THE JAMAICA PUBLIC SERVICE CO. LTD.

ANNUAL TARIFF ADJUSTMENT SUBMISSION FOR 2017

&

EXTRAORDINARY RATE REVIEW

May 5, 2017

Preamble

This submission is made in relation to the annual Performance-Based Rate-Making (PBRM) tariff adjustment filing for 2017, 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…."

In accordance with the Licence, the OUR's January 7, 2015 Determination Notice, Determination Notice Addendum 1 and the Extraordinary Rate Review Determination Notice (2017/ELE/001/DET.001), the 2017 annual non-fuel tariff adjustment will incorporate changes to the annual inflation adjustment, the resetting of the new foreign exchange rate and a Z factor adjustment that became applicable as a requirement of Determination 4 of the Extraordinary Rate Review Determination. Determination 1 of the Extraordinary Rate Review Determination also stipulates that JPS' Revenue Requirement should be reviewed in light of JPS' application for the recovery of asset impairment cost and accelerated depreciation expenses. JPS will review the revenue requirement approved by the OUR in the 2014 – 2019 Determination Notice in accordance with the requirements of Determination 4 while taking note of our earlier communication to the OUR in which JPS indicated its state of readiness for implementing Determination 3. The application will not include a Q factor adjustment as JPS and the OUR continue to work towards the establishment of a baseline.

The 2017 Annual Adjustment filing is developed in the context of the new Electricity Licence that was established in January 2016. Several new parameters were introduced in the Licence. In the absence of a prior consensus between the OUR and JPS on the setting of these parameters, JPS outlined its position in relation to the parameters in its 2016 Annual Adjustment Filing. The OUR concurred with several of these positions and, in the 2017 Annual Tariff Filing, JPS' proposal is informed by the precedence established by the OUR in the 2016 Annual Tariff Adjustment Determination Notice.

In the past year, JPS along with major sector stakeholders accomplished the historic achievement of bringing LNG to Jamaica. The introduction of LNG into the Jamaican market has been a major game changer for the industry as many of our larger customers are now seriously contemplating self-generating using gas as the fuel of choice. JPS' analysis indicates that the best alternative option (BAO) is at a cost which is lower than the grid cost for our larger customers and there is a real possibility of significant grid defection. The impact of grid defection by the larger customers would be significant for other rate classes and it is because of this that JPS is proposing the introduction of a new rate class for customers whose peak demand at a single location is at or above 2MVA in the 2017 tariff adjustment filing.

Glossary

ABNF	-	Adjusted Non-fuel base rate
CIS	-	Customer Information System
CPI	-	Consumer Price Index
EDF	-	Electricity Disaster Fund
EEIF	-	Energy Efficiency Improvement Fund
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
Licence	-	The All Island Electric Licence 2001
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

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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 PBRM from a Price Cap to a Revenue Cap regime. The amended Licence shall hereafter be cited as the Electricity Licence.

The methodology to be utilised in computing the PBRM is set out in detail in Exhibit 1. Exhibit 1 of the Electricity Licence 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"

$$\mathrm{TUVol_{y-1}} = \left\{\frac{\mathrm{kWh\ Target_{y-1}} - \mathrm{kWh\ Sold_{y-1}}}{\mathrm{kWh\ Target_{y-1}}}\right\} \times \text{Non Fuel Rev Target for Energy}$$
$$+ \left\{\frac{\mathrm{kVA\ Target_{y-1}} - \mathrm{kVA\ Sold_{y-1}}}{\mathrm{kVA\ Target_{y-1}}}\right\} \times \text{Non Fuel Rev Target for Demand}$$
$$+ \left\{\frac{\#\text{Customer Charges Billed Target}_{y-1} - \#\text{Customer Charges Billed}_{y-1}}{\#\text{ Customer Charges Billed Target}_{y-1}}\right\} \times$$
$$\text{Non Fuel Rev Target for Customer Charges}$$

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.

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

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 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 Performance-Based Rate-Making (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; and

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

<u>The Growth Rate (dI)</u>

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.

