expected to recover 2.1 GWh of energy in 2018 under this project.

A meaningful reduction in system losses will require investments of this magnitude over the next 5 to 10 years. This will require a healthy net income annually to support the expenditure requirements.

NOTE: Detailed losses initiatives can be found in Appendix C: Losses Initiatives.

2.6 System Losses Penalty

System Losses and its associated penalty have been a major challenge for JPS for a significant period of time. In 2015, JPS incurred System Loss penalty of US$37M (Fuel Penalty of US$22.1M net of Heat Rate surplus) and this penalty was a major consideration in the renegotiation of the 2016 license. 2016 was a transitional year and system losses penalty was applicable for only the first half of that year and was US$12.6M. The shifting of the system loss penalty to non-fuel Revenue commenced as at the 2017/18 Regulatory period.

Based on the targets set out by the OUR for the 2018/2019 regulatory period, JPS estimates 2018/2019 system losses penalty is approximately US$8M, which is already beyond the threshold of US$6M significantly reducing JPS' capital spending capacity as discussed in the preceding sections. JPS strongly suggests that any increase in the estimated 2018/2019 system losses penalty of US$8M presented in this filing does not meet the licence requirement of "reasonable" and 'attainable" as outlined below.

The Electricity Licence 2016

Schedule 3 of the Licence is the relevant section and specifically Paragraphs 37 and 38, with 37 addressing targets as follows:

> *The Office shall have the power to set targets for losses, heat rate and quality of service. All targets set should be reasonable and achievable taking into consideration the Base Year, historical performance and the agreed resources included in the five (5) Year Business Plan, corrected for extraordinary events. The Office shall take into consideration the role of the GOJ in addressing the non-technical aspect of the system losses that are not entirely within the control of the Licensee.*

A primary basis of the licence is to fund programs rather than to establish penalty as the intent of the licence is to incentivize the Company to operate efficiently through fair, reasonable and achievable targets.

Paragraph 38 of schedule 3 of the amended Licence sets out the requirements for target setting under the amended Licence, as follows.

> *The target set by the Office for losses shall normally be done at the Rate Review and be for a "rolling" ten (10) year period and broken out year by year over the following three (3) categories:*
>
> d. *Technical losses;*
> e. *The aspect of non-technical losses that are within the control of the Licensee; and*

f. The aspect of the non-technical losses that are not totally within the control of the Licensee.

Paragraph 38 speaks to the establishment of system losses targets over rolling ten-year periods in the three stated categories. Those targets are required to be set as a part of the rate review process and should be developed in a consultative process involving JPS, the Regulator and consumer interest. The requirement for consultation is particularly important between JPS and the Regulator and this is most clearly enunciated in Exhibit 1. These clauses formally acknowledge the shared responsibility that JPS and the Government has for system losses. We are now in the second year of review following the promulgation of the Licence and JPS and the OUR have not agreed on a methodology for allocating non-technical losses between the aspects within JPS' control and the aspects not totally within JPS' control. In order for such a methodology to be developed there is a need for a common understanding of the causal factors driving non-technical losses and the allocation of those factors to the two respective segments, that is, what is totally or not totally within JPS' control.

Open deliberation of these considerations in a constructive and consultative manner will help to ensure that the methodology can be administered fairly and transparently. JPS believes that the Losses Interface Committee provides the most suitable forum for developing a mutual understanding and a shared perspective with respect to the administration of this aspect of the incentive mechanism. In our view this will require a clear understanding of each causal factor and the underlying drivers so that the factors can be objectively allocated to the appropriate NTL segment. The collaborative approach can facilitate the collection of additional information that the parties may deem necessary to more precisely determine responsibility. Secondary to this process but equally important is the development of an agreement on the methodology used to measure and report system losses, the Losses Spectrum.

The Amended Licence 2016, which was developed partially to address concerns JPS raised about the substantial nature of the penalties, requires a shared responsibility approach for non-technical system losses between the Government and JPS and provides for consultation between the OUR and JPS in administering the mechanism. JPS believes that the penalty should incentivise the Company to achieve reduction in system losses. Against this background, JPS seeks to engage the OUR in a collaborative effort to develop a fair and objective methodology to measure and report system losses, and a basis for establishing reasonable and predictable targets for the administration of system losses incentive mechanism in a more sustainable manner.

2.7 Conclusion

JPS should be given a fair opportunity to earn a return and be set reasonable targets that provide an incentive for the utility to achieve these targets. An assessment on the impact on 2018 suggests that a penalty impact greater than $6M results in an equivalent reduction in EBITDA and the inability of the Company to fund its capital expenditure program for the year. As JPS implements the planned loss reduction projects, the Company is receptive to targets that are more stringent. However, at this stage, JPS is unable to fund the significant increase in capex needed and simultaneously absorb significant increase in penalties.

The Company is therefore proposing:

1. Elimination of the system loss penalty for 2018/19 regulatory period with the acceleration of the Smart Meter program by increasing the installation from 100,000 to 200,000 meters.

2. Adjusted penalty structure that is aligned with the losses strategy and the execution of the losses capital program that will ultimately deliver loss reduction in a sustainable way.

3. Z-Factor Adjustment

3.1 Accelerated Depreciation of JPS Steam Generation Plants at Old Harbour and Hunts Bay

In a discussion paper presented to the OUR on April 5, 2018 JPS presented a request for the consideration of a Z factor adjustment as a part of the 2018 Annual Adjustment Filing. The Company introduced the subject in a discussion with the OUR on February 13, 2018, and thereafter presented the discussion paper for the OUR's consideration. The discussion paper also addressed the matter of the Depreciation study that would be conducted to support JPS' 2019 Rate Review filing.

This Z-factor filing seeks to garner regulatory recovery for costs that JPS must recognize in its financial statements given the requirements of International Financial Reporting Standards (IFRS) in relation to the impending retirement of the aged steam powered production plants from JPS' generation fleet consequent on the age and inefficiency of the said generating plants and the mandate issued by the Generation Procurement Entity/Electricity Sector Enterprise Team. JPS is therefore, seeking to recover US$12.8 million on incremental depreciation costs in the 2018 Annual Adjustment filing with the remaining US$3.8 million to be sought in the 2019 Rate Review Process submission.

3.1.1 Background

JPS has executed purchased power agreements (PPA) with South Jamaica Power Company Limited (SJPC) and New Fortress Energy (NFE) to supply power from two power generation plants projected to be completed in July 2019 and June 2020, respectively, consequent on the mandate of the Generation Procurement Entity/Electricity Enterprise Team. SJPC is well advanced with the construction of its 192MW facility in Old Harbour (OH), with generators currently being installed while NFE has broken ground to commence the construction of a 94MW facility at Jamalco. When both plants are completed, it is anticipated that existing steam powered generation plants at Old Harbour and Hunts Bay (HB), which are owned and operated by JPS will be displaced from the schedule of active generation plants and retired. These steam generation plants have far exceeded their originally estimated and manufacturer assigned useful lives and have required considerable capital and operating expenditure to maintain their operations on an ongoing basis. Significant additional investments are required to bring the units to the efficiency levels necessary for long-term operations and these expenditures are not considered economically or operationally justifiable. Current load growth forecasts in the medium term do not support maintaining these generation resources alongside the SJPC and NFE facilities.

The current fleet of steam generating plants at OH and HB will be required to remain in service until at least six months after the completion of commissioning of both facilities into service to accommodate a smooth transition to the new plants to mitigate any contingent shortfall during the period immediately following deployment. Decommissioning activities are therefore expected to commence at OH within twelve (12) months of the commercial operating date (COD) with the expectation that the plant will be fully retired by June 2020. Similar activities at HB B6 are expected to commence within six (6) months of the July 2020 COD of the Jamalco plant and be fully retired by December 2020. Based on current projections, the SJPC construction is expected to be completed by July 2019.

3.1.2 Cost Recovery

Depreciation is a measure of the consumption of the utility value of an asset over its useful life. The recovery of asset values should reflect the pattern of usage of such asset to benefit customers over the period they remain in use. General ratemaking principles support the fair recovery of costs prudently incurred by a regulated business and the recovery of depreciation costs for approved assets is one such cost. As stated in previous determinations issued by the OUR, depreciation allowances preserve the "integrity of the investment" a regulated business makes in approved assets. JPS is also acutely aware that the OUR supports the fair recovery of asset values over a reasonable period in cases where it is recognized that the actual useful life of an asset (or group of assets) approved by the regulator has changed because of advanced technology, shifts in market conditions or other similar justifiable reason.

Paragraph 5 of Condition 15 of the Electricity Licence lays out the methodology that shall be used to determine depreciation charges under the regulatory regime. It states:

> "*Annual depreciation allowance shall be computed by applying reasonable annual straight line depreciation rates to the value of property, plant and equipment stated at book value. As a part of the Rate Review Process, the Office shall determine the adequacy of the depreciation rates based on a depreciation study conducted by a reputable firm of chartered accountants engaged by the Licensee*."

The Z-factor mechanism described in Paragraph 46 of Schedule 3 of the Electricity Licence provides for alterations to be made to the tariff within the framework of the annual Performance Based Rate-making Mechanism adjustment. The Z-factor may be applied in a number of circumstances as outlined in the Electricity Licence, however, the provisions that are most relevant to the recovery of accelerated depreciation arising from the impending decommissioning of the steam generation plants under consideration are those described in paragraph 46.d.(i), which states in part:

"The Z factor is the allowed percentage increase in the Revenue Cap due to …:

(i) Any special circumstances that satisfy all of the following:

a) *affect the Licensee's costs or the recovery of such costs, including asset impairment adjustments;*
b) *are not due to the Licensee's managerial decisions;*
c) *have an aggregate impact on the Licensed Business of more than $50 million in any given year; and*
d) *are not captured by the other elements of the revenue cap mechanism"*

The incremental depreciation cost imposed on the business by the requirement to decommission the old steam generating plants to accommodate the commissioning of the new Gas fired power plants to be owned and operated by independent power producers satisfies the four criteria listed in the provision.

3.1.3 IFRS Requirements

As defined in paragraph 6 of IAS 16 (of the International Financial Reporting Standards) "*depreciation is the systematic allocation of the depreciable amount of an asset over its useful life*." The standard states that depreciable amount is the cost of an asset, or other amount substituted for cost, less residual value, and that useful life is the period over which an asset is expected to be available for use by an entity or the number of units of production expected to be obtained from an asset by an entity. It states further that useful life can be determined by considering factors such as, the expected usage of the asset, physical wear and tear, technological and commercial obsolescence, and legal and other similar limits on the use of an asset.

3.1.4 Analysis

As at June 2017, the carrying value of the Old Harbour and Hunts Bay (B6) steam assets were approximately US$24.5 million and US$4.5 million respectively. Since these assets have been in service for a considerable period, the depreciable amount will be their depreciated cost, or carrying value, less any estimated residual value recoverable from their disposal at the end of their useful lives. Based on assessments carried out by JPS, the technology on which these plants were developed is now outdated, and their capacity to generate energy efficiently is significantly restricted. This is evident in the comparatively high heat rate associated with these plants ranging from 14,000 to 16,000 kJ/kWh in comparison to 9,000 kJ/kWh for more recent technology such as the combined cycle plant being implemented by SJPC.

With regards to residual value, JPS' market assessment indicate that the plants will realize the most favourable recoverable value through the sale of the metals used to construct the plant as there is no secondary market for these plant models at this time. Scrap values for metals vary with the market price for metals at the time of disposal, however, JPS estimates that values in the region of US$1.4M to US$2M may be realisable. As outlined in the 2014-2019 Rate Review filing, there are significant costs associated with decommissioning these plants in the 2019 to 2020 period, forecasted at US$10.4M excluding severance costs of potentially US$9M. Given the significance of these costs, JPS proposes that the residual value offset be deferred at this point in time, and instead be applied in 2019 against the decommissioning costs, which will have a significant incremental impact on tariffs then. Determining the residual values for these plants can also be more reliably estimated in 2019. This treatment is acceptable under the accounting standards, as IAS 16 lists as an element of the cost of an asset expenditure incurred in the interest of dismantling and removing the item and restoring the site on which it is located, which justifies the use of realisable value as an offset in the manner proposed. It is also customary for residual values to be set off against prudently incurred decommissioning costs.

Based on the foregoing, in order to satisfy the requirements of IAS 16 and paragraph 5 of Condition 15 of the Electricity Licence, JPS is required to modify the depreciation rates applying to these steam assets to achieve a full write-off of their carrying values over the period to their projected retirement dates. This treatment has resulted in the acceleration of the depreciation charges, with the application commencing at the date the Company became aware that the useful lives would conclusively change. That date was June 2017 and the effect of the acceleration has resulted in higher depreciation charges for the period 2017 to 2020 as noted below in Table 3-1. Detailed breakdown and discussion of the related capital expenditures is provided in Appendix D.

Table 3-1: Incremental Depreciation Charges

	31-Dec-17	31-Dec-18	31-Dec-19	31-Dec-20	Total
	US$	US$	US$	US$	US$
Hunts Bay Steam Unit #6	187,658	375,317	375,317	375,317	1,313,609
Old Harbour	1,568,659	3,137,318	3,137,318	-	7,843,295
Total	**1,756,318**	**3,512,635**	**3,512,635**	**375,317**	**9,156,904**

3.1.5 Ongoing Expenditure Requirements

Considering that these steam generating plants represent a critical component of the extant generation fleet, JPS has an obligation to ensure that they continue to operate in a reliable manner until the new plants are fully commissioned. This obligation will necessitate additional capital expenditure in the interest of undertaking significant preventative maintenance and overhaul activities, which will be required prior to retirement. The depreciation of these capital expenditures will also need to be accelerated so that they may likewise be written off by the retirement date of the plants. These expenditures relate to the Old Harbour power station and Hunts Bay Unit #6, and are projected at US$13.2M, with US$6.0M incurred in 2017 and a further US$7.2M planned for 2018-2020. These expenditures will be depreciated over calendar years 2018-2020 resulting in depreciation charges of US$2.6M, US$6.3M and US$4.2M in each year, respectively. These costs were not included in the analysis above and will have the effect of increasing the accelerated depreciation charges per annum as represented in Table 3-2 below.

Table 3-2: Total incremental Depreciation Charges

	31-Dec-17	31-Dec-18	31-Dec-19	31-Dec-20	Total
	US$	US$	US$	US$	US$
Old Harbour - Existing	1,568,659	3,137,318	3,137,318	-	7,843,295
Hunts Bay Unit #6 - Existing	187,658	375,317	375,317	375,317	1,313,609
Old Harbour - Additional	-	2,399,406	5,060,848	1,899,445	9,359,699
Hunts Bay Unit #6 - Additional	-	237,496	1,248,077	2,339,052	3,824,626
Total	**1,756,317**	**6,149,537**	**9,821,560**	**4,613,814**	**22,341,228**

3.1.6 The Impact on Customers

As is the case in other jurisdictions, these costs are typically recovered through an appropriate tariff mechanism and as such, JPS proposes the adjustment of the tariffs in 2018 to permit JPS to recover the accelerated depreciation costs for the 2017, 2018 and half the 2019 allocation, totalling US$12.8M.[7] While this is an unusual request for an annual tariff filing, we believe the timing is most appropriate for the following reasons:

[7] $1.7M + $6.1M+ $4.9M (0.5 x $9.8M) for 2017, 2018 and six months of 2019.

1. It ensures a reasonable allocation of costs to customers and abates the significant tariff impact of decommissioning and other costs that will affect tariffs in 2019 given indications made by the OUR in the January 7, 2015 rate review determination. These costs are expected to total over US$20M;

2. It ensures compliance with the regulatory requirement under Condition 15 of the Electricity Licence that "*Annual Depreciation shall be computed by applying reasonable annual straight line depreciation to the value of property, plant and equipment stated at book value";*

3. It satisfies the requirements of IFRS for depreciation to be determined as the systematic allocation of the cost or carrying value of an asset over its useful life;

4. The mandate to replace the subject capacity was issued in the current 2014-2019 Rate Review period; and finally; and

5. It satisfies the regulatory principle that "the cost causer pays the cost." This principle requires that costs are recovered from those who, caused the cost to be incurred or benefitted from the cost being incurred. In this context, that asset costs are recovered from customers who derive benefit from their operation. A literal interpretation of this principle indicates that the commencement of recovery of the asset cost should ideally have started at the date it was determined that the depreciation cost should be accelerated and it is in this context that JPS presents the proposal for this matter to be considered in this 2018 Annual Adjustment filing.

3.1.7 Conclusion

JPS' request to recover US$12.816 million (J$1,640.529 million) of accelerated depreciation costs through the Z-factor clause in this 2018 Annual Adjustment filing is prudent, reasonable and justifiable. The associated Z-factor will be 4.10%.[8]

JPS has laid out justifications from customer perspective in that it is fair and reasonable for the customers who benefit from the cost to pay the cost and that the timely application of the tariff will avoid a significant increase in tariffs in 2019. We have also made reference to the Accounting and Regulatory obligations JPS is required to observe in the circumstance of the impending retirement of the obsolete steam generating assets.

JPS therefore kindly requests a reasonable assessment and a favourable consideration of this request, which will assist in avoiding rate shocks in 2019 while granting JPS the opportunity to recover reasonable and prudently incurred costs in 2018 when those revenues are required to support needed capital investments.

[8] $1,640,529,190 / $39,965,567,027 = 4.10%.

3.2 Separation Costs

With the commercial operations date for the new 190MW LNG fired plant set for June 2019, the old steam powered generation plants at Old Harbour and Hunts Bay will be closed on a phased basis commencing in June 2019. Attendant to the plant closures, JPS will incur staff separation costs as operations wind down in each location. In accordance with the construction and operations mandate for the 190MW plant, the Old Harbour location will be the first to be closed commencing in June 2019, while the Hunts Bay Unit 6 will be decommissioned in July 2020. Having assessed the financial implications from the winding down operations at the Old Harbour Plant, the company thinks it is prudent at this time to request recovery of the costs it expects to incur within the 2018-2019 regulatory period.

A schedule has been developed and the company expects to separate 68 persons employed at the Old Harbour location progressively over the 12 months to June 2019 at a total cost of US$5.579 million (J$714.196 million). Given the certainty of this cost JPS proposes to recover a third of the cost which translates to US$1.894 million (J$242.432 million) through this 2018 annual filing, and the remaining US$3.7 million (J$471.764 million) in the 2019 Rate Review filing. A further US$3.3 million (J$422.4 million) associated with the Hunts Bay staff separation costs will also be recovered in the subsequent 2019 rate filing. Positing a similar treatment to that proffered in relation to the accelerated depreciation element of the decommissioning cost JPS believes passing these costs through the 2018 tariff will result in more effective management of the tariff increase anticipated in 2019 thereby avoiding sharp rate increases. The Company therefore believes that taking a strategic view of the tariffs over the next three years this proposal will redound to the bvenefit of customers given the incremental decommissioning costs that will affect the 2019 rate review filing.

This filing is being made under the Z-factor clause since the decision to close the plants is one that originated in the Ministry of Energy in its approval of the retirement of these plants operating on technology considered obsolete in order to facilitate the introduction of the new LNG fired combined cycle facilities. In taking the decision to separate staff at this time, JPS is only executing prudently on fulfilling this mandate and ensuring that customers pay only costs that are absolutely necessary or prudently incurred.

The associated Z-factor adjustment associated with the US$1.89M will be 0.61%.[9]

[9] $242,432,000 / $39,965,567,027 = 0.61%.

4. Extraordinary Rate Review: Debt Refinancing Cost Recovery

4.1 Electricity Licence

Paragraphs 59 to 61 of the Electricity Licence lay out the provisions for the filing of an extraordinary Rate Review and these are reproduced as follows:

59. *The Licensee or the Minister may request the Office to conduct an extra-ordinary Rate Review owing to exceptional circumstances that have a significant impact on the electricity sector and/or the Licensee, but were not factors considered or known when the Rate Review was undertaken. The Office is empowered, to review the rates for this purpose outside of the five yearly Rate Review periods.*

60. *For the avoidance of doubt, the Extra-ordinary Rate Review shall not result in a rescheduling of the time period for the next stipulated Rate Review.*

61. *Where possible, the scope of such extraordinary Rate Review will be limited to the impact of the exceptional circumstances and therefore the review process is expected to be completed within a 60 day period, unless the Office and the Licensee agree otherwise.*

We are of the view that the filing satisfies the criteria and such the filing is presented in the ensuing section.

4.2 Background

JPS has certain 10-year bonds with principal value of US$179.1M, an attendant coupon rate of 11% per annum and a maturity date on July 6, 2021 currently outstanding. JPS has taken note of the fact that market conditions are favourable at this time and presents an opportunity for the bonds to be refinanced during the third quarter of the 2018 financial year. The market conditions are unique as despite increases in US Treasury rates in the last 18 months and projections for a further 0.5 to 0.75% increase in those rates during 2018, and a 2% increase in LIBOR over the last 2 years, 10 year bonds issued by the GoJ have remained stable in the market yielding an average of 5.4% to 5.7% over the past year.

As at April 27, 2018 the 2028 and 2045 bonds are trading at a yield of 5.38% and 6.46%, respectively.[10] These conditions are certainly new to the Jamaican context in the bond markets and situation is truly unique and there is no certainty as to how long the favourable conditions are expected to remain in the market. The stability of bond prices is driven mainly by the confidence investors have placed in the Jamaican market given the discipline displayed by the Government of Jamaica (GoJ) in meeting and exceeding the targets established under the IMF Stand-by Agreement over the past six years. This confidence could be shaken by any number of events whether they be natural disasters or a failure of the GoJ to continue to meet the markets expectation.

With the GoJ bonds trading at this low level it is highly likely that the Company would be able to access the markets to refinance the outstanding bonds at interest rates that were at or below 8%.

[10] Oppenheimer Caribbean Sovereigns Indicative Levels; Friday, April 27, 2018.

Recent market activity indicates that Latin American Corporates are achieving coupons in the market that were priced 1% to 2% above the Sovereign rate. Given this trend, we are confident that an 8% coupon would be reasonably achievable by JPS barring the occurrence of unforeseen circumstances. The achievement of an 8% coupon would translate to significant savings for JPS' customers as this would signify a 3% reduction in the rates currently being paid by the Company on the existing bond. In monetary terms this would translate to a saving of US$5.37M per annum for the remaining three years of the life of the bond or US$16.11M in total. In the context of achieving this beneficial outcome for our customers JPS hereby presents an Extraordinary Rate Review filing for the recovery of refinancing costs totalling US$5.3M during the tariff year 2017-2018 thereby reducing the overall interest expense which is factored into the non-fuel rate payable by the customers.

Refinancing the bonds will result in certain costs being incurred immediately. There are essentially three components of costs, namely, a prepayment penalty cost amounting to 1.833% of the outstanding bond value, unamortized finance costs and the cost of issuing the new bond amounting to approximately 2.75% of the principal value. The prepayment penalty or a breakage cost represents the "make whole" clause in the existing bond agreement to compensate lenders for the early settlement of the debt obligation. The unamortized financing cost is embedded in the tariff with the expectation that the amounts would be recovered over the period to 2021. The refinancing of the bond at an advanced date necessitates the extinguishment of these costs through current tariffs. Based on extensive discussions with potential financers, JPS anticipates new financing cost to average 2.75%, which translates to approximately US$4.95M of costs and proposes that this cost is recovered in the 2018-2019 regulatory year. The details are provided in Table 4-1.

The cost of these three items is US$10.7M ($679.936M), of which JPS is seeking to recover the US$5.312M ($679.936M) through an extraordinary rate review mechanism as permitted in the 2016 License. JPS proposes that the remaining $5.4M be financed using the reduced interest to be realized from the transaction during the first year of the refinancing. This demonstrates the Company's unwavering commitment to lowering the cost of energy to the customer.

Table 4-1: Debt Refinance Costs

	USD '000
Make Whole/Breakage Fee	3,299
Embedded Unamortized Financing Costs	2,463
New Financing Costs	4,950
Total	**10,712**
Offset Interest Rate Savings	(5,400)
Total Refinance Costs	**5,312**

JPS is prepared to pass on all incremental savings to the customer and proposes that on completion of the refinancing and determination of the precise magnitude of the saving with the established interest rate, a reconciliation be completed to account for the difference between the estimate proposed in this application and the actual outcome of the exercise. Such a reconciliation maybe facilitated as an adjustment to the revenue target for the 2019/2020 tariff year.

4.3 Conclusion

This initiative to refinance debt as detailed above provides the opportunity for significant rate reduction through the reduction of interest cost on a sustained basis. The expectation is that the higher rate of interest would have been incurred up to 2021 and therefore at a minimum the saving to the customer is \$16.11M relative to an overall cost of refinancing of US\$10.7M. This analysis ignores any potential incremental interest cost that might be associated with an increased interest rate should refinancing take place at a later date. All indications in the market are that interest rates are expected to trend up in the foreseeable future. This is clearly beneficial to the customer and as such we urge the Office to consider this proposal favourably.

5. Proposed 2018 Tariff Basket and Rates

The proposed non-fuel revenue change for 2018 has increased by 0.53% relative to 2017. Under the required rate increase of 0.53%, the non-fuel bill component for customers would increase by 2.4% reflecting resetting of the reference exchange rate from US$1:J$131 to US$1:J$128.

Notwithstanding JPS' concern that it has not been able to generate a reasonable rate of return, the Company is acknowledges that a substantial increase in tariffs will present a challenge for customers, many of whom are also challenged to balance their budgets. As such JPS proposes a saw-off, or a cap, on the increase in the tariffs at 2% on the non-fuel component of the tariff to be applied during the 2018/2019 tariff year. This will provide for a greater level of reception of any increase in the market while permitting JPS to pursue the investments the sector requires. JPS further proposes that the recovery of the differential between the determined level of increase and the propose saw-off at 2% be deferred to the 2019/20120 period.

The approved tariff basket for 2017, shown in Table 5-1 below, is derived using the product of the 2016 billing determinants and the approved non-fuel tariffs arising from the OUR's 2017 Annual Tariff Adjustment Determination Notice. The actual revenue for 2017 is derived from the 2017 billing determinants and the approved non-fuel tariffs (see Table 5-2).

Table 5-1: 2017 Approved Non-Fuel Tariff Basket

	Block/ Rate Option			12 Months 2017 Customer Revenue	Energy Revenue	Demand (KVA) revenue				Total Demand Revenue	Total Revenue
						Std.	Off-Peak	Part Peak	On-Peak		
Rate 10	LV	<100	-	1,144,861,891	5,007,387,075					-	6,152,248,966
Rate 10	LV	>100	-	1,814,387,466	12,473,872,292					-	14,288,259,758
Rate 20	LV		-	756,998,307	11,486,125,671					-	12,243,123,978
Rate 40	LV - Std		-	138,531,159	3,787,828,143	3,946,720,401				3,946,720,401	7,873,079,704
Rate 40	LV - TOU		-	9,746,329	658,305,778		23,598,632	238,400,275	242,316,105	504,315,012	1,172,367,119
Rate 50	MV - Std		-	9,079,914	1,009,384,390	891,987,563				891,987,563	1,910,451,867
Rate 50	MV - TOU		-	1,582,737	261,428,765		12,144,780	106,649,615	105,804,829	224,599,224	487,610,726
Rate 70	MV -STD		-	1,999,247	938,195,349	1,078,623,885				1,078,623,885	2,018,818,481
Rate 70	MV -TOU		-	416,510	174,251,004		11,213,630	108,223,161	93,411,721	212,848,512	387,516,026
Rate 60	LV		-	14,544,279	1,712,616,635					-	1,727,160,915
TOTAL				3,892,147,840	37,509,395,103	5,917,331,849	46,957,042	453,273,051	441,532,655	6,859,094,597	48,260,637,539

Table 5-2: Actual 2017 Revenues

	Block/ Rate Option			12 Months 2017 Customer Revenue	Energy Revenue	Demand (KVA) revenue				Total Demand Revenue	Total Revenue
						Std.	Off-Peak	Part Peak	On-Peak		
Rate 10	LV	<100	-	1,229,825,054	5,072,968,512					-	6,302,793,566
Rate 10	LV	>100	-	1,803,478,876	12,061,702,541					-	13,865,181,417
Rate 20	LV		-	776,444,976	11,747,160,631					-	12,523,605,606
Rate 40	LV - Std		-	141,460,612	3,837,255,225	3,989,916,990				3,989,916,990	7,968,632,827
Rate 40	LV - TOU		-	9,489,482	650,234,764		22,875,864	233,261,961	235,480,039	491,617,865	1,151,342,110
Rate 50	MV - Std		-	9,676,911	1,119,967,709	1,116,557,227				1,116,557,227	2,246,201,847
Rate 50	MV - TOU		-	1,950,654	288,718,290		14,124,417	128,278,041	121,769,790	264,172,248	554,841,192
Rate 70	MV -STD		-	1,582,737	944,375,230	969,750,858				969,750,858	1,915,708,825
Rate 70	MV -TOU		-	312,382	161,161,434		8,253,871	79,971,186	87,378,752	175,603,809	337,077,626
Rate 60	LV		-	14,451,908	1,640,886,392					-	1,655,338,300
TOTAL				3,988,673,592	37,524,430,728	6,076,225,075	45,254,152	441,511,188	444,628,582	7,007,618,997	48,520,723,317

Table 5-3: 2017 Billing Determinants[11]

Class	Block/ Rate Option	Average 2017 Customer	Energy kWh Std.	Demand-KVA Std.	Demand-KVA Off-Peak	Demand-KVA Part Peak	Demand-KVA On-Peak
Rate 10 LV	<100	231,726	528,985,246	-	-	-	-
Rate 10 LV	>100	339,815	540,156,854	-	-	-	-
Rate 20 LV		65,670	637,739,448	-	-	-	-
Rate 40 LV - STD		1,698	669,678,050	2,244,666	-	-	-
Rate 40 LV - TOU		114	113,479,016	-	305,174	298,247	235,148
Rate 50 MV -STD		116	202,525,806	701,170	-	-	-
Rate 50 MV -TOU		23	52,209,456	-	198,907	185,127	136,969
Rate 70 MV -STD		19	256,623,704	639,842			
Rate 70 MV -TOU		4	43,793,868		121,649	119,705	101,808
Rate 60 STREETLIGHTS		430	68,313,339	-	-	-	-
TOTAL		639,615	3,113,504,786	3,585,678	625,731	603,079	473,926

Table 5-4: Approved Non-Fuel Tariffs for 2017

Class	Block/ Rate Option	Customer Charge	Energy-J$/kWh	Demand-J$/KVA Std.	Demand-J$/KVA Off-Peak	Demand-J$/KVA Part Peak	Demand-J$/KVA On-Peak
Current Rates							
Rate 10 LV	<100	442.27	9.59				
Rate 10 LV	>100	442.27	22.33				
Rate 20 LV		985.3	18.42				
Rate 40 LV - Std		6,941.83	5.73	1,777.51			
Rate 40 LV - TOU		6,941.83	5.73		74.96	782.11	1,001.41
Rate 50 MV - Std		6,941.83	5.53	1,592.42			
Rate 50 MV - TOU		6,941.83	5.53		71.01	692.92	889.03
Rate 70 MV -STD		6,941.83	3.68	1,515.61			
Rate 70 MV -TOU		6,941.83	3.68		67.85	668.07	858.27
Rate 60 LV		2,799.13	24.02				

The proposed revenue and corresponding proposed rates for 2018/2019 arising from the application of the annual adjustment formula are provided in Table 5-5 and Table 5-6 respectively.

Table 5-5: Proposed Revenues for 2018/2019

Class	Block/ Rate Option	Customer Charge	Energy-J$/kWh	Demand-J$/KVA Std.	Off-Peak	Part Peak	On-Peak	Total Revenue
Rate 10 LV	--100	1,236,328,658	5,099,795,563	-	-	-	-	- 6,336,124,221
Rate 10 LV	> 100	1,813,016,097	12,125,487,662	-	-	-	-	13,938,503,759
Rate 20 LV		780,550,999	11,809,282,380	-	-	-	-	12,589,833,379
Rate 40A LV		-	-	-	-	-	-	-
Rate 40 LV - Std		142,208,689	3,857,547,534	4,011,016,610	-	-	-	8,010,772,832
Rate 40 LV - TOU		9,539,664	653,673,358	-	22,996,837	234,495,505	236,725,313	1,157,430,678
Rate 50 MV - Std		9,728,085	1,125,890,362	1,122,461,844	-	-	-	2,258,080,291
Rate 50 MV - TOU		1,960,970	290,245,100	-	14,199,110	128,956,406	122,413,737	557,775,323
Rate 70 MV -STD		1,591,107	949,369,308	974,879,129	-	-	-	1,925,839,544
Rate 70 MV -TOU		314,034	162,013,694	-	8,297,519	80,394,092	87,840,832	338,860,171
Rate 60 LV		14,528,333	1,649,563,785	-	-	-	-	
TOTAL		**4,009,766,637**	**37,722,868,746**	**6,108,357,583**	**45,493,466**	**443,846,003**	**446,979,882**	**48,777,312,317**

[11] The Rate 70 rate was implemented in October 2017 and to analyse the data for a full year, the corresponding Rate 70 customers' consumption was pulled from their previous rate classes (R40 & R50) and sum to the Rate 70 data for October to December 2017.

Table 5-6: Proposed 2018/2019 Tariff

Class		Block/ Rate Option	Customer Charge	Energy-J$/kWh	Demand-J$/KVA			
					Std.	Off-Peak	Part Peak	On-Peak
Rate 10	LV	--100	444.61	9.64	-	-	-	-
Rate 10	LV	> 100	444.61	22.45	-	-	-	-
Rate 20	LV		990.50	18.52	-	-	-	-
Rate 40A	LV		-	-	-	-	-	-
Rate 40	LV - Std		6,978.54	5.76	1,786.91	-	-	-
Rate 40	LV - TOU		6,978.54	5.76	-	75.36	786.25	1,006.71
Rate 50	MV - Std		6,978.54	5.56	1,600.84	-	-	-
Rate 50	MV - TOU		6,978.54	5.56	-	71.39	696.58	893.73
Rate 70	MV -STD		6,978.54	3.70	1,523.62	-	-	-
Rate 70	MV -TOU		6,978.54	3.70	-	68.21	671.60	862.81
Rate 60	LV		2,813.93	24.15	-	-	-	-

A detailed analysis of the non-fuel tariff adjustment for 2018/2019 and the total bill impact for the typical JPS customer in each rate has been provided in Appendix E. This demonstrates that the total non-fuel bill impact of the proposed tariff increase for all JPS customer classes will result in 2.4% increase. Assuming no change in the current fuel prices, the total bill impact (including Fuel and IPP charges) will be a range of upward adjustment of 1.1% for a typical residential customer, 1.2% for Rate 20 customers, 1.0% for Rate 40 and Rate 50 customers, while Rate 70 standard customers will experience a marginal increase of 0.8% on average.

Section 4.1 discusses some additional requested changes as part of the annual tariff adjustment application. This includes a proposed adjustment to the 2017/2018 approved prepaid rates for Rate 10 and 20 customers. Proposed post-paid and pre-paid rates for customers enrolled in the community renewal programme are also presented.

5.1 Pre-paid Rates

5.1.1 Rate 10 Pre-paid Rates[12]

JPS will be using a two-tiered tariff structure until the 2019 rate case filing, where the cost of service study will serve to delink the revenue requirement of its post-paid customers from its pre-paid customers.

The design of the pre-paid tariff is based on the approved post-paid rates. The proposal for the pre-paid tariff assumes the acceptance of JPS' tariff proposal Rate 10 in Table 5-6.

JPS proposes that the non-fuel tariff for Rate 10 pre-paid customers should be as follows:

- $ 15.3579/kWh for the first 118kWh in a 30 day cycle.
- $ 22.4491/kWh for every kWh above 118kWh in a 30 day cycle.

[12] The analysis only factored the accounts of the postpaid customers.

Table 5-7: Analysis of JPS Proposed Prepaid Rate for Rate 10 Customers

Customer Bands	Customer Count	Test Year Demand (MWh)	Average Consumption (kWh/month)	Post-paid Rate	Pre-paid Rate	Monthly Post-paid Revenue	Monthly Pre-paid Revenue	Monthly Variance	Annual Variance
0-50 kWh	82,440	23,081	23.33	28.70	15.36	55,199,433.24	29,542,275.07	(25,657,158.17)	(307,885,898.04)
50-100 kWh	111,262	103,177	77.28	15.39	15.36	132,328,258.07	132,070,308.25	(257,949.82)	(3,095,397.84)
100-200 kWh	203,929	354,278	144.77	16.67	16.67	492,145,098.17	492,145,098.17	-	-
200-300 kWh	80,328	232,621	241.32	18.98	18.98	367,922,611.18	367,922,611.18	-	-
300-400 kWh	27,945	114,811	342.37	20.01	20.01	191,446,268.30	191,446,268.30	-	-
400-500 kWh	11,225	59,760	443.67	20.56	20.56	102,388,263.69	102,388,263.69	-	-
500- 1000 kWh	12,396	97,893	658.10	21.18	21.18	172,782,364.97	172,782,364.97	-	-
>1000 kWh	3,540	86,835	2,044.14	22.04	22.04	159,487,073.42	159,487,073.42	-	-
Total						**1,618,499,938**	**1,618,241,988**	**(25,915,108)**	**(310,981,296)**

5.1.2 Rate 20 Pre-paid Rates

As with the design of prepaid rates for Rate 10 customers, the prepaid design for Rate 20 customers is dependent on the approved post-paid tariffs. Assuming the acceptance of JPS's tariff proposal in Table 5-6, the prepaid Rate 20 tariff is described as follows:

- $ 117.5791/kWh for the first 10kWh in a 30 day cycle; and
- $ 18.5189/kWh for every kWh above 10kWh in a 30 day cycle.

The analysis for this proposal is shown in Table 5-8 below. This tariff structure retains revenue neutrality for JPS for Rate 20 customers.

Table 5-8: Analysis of JPS Proposed Pre-paid Rate for Rate 20 Customers

Customer Bands	Customer Count	Test Year Demand (MWh)	Average Consumption (kWh/month)	Post-paid Rate	Pre-paid Rate	Monthly Post-paid Revenue	Monthly Pre-paid Revenue	Monthly Variance	Annual Variance
(0-50] kWh	10,940	2,778	21.16	65.33	65.33	15,123,267.83	15,123,267.83	-	-
(50-100] kWh	7,781	6,982	74.78	31.77	31.77	18,485,793.23	18,485,793.23	-	-
(100-1000] kWh	30,850	128,470	347.03	21.37	21.37	228,784,559.44	228,784,559.44	-	-
(1000-7500] kWh	9,482	283,614	2,492.56	18.92	18.92	447,163,868.17	447,163,868.17	-	-
>7500 kWh	1,002	218,449	18,172.28	18.57	18.57	338,049,793.27	338,049,793.27	-	-
Total						**1,032,484,014.11**	**1,032,484,014.11**	**-**	**-**

5.2 Forward-looking Model

Due to the implementation of the Smart Streetlight Programme (SSP), JPS proposes a forward-looking mechanism to account for the reduction of Rate 60 consumption in the rate design for 2018.

Using the Rate 60 projected consumption, the analysis shows a 14% YTD reduction in consumption as a result of the LED streetlights. Therefore, proposed rates for 2018/2019 arising from the forward-looking model for the application of the annual adjustment formula are provided in Table 4-9 respectively.[13] The proposed non-fuel revenue change for 2018 under the forward-looking model increased by 0.78% relative to 2017.

[13] It is assumed that the 3,113 MWh sold in 2017 is held constant and the difference in the Rate 60 consumption was redistributed to the other rate classes using a weighted average.