<u>The Z-Factor</u>

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

1.2 Computation of Exhibit 1 Parameters

The Electricity Licence introduced several parameters that were not previously defined in the earlier Licence nor established by the OUR in any Determination Notice before 2016. In the absence of a prior consensus between the OUR and JPS on the setting of these parameters, JPS outlined its position in relation to the parameters in the 2016 Annual Adjustment Filing. The OUR concurred in establishing the Exhibit 1 parameters and the precedence set by the OUR in the 2016 Annual Tariff Adjustment Determination Notice will serve as the basis for JPS' proposal for the Exhibit 1 parameters in 2017. The Extraordinary Rate Review Determination Notice by the OUR which was published on February 1, 2017 will also have a significant bearing on the application of these parameters in this filing. Determinations 1, 3 and 4 specifically has significant bearing on the computation of the Revenue Cap for 2017 (RC_{2017}) and the application of the Z factor, as will be shown in the ensuing sections. Determinations 1, 3 and 4 are stated as follows:

<u>Determination 1</u>

JPS' asset impairment and incremental depreciation expenses arising from the application of the depreciation rates in Schedule 4 of the Licence 2016 is recoverable in its tariffs and shall be recovered as follows:

a) The asset impairment costs incurred in 2016 shall be recovered applying the Z-factor mechanism;
b) The projected increase in depreciation expenses in 2017 and 2018 shall be recovered by the adjustment of the revenue requirement in the existing tariffs;
c) All projected increases in depreciation expenses in 2019 and beyond shall be addressed in future Five Year Rate Reviews.

Determination 3

a) The Office has determined that JPS shall provide details on each project in its investment plan for 2017 and 2018. The information provided shall include the purpose, a break-out of the cost into its components, the implementation schedule and the benefit to be derived from the specific investment, including any supporting return on investment projections.

b) The detailed investment plan shall be submitted no later than thirty (30) days after this Determination Notice becomes effective. Thereafter, the OUR shall review JPS' investment plan and make a determination on the changes to the company's base revenue requirement, which shall be published prior to 2017 July 1, being the date the revenue revision shall take effect.

Determination 4

a) JPS shall be allowed to recover US$13,378,012 of expenses caused by its 2016 depreciation asset impairment charge plus the associated opportunity cost. The recovery of these costs amounting to US$15,146,585 shall be recovered by way of the Z-factor mechanism over a one (1) year period.

b) The Z-factor adjustment approved in this Determination 4 along with the Extraordinary Rate Review adjustment to be approved shall be implemented in 2017 July.

c) Notwithstanding the above, the OUR reserves the right to adjust the timetable of the Z-factor implementation should conditions at the time of implementation so warrant.

1.2.1 The Rate of Change of Revenue Target (dPCI)

The annual adjustment in the 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.

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 the 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 Rate Determination Notice. In its response to the 2016 Annual Tariff 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. JPS' expectation is that there will be no further adjustments to these parameters.

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 23.517% 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 2017 and March 2014 of 11.44%, derived from the CPI data[1] published by Statin (see Appendix);
- U.S. point-to-point inflation rate (INF_{US}) between March 2017 and March 2014 of 3.18%, derived from the U.S. Department of Labor statistical data[2] (see Appendix); and
- The 16.96% increase in the Base Exchange Rate $\left(\frac{\mathbf{EX_n - EX_b}}{\mathbf{EX_b}}\right)$ from J$112: US$1 to J$131.00: US$1.
- The Q Factor is set to zero.
- The computed value of the Z factor is 4.941%. When multiplied by RC_{2017}, this computed value of the Z factor will yield the US$15,146,585 that the OUR allowed JPS to recover as per Determination 4 of the Extraordinary Rate Review Determination Notice. The calculation of the revenue cap will be expanded on in the next section of the document.

The table below sets out the details of the computation of the growth rate, dI. The adjustment factor, dPCI, which amounts to 23.517% is computed by adding the Z factor to dI.

Table 1-1: Escalation Factor Net of Q Factor and Z Factor Adjustment

Annual Adjustment Clause Calculation			
ESCALATION FACTOR (dI) based on point to point data as at March 2017			
Line	Description	Formula	Value
L1	Base Exchange Rate		112.00
L2	Proposed Exchange Rate		131.00
L3	Jamaican Inflation Index		
L4	CPI @ Mar 2017		238.7
L5	CPI @ Mar 2014		214.2
L6	US Inflation Index		
L7	CPI @ Mar 2017		243.8
L8	CPI @ Mar 2014		236.3
L9	Exchange Rate Factor	(L2-L1)/L1	16.96%
L10	Jamaican Inflation Factor	(L4-L5)/L5	11.44%
L11	US Inflation Factor	(L7-L8)/L8	3.18%
L12	Escalation Factor	L9*{0.8+(0.8-0.0688)*L11}+(0.8-0.0688)*L11+(1-0.8)*L10	18.58%
L13	**Escalation Factor net of Q**	**dI - Q**	18.58%

[1] Obtained from the Statistical Institute of Jamaica.
[2] Obtained from U.S. Bureau of Labor Statistics website, http://data.bls.gov/cgi-bin/surveymost

It should be noted that the 23.517% increase represents the adjustment between 2014 and 2017 and does not represent an annual increase. Under the old Licence and during the Price Cap regime, dI and dPCI represented annual adjustment factors but this interpretation should not be carried forward to the treatment of the parameters in the new Licence.