Table 5-9: Proposed Tariff for 2018/2019 (Forward-looking Model)

Class		Block/ Rate Option	Customer Charge	Energy-J$/kWh	Demand-J$/KVA			
					Std.	Off-Peak	Part Peak	On-Peak
Rate 10	LV	--100	445.74	9.67	-	-	-	-
Rate 10	LV	> 100	445.74	22.50	-	-	-	-
Rate 20	LV		993.01	18.56	-	-	-	-
Rate 40A	LV		-	-	-	-	-	-
Rate 40	LV - Std		6,996.23	5.77	1,791.44	-	-	-
Rate 40	LV - TOU		6,996.23	5.77	-	75.55	788.24	1,009.26
Rate 50	MV - Std		6,996.23	5.57	1,604.90	-	-	-
Rate 50	MV - TOU		6,996.23	5.57	-	71.57	698.35	896.00
Rate 70	MV -STD		6,996.23	3.71	1,527.49	-	-	-
Rate 70	MV -TOU		6,996.23	3.71	-	68.38	673.31	865.00
Rate 60	LV		2,821.06	24.21	-	-	-	-

Since the rate design is dependent on the post-paid tariff, the prepaid rates for Rate 10 and Rate 20 are as follows:

i. Rate 10 Pre-paid tariff

Table 5-10: Analysis of JPS Proposed Pre-paid Rate for Rate 20 Customers (Forward-looking Model)

Customer Bands	Customer Count	Test Year Demand (MWh)	Average Consumption (kWh/month)	Post-paid Rate	Pre-paid Rate	Monthly Post-paid Revenue	Monthly Pre-paid Revenue	Monthly Variance	Annual Variance
0-50 kWh	82,440	23,081	23.33	28.78	15.35	55,353,299.26	29,523,041.82	(25,830,257.44)	(309,963,089.28)
50-100 kWh	111,262	103,177	77.28	15.44	15.35	132,758,174.44	131,984,324.98	(773,849.46)	(9,286,193.52)
100-200 kWh	203,929	354,278	144.77	16.72	16.72	493,621,238.24	493,621,238.24	-	-
200-300 kWh	80,328	232,621	241.32	19.03	19.03	368,891,848.83	368,891,848.83	-	-
300-400 kWh	27,945	114,811	342.37	20.05	20.05	191,828,969.48	191,828,969.48	-	-
400-500 kWh	11,225	59,760	443.67	20.61	20.61	102,637,262.39	102,637,262.39	-	-
500- 1000 kWh	12,396	97,893	658.10	21.23	21.23	173,190,255.35	173,190,255.35	-	-
>1000 kWh	3,540	86,835	2,044.14	22.09	22.09	159,848,886.20	159,848,886.20	-	-
Total						**1,622,776,635**	**1,622,002,785**	**(26,604,107)**	**(319,249,283)**

- $ 15.3488/kWh for the first 117kWh in a 30 day cycle.
- $ 22.496/kWh for every kWh above 117kWh in a 30 day cycle.

ii. Rate 20 Pre-paid tariff

Table 5-11: Analysis of JPS Proposed Pre-paid Rate for Rate 10 Customers (Forward-looking Model)

Customer Bands	Customer Count	Test Year Demand (MWh)	Average Consumption (kWh/month)	Post-paid Rate	Pre-paid Rate	Monthly Post-paid Revenue	Monthly Pre-paid Revenue	Monthly Variance	Annual Variance
(0-50] kWh	10,940	2,778	21.16	65.49	65.49	15,160,306.30	15,160,306.30	-	-
(50-100] kWh	7,781	6,982	74.78	31.84	31.84	18,526,523.65	18,526,523.65	-	-
(100-1000] kWh	30,850	128,470	347.03	21.42	21.42	229,319,853.21	229,319,853.21	-	-
(1000-7500] kWh	9,482	283,614	2,492.56	18.96	18.96	448,109,246.32	448,109,246.32	-	-
>7500 kWh	1,002	218,449	18,172.28	18.61	18.61	338,777,956.53	338,777,956.53	-	-
Total						**1,034,733,579.71**	**1,034,733,579.71**	**-**	**-**

- $ 117.873/kWh for the first 10kWh in a 30 day cycle.
- $ 18.5592/kWh for every kWh above 10kWh in a 30 day cycle.

5.3 Community Renewal Rate

The OUR approved that PATH beneficiaries are eligible for this Community Renewal Rate under the Tariff adjustment made in September 2017. JPS has since been working with the PATH to implement this rate.

In designing the process, JPS was advised by PATH that PATH beneficiaries do not have a PATH Identification card but only a PATH beneficiary number. As such, JPS will rely on PATH to do a validation of all applicants.

For validation of PATH Beneficiary JPS must rely on:

- PATH Beneficiary family number;
- Name of head of household;
- Name of family representative; and
- Beneficiary date of birth.

Customers who qualify to benefit from the Community Renewal rate should:

- Be a PATH Beneficiary;
- Be a JPS customer – i.e. You have an Electricity Contract with JPS; and
- Not have any outstanding arrears with JPS.

JPS recognizes that a key element of the success of the Community Renewal Programme is the affordability of electricity for residents in the targeted communities as these are communities generally have high levels of unemployment with many of those employed earning minimum wage. JPS is proposing that the Community Renewal rate to be charged for 2018/2019 for both the post-paid and pre-paid customers be $9.64/kWh ($9.67/kWh using the forward-looking model) for consumption up to150kWh. This rate will not attract a customer charge or any other charges as long as consumption remains below 150kWh in a billing cycle.

Qualifying customers consuming more than 150kWh per month will pay the same pre-paid or post-paid rate (whichever is applicable) including the customer charge for the excess consumption.

6. Overview of Fuel Efficiency Mechanism

6.1 Introduction

Regarding the monthly adjustment to JPS fuel rates, Exhibit 2 of Schedule 3 of the Electricity Licence provides as follows:

> *"A. Alternative 1 Fuel Cost Adjustment Mechanism (FCAM)*
> *The cost of fuel per kilo-watt-hour (net of efficiencies) shall be calculated each month on the basis of the total fuel computed (inclusive of fuel additives) to have been consumed by the Licensee and Independent Power Producers (IPPs) in the production of electricity. Effective January 1, 2016, this will be calculated each month based on the Licensee's generating heat rate as determined by the Office at the adjustment date and the IPPs generating heat rate as per contract and system losses, as determined by the Office at the adjustment date, applied to the total net generation (the Licensee and IPPs). Effective July 1, 2016, this will be calculated each month based on the Licensee's generating heat rate as determined by the Office as at June 30, 2016 (and on each succeeding rate review date) and the IPPs generating as per contract."*

As required by the Electricity Licence, the cost of fuel per kilo-watt-hour shall be computed on a monthly basis under the appropriate rate schedule having regard to the applicable efficiency adjustments and effective dates as specified in the Electricity Licence. Accordingly, the fuel cost portion of the monthly bill should be calculated in the following manner:

"F = Fm/Sm

Where:

Billing Period	=	*The billing month during the effective period for which adjusted fuel rates will be in effect as determined by the Office.*
F	=	*Monthly Adjustment Fuel Rate in J$ per kWh rounded to the nearest one-hundredth of a cent applicable to bills rendered during the current Billing Period.*
F_m	=	*Total applicable energy cost for period [fuel, fuel additives, IPP and Take or Pay charges].*

The total applicable energy cost for the Billing Period is:

a) *the cost of fuel, adjusted for the determined heat rate up to June 30, 2016, and which fuel is consumed in the Licensee's generating units or burned in generating units on behalf of the Licensee or incurred in relation to the Licensee's contractual obligation, such as but not limited to the minimum take-or-pay obligation under a gas supply agreement, for the preceding calendar month plus;*

b) *the fuel portion of the cost of purchased power (including IPPs), adjusted for the contract heat rate, for the said preceding calendar month; and*
c) *an amount to correct for the over-recovery or under-recovery of total applicable energy cost for a billing period, such amount shall be determined as the difference between the actual total applicable energy cost for a given month adjusted for the determined heat rate and system losses, if applicable and the fuel costs billed for such month, using fuel costs and fuel weights.*
d) *an amount to correct for the over-recovery or under-recovery of the non-fuel portion of the purchased power. This amount shall be determined as the difference between the actual IPP non-fuel cost for a given month and the estimated base non-fuel IPP charge billed to customers for such calendar month.*

Sm = *the kWh sales in the Billing Period. The kWh sales in the billing period is the actual kWh sales occurring in the previous calendar month.*

The Fuel Rate Adjustment including the Schedule for the application of the fuel charge to each rate class, shall be submitted by the Licensee to the Office within ten (10) days of the start of each applicable billing month and shall become effective on the first billing cycle on the applicable billing month."

The fuel efficiency mechanism determines how much fuel cost JPS can pass through to customers. The pass through is dependent on how well JPS performs relative to the target. With respect to the determination of the Heat Rate target, Schedule 3, paragraph 40 of the New License provides as follows:

"The Office shall determine the applicable heat rate (whether thermal, system, individual generating plants of the Licensee or such other methodology) and the target for the heat rate."

In the 2014 – 2019 Rate Case Determination Notice, the OUR determined that the Heat Rate Factor that shall be used in the FCAM should be the ratio of JPS Heat Rate target (thermal) to JPS heat rate actual (thermal) which is used in the fuel pass through formula as follows:

$$\text{Pass Through Cost} = \left[\text{IPPs Fuel Cost} + \left(\text{JPS Fuel Cost} \times \left(\frac{\text{JPS Thermal Heat Rate Target}}{\text{JPS Thermal Heat Rate Actual}}\right)\right)\right]$$

The OUR upheld its decision to use the thermal heat rate in both the 2015 and 2016 Annual Determination Notices and at this point JPS is not opposed to the use of the thermal heat rate.

6.2 JPS' Heat Rate Performance

The heat rate of JPS thermal plants improved during the 2017 when compared to 2016. Compared to 2016, the heat rate improved by 250 kJ/kWh or 2.2% in 2017. The major factors contributing to the improvement in efficiency were the Rockfort Diesel Barge (1% efficiency improvement post Major Overhaul), Bogue Combined Cycle Plant (1% efficiency improvement post major overhaul

GT12 & GT13), and (18%) reduced production from Old Harbour Station. In addition, there was a 1% reduction in production from JPS's simple cycle gas turbine fleet that contributed to this performance adjustment. Renewables production increased by (46%) because of a full year operations of BMR Windfarm and Content Solar. JPPC, JEP & WKPP availability improvement of 1% helped to keep simple cycle gas turbine production lower than 2016.

Table 6-1 summarizes JPS' heat rate performance versus target from January 2016 to January 2018.

Table 6-1: JPS Thermal Heat Rate Performance

Months	JPS Thermal Heat Rate Actual (kJ/kWh)	OUR Heat Rate Target (kJ/kWh)	Variance From Target (kJ/kWh)
Jan-16	11,996	12,010	14
Feb-16	12,175	12,010	-165
Mar-16	12,240	12,010	-230
Apr-16	12,044	12,010	-34
May-16	11,432	12,010	578
Jun-16	11,352	12,010	658
Jul-16	11,218	11,620	402
Aug-16	11,065	11,620	555
Sep-16	11,462	11,620	158
Oct-16	11,448	11,620	172
Nov-16	11,469	11,620	151
Dec-16	10,953	11,620	667
Jan-17	11,158	11,620	462
Feb-17	11,181	11,620	439
Mar-17	11,148	11,620	472
Apr-17	11,081	11,620	539
May-17	11,134	11,620	486
Jun-17	11,227	11,620	393
Jul-17	11,474	11,450	-24
Aug-17	12,109	11,450	-659
Sep-17	11,628	11,450	-178
Oct-17	11,281	11,450	169
Nov-17	11,191	11,450	259
Dec-17	11,360	11,450	90
Jan-18	11,208	11,450	242
Feb-18	11,472	11,450	-22
Mar-18	11,079	11,450	371

The actual heat rate performance in 2017 ranged from 11,081 kJ/kWh (3.2% below the approved target) to 12,109 kJ/kWh (5.8% above the approved target). The average actual heat rate performance in 2017 was 11,341 kJ/kWh, or within 1% of the approved target of 11,450 kJ/kWh. JPS experienced significantly higher heat rate than the OUR approved target in August and September 2017, with the variance of 489kJ/kWh and September was 178kJ/kWh, respectively. This was due to a generator incident of Bogue GT#12 (1/3 of CC Plant) in August and September saw Boiler tube leak on Old Harbour Unit #4 and Hunts Bay Unit #B6.

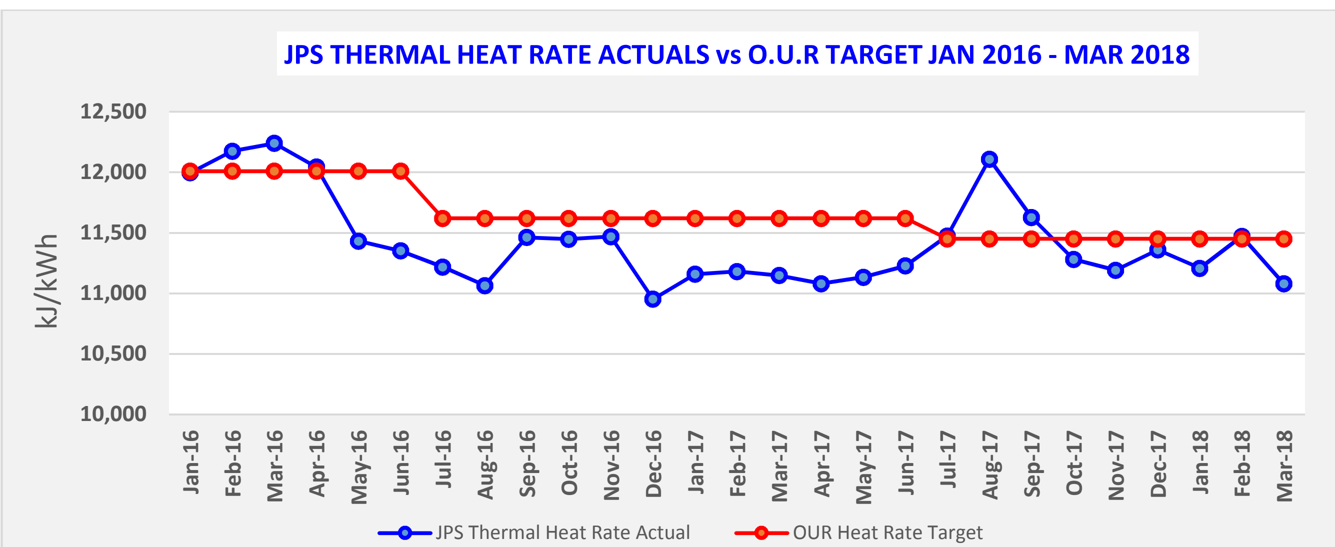
This shows that even one-time incidents during the year can significantly impact the annual heat rate performance highlighting the importance of proper heat rate target setting for the utility. It should also be noted that due to these events JPS underperformed relative to the 2017 forecast heat rate, which was developed based on a planned maintenance schedule for 2017 that had no major intervention on JPS' large steam sets reflected.

It is also observed that over the period January 2016 to March 2018, ten (10) or (37%) of the month's actual heat rate performance were above 11,450 kJ/kWh. The average for these 10 months was 11,807 kJ/kWh. The average heat rate for the entire period was 11,429 kJ/kWh, which was a mere 0.21% below the current OUR Target (11,450 kJ/kWh). Despite last year's improved performance of 11,341 kJ/kWh, this was still just 0.95% below the OUR target. Whilst JPS continues to make every effort to improve the performance of its fleet, any adverse forced outage of its fleet as well as the IPPs could negatively impact JPS' ability to recover fuel cost. The Bogue CCGT plant which is now due major overhaul could have a severe impact on JPS fuel recovery in case it should have high forced outage rate.

6.2.1 Thermal Heat Rate Performance vs Target: (January 2016 – March 2018)

Figure 6-1 shows the thermal heat rate performance versus OUR target. In 2017, JPS thermal heat rate performance was better than target January to July and October to December. The variance for August was 489kJ/kWh and September was 178kJ/kWh. This was due to a generator incident of Bogue GT#12 (1/2 of CC Plant) in August and September saw Boiler tube leak on Old Harbour Unit #4 & Hunts Bay Unit #B6.

Figure 6-1: Thermal Heat Rate Performance vs Target, Jan 2016 – Mar 2018



6.3 Comparing Regulatory Review Periods: July 2016 – June 2019

The forecast for the period July 2018 to June 2019 indicates several instances in which the current OUR target (11,450 kJ/kWh) will be exceeded should the assumptions for this forecast materialize. One major consideration in this forecast is the Major Overhaul maintenance on the Bogue CC Plant that is scheduled for the first quarter (Q1) of 2019. This unit was last overhauled in 2013, is now due and must be conducted during that period (Q1, 2019) in order to prevent the exposure of suboptimal operating conditions. Some of the major components for the overhaul are: Turbine, Heat Recovery Generator (HRSG), Generator and controls upgrade. The average heat rate impact for this outage is projected to be 250 – 270 kJ/kWh to the system.

The 2018/19 forecast also indicates that six (6) months or 50% of the period, the OUR target will be exceeded if the projected figures are realized. In this regard, the average heat rate would be 11,788 kJ/kWh, with the remaining six months averaging at 11,175 kJ/kWh, thus closing the period 2018/19 at 11,481kJ/kWh. Whilst these assumptions presents some adverse cases, given JPS' current base load fleet (aging steam units) and the available peaking unit, the current case presented could see JPS thermal heat rate exceeding 11,450 kJ/kWh.

In support of the foregoing outcome, over the periods of review (July 2016 – June 2017), there were periods in which the OUR targets were exceeded. The period 2017/18 also shows actual high heat rate performances across respective months in Q2 of 2017, and February of 2018.

6.4 Heat Rate Forecast for July 2018 to June 2019

JPS prepared Thermal heat rate forecast for best case and worst case scenarios taking into account considerations discussed in Section 5.3. JPS heat rate forecast for 2018/19 is based on the assumptions of several parameters for new and existing generating units. These parameters include: maximum capacity ratings, forecasted capacity factors and energy production. The assumptions on these factors in relation to 2018/19 are outlined in the ensuing (for best case forecast scenario).

6.4.1 Model Assumptions

Projected Maximum Capacity Rating (MCR)

- Rockfort's maximum capacity rating is forecasted to remain at 20MW x 2 for the period 2018/19.
- Hunts Bay's maximum capacity rating will remain at 122.5MW for the period 2018/19.
- Old Harbour's maximum capacity rating will remain at 193.5MW for the period 2018/19.
- Bogue's maximum capacity rating is forecasted to remain at 211.5MW for the period 2018/19.
- JPS Renewables MCR is forecasted at 32.52MW for the period 2018/19.
- IPP's MCR forecasted at 403MW in 2018/19, this includes 98.3MW Wind and 57MW Solar.

Forecasted Capacity Factor

- Rockfort's capacity factor is forecasted to average 77% for 2018/19 period. This is inclusive of major maintenance outage on Engine #2.

- Hunts Bay's #B6 capacity factor is forecasted to average 62% for the 2018/19 period. The capacity factor of Hunts Bay's gas turbines are projected to average less than 6%, for the 2018/19 period.

- Old Harbour's capacity factor is forecasted to average 44% for 2018/19.

- Bogue's capacity factor is forecasted to average 38% for 2018/19. Capacity factor for the peaking units is 3% for 2018/19 with the return of GT#11 on natural gas. The Combined Cycle Plant forecasted at 71% capacity factor.

- JPS Hydro Renewables capacity factor forecasted to average 53% for 2018/19. Capacity factor for Wind farms 32% and Munro 13%, Solar Farm 24%.

- IPP's Thermal capacity factor forecasted to average 73% for 2018/19. This is inclusive of major overhaul outage on JPPC Engine #2 for 19 days.

- The overall system capacity factor is forecasted at 60% for the 2018/19 period.

Forecasted Energy Production

- Rockfort's energy production is forecasted at 269GWh for the 2018/19 period. This is inclusive of major maintenance outage on Engine #1.

- Hunts Bay's #B6 energy production is forecasted at 374GWh for 2018/19. The energy production forecasted for Hunts Bay's gas turbines projected at 15GWh for 2018/19.

- Old Harbour's energy production is forecasted at 751GWh for 2018/19.

- Bogue's CC plant energy production is forecasted at 753GWh for 2018/19. This is inclusive of a major maintenance outage of the combined cycle plant in Q1, 2019. Energy production for the peaking units is forecasted at 29GWh for 2018/19 with the return of GT#11 on natural gas.

- JPS Hydro Renewables energy production is forecasted at 137GWh for 2018/19. Energy production for Wind farms: BMR 113GWh, Wigton 168GWh and Munro 3GWh, and the Solar Farms: WRB Solar 41GWh and Eight Rivers Solar 40GWh.

- IPP's Thermal energy production forecasted at 1,613 GWh for 2018/19. This is inclusive of major overhaul outage on JPPC Engine #1 for 21 days.

- The overall system demand is forecasted to remain flat for 2018/19 period vs the 2017/18 period, largely due to hotter than normal summer for 2017 not expected for 2018 along with increased fuel prices, and growth from small commercial and residential customers.

6.4.2 System Heat Rate Model Results

Fuel Pricing Index

HFO #6 Fuel prices for 2018 was modelled at US$66.84/barrel average for JPS Plants. HFO #6 price average for the IPPs US$62.83/barrel was forecasted. For ADO #2 the average for 2018 was forecasted at US$99.58/barrel. 2018 VOM for the IPPs averaged US$16.99/MWh in the model, inclusive of new JPPC contract. The merit order top ten units / plant from the above for 2018 RF#2, RF#1, JPPC, WKPP, HB #B6, OH#4, OH #3, JEP, BG CCGT, OH#2.

The forecasted heat rate by plant is as follows for 2018 (best case forecast scenario):

- Rockfort is forecasted at 9,074 kJ/kWh with planned major outage intervention on RF#1.

- Old Harbour plant heat rate is forecasted at 13,272 kJ/kWh with OH#2 with cycling duties enabled.

- Hunts Bay HB#B6 forecasted at 12,777kJ/kWh. Hunts Bay gas turbines forecasted at 15,032kJ/kWh which is reflective of their peaking duties.

- Bogue gas turbine GT#3-GT#11 are forecasted at 12,977kJ/kWh as per their peaking duties. Bogue CCGT is forecasted at 9,260kJ/kWh.

- IPPs are forecasted at 8,452 kJ/kWh with SJPC coming online in June 2019, and major overhaul on JPPC engine #1 and new PPA heat rate. Also Major maintenance outages on JEP & WKPP 12 engines averaging 18 days per engine.

6.4.3 JPS Thermal and System Heat Rate Forecasts for the 2018/19 Regulatory Period

JPS Thermal heat rate forecast for 2018/2019 is 11,306 kJ/kWh under the best case forecast and 11,540 kJ/kWh under the worst case forecast as illustrated in Table 6-2.

Table 6-2: 2018/2019 JPS Thermal Heat Rate Forecast

Heat Rate (kJ/kWh)	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	**Totals**
JPS Thermal - Best Case	11,156	11,067	11,179	11,292	11,057	10,998	11,561	12,176	12,037	11,228	11,080	10,843	**11,306**
JPS Thermal - Worst Case	12,675	11,488	11,015	11,382	11,578	11,423	11,555	12,176	12,037	11,228	11,080	10,843	**11,540**

6.5 Proposed Heat Rate Target

The JPS Thermal heat rate performance over the period will depend on several factors affecting the economic dispatch which include the:

1. Growth in system demand;
2. The addition of more renewables;
3. The addition of new generating units and the installed reserve margin (OUR);
4. Heat rate improvements made to existing generating units (JPS);
5. Availability and reliability of JPS generators (JPS);
6. Availability and reliability of IPP generators (IPPs);
7. Absolute and relative fuel prices for JPS and the IPPs and the impact on economic dispatch;
8. Spinning reserve policy (JPS & OUR); and
9. Network constraints and contingencies (JPS).

6.5.1 Key Considerations

While all the above factors influence the resultant system heat rate, JPS has sole direct control over only a few. JPS' view is that in establishing the heat rate target, consideration must be given to the major maintenance outage for the Bogue CC plant which is schedule for Q1 2019,the likelihood of and the effect of a major failure of one of the key steam turbines in the fleet that are now at their end of life. The forecasts provided for 2018/19 do not provide for major incidents on key JPS and IPP Thermal Sets. It assumes a planned maintenance schedule for 2018 that has no major intervention on JPS' large steam sets (OH#2, OH#3, and OH #4, HB #B6).

It is JPS' view that the heat rate target must significantly consider the effect of the major maintenance outage on the Bogue Combined Cycle Plant given the fact that this unit was last overhauled in 2013 (five years ago) and is JPS' most efficient generating unit. Also taking into consideration the criticality of the unit to the entire system we believe that special attention should be given to this major upcoming event when setting the 2018/19 heat rate target. Another point to note is in August 2017 when JPS lost half of the combine cycle plant due to a force outage on GT #12, JPS' monthly heat rate spiralled to 12,109 kJ/kWh in that month, and 11,628kJ/kWh in the following month. This goes to show the importance of this unit to the system. JPS also strongly believe that the OUR should also take into consideration a major failure of one of the key steam turbines lasting for a month. As is being seen in the past, the reliability of some of these assets continue to affect JPS Thermal Heat Rate performance with Old Harbour Unit #4 having boiler tube leak incidents for at least five times in 2017, along with a generator failure requiring rewind. While a boiler tube leak requires 72hrs to repair, a generator overhaul takes a month to complete.

With an average regulatory target of 11,555kJ/kWh for 2017 and a performance by JPS of 11,341kJ/kWh, JPS achieved a 213kJ/kWh positive variance on fuel recovery for 2017. Assuming a target of 11,450kJ/kWh for 2018 and the same performance from JPS, the positive variance would be cut in half down to 108kJ/kWh. Such a reduction would be difficult to cover should incidents take place similar to what occurred with Old Harbour Unit #4 (was due major overhaul in 2017, last overhaul was 2012). Of note Hunts Bay Unit #B6 is now in the recommended year for major overhaul and is showing similar issues as that of Old Harbour Unit #4 in 2017. Hunts Bay Unit#B6 was last overhauled in 2013. JPS' experience in the past have shown that incidents of this nature on these units have pushed monthly heat rate performance to 11,628kJ/kWh.

It should be noted that JPS will be accommodating outages at the Old Harbour Power Station for the New Old Harbour 190MW CCGT. These outages are forecasted to negatively impact JPS Thermal Heat Rate for the year by 17kJ/kWh.

As well, while the 2017 performance did not end above 11,450kJ/kWh, we note the three year average performance of 11,414kJ/kWh and how easily this average can be negatively impacted by failures on key baseload units that have passed the major overhaul / retirement dates. JPS is concerned that this might hinder the Company's ability to fully recover on its fuel costs. It is important to note that for the period presented (Jan 2016 – Mar 2018), ten (10) of the twenty-seven (27) months heat rate performance were above 11,450 kJ/kWh target, or 37% of the period.

As such, JPS expects higher likelihood for the worst case forecast of 11,540 kJ/kWh relative to the best case forecast of 11,306 kJ/KWh during the July 2018 – June 2019 period.

Accordingly, JPS proposes a heat rate target 11,482 kJ/kWh, which is based on a weighted average of best case (25%) and worst case (75%) forecast. JPS believes that the proposed heat rate target of 11,482 kJ/kWh is reasonable, especially considering the scheduled major overhaul maintenance on the Bogue CC plant in the first quarter (Q1) of 2019. This would help JPS mitigate against any shock failure lasting for at least a month on key JPS generating sets required to meet the regulated heat rate target and not impact negatively on JPS' fuel recovery costs.

7. Ensuring Quality of Service – The Q-factor

7.1 Introduction

The Q-factor mechanism is included in the annual revenue adjustment formula as a component of dPCI i.e., the allowed price adjustment to reflect changes in the quality of service provided to customers. Specifically:

$$dPCI = dI \pm Q \pm Z$$

JPS and the OUR have agreed in principle that the Q-factor should meet the following criteria:

- The Q-factor should provide the proper financial incentive to encourage JPS to continually improve service quality. It is important that random variations should not be the source of reward or punishment;

- The measurement and calculation of the Q-factor should be accurate and transparent without undue cost of compliance;

- It should provide fair treatment for factors affecting performance that are outside of JPS' control: such as those due to disruptions by the independent power producers; natural disasters; and other *Force Majeure* events, as defined under the Electricity Licence; and

- It should be symmetrical in application, as stipulated in the Electricity Licence.

7.2 JPS' OMS Data for Reliability Baseline

Since the implementation of a modern Outage Management System (OMS) JPS has been working with the OUR through various consultations, reporting etc. to resolve important concerns that arose post implementation. Through continued engagement with the OUR JPS has managed to not only improve on the quality of data and key outage processes but also developed a mutual level of confidence in its reliability reporting to the OUR. In its 2017 Annual Tariff Filing, JPS established that the quality of the reliability data is consistent with industry standards and that the effective management of reliability data is not characterised by the identification of an error event or a series of isolated error events, but rather, must take a lifecycle approach (see Electric Power Research Institute Smart Grid Assessment 2012 Technical Report). For the 2017 annual review, the OUR concurred that the Q-factor review should be focused on improving the quality of the outage data to allow for the setting of a reliable Q-Factor baseline. It was further outlined that subject to the relevant regulatory requirements, the OUR would be in consultation with JPS establish the Q-Factor baseline by the end of 2018 to facilitate the implementation of the Q-Factor incentive scheme at the 2019-2024 Rate Review.

In 2017 JPS continued its commitment to achieving high quality OMS data through the life cycle approach philosophy as the T&D grid undergoes daily changes due to operational configuration, growth, and network additions, as well as routine switching for maintenance. Through the revision of the GIS Update Policy and the acquisition of the ArcFM software, the Company is now equipped to achieve and maintain a very high level of data accuracy and quality, consistent with industry standard.

7.3 Q-Factor Reliability Benchmark and Implementation Issues

For the implementation of the Q-Factor, it was established with the OUR that the following criteria should be satisfied:

- Measurement and calculation should be accurate and transparent;

- Fair treatment for factors affecting performance that are outside of JPS control; and

- Provide proper financial incentive to deliver an acceptable level of service quality.

The establishment of a reliable and credible baseline supported by outage improvements strategies is considered crucial to JPS' expected annual revenue and customer service satisfaction. It is therefore essential that such baseline is reasonable and is aligned to the quality of service projections that JPS will put forward in its 5-Year Business Plan for the 2019 Rate Review period. JPS and the OUR have been working on the data improvement strategies to ensure that the outage dataset is captured completely and accurately to facilitate the evaluation and establishment of the Q-Factor benchmark.

7.4 Reliability Baseline

In preparing the 2017-2018 reliability performance dataset, JPS has reviewed and addressed all of the OUR's concerns with respect to the data quality noted in the 2017 Annual Filing Determination. Below are some highlighted comments noted by the OUR in the last Annual Review and JPS corresponding response.

1. **Period of Outage Data**
   - **OUR Position:** A single outage with negative duration was found in the 2016 raw dataset.
   - **JPS Response:** This issue has been fully addressed and the dataset provided in Appendix F (excel workbook) does not contain outages with negative duration.

2. **Variation in Daily Customer Count**
   - **OUR Position:** Unreasonable high variation in daily customer count.
   - **JPS Response:** The daily customer count utilized to compute the reliability statistics in OMS is extracted once daily via an automated process from the Customer Information System (CIS). This value is the sum of active and connected customers on the network at that time as represented in the CIS. Other data set provided to the OUR are static reports and would account for some variation. However, JPS will continue to examine this variation towards a convergence of data reporting to the OUR.

3. **Variance between Raw and Calibrated Dataset**
    - **OUR Position:** Forty two outage events were included in the raw dataset but were omitted in the calibrated dataset.
    - **JPS Response:** This was a result of step restorations inaccurately reflected in both dataset. This was subsequently resolved in OMS.

4. **Variance between Monthly and Annual Dataset Submissions**
    - **OUR Position:** System outage data submitted as a part of a different dataset was found to be incongruent with the annual dataset (Number of outages and data categories).
    - **JPS Response:** Outage queries and subsequent resolution are an ongoing part of the outage management process. This may introduce the changing of outage categories between the various systems, as well as outages being classified as non-reportable.

5. **Ratio of Non-Reportable to Forced Outage Data**
    - **OUR Position:** The number of events designated as non-reportable is high relative to total forced outages.
    - **JPS Response:** Outage calibration are an ongoing part of the outage management process. This may introduce the changing of outage categories between the various systems, as well as outages being classified as non-reportable. Different data set not submitted for Q-Factor reporting are likely uncalibrated.

6. **Provision for Major Event Day (MED)**
    - **OUR Position:** The Licence does not make provision for Major Event Day (MED) in the Q-factor. Unless there are modifications in the Electricity Licence the relevant outage for major system failure must be included in the calculation of the quality indices.
    - **JPS Response:** With the adoption of the IEEE1366-2012 Standard, the Major Event Days (MED) 2.5beta methodology was applied as included in the standard. The objective of this standard is to provide a consistent basis as used across the industry to prevent the use of random variations being used as source of reward or punishment in quality indices.

7. **Force Majeure**
    - **OUR Position**: Any relief required for force majeure condition should be in accordance with the Electricity Licence.
    - **JPS Response:** JPS clarifies that these events are in accordance with Condition 11, Paragraph 2 of the Electricity Licence. Detail events with supporting documentation will be reported on a monthly basis during the reporting year.

JPS is proposing that the 2016-2018 dataset is to be used to establish a baseline for the 2019-2024 Q-Factor targets, as this dataset is in keeping with OUR standards. Q-factor target was set at zero every year since the OUR Determination from January 7, 2015 with respect to the 2014-2019 Tariff Review filing, pending the agreement of baseline dataset that is being submitted in this years' annual filing. As such no Q-factor target is being proposed at this time in observance of the data quality process and concerns raised by the OUR. JPS expects 2017/2018 data submission be used to establish targets for the 2019 rate review application. JPS remains fully committed and encouraged by the progress made over the past number of years that has brought JPS to this point and will take necessary steps to ensure continued improvement with service reliability.

Non Reportable Outages

To maintain the accuracy of OMS dataset, validation and adjustment are daily processes for JPS. Data calibration is done when outage characteristics are abnormal. The calibration process is done via a Rules Base Dictionary provided in Appendix G which was developed and presented to the OUR in 2016.

In the following sections, JPS will highlight its reliability performance and describe the initiatives being implemented to continuously improve reliability.

7.5 2017 Reliability Performance

Figure 7-1, Figure 7-2 and Table 7-1 highlight JPS 2017 reliability performance. In 2017, JPS saw a reliability performance of 3% better than 2016 SAIDI and 4% worse than 2016 SAIFI performance. Higher SAIFI statistics was mainly due to the abnormal weather events experienced during the year, which impacted the grid negatively, as illustrated in Figure 7-2. In particular, there was significant weather feature in May and September affected JPS' performance due to excessive rainfall.

The improvement in reliability performance was a direct result of the strategies and initiatives undertaken during the year, which are outlined in detail in Section 7.6.

Figure 7-1: SAIDI Performance in 2017 – (inclusive of Generation, Transmission and Distribution)

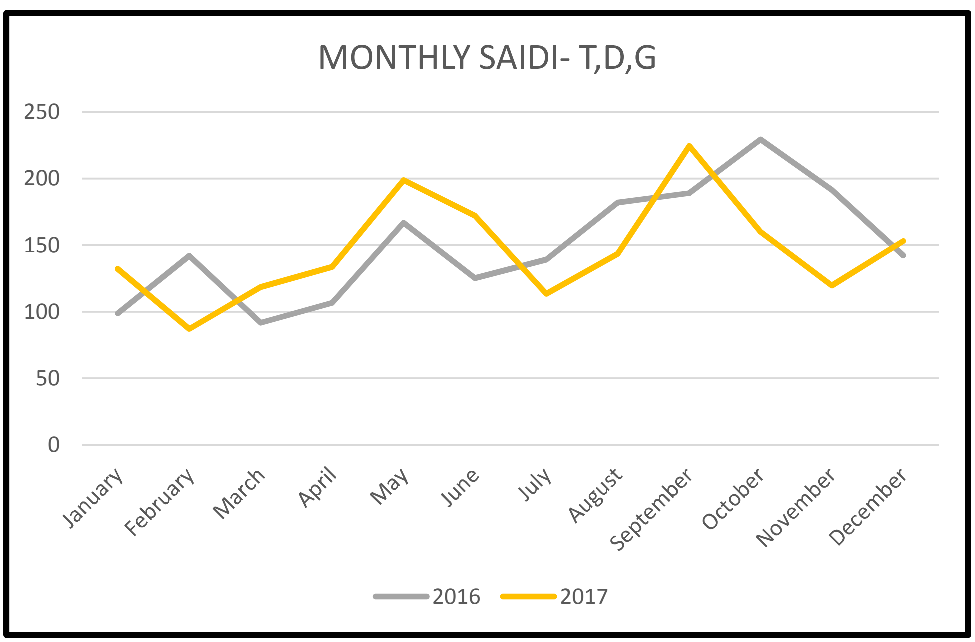


Figure 7-2: SAIFI Performance in 2017 – (inclusive of Generation, Transmission and Distribution)

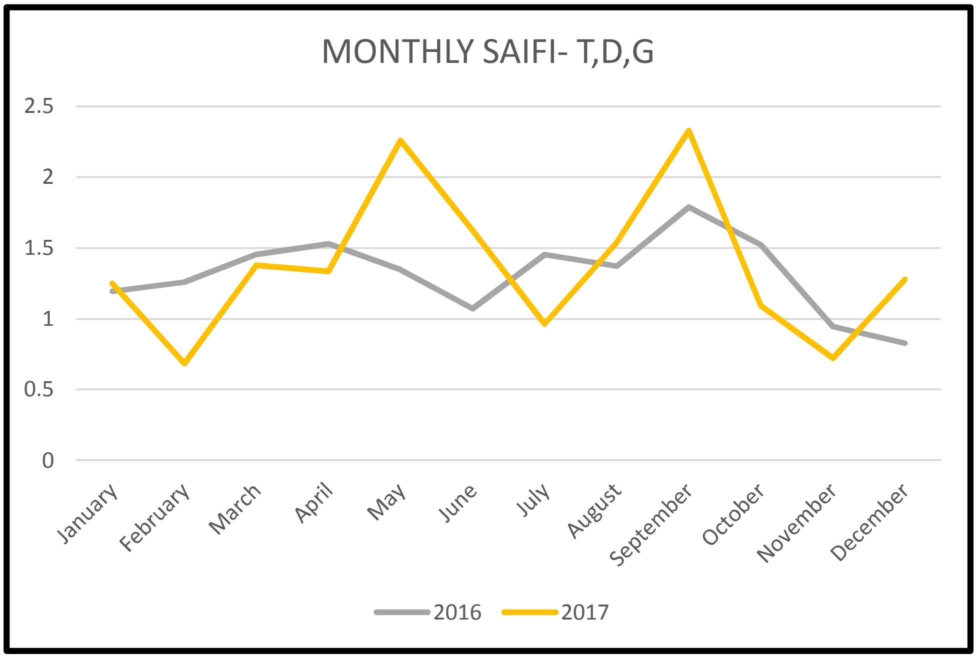


Table 7-1: Summary of Reliability Performance in 2017

Indicators	Unit	Category	Generation	Transmission	Distribution	Force Majeure/Major Event Day	Total
SAIDI	Minutes/Customer	Forced	110.135	101.934	1,541.534	305.956	2,059.558
		Planned	0.000	217.084	524.622	0.000	741.705
		Total	110.135	319.017	2,066.155	305.956	2,801.264
SAIFI	Interruptions/Customer	Forced	6.198	0.958	9.307	1.014	17.478
		Planned	0.000	0.552	1.648	0.000	2.200
		Total	6.198	1.511	10.955	1.014	19.677
CAIDI	Minutes/Customer	Forced	17.770	106.362	165.628	301.732	117.840
		Planned	0.000	393.039	318.416	0.000	0.000
		Total	17.770	211.174	188.607	301.732	142.359
MAIFI	Interruptions/Customer	Forced	9.986	1.023	23.052	0.000	34.061
		Planned	0.000	0.611	1.109	0.000	1.721
		Total	9.986	1.634	24.162	0.000	35.782

7.6 2017- 2018 Reliability Performance Improvement Strategy

A total of $49M was invested in improving the reliability performance, with $26M allocated to T&D initiatives and $23M to Generation. The 2017 reliability performance improvement strategy encompassed the following:

1. Employment of automated grid management through the use of technology on the T&D network.

2. Traditional/ routine activities, involving lightning mitigation, structural integrity, routine inspections and the application of the appropriate solutions to problem areas.