1.2.2 The Revenue Cap for 2017 (RC_{2017})

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 Licence contemplates that for each year of the rate review period, the parameter RC_y will be established without factoring inflation. During the annual adjustments, 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 rate review and so JPS 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 described under the price cap regulation. JPS' position was that the 2016/2017 revenue target should be based on the revenue requirement established in the OUR's 2014- 2019 rate determination with allowance made 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 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 amended Licence. The amended 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 Determination, 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. Using the same rationale as established in 2016, the revenue cap for 2017 would have been determined as follows:

$$\mathrm{RC}_{2017} = (\text{Revenue Requirement Established in } 2014 - 2019 \text{ rate review}) \times (1 - \mathrm{X})^3$$

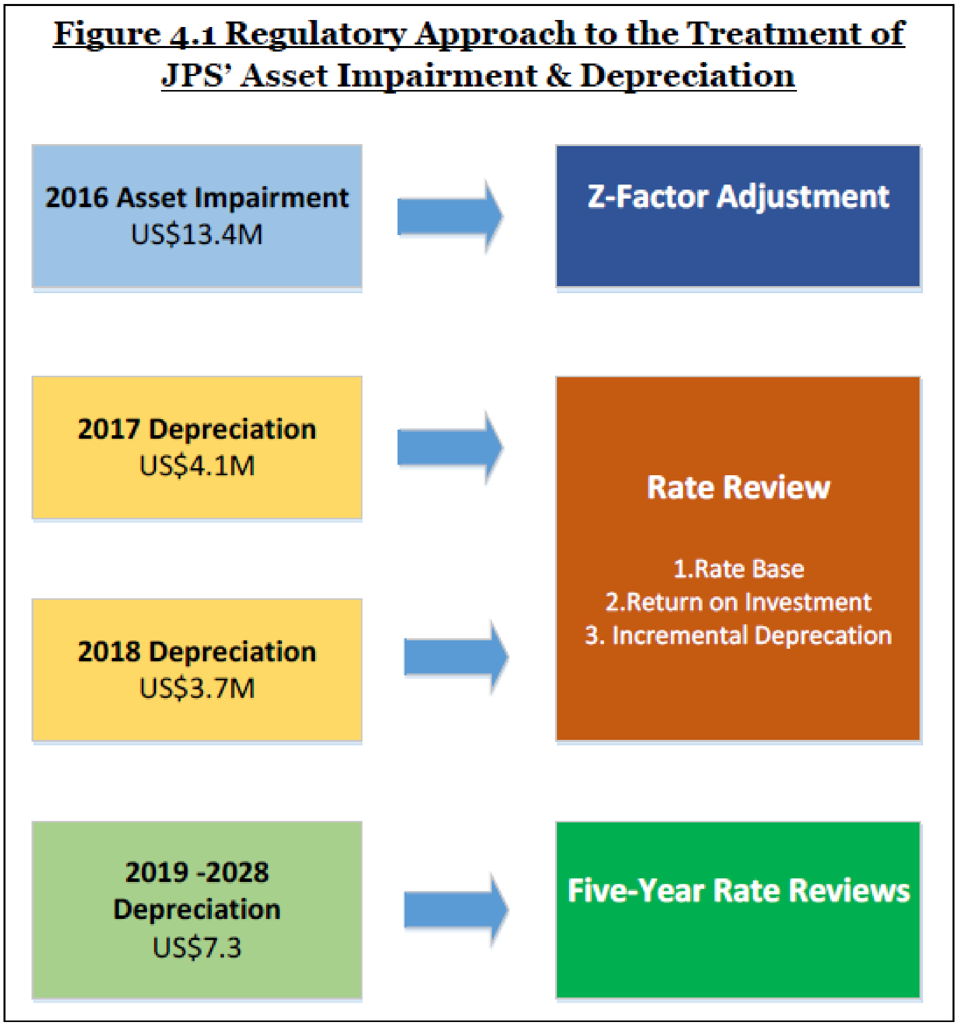
The above formulation for RC_{2017} however does not contemplate Determinations 1, 3 and 4 of the Extraordinary Rate Review Determination. In the Determination, the OUR concluded that in the treatment of JPS' asset impairment and depreciation costs spanning the period 2016 – 2028, the recovery of cost via the tariff shall be based on the following principles:

- Historic asset impairment and costs (i.e. for 2016) shall be recovered through the Z-factor mechanism;

- Future costs for the periods 2017 and 2018 shall be recovered through an adjustment of the revenue requirement under this Extraordinary Rate Review;
- Future costs anticipated after 2018 will be addressed at the Five Year Rate Reviews.

The OUR's determination is summarised in Figure 1-1 below:

Figure 1-1: Summary of Extraordinary Rate Review Recovery Process



To implement the approach that the OUR has outlined in its Extraordinary Rate Review Determination Notice dated February 1, 2017 would require a projection of the fixed asset portion of JPS' rate base starting with the NBV as of December 2016 as the base and then adding future costs for the periods 2017 and 2018. While JPS is wary of a hybrid approach in which portions of the revenue requirement are based on 2013 costs and others based on costs incurred subsequent to that date, we are aware of the dilemma arising from the need to capture the accelerated depreciation costs incurred after 2013. The Company is therefore prepared to proceed as stipulated by the OUR, to revise the fixed asset portion of the rate base using costs incurred subsequent to 2013 however, we have indicated to the OUR by way of letter dated April 27, 2017 that we will defer the recovery of additional revenues on investments in fixed assets additions during 2017 and 2018 tariff periods until after the expenditure is incurred as the Company is not yet in a position to implement the business processes and procedures necessary to sufficiently forecast the capital investment with the level of precision and granularity within the timeframe stipulated by the OUR. JPS is however proposing that the 2016 Rate Base be used as a proxy for the 2017 and 2018 rate bases. JPS reserves the right to request the incremental revenues in the tariff filings following each year.

The company's preliminary capital investment forecasts indicate that our expenditure will be much more than expenditures in 2016 as there are several proposed projects which the company believes it must pursue to maintain grid stability and improve efficiency. These include the LED Street Lighting project which is mandatory by legislation, an Energy Storage Project and the possible refurbishment and or replacement of GT11 and GT8 to increase the current reserve margins. In summary, we are expecting the rate base to grow in 2017 and 2018 and thus, using 2016 as the proxy will not be prejudicial to the customers.

JPS is working to ensure that all the necessary resources are acquired and that the business processes are sufficiently developed to allow us to accurately forecast the capital expenditure as part of the business plan for the 2019 Rate Case submission. To facilitate this, the company has recently procured a Corporate Planning system that will allow for the collation and analysis of capital investment plans in an efficient and cost effective manner. Given the foregoing, JPS' proposal is to adjust the rate base as at December 2016 to reflect the values for approved fixed asset on record as at that date.

Using the 2016 Annual Tariff Adjustment and the Extraordinary Rate Review Determinations, JPS is proposing that the following formula be used to determine the revenue cap for 2017:

$$\mathrm{RC}_{2017} = (\text{Revenue Requirement Established in } 2014 - 2019 \text{ rate review}) \times (1 - \mathrm{X})^3 + \frac{\text{Adjustments}}{(1+\mathrm{dPCI})}$$

The above formula for RC_{2017} takes account of the methodology that would apply based on the agreed approach established in the 2016 Annual Tariff Adjustment Determination but also includes an additional term $\frac{\text{Adjustment}}{(1+\mathrm{dI})}$ which was added to make allowance for the adjustments stipulated in Determination 1 of the Extraordinary Rate Review Determination. The Adjustments should not be subjected to inflationary adjustments given that it represents cost as of December 2016 and application of the Exhibit 1 formula for producing ART_{2017} would erroneously inflate the Adjustments if the $\frac{1}{(1+\mathrm{dPCI})}$ was not included to cancel the inflationary effect.

1.2.2.1 Computation of Adjustments

In the Extraordinary Rate Review Determination, the OUR asserted that the increased depreciation costs claimed by JPS going forward (i.e. from 2017 onward) requires a review of components of the revenue cap mechanism, as it is forward looking and can address costs prospectively. The OUR further stated that compensation