3. Intensifying outage management processes and improving outage data quality.

7.6.1 Automated/Technological Approaches

JPS continues to improve the T&D system reliability by leveraging various grid technologies. During 2017 the following reliability initiatives were employed:

- Installation of Distribution Automated (DA) switches;
- Installation of Smart Fault Circuit Indicators (FCI);
- Installation of Dropout Reclosers (TripsaverII) at sub feeder levels;
- Calibration of Feeder Reclosers with Single Pole Tripping (SPT) features;
- Installation of Smart Meters; and
- Leveraging Enterprise Asset Management (EAM).

Distribution Automated Switches

The main function of these devices is to limit faulted section of a distribution feeder and allow for faster response and restoration of affected circuits at the primary and secondary distribution level. These devices are pivotal to the self-healing grid strategy; these devices will further optimize the functionality of the recently acquired ADMS. Since 2014, 198 devices have been installed on the network as follows:

- 2014 – 41 devices
- 2015 – 35 devices
- 2016 – 62 devices
- 2017 – 60 devices

Smart Fault Circuit Indicators

Traditionally, the operations field personnel would patrol and inspect the entire line section until the fault is located. With the introduction of the smart FCIs, field personnel can now travel directly to the faulted location while be guided by the system controller/dispatcher on duty. Additionally, the FCIs will give a visual identification (flashing lights) to direct the crews.

Recent advances in smart grid technology and communications have resulted in the development of smart FCIs with advanced functional and communication capabilities. These devices will further optimize the functionality of the recently acquired ADMS. The continued leveraging of these technologies on the network will continue to improve overall response time.

A total of 45 Smart FCIs have also been installed on the distribution network in 2017, adding to the 410 previously installed.

Dropout Reclosers (TripsaverII)

A total of 81 additional units were installed on the distribution network in 2017, adding to the 120 previously installed. These devices have been installed on targeted frequently blowing fused sections. The technology utilizes the principle that 70-80% of sustained outages on fused laterals are transient in nature. The proliferation of these devices on the T&D network will therefore prevent the transient events from translating to sustained outages.

Single Pole Tripping (SPT) Reclosers

A total of 64 feeders have been implemented with SPT reclosers on the distribution network. Distribution line faults are predominately single-line-to-ground; double-line-to-ground in nature and as such the faulted phase can then be isolated and the remaining phases remain in service. This functionality will allow the affected feeder to maintain supply to the customers being supplied by the unaffected phase(s). This initiative have and will continue to improve system reliability as only the affected phase(s) will experience an outage.

Smart Meters

Consistent with its objective to attain a smarter grid, JPS installed over 40,000 Smart Meters to date and will continue this project more aggressively in 2018. These meters will ultimately be integrated into existing OMS and ADMS, thereby providing real time outage and power quality data.

Enterprise Asset Management (EAM) Application

In 2017, JPS embarked on an asset management approach to its maintenance practices in the Generation and Transmission areas. This approach is expected to improve the way in which our assets are maintained, thereby improving our system reliability and is a first step to the attainment of a Reliability Centered Approach philosophy. JPS will continue expanding EAM across the business towards ensuring full Generation, Transmission and Distribution assets are embedded and integrated with all data management systems to improve our lifecycle management of these assets.

7.6.2 Traditional/ Routine Activities - Reliability Improvement Methods

The approaches to improve service reliability included traditional methods that had previously being employed by JPS. These consist of:

- Reliability Focused T&D Structural Integrity and Pole Rehabilitation;
- Improved data driven operational and maintenance practices;
- Infra-red Scanning;
- Ultrasonic Detection;
- Deployment of Unmanned Aerial Systems (Drones);
- Routine preventative maintenance;
- Strategic vegetation management (more intense tree trimming);
- Application of medium voltage covered conductor solutions in high vegetation growth;
- Lightning mitigation programs;
- Live Line washing of insulators in contaminated areas; and
- Targeted focus on the worst performing circuits areas.

These methods are routine perennial activities geared at improving T&D reliability on a sustained basis.

7.7 2018 Reliability Improvement Plan

Frequently use of customer satisfaction surveys to assess its' quality of service and customer relations are employed by JPS. Carefully designed survey instrument help to provide a consistent frame of reference for respondents but customers in different market segments (demographic or geographic) may still demonstrate systematic bias in their ratings of service on various dimensions.

In 2017, JPS conducted one Customer Satisfaction Survey. This was done in the first quarter through a random sampling method islandwide. While this was a general survey focussed on soliciting customers overall satisfaction perspective with JPS Service, specific questions were asked about the reliability of service within their area as experienced over the past three months.

The result revealed that 79% of customers believed JPS power supply is very reliable or reliable.

14% of respondents were neutral, while 5% indicated that the service was unreliable. 2% did not provide a response.

JPS will continue its thrust towards improving the reliability of service provided to its customers. The continued process of lifecycle data management for the OMS and the increased use of automated technologies form the backbone of the major initiatives geared at improving the reliability performance. We continue to invest in the rehabilitation and reinforcement of T&D

network. In 2017, US$17.3M was invested in these types of projects and JPS has budgeted US$38.07M for investment in similar projects as well as Grid Modernization in 2018. JPS will be also be employing a Utility Arborist by May 31, 2018, to establish an Integrated Vegetation Management Framework (IVM) to minimize vegetation related outages.

With the growing penetration of renewables on the system, we have seen a significant increase in intermittencies affecting both the quality and reliability of supply. Additionally, there have been a resulting increase in under frequency points operating, as part of the system protection, giving rise to customer dissatisfaction. JPS has invested in a 24.5MW Energy Storage Project which is expected to correct this issue by rapidly deploying power to the grid where supply intermittency creates a void. Project start date is January 2018, with an expected completion by April 2019.

JPS 5-year Year Reliability Improvement Plan (2019-2024), is being developed, and will provide a comprehensive outlook of all reliability initiatives, being considered and aligned with the various system improvements plans (IRP, PSP, etc.) being developed for Jamaica. The 5-Year Reliability Improvement Plan will be submitted as an addendum to the JPS 5-year Business Plan.

7.8 2018 System Reliability Objectives:

The 2018 initiatives are geared towards improving reliability and measurement. Specifically, JPS' detailed objectives are as follows:

SAIFI:

- Reduction in the number of outages through technology and cost effective approaches.
- Reduction in the number of outages through an Asset Management Approach to our maintenance practices (Enterprise Asset Management).
- Minimize the impact of outages (No. of customer affected per outage) through technological approaches.

Reduction in CAIDI (Response Time):

- Maximize use of OMS - quicker response to outages;
- Increased outage detection through Smart Meters;
- Faster outage trouble shooting:
    - Optimize use of Fault Circuit Indicators;
    - Introduction of Fault Location Identification and Service Restoration FLISR in ADMS.
- Implementing automatic call-out of crews/trouble-shooters for faster outage restoration;
- Increasing crew availability and hours of coverage; and
- Institutionalizing a culture of "restore before repair".

8. Other Regulatory Matters

8.1 EEIF, Smart Streetlight Programme and the System Benefit Fund

8.1.1 Background

The Office in Determination 12(e) of the 2017 Annual Adjustment & Extraordinary Rate Review – CPLTD Determination Notice declared that it would make a determination at the 2018 Annual Rate Adjustment as to how JPS will pay over the residual amounts owing to the Electricity Efficiency Improvement Fund (EEIF) to the System Benefit Fund (SBF).

The EEIF

The Electricity Efficiency Improvement Fund (EEIF) was initiated by the OUR in the 2009 five-year rate review to provide a stream of revenue (US$13M pre-tax) to fund loss reduction capital programmes. In 2011, the rules of the EEIF were finalised and the fund became the primary financing source for JPS' Residential Automated Metering Infrastructure (RAMI) initiative. At the end of December 2016, the EEIF funded assets totalling US$60.6M. As customers directly fund these assets JPS does not earn a return on them as they are excluded from the Rate Base.

The SBF

Section 51 of The Electricity Act of 2015 sets out the provisions for the System Benefit Fund (SBF). The Act assigned administration and control responsibilities for the Fund to the OUR. It establishes funding sources and purpose of the fund as follows.

Financing of the SBF can be from any of the following sources:

a) tariffs as determined by the OUR
b) fines collected from breaches of the Act
c) contributions from the Consolidated Fund
d) any other source

The resources of the SBF are to be utilized for:

a) promoting increased penetration of renewable energy or energy security
b) promotion of energy conservation,
c) the purpose of providing electricity to rural areas,
d) any other purpose that the Minister may decide, by publishing an order in the Gazette.

On August 15, 2017 the Hon. Minister of Science, Energy & Technology directed that the SBF be established and initially funded with an amount of US$5M in order to allow JPS to recover the cost of implementing the Smart Streetlight programme.

The Smart Streetlight Programme (SSP)

The Licence includes at Condition 28 a requirement for JPS to commence as of December 30, 2016, a programme for the installation of LED streetlights enabled with smart technology. The new lights replace the existing installed inventory of 105,000 HPS lamps. The Licence directs the

OUR to utilise "*a Fund or the System Benefit Fund (as defined in the EA)*," as the mechanism for JPS to recover the cost of the Smart Streetlight Programme (SSP).

On August 23, 2017, under authority of the Act, the Minister gazetted an order authorizing the use of the SBF for JPS to recover the cost of implementation of the SSP.

The SSP commenced on schedule in December 2016 and at December 31, 2017, 36,440 lamps were installed, exceeding the 35,000 year-end target. Phase II of the project is scheduled to commence in June 2018 following a second round of procurement to ensure the programme and customers continue to reap gains from a beneficial cost curve for LED luminaires. The programme targets and planned capital expenditure schedule are shown in Table 8-1 below.

Table 8-1: SSP Schedule and Capital Expenditure

	2017	2018	2019	Total
Installations	36,440	5,000	63,560	105,000
Contract and Services (US$'000)	1,327	374	4,752	6,453
Material Cost (US$'000)	8,485	1,327	17,852	27,664
Other (US$'000)	2,185	822	1,726	4,733
Total	11,997	2,523	24,330	38,850

8.1.2 EEIF & SBF

In July 2017 the OUR completed an audit of the EEIF and declared that there was US$17.4M in accumulated capital tax credit outstanding, to the fund from JPS. In determination orders 12 (a), (b) and (d) of the 2017 Annual Adjustment Determination Notice, the Office terminated the EEIF and established the SBF at an initial funding rate of $5M per annum. The initial funding e is to be done by transfer from the residual credit provisionally assessed as due to the EEIF from JPS. JPS was mandated to make initial payments of US$500,000 per month for 10 months, commencing September 2017, for an accumulated total of US$5M by June 2018. In a subsequent decision, the OUR delayed the commencement of the SBF to January 2018 at an accelerated funding rate that would still achieve the US$5M total by June 2018.

A final decision on the total outstanding amount due to the EEIF as at June 30, 2018 the date of its termination is to be made after a final audit requested by the OUR to inform its determination on recovery at the 2018 Annual Adjustment. The EEIF could be due further amounts from the capital tax allowances extending into future years.

International auditing firm KPMG has been engaged to establish the precise extent of JPS' liability to the fund in respect of past and future tax benefits as well as unused balances. KPMG has commenced the exercise and is expected to complete its report by June 2018.

While the report will be completed post filing of the 2018 Annual Adjustment, the intent is to submit in a timely manner so the OUR can evaluate and decide within the 60-day filing review period.

8.1.3 JPS' Proposed Way Forward

Given the interconnection of the EEIF, the SBF and the SSP, JPS is proposing a comprehensive approach that addresses the requirement for the two funds and best serves customers. The proposal is guided by the following principles:

- Residual obligations to the EEIF by JPS will be honoured.
- Tariff impact on customer from discharging responsibilities to both the EEIF and the SSP (through the SBF) should be minimal.
- The SBF should have a net positive inflow in 2018.
- The treatment of the EEIF balance and SBF contribution should not negatively impact JPS' capital expenditure capacity for the SSP.

8.1.4 Offset of EEIF Obligations Against SSP Capital Expenditure

JPS is proposing that the OUR approves a direct set-off of the total capital expenditure cost of the Smart Streetlight Programme against the determined present and future liability to the EEIF.

As shown in Table 8-1 the capital expenditure by JPS on the SSP in 2017 was US$11.997M. The budgeted capex for the 2018 programme is US$2.523M to install an additional 5,000 lamps. On the current schedule the remaining 63,560 lamps will be installed in 2019 at a cost of US$24.330M. The US$17.4M already identified as owing to the EEIF exceeds the US$14.520M combined capex spent on the SSP in 2017 and planned for 2018.

JPS therefore requests that the Office approves in its 2018 Annual Adjustment Determination, the setoff of the SSP capex for 2017 and 2018 against the residual balance of the EEIF to include a net inflow to the SBF (discussed below). The OUR and JPS would agree the schedule for 2019 and beyond based on the final outcome of the KPMG audit.

Condition 28.7 of the Licence stipulates that if JPS has not completed the SSP by the time of its next Rate Review in 2019, the programme should be included in the Company's Business Plan to allow the revenue requirement to be adjusted to include the cost.

While the total extent of the liability to the EEIF is indeterminate, indications are that it may be sufficient to offset all or substantially the SSP capital cost given the ongoing price reductions on LED luminaires. In the event this is determined to be so, JPS recommends that the Office utilises the full amount due to the EEIF finance the SSP.

Utilising the residual EEIF would be consistent with the discretion allowed the Office under Condition 28.6 to utilise "a Fund *or* the System Benefit Fund" to recover the cost of the SSP.

8.1.5 SBF Contribution

In requesting the commencement of the SBF, the Minister clearly stated that the intent (without prejudice to other future intention) was to operationalise the sections of Condition 28 relating to the SSP. There was also acknowledgement that the SBF funding would normally be through the tariff. The OUR's decision that JPS initially fund the US$5M for the SBF from the residual amounts due to the EEIF therefore avoids an initial resort to imposing new tariffs.

To meet the mandated licence schedule, JPS utilised its own capital to operationalise the SSP. As the SBF was intended to provide this funding, the setoff between the remnant EEIF and the SSP capex achieves both objectives of financing the SSP and deferring the start of customer funding of the SBF. The streetlight programme is, at this time, the sole project approved for funding through the SBF.

However, in recognition of the possibility that other projects could be so designated for funding by the Minster or the OUR, JPS proposes that the offset would include JPS paying over to the OUR a sum of US$100,000 per month adjusted such that the SBF as at December 31, 2018 will reflect a net positive cash inflow of US$1.2M. The inflows for subsequent years would be determined by the assessed residual value in the EEIF as well as any funding target established for the SBF.

This inflow to the SBF would either preclude or mitigate the customer tariff impact of the financing requirement of the SBF in the near term.

JPS would also support the continued funding of the SBF from the EEIF residual in the event the assessed amount exceeds the capital cost recovery of the SSP.

8.1.6 Advantages of JPS' Proposal

This arrangement – utilising the residual sums due to the EEIF to fund the SBF as the mechanism to recover the capital cost of the SSP – offers several benefits.

- The offset against the EEIF obligations foregoes the immediate need to adjust tariffs for customers to fund the SBF.
- Streetlights are excluded from Rate Base as the value of the assets treated as contributed capital, therefore JPS does not earn a return on the assets. This results in a lower overall cost of the Smart Streetlight Programme for customers.
- JPS retains ownership, management and maintenance responsibilities for the streetlight assets and the replacement obligation at the end of useful life.
- By funding the SSP via the SBF, the customer (the Government of Jamaica) avoids the capital cost component of the Smart LED streetlight change-out.

Subject to the EEIF audit and capex verification, JPS and the OUR would agree on the final reconciliation of the EEIF obligations, the SSP capex and the SBF funding needs.

SBF CAPITAL TAX ALLOWANCE

JPS will consult with the OUR on possible tax treatment for the System Benefit Fund to prevent a repeat of the capital tax allowance complexity that emerged with the EEIF.

8.2 Rate 70 Interim Rates Continuation

Rate 70 (Wholesale Tariff) was developed by JPS to mitigate adverse rate impacts for other customer classes related to potential grid defection of larger industrial load. The 2017 Determination Notice approved on an interim basis the introduction of this new rate for customers whose peak demand at a single location was at or above 2 MVA. The OUR also provided guidance on additional information to be provided by JPS prior to the rate being approved as final.

JPS is working to develop analysis that fully supports the rate design for Rate 70 and other customer rates. As well, a full Cost of Service Study (COSS) is being developed to provide the foundation to appropriately assess Rate 70 and other rate classes. To date the COSS has been delayed by the ongoing efforts to complete the Integrated Resource Plan (IRP) and is expected to be integrated into the rate design process for the 2019 Rate Case submission.

9. Appendices

Appendix A: STATIN CPI New Release – CPI Index for Jamaica, March 2018

STATISTICAL INSTITUTE OF JAMAICA

7 Cecelio Avenue Kingston 10 Jamaica
Tel.: (876) 630-1600 Fax (876) 926-1138
Email: info@statinja.gov.jm

News Release
Consumer Price Index
March 2018

KINGSTON, April 17, 2018: The All Jamaica Consumer Price Index declined for the second consecutive month as a negative 0.1 per cent inflation rate was recorded for March 2018.

According to the Consumer Price Index (CPI) bulletin released today by the Statistical Institute of Jamaica (STATIN), the main contributor to this movement was the 1.0 per cent fall in the index for the heaviest weighted division: 'Food and Non-Alcoholic Beverages'. The decline was due to lower prices for agricultural produce resulting in a 4.3 per cent reduction in index for the class 'Vegetables and Starchy Foods'. The division 'Transport' also recorded a decline in its index of 0.4 per cent for the period, on the account of lower fuel prices.

These movements were tempered, however, by the upward movement of a 3.2 per cent in the index for the division 'Housing, Water, Electricity, Gas and Other Fuels', primarily resulting from higher electricity, water and sewage rates.

As at March 2018, the calendar year-to-date inflation was -0.2 per cent and the movement in the index for the fiscal year was 3.9 per cent.

A breakdown of the three regions for the month showed that Greater Kingston Metropolitan Area (GKMA) declined by 0.3 per cent, while Other Urban Centres (OUC) and Rural areas each registered negligible movements in their index.

The March 2018 Consumer Price Index Bulletin outlines additional information and may be obtained from the Statistical Institute of Jamaica website at www.statinja.gov.jm or from the Information Section of Institute, 7 Cecelio Avenue, Kingston.

-30-

Contact: Georgia Garvey-Green
Manager, Corporate Communications
info@statinja.gov.jm
630-1600 ext 1631

Appendix B: US Bureau of Labour CPI Index for March 2018

Table 1. Consumer Price Index for All Urban Consumers (CPI-U): U.S. city average, by expenditure category, March 2018
[1982-84=100, unless otherwise noted]

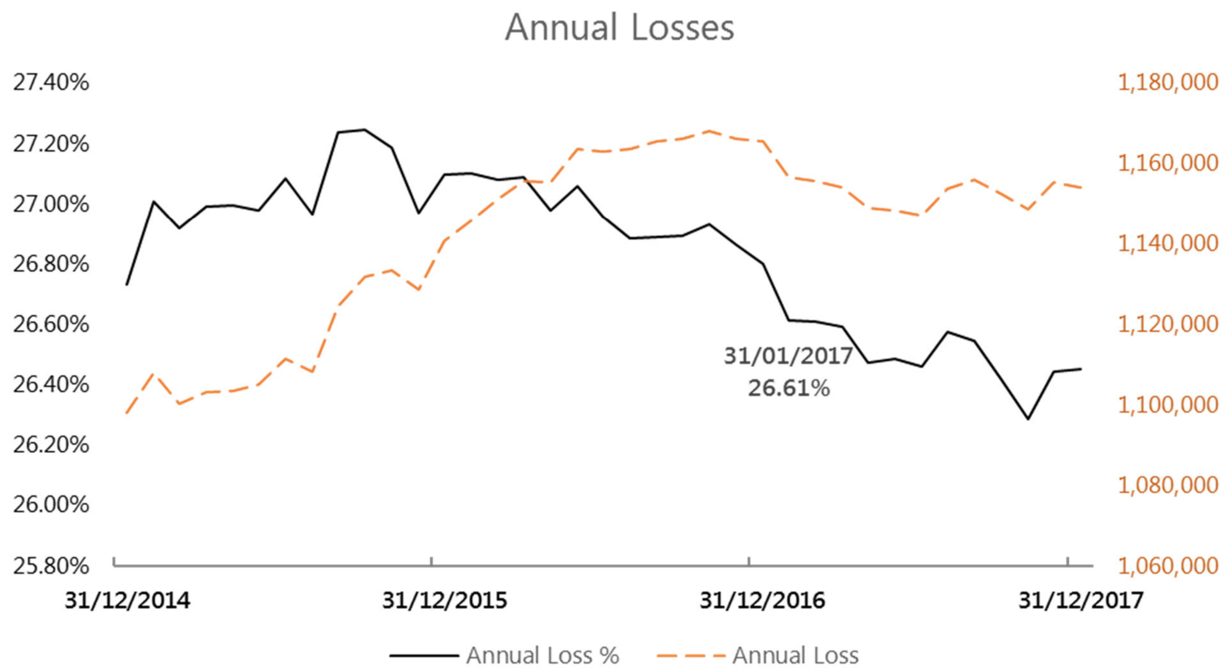
Expenditure category	Relative impor-tance Feb. 2018	Unadjusted indexes			Unadjusted percent change		Seasonally adjusted percent change		
		Mar. 2017	Feb. 2018	Mar. 2018	Mar. 2017-Mar. 2018	Feb. 2018-Mar. 2018	Dec. 2017-Jan. 2018	Jan. 2018-Feb. 2018	Feb. 2018-Mar. 2018
All items	100.000	243.801	248.991	249.554	2.4	0.2	0.5	0.2	-0.1
Food	13.306	249.165	252.266	252.370	1.3	0.0	0.2	0.0	0.1
Food at home	7.327	238.256	239.190	239.158	0.4	0.0	0.1	-0.2	0.1
Cereals and bakery products	0.959	272.174	271.245	272.345	0.1	0.4	0.3	-0.1	0.4
Meats, poultry, fish, and eggs	1.610	244.306	247.095	249.516	2.1	1.0	-0.2	-0.2	0.8
Dairy and related products	0.735	218.567	216.412	216.497	-0.9	0.0	0.0	-0.3	0.3
Fruits and vegetables	1.298	292.932	298.503	293.870	0.3	-1.6	0.5	-0.5	-0.7
Nonalcoholic beverages and beverage materials	0.873	168.455	167.736	167.758	-0.4	0.0	0.0	-0.1	0.4
Other food at home	1.852	210.002	210.115	210.012	0.0	0.0	0.0	-0.1	-0.2
Food away from home[1]	5.978	267.055	273.435	273.733	2.5	0.1	0.4	0.2	0.1
Energy	7.687	198.597	213.519	212.554	7.0	-0.5	3.0	0.1	-2.8
Energy commodities	4.254	209.029	233.414	232.716	11.3	-0.3	5.8	-0.9	-4.7
Fuel oil	0.117	240.619	292.718	288.737	20.0	-1.4	9.5	-3.6	-0.7
Motor fuel	4.059	205.155	229.666	229.068	11.2	-0.3	5.6	-0.8	-4.9
Gasoline (all types)	3.971	204.217	227.420	226.872	11.1	-0.2	5.7	-0.9	-4.9
Energy services[2]	3.433	197.709	203.932	202.625	2.5	-0.6	-0.8	1.4	-0.2
Electricity[2]	2.634	205.692	210.970	210.273	2.2	-0.3	-0.2	0.4	0.0
Utility (piped) gas service[2]	0.799	170.755	179.557	176.567	3.4	-1.7	-2.6	4.7	-1.2
All items less food and energy	79.007	251.290	255.783	256.610	2.1	0.3	0.3	0.2	0.2
Commodities less food and energy commodities	19.895	145.527	144.412	145.050	-0.3	0.4	0.4	0.1	-0.1
Apparel	3.136	128.250	126.587	128.604	0.3	1.6	1.7	1.5	-0.6
New vehicles	3.775	148.543	146.807	146.727	-1.2	-0.1	-0.1	-0.5	0.0
Used cars and trucks	2.407	139.372	137.768	139.892	0.4	1.5	0.4	-0.3	-0.3
Medical care commodities	1.740	376.440	381.975	381.804	1.4	0.0	-0.1	-0.3	0.1
Alcoholic beverages	0.970	244.978	248.166	248.287	1.4	0.0	0.0	0.2	0.1
Tobacco and smoking products	0.646	987.910	1,049.343	1,046.450	5.9	-0.3	0.3	0.1	-0.2
Services less energy services	59.112	316.481	324.690	325.610	2.9	0.3	0.3	0.2	0.3
Shelter	32.697	295.044	303.653	304.847	3.3	0.4	0.2	0.2	0.4
Rent of primary residence[2]	7.779	304.868	315.277	315.883	3.6	0.2	0.3	0.2	0.3
Owners' equivalent rent of residences[2,3]	23.606	302.259	311.280	312.107	3.3	0.3	0.3	0.2	0.3
Medical care services	6.939	505.991	515.205	516.713	2.1	0.3	0.6	0.0	0.5
Physicians' services[2]	1.750	383.965	380.470	380.766	-0.8	0.1	0.3	0.2	0.2
Hospital services[2,4]	2.324	314.529	329.701	330.759	5.2	0.3	1.3	-0.5	0.6
Transportation services	5.987	307.490	320.089	320.774	4.3	0.2	0.8	1.0	0.2
Motor vehicle maintenance and repair[1]	1.116	279.600	284.032	283.656	1.5	-0.1	0.1	0.3	-0.1
Motor vehicle insurance	2.396	517.619	563.365	563.762	8.9	0.1	1.3	1.7	0.3
Airline fares	0.712	283.583	265.272	267.482	-5.7	0.8	-0.6	0.6	0.6

[1] Not seasonally adjusted.
[2] This index series was calculated using a Laspeyres estimator. All other item stratum index series were calculated using a geometric means estimator.
[3] Indexes on a December 1982=100 base.
[4] Indexes on a December 1996=100 base.
NOTE: Index applies to a month as a whole, not to any specific date.

Appendix C: Loss Initiatives

System losses continued its downward trend that began in mid-2015. Total system loss decreased by 0.35 percentage points and 11.5 GWh compared with 2016. This is due to increased demand from new and existing customers; reduced cost of electricity and internal losses; and increased returns from the loss initiatives.

Figure C1-: System Loss Trend



Main Drivers	GWh Recovery	Percentage Impact
Audits and Investigations	11.5 GWh	0.25%
Internal Inefficiencies improvement	2.3 GWh	0.06%
Smart Grid Analytics	0.015 GWh	0.0003%
Community Renewal	0.098 GWh	0.002%
Technical Loss Initiatives	0.216 GWh	0.005%
Positive Impact of Organic Sales*		0.02%
	Total	**0.35%**

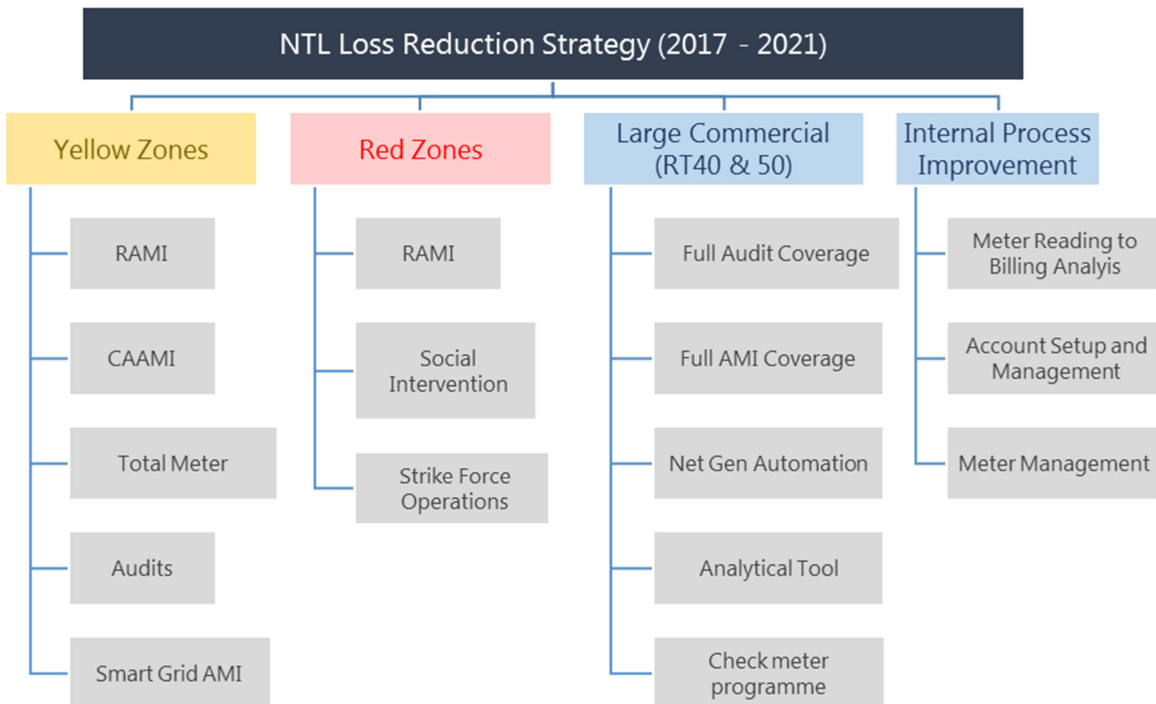
*There is a positive trend in sales from R40 and R50 which has a direct impact on losses with a correlation coefficient of -0.87.

2018 Loss Reduction Initiatives

The Strategies to be employed over the 2018/2019 period are broken into two major components: Technical and Non-Technical Loss Reduction.

Technical Loss Reduction is geared primarily at correcting three (3) major issues: Power Factor Correction, Feeder Phase Balancing and Voltage standardization. Non-Technical Loss Reduction is more complex due to the multifaceted nature of the challenges faced. The strategies under consideration are categorized in a four (4) pronged approach targeting Red Zone communities, Yellow Zone communities, Large Industrial and Commercial Customers and Internal Process Improvement.

Figure C-2: Four (4) Pronged Strategy for Loss Reduction



Red zones are settlements where a large percentage of the population cannot afford electricity and primarily includes inner city and squatter settlements. Strategies in Red Zone areas are focused on social intervention programs and initiatives geared toward assisting the community at large. These are described later in the Community Renewal Section.

Yellow zones are classified as areas or communities where the majority of the population can afford electricity but some choose to steal. Illegal theft in these communities is usually done by bypassing or tampering with the meter and the level of sophistication is much higher. Solutions for reducing losses in Yellow Zone areas are predominantly audits aided by the analysis of data from Advanced Metering Infrastructure (AMI) such as Smart Meters, RAMI, CAAMI and Transformer Total Meters. This strategy involves a continuation of routine revenue meter audits coupled with improved data analytics.

Large Industrial and Commercial Customers represent 0.3% of the total customer base, however, they contribute to 45% of annual sales. Priority is given to tackling losses for these customers through investments in the application of Advanced Metering Infrastructure (AMI) for the automation of meter reading and theft detection.

Internal Process Improvement is a loss reduction initiative geared at identifying and mitigating the impact of internal issues that contribute to losses. It involves a review of business processes to identify root causes and develop mitigating activities.

Technical Loss Reduction Initiatives

JPS' technical energy loss is estimated at 8.6% of net generation, which has been reviewed and validated by KEMA DNV, international consultants, and benchmarked as within acceptable levels against several utilities of similar geographical territory and network characteristics.

JPS acknowledges and agrees with the OUR in the latest determination that there is a need to update the measurement and modelling of technical losses due to changes in the Transmission and Distribution network. JPS acquired DigSilent in 2016 and is actively updating the model. JPS has also incorporated ADMS in 2017 to provide near real time modelling of the primary technical loss. JPS will have a more current technical loss profile for 2018.

Nothwithstanding, JPS continues to work diligently towards its optimal technical loss level through several economically feasible initiatives. These include: (1) primary distribution feeder power factor correction, (2) primary distribution feeder phase balancing and, (3) Voltage standardization program (VSP).

These projects include, but are not limited to: (1) upgrading of over 75% of the primary distribution network voltages from 12kV and 13.8kV to 24kV, (2) re-conductoring of distribution lines, (3) reconfiguration of primary distribution feeders, (4) rehabilitation of the secondary distribution network, (5) installation of substation bulk capacitor banks and (6) the replacement of distribution transformers (pole and pad mounted) with low loss transformers.

- Power Factor (PF) Correction

  Over 240 MVARs or 400 pole-mounted capacitor banks are presently installed on the 110 feeders island-wide. This is aimed at maintaining a minimum of 0.95 PF for each feeder during peak and off peak load conditions. The PF of 0.95 is the optimal point at which the greatest return on investment is achieved. This is achieved by the use and application of both switched and fixed pole-mounted capacitor banks to address the peak and off peak VAR demands, respectively.

  Several feeders were corrected and improved throughout the year to bring these feeders within acceptable power factor levels. The plan for the next five years is to correct and maintain 95% of all feeders above 0.95 power factor.

- Feeder Phase Balancing

  Feeder phase balancing is essential in maintaining good voltage quality and reliability of supply by ensuring the neutral current for the 3-phase system is less than 10% of the feeder average current. Phase imbalance above 20% translates into energy loss due to increased line current and voltage drop, it also makes economic sense to prioritize and improve these to below 10%.

  In 2016, the focus continued to be on identifying feeders with phase imbalance above 20% to economically improve and maintain to within acceptable phase balanced levels. For 2017-2021, efforts will be placed on the continuation of this effort as part of our routine operation of maintaining the phase imbalance of the corrected feeders within acceptable levels.

- Voltage Standardization Program (VSP)

  In 2016, JPS resumed the 24kV Voltage Upgrade program. The Voltage Standardization Programme is aimed at standardizing the medium voltage network across the island at 24 kV, further improving the technical losses on these feeders, allowing for improved reliability and transferability of these feeders. The upgraded feeders at the end of 2017 were Greenwood 110 feeder, Martha Brae feeder 110Duncan's 110 feeder, Roaring River 210, 310, 410 feeders and Hope 510 feeder.

  In 2018, the following three feeders are targeted for upgrade:
  1. Ocho Rios 310, 410 and 510

Non-technical Loss Reduction Initiatives

Initially, the fight against losses focussed on initiatives aimed at Red Zones, Yellow Zones and Large Industrial & Commercial Customers. A renewed focus targeting internal processes is aimed primarily at identifying the root cause of internal process inefficiencies that contribute to losses.

Red Zone Communities

Communities that exhibit energy loss in excess of 70%, have a high propensity of throw-ups, and are uninviting of normal commercial operations are classified as 'Red Zones'. The 'Red Zone' community infrastructure reconfiguration and community renewal strategy is geared towards providing a holistic solution for at-risk communities as it relates to social and economic challenges contributing to electricity theft. These communities cannot benefit from our normal commercial operations because of high crime rate.

Additionally, many in these communities are unemployed and do not have a steady income stream, which further fuels the propensity to steal electricity. In many of these communities' householders have grown up in a culture where electricity theft is the norm and as such there is no reservation in stealing electricity. Annually, over 200,000 illegal connections (Throw-ups) are removed from the power grid primarily in such 'Red Zone' communities.

Strategies to tackle Red Zone issues are mainly social intervention programs and Strike Force operations.

RAMI and CAAMI Rehabilitation & Reliability Improvement

In 2009, JPS began the installation of a cluster metering system called RAMI. This system was designed to move the metering point from easy access by installing the meters in an enclosure situated on the utility pole. The system design allowed for the meters in the enclosure to be read and controlled remotely. Over time, the failure of communication system affected the efficacy of the metering platform and the Company embarked on a programme to rehabilitate the communications systems in 2015.

Upgrading works were carried out on 10,200 meters in seven (7) communities across the island in 2014 and this resulted in average remote meter reads improving from approximately 30% to 90% within the completed communities. In 2015, work started in four additional communities in the Kingston Metropolitan Area, but the success rate was significantly lower than that obtained in the seven communities addressed previously. Six sites/communities were slated for maintenance in 2016, namely, Arnette Gardens, Old Harbour, Denham Town, Tivoli Gardens, Hanna Town, and New Twickenham Park.

In assessing the root cause of communication problems, it was determined that there was a high level of interference from unauthorized personnel accessing the enclosures to abstract electricity illegally. The interference and the persistence of these persons affected the communication in such a way that it was nearly impossible to overcome this problem. A decision was taken to explore other solutions to this problem. These include:

1. Replace the Quadlogic system with a system with one that has a more robust communication platform; and

2. Troubleshoot and resolve the communication issues for the ENT and YPP systems.

Strike Force Operations

Strike force operations will continue for the period 2017 – 2021 and is one of the more publicly visible signs of JPS' efforts in the fight against losses. Illegal 'Throw-up' connections are an on-going problem particularly in red zone communities and this has been difficult for JPS to eradicate. JPS' intent in conducting these operations is to frustrate those consumers to the point where they would find it easier to regularize their supply and enter into a contract with JPS for the supply of electricity. The Strike Force teams comprising of linesmen, technicians and the police have been engaged in the removal of illegal connections from the electricity network, arresting guilty parties and providing information to residents on the available options for accessing electricity service legally. These efforts are targeted at communities in which highest losses are experienced across the island.

In 2017 the strike force operations within the parishes helped to deter energy theft and reinforced the physical presence of JPS teams. There were in excess of 273,322 throw-ups removed, 4,273 idle services removed, 396 arrests, 82 court summons along with 282 customers regularized in the period.

Strike Force operations is integral to creating a conducive environment for the success of the other components of the loss reduction strategy.

Yellow Zone Initiatives

The Yellow zone strategy is planned around the use of Smart Grid Transformer Total meters, Smart Grid AMI Revenue meters, RAMI and CAAMI combined with audits. The strategy targets areas where most customers do not face the difficulties in paying for electricity that are observed in red zone communities. These customers are more averse to being seen to be stealing and therefore mask their attempts at electricity theft. In these cases, there is minimal or no visible evidence of electricity theft, in the form of throw-ups. Illegal abstraction is, in most cases, is done through more sophisticated means, such as meter bypass and meter tampering. Solutions to reducing losses in Yellow Zone areas are predominantly audits aided by the data from Advanced Metering Infrastructure (AMI) such as Smart Meters, RAMI, CAAMI and Transformer Total Meters. This strategy involves a continuation of routine revenue meter audits coupled with improved data analytics, to increase the probability of finding irregularities on investigation.

Transformer Total Meter Installation

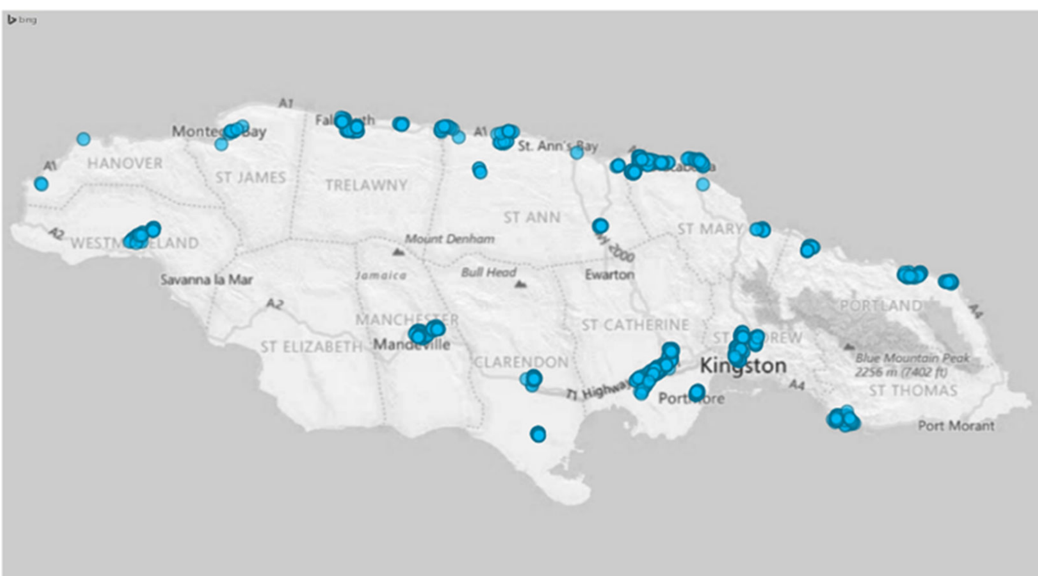
Transformer Total Meters are energy meters installed on the low voltage side of distribution transformer locations, to which the customer connections are made. The Transformer Total Meters are used to measure the energy delivered to services via the secondary distribution network. The information from the Transformer Total Meters is compared against the sum of the energy registered on customers' meters and is used to compute the energy loss on each transformer circuit. The total meters planned for installation in 2017 will further improve JPS' ability to prioritize high loss circuits for action such as audits and the installation of Smart Grid AMI meters. Simultaneously our strike, recovery and forward billing rates are expected to improve with the implementation of these two systems.

In 2014, one thousand eight hundred (1,800) Transformer Total Meters were installed with a further 500 installed in 2015. These were a mixture of Itron Sentinel and ENT meters. In 2016, 933 Smart Transformer meters, called total or totalizing meters, were installed while another 1,041 was installed in 2017. The total meters would be associated with the over 40,000 Revenue Meters to create an energy balance for the transformer circuit. The table below shows the deployment across Jamaica in 2017:

Table C-1: Transformer Total Meter 2017

Parish	Total Meter Count
Clarendon	42
Hanover	19
KSAN	86
KSAS	54
Manchester	80
Portland	83
St James	9
St Thomas	84
St. Ann	59
St. Catherine	280
St. Mary	126
Trelawny	78
Westmoreland	41
Grand Total	**1,041**

Figure C-3: Current Coverage of Transformer Total Meters Installed in 2017



Further steps to leverage the installation of Transformer Total Metering will be Customer to Transformer mapping and data gathering and analysis using a recently acquired analysis tool called

AATDAT (Advanced Automated Theft Detection Analytical Tool). The tool is used to generate and report on circuit losses automatically and to identify and prioritize the circuits and customers most likely to be contributing to the losses being experienced on a circuit. AATDAT is currently providing information on loss impacting events from these meters.

Smart Grid AMI and Smart Meters

The Smart Grid AMI project, in summary, involves the replacement of existing ANSI type analogue meters with smart meters for residential and small commercial (R20) customers. This solution will focus on the use of AMI ANSI meters for Smart Grid and the use of analytics to identify the services or premises contributing to energy loss on each circuit.

To date, the project has completed the implementation of a Smart Grid Network and the change-out of over 40,200 smart meters island-wide. The primary objectives of the project are to identify and reduce losses on the system and improve reliability and responsiveness for both utility and customers, provide more data points for grid analysis and stability assessment, prepare the grid for demand response and eventually lead to revenue diversification for JPS. The Smart AMI meters being deployed also have pre-paid metering ability.

The Smart Grid AMI meters will provide functions with far greater analytics and information on losses within the yellow zones, such as:

1. Automating and quantifying energy loss per network segment at the feeder, sub-feeder and transformer levels while facilitating periodic energy loss progress reports (daily, weekly, monthly).

2. Automating the detection of fraudulent activities by use of meter events and tamper flags.

JPS plans to install over 100,000 Smart Grid AMI meters in 2018.

Advanced Automated Theft Detection Analytical Tool (AATDAT)

The AATDAT tool is a business intelligence tool designed to utilize metering data from AMI meters and other utility data sources to identify with a high degree of precision, the services or locations of possible theft or loss.

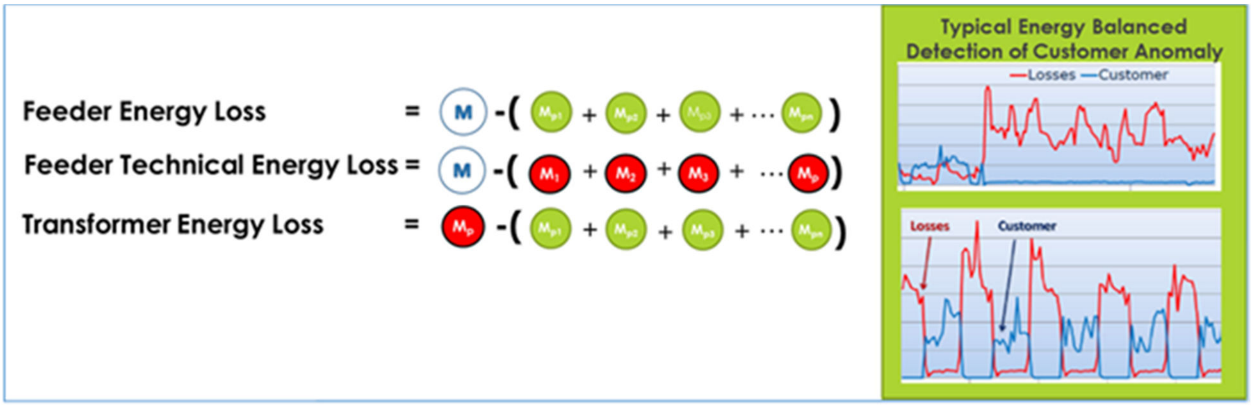
For phase 1 of this implementation, the tool is expected to accurately and reliably identify and report theft perpetrated by smart metered customers by utilizing load profile interval data matched against similar data from Transformer Total Meters along with power lost or restored, low voltage conditions, tampering detected and other meter events. Specific use cases will then be developed to zoom in on accounts that have a high probability of theft.

Phase 2 will involve expansion into the wider non-AMI population. The Advanced Automated Theft Detection Analytical Tool model is designed to detect theft perpetrated by customers in the following ways:

- Correlation of customers' energy usage and transformer energy loss.

- Correlation between transformer meter and customer meter interval voltage information.
- Correlation between AMI meter event flags and transformer energy loss.
- Identify instances of customer anomalies contributing to less than a 1% change in transformer energy loss.

Figure C-4: Energy Balance within AATDAT



Community Renewal Programme (CRP)

The CRP seeks to identify innovative ways to uplift and empower communities through electricity regularization as well as through social intervention initiatives. The initiative was expanded to St. Catherine, St. James and Westmoreland in 2017.

JPS' plan for 2017 was to on-board 2,500 customers through the implementation of several projects. A successful implementation of the project should result in billed sales increasing by approximately 300 MWh for 2017.

During the year, the programme focused on completing projects that began in 2016 with an expected increase in customer base of 1,500 and launching new projects in five (5) additional communities with an expected increase in customer base of 1,000 as follows:

2016 Projects carried forward	2017 Projects
1. Majesty Gardens Ready Board	1. Granville
2. Whitfield/Maxfield	2. Russia Phase 2
3. Ellerslie Gardens/Tawes Meadows	3. Canaan Heights
4. Russia Phase 1	4. Red Pond
5. Goldsmith Villa	5. Rose Town

In mid- 2017 the target for the CRP was revised to 1,500 as a result of the late receipt of Hexing enclosures and meters and the extensive testing period of the Hexing solution which ended in May

2017 which took three months more than anticipated. JPS on-boarded 1,322 customers from the revised target of 1,500 In January 2017–December 2017 and transferred 259 existing customers to the Hexing solutions. The connections resulted in an increase in billed sales by approximately 1,313MWh YTD and collections totalling over J$25m in revenue.

Status of Initiatives

The programme has recorded some success, which is evidenced by the increase in billed sales in the target communities and the decline in system losses in a few of these communities since customer conversion in 2017.

The table below shows the status of these communities as at January 2018.

Table C-2: Community Renewable Community Project

Year	Project Area	Status
2015	McGregor Gardens	Project closed
2016	Ellerslie Gardens	Project closed in December 2017
	Tawes Meadows	Project closed in December 2017
	Russia Phase 1	Project Closed in December 2017
	Majesty Gardens Ph1 & 2	Connections Ongoing
	Goldsmith	Project closed in December 2017
2017	Granville	Construction 100% complete, connections to be done in conjunction with Parish
	Russia Phase 2	Construction 100% complete, line submitted to GEI for approval
	Canaan Heights	Construction 70% complete
	Red Pond	Construction 40% complete
	Rose Town	Project cancelled

Figure C-5 shows the kWh consumption in these communities. For customers that were on-boarded through the CRP initiative, over 1,340 MWh of billed sales was recorded between January and December 2017. In addition to increased billed sales, the Company has collected over J$25 million from these customers over a 12-month period, from January to December 2017. Figure C-6 shows revenues collected over a one (1) year period in these communities.

Figure C-5: kWh Consumption in Community Renewal Communities

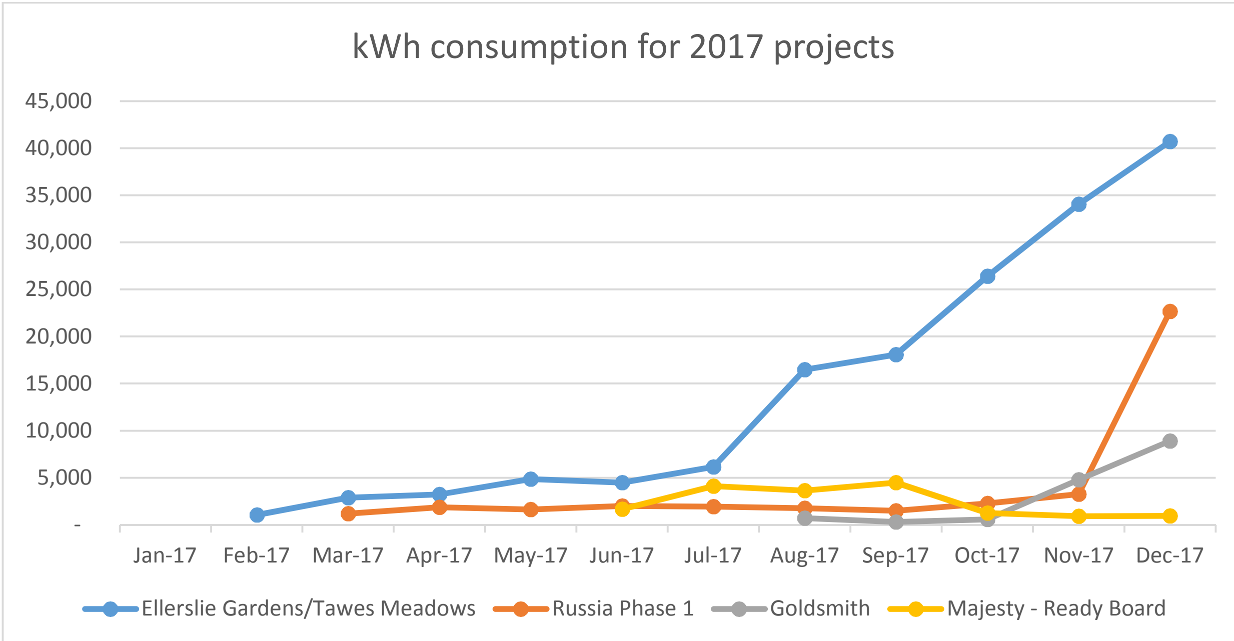


Figure C-6: Collections (J$) in Community Renewal Communities

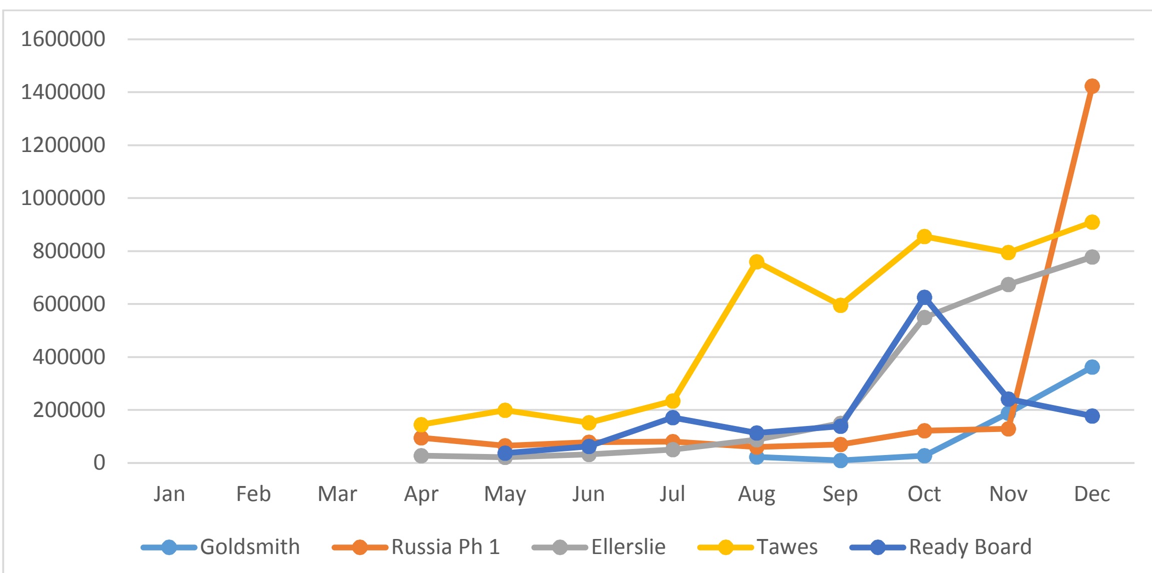
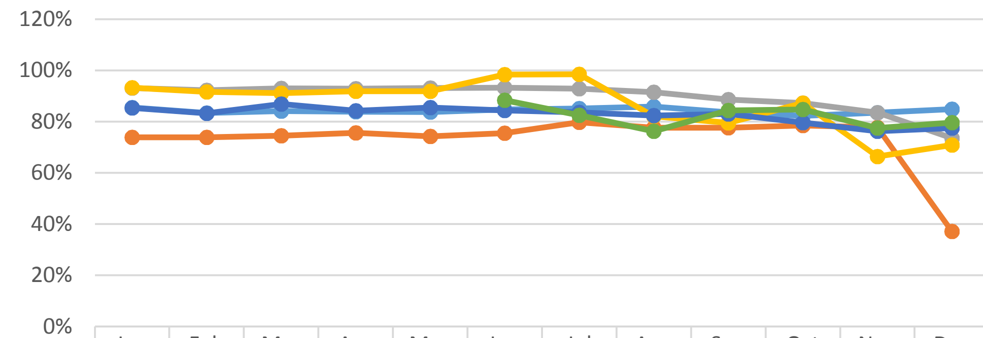


Figure C-7 shows the losses in those same communities. Losses remain relatively high with Maxfield recording the highest increase of 39% and Russia Phass 1 had the highest decrease of 37% when the results at January and December 2017.

Figure C-7: Losses in Community Renewal Communities



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Granville	85%	83%	84%	84%	84%	85%	85%	86%	84%	82%	83%	85%
Russia Ph 1	74%	74%	75%	76%	74%	76%	80%	78%	78%	78%	78%	37%
Goldsmith Villa	93%	92%	93%	93%	93%	93%	93%	91%	89%	87%	83%	73%
Tawes Meadows	93%	92%	91%	92%	92%	98%	98%	82%	80%	87%	66%	71%
Ellerslie Gardens	85%	83%	87%	84%	86%	84%	84%	82%	83%	80%	76%	77%
Majesty Ready Board						88%	83%	76%	84%	85%	78%	80%

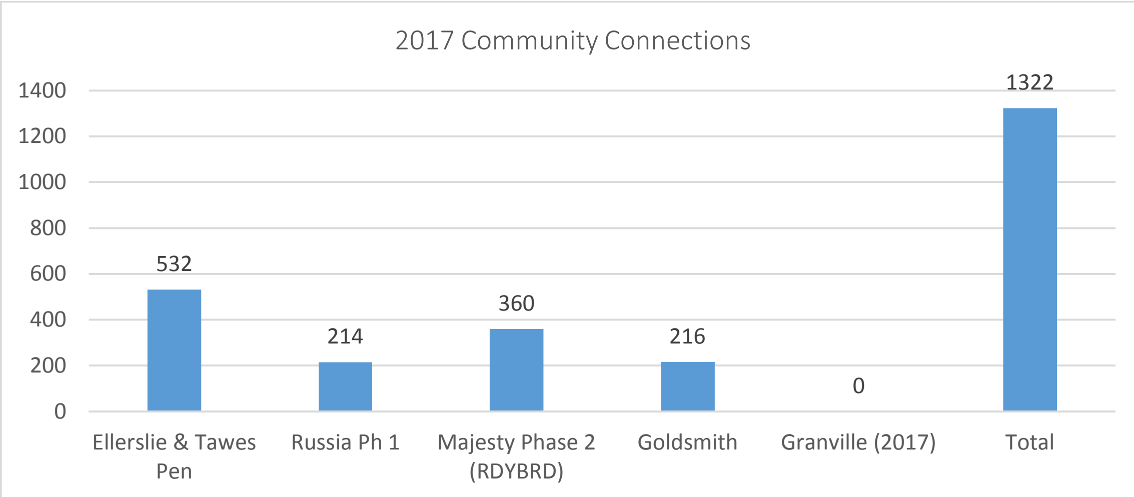
Granville Russia Ph 1 Goldsmith Villa
Tawes Meadows Ellerslie Gardens Majesty Ready Board

While the billed sales have increased, the losses are still relatively high which indicates that more social intervention needs to be done. Lack of income, unemployment remains the main reason for non-payment of bills or refusal to sign up for JPS' Service.

JPS was able to convert 1,322 consumers to customers from the 2016 projects. This was due to the change in the Company's strategy to use prepaid meters for connections. During 2017 we connected 1,581 meters using the Hexing prepaid/ post-paid solution, installed 2,515 new Hexing meters, 886 poles and 46.6km of conductors.

A total of 856 households were upgraded to the regulated eligibility code for safe electric consumption as determined by the JS21 and the National Building Code. This enabled the facilitation of legal connection to JPS' distribution lines across various communities.

Figure C-8: Total Connections for 2017 in Community Renewal Communities



The CRP continue to face some major challenges which sometimes hamper our ability to on-board customers as well unforeseen delays which impacted on our implementation schedule for 2017. These include:

- Violence encountered in some communities; especially in Russia and Granville;
- Damage to the Energy Guard Boxes shortly after implementation in Ellerslie Gardens and Tawes Meadows;
- Bridging of the energy guards;
- Technical limitations of the metering infrastructure (or device);
- Delay in social intervention implementation; and
- Delays with implementing metering infrastructure due to manufacturing issues and communication difficulties.

Methodology

The launch of the Project in each community begins with community outreach through community meetings and other means of engagement. Several social intervention programmes are offered to residents in the project areas either free of cost or at a minimal cost to residents. A list of the interventions offered under the Programme in 2017 can be seen in Table C-3 below:

Table C-3: List of Social Interventions Offered under 2017 Programme

House Wiring	Internship Programme
Ready Board Programme	Energy Conservation Sessions/Competition
Light Bulb Swap	Service Centres
Wellness Fairs	Youth Education & Recreation Programme
Community Facilitation	Best Practice Symposium

The two (2) primary reasons for offering these interventions to customer are to 1) assist in the conversion of consumers to customers, and 2) to promote sustainable behavioural change by keeping persons engaged throughout the communities.

2018 Plans for the Community Renewal Programme (CRP)

The Community Renewal strategies for 2018 aims to on-board up to 800 new customers with an expected 96 MWh recovery. We will also seek to promote customer retention of 1581 customers connected to the Hexing AMI prepaid metering system. This will be accomplished through the following initiatives:

1. High Loss communities in KSAS, St. James, Westmoreland, St. Catherine and Clarendon will be targeted.

2. Continuing work with JSIF to improve success rate on implementing the program. Several of the communities in the CRP with high losses are also communities that JSIF is actively working in. Through JSIF's Poverty Reduction Program (PRP) & Integrated Community Development Program (ICDP), over 40 communities are being targeted across Jamaica for renewal. JSIF presently has projects in 5 of the 10 communities being targeted by JPS for the 2017 programme. There is a 30% consumer compliance rate in red zones (community profile). JPS believes that by partnering with JSIF in affected communities the reception to the programme will be greater due to the expansion of the range of services offered and the strong emphasis on social upliftment.

3. Community Facilitators, will be retained as they have proven to be an additional benefit to the customers in project areas. This will allow participants to have easy access to JPS. Our facilitators become the bridge between the community and JPS as they provide easy access to solutions for issues that may require greater assistance. The Facilitators will undertake education and promotional activities, promote positive relationships between the community and JPS as well as to offer door step customized services such as energy audits. The community facilitators continue to conduct small group sessions aimed at educating, promoting and building relationships.

4. JPS also offers Energy Management and Customer Education. The programme includes bulb distribution (LED/Fluorescent bulbs exchanged for incandescent bulbs), and house wiring. The house wiring is important in the process as residents have indicated they are

not able to afford the total cost of house wiring. JPS therefore provide assistance by paying or partnering with other organizations to pay the majority of the house wiring cost.

5. The programme will be offering prepaid metering and Payment Options to JPS' customers in the project areas. These options include pre-paid metering, flexible payment arrangements and deposit payment in instalments.

6. JPS hopes to contribute to the income earning potential of the community members through job creation. The programme named "Building Capacity to pay" will be pursued through the provision of internships.

7. In an effort to properly identify where the illegal consumers are located and also to assess and address the specific needs of each community, the validation exercise will continue in 2018. This will be done initially in 3 parishes Kingston and St. Andrew and, St. Catherine. Based on statistical reports there are approximately 180,000 households with access to illegal electricity. The validation exercise is a desktop analysis that will help us to identify actual locations at a community level of actual customers and illegal users are located. We are currently aiming to cross match 200,000 households under the project. In addition to this, in 2016, JPS began carrying out survey periodically to access the effectiveness of the programmes. In the 4th quarter, over 450 surveys were carried out in 5 communities. In 2018, we are aiming to carry out entry and exit surveys in 5 communities. The aim is to carry at least 500 surveys in 2018 to get a representative sample of the CRP communities.

8. Other initiatives under the JPS Community Renewal Programme include activities such as health and wellness fairs, sponsorship of community based programmes in areas of education, entertainment and sports, on the job training for At Risk Youth in our Parish Offices, Non-Governmental Organisation Partnership and the continuation of our clean up drive under the Environmental Preservation programme.

Appendix D

JAMAICA PUBLIC SERVICE COMPANY LIMITED
POWER GENERATION DIVISION

CAPEX REQUIREMENT OVERVIEW 2017 – 2020

1. **The table below illustrates the amount of capital expenditures that were undertaken during the year 2017 to support plant reliability and efficiency.**

STEAM PLANT	2017 CAPEX SPEND USD	MAINTENANCE ACTIVITIES	JUSTIFICATIONS
Old Harbour Common Plant	$484,180	Old Harbour General Plant (common systems) capital expenditures included the needed replacement of chemical pumps, replacement pump motors and mechanical and electrical spares to support the operations of the three (3) generating units.	This expenditure was incurred to shore up the reliability of the plant common systems to include compressed air system, service water, water treatment and chemical treatment that are required for the reliable operation of the three (3) generating units This station has completed 50 years of operations and number of subsystems have exceeded their useful life. Hence, the refurbishment of these auxiliaries are very important for the continued operation of these units to retirement.
Old Harbour Unit #2	$878,430	Unit #2 expenditures included steam turbine casing crack re-inspection necessary routine pumps overhaul, motor replacements. Forced draft fan motor replacement, air preheater systems overhaul.	As part of the 2016 maintenance plan, Old Harbour Unit 2 was removed from service in August2016 to carry out overhaul of the turbine and other equipment. On opening of the turbine, an initial inspection showed that the steam turbine seemingly developed several axial and circumferential cracks on the high-pressure glands area. On recommendation of an expert metallurgist a follow up inspection of the cracked casing was necessary in 2017 to ascertain growth rate of the crack, and better project probability of failure its. Much needed overhauls were also done on major components of the unit's balance of plant systems.
Old Harbour Unit #3	$3,606,850	Unit #3 expenditures included 80MVA GSU Transformer replacement, boiler tube replacement,	There was a very premature failure of the Unit 3 80MVA GSU in October 2017. This resulted in the expenditure of approximately USD3M to replace the transformer, which

		necessary routine pumps overhaul, and motor replacement.	was the most cost effective method of restoration. . Expenditures were also incurred to do partial replacement of boiler tubes that which were at or near end of life. As Unit 3 is a base load unit, every effort was made to make it as reliable as possible

Old Harbour Unit #4	$4,135,850	Unit #4 expenditures included Generator rotor rewind, and stator inspection, boiler Superheater partial replacement (US$2.2M), pumps overhaul, motor replacement, and Air preheater major repairs.	Unit #4 last major overhaul was done in 2012. Having operated for just under 40,000 hours some of the Superheater tubes were reaching their end of life; this led to frequent forced outages due to boiler tube failures during the period February to September 2017. In addition, the generator had been operating with shorted turns condition in its rotor for many years; however, the condition deteriorated in 2017 hence the unit had to be derated to a level. A mini overhaul was therefore conducted on this unit over the period November 2017 to January 2018 to remedy the tube related issues, investigate, and correct the deteriorating condition of the generator rotor. The Generator rotor was rewound during the mini overhaul. Other plant auxiliaries were rehabilitated to improve the reliability and efficiency of the unit.
Hunts Bay Unit #6	$814,100	HBB6 expenditures included partial Superheater tube replacement, CW pump breaker replacement, CW pump overhaul. Air preheater systems major rehabilitation and replacement 750KVa station transformer	The 750-kVA 4.16/480kV station service auxiliary transformer developed leaks over the last 2 years. Temporary repairs were done but did not last as long as expected. This transformer contained the carcinogenic material polychlorinated biphenyl (PCB). Based on the repeated leak and the hazardous material the transformer had to be replaced. In addition, the compressed air system was compromised, requiring the procurement of a new 300cfm clean air compressor. These maintenance activities (CW Pump and AIR Preheater) amongst others, saw unit 6 achieving EFOR of 3% in 2017.
2017 Capital Expenditure	**$9,919,410**		

2. **The table below illustrates the amount of capital expenditures that will be undertaken during the year 2018 to support plant reliability and efficiency.**

STEAM PLANT	2018 CAPEX SPEND USD	MAINTENANCE ACTIVITIES	JUSTIFICATIONS
Old Harbour General Plant	$382,095	Old Harbour General Plant expenditures are forecasted to be 25% less than 2017 based on corrective works done. Replacement electrical and mechanical components such as valves and motors for common plant forecasted.	In keeping with the retirement schedule and as the plant gets closer to retirement, the CAPEX allocations will be significantly reduced. However, there will be the need for overhaul plant auxiliaries in order to maintain optimal reliability of the units they support. In this regard, there are some key electrical and mechanical components that will be required for replacement or overhaul.
Old Harbour Unit #2	$398,713	Unit #2 expenditures forecasted to include air preheater partial basket replacement, valves & motor replacement where necessary.	This unit is scheduled to undergo its' annual overhaul in August 2018. During this some balance of plant systems will be rehabilitated.
Old Harbour Unit #3	$611,579	Unit #3 forecasted expenditures includes partial Superheater tube replacement, and routine balance of plant equipment overhaul.	The need to have this unit in a reliable state up to retirement is paramount. This unit was last overhauled in 2015, however there are some Superheater tubes that are now at their end of life and will be replaced during the annual overhaul exercise in June 2018. The Air Heater will be rehabilitated during this outage in order to maintain efficiency and reliability of the unit going forward.
Old Harbour Unit #4	$490,739	Unit #4 forecasted expenditures includes routine overhaul of soot-blower systems and major motors	This unit represent a very high degree of system reliability and efficiency in light of its contribution to generating capacity and the benefits to derive from the recent major intervention in November 2017. In order to maintain the gains of this intervention and bolster the required base load capacity going

			forward, the soot-blower system and major motors (Feed Water & Circulating Water Pump) are key candidates for the CAPEX expenses expected in this regard.
Hunts Bay Gen Plant	$100,000	Hunts Bay General Plant forecasted expenditures include necessary overhaul on fire protection and compressed air systems	The safety of all our generating assets are key element of protecting the long term value of the business. In this regard, the leadership team at Hunts Bay Power Station is taking the right approach in ensuring the fire system is in an operable state at all time given the nature of hazards that are associated with the type of technologies that are deployed at that facility. In order to maintain plant reliability, the compressed air system plays a pivotal role in the operability of all pneumatically controlled system on the units. Therefore, the proposed CAPEX provision is needed at this time.
Hunts Bay Unit #B6	$2,095,813	HBB6 forecasted expenditures includes partial boiler tube replacement, air preheater inspection and full basket replacement and routine overhaul of turbine balance of plant equipment and controls	The Hunts Bay Unit #B6 is located in the heart of the load center. Therefore, the reliability of the unit is second to none. In order to perform reliably to its retirement date, there is need to do partial Boiler Tube replacements and Air Heater re-basketing and rehabilitation. The rehab of key balance of plant equipment are in the support of the unit achieving the desired reliability performance.

3. **The table below illustrates the amount of capital expenditures that are required during for the year 2019 to support plant reliability and efficiency. In light of the proposed retirement dates for these units, the capital outlay will be significantly reduced. The maintenance activities will be primarily around routine overhauls and emergency replacements of plant items sustain plain operations.**

STEAM UNITS	**2019 CAPEX REQ.(US$)**	**MAINTENANCE ACTIVITIES**	**JUSTIFICATION**
Old Harbour General Plant	$229,257	Forecasted to do routine overhauls and emergency replacements	The allocated CAPEX provisions are based on past performance, maintenance requirements and the maintenance philosophy in place to manage the units to their retirement date.
Old Harbour Unit #2	$279,099	Forecasted to do routine overhauls and emergency replacements	
Old Harbour Unit #3	$458,684	Forecasted to do routine overhauls and emergency replacements	
Old Harbour Unit #4	$490,739	Forecasted to do routine overhauls and emergency replacements	
Hunts Bay Gen Plant	$50,000	Forecasted to do routine overhauls and emergency replacements	
Hunts Bay Unit #B6	$545,488	Forecasted to do routine overhauls and emergency replacements	
Annual Expenditure	**$2,053,267**		

4. **The table below illustrates the amount of capital expenditures that are required during for the year 2020 to support plant reliability and efficiency. In light of the proposed retirement dates for these units, the capital outlay has reduced to support the remaining assets. The maintenance activities will be primarily around routine overhauls and emergency replacements of plant items.**

STEAM UNITS	**2020 CAPEX REQ. (US$)**	**MAINTENANCE ACTIVITIES**	**JUSTIFICATIONS**
Old Harbour Gen Plant	$100,000	Forecasted to do routine overhauls and emergency replacements	The allocated CAPEX provisions are based on past performance, maintenance requirements and the maintenance philosophy in place to manage the units to their retirement date.
Old Harbour Unit #4	$341,665	Forecasted to do routine overhauls and emergency replacements	
Hunts Bay Gen Plant	$50,000	Forecasted to do routine overhauls and emergency replacements	
Hunts Bay Unit #B6	$445,488	Forecasted to do routine overhauls and emergency replacements	
Annual Expenditure	**$937,153**		

Appendix E: Bill Impact

Bill Impact – Rate 10

	Before			After			Change	
	March 2018 Bill			March 2018 Bill			March 2018 Bill	
Description	Usage	Rate	Charges (J$)	Usage	Rate	Charges (J$)	Charges (J$)	%
Base/Exchange Rate	131.00	128.0000		128.00	128.0000			
Non-Fuel Charges								
Energy 1st	100	9.59	959.00	100	9.64	964.00	5.00	0.5%
Energy Next	61.52	22.33	1,373.74	61.52	22.45	1,381.12	7.38	0.5%
Customer Charge		442.27	442.27		444.61	444.61	2.34	0.5%
EEIF Charges	161.52	-	-	33	-	-	-	0.0%
Sub Total			2,775.01			2,789.73	14.72	0.5%
F/E Adjustment			(50.84)			-	50.84	
Total Non-Fuel Bill			**2,724.17**			**2,789.73**	**65.56**	**2.4%**
Fuel & IPP Charges	161.52	18.513	2,990.30	161.52	18.513	2,990.30	-	0.0%
Early Payment Incentive		-	-		-	-	-	0.0%
GCT			415.81			415.81		
Bill Total			6,130.28			6,195.85	65.56	1.1%

Bill Impact – Rate 20

	Before			After			Change	
	March 2018 Bill			March 2018 Bill			March 2018 Bill	
Description	Usage	Rate	Charges (J$)	Usage	Rate	Charges (J$)	Charges (J$)	%
Base/Exchange Rate	131.00	128.0000		128.00	128.0000			
Non-Fuel Charges								
Energy	811.62	18.42	14,950.04	811.62	18.52	15,031.20	81.16	0.5%
Customer Charge		985.29	985.29		990.50	990.50	5.21	0.5%
EEIF Charges	811.62	-	-	811.62	-	-	-	0.0%
Sub Total			15,935.33			16,021.70	86.37	0.5%
F/E Adjustment			(291.94)			-	291.94	
Total Non-Fuel Bill			**15,643.39**			**16,021.70**	**378.32**	**2.4%**
Fuel & IPP Charges	811.62	18.513	15,025.92	811.62	18.513	15,025.92	-	0.0%
Bill Total			30,669.31			31,047.63	378.32	1.2%

Bill Impact – Rate 40 STD

							Change	
	March 2018 Bill			March 2018 Bill			March 2018 Bill	
Description	Usage	Rate	Charges (J$)	Usage	Rate	Charges (J$)	Charges (J$)	%
Base/Exchange Rate	131.00	128.0000		128.00	128.0000			
Non-Fuel Charges								
Demand	111	1,777.51	197,771.12	111	1,786.91	198,816.99	1,046	0.5%
Energy	33,125	5.73	189,808.99	33,125	5.76	190,802.75	994	0.5%
Customer Charge		6,941.83	6,941.83		6,978.54	6,978.54	37	0.5%
EEIF Charges	33,125	-	-	33,125	-	-	-	0.0%
Sub Total			394,521.93			396,598.28	2,076	0.5%
F/E Adjustment			(7,227.88)			-	7,228	
Total Non-Fuel Bill			**387,294.05**			**396,598.28**	**9,304.23**	**2.4%**
Fuel & IPP Charges	33125.47765	17.773	588,737.65	33125.47765	17.773	588,737.65	-	0.0%
Bill Total (J$)			976,031.70			985,335.93	9,304	1.0%

Bill Impact – Rate 50 STD

	March 2018 Bill			March 2018 Bill			Change March 2018 Bill	
Description	Usage	Rate	Charges (J$)	Usage	Rate	Charges (J$)	Charges (J$)	%
Base/Exchange Rate	131.00	128.0000		128.00	128.0000			
Non-Fuel Charges								
Demand	428	1,592.42	681,947.68	428	1,600.84	685,553.51	3,606	0.5%
Energy	139,548	5.53	771,700.60	139,548	5.56	775,887.05	4,186	0.5%
Customer Charge		6,941.83	6,941.83		6,978.54	6,978.54	37	0.5%
EEIF Charges	139,548	-	-	139,548	-	-	-	0.0%
Sub Total			1,460,590.11			1,468,419.10	7,829	0.5%
F/E Adjustment			(26,758.90)			-	26,759	
Total Non-Fuel Bill			**1,433,831.21**			**1,468,419.10**	**34,587.89**	**2.4%**
Fuel & IPP Charges	139,548	14.811	2,066,817.48	139,548	14.811	2,066,817.48	-	0.0%
Bill Total (J$)			3,500,648.69			3,535,236.58	34,588	1.0%

Bill Impact – Rate 70 STD

	March 2018 Bill			March 2018 Bill			Change March 2018 Bill	
Description	Usage	Rate	Charges (J$)	Usage	Rate	Charges (J$)	Charges (J$)	%
Base/Exchange Rate	131.00	128.0000		128.00	128.0000			
Non-Fuel Charges								
Demand	2,471	1,515.61	3,745,221.82	2,471	1,523.62	3,765,015.32	19,794	0.5%
Energy	885,224	3.68	3,257,622.74	885,224	3.70	3,275,327.21	17,704	0.5%
Customer Charge		6,941.83	6,941.83		6,978.54	6,978.54	37	0.5%
EEIF Charges	885,224	-	-	885,224	-	-	-	0.0%
Sub Total			7,009,786.39			7,047,321.08	37,535	0.5%
F/E Adjustment			(128,423.57)			-	128,424	
Total Non-Fuel Bill			**6,881,362.83**			**7,047,321.08**	**165,958.25**	**2.4%**
Fuel & IPP Charges	885,224	14.811	13,110,866.25	885,224	14.811	13,110,866.25	-	0.0%
Bill Total (J$)			19,992,229.08			20,158,187.33	165,958	0.8%

Appendix F: 2018 Reliability Statistics Dataset (Excel workbook provided separately)

Appendix G: Rule Base Data Dictionary

	Rule	Condition	Action
1	Excessive Customer Count/(OMS/GIS Glitches)	1. Fuses where the customer count is greater than or equal to 120% of the device capability.	1. Send list to Parish &/GIS Dept. dfaily/weekly for field validation. Reportable type is finalized after investigation.
		2. Assignment of loads to a transformer in excess of 120% greater than its capacity.	2. Automated limiting of loads to transformer capacity and follow up with field validation to improve data accuracy.
		3. When opening of a SCADA device, trigger OMS to infer that the start time is equal to the earlier start time of that of a previously unverified or unfrozen downstream outage.	3. For all instances of outage on a SCADA device, automatically, start time & end time is taken from the actual time of operation reported by ICCP and initial staged time maintained for downstream outage.
		4. Difference of 10 minutes between OMS outage completion time and field crew mobile tablet completion time.	4. The outage compleiton/restoration time is automatically adjusted to crew completion time as recorded by mobile.
2	Non Utility Related Outages	Premises found locked and customer outage cannot be verified; Premises Not Found; Defective Customer Equipment and Disconnection	Call Closed and outage made Non Reportable
3	Incorrect Customer Device Mapping	Customer incorrectly represented in GIS to wrong transformer, feeder or parish.	The customer is transferred to the correct device. Original outage is made Non Reportable. OMS generates a new outage.
4	Operator Error	If outage mismanagement results in an outage greater than 50% of actual SAIDI, the outage is made non reportable. Trigggers: - Load Transfers - Use of Mobile Transformers - Protection & SCADA functional checks	- Outage made Non Reportable after review by Reliability Department - Refresher training and operator performance appraisal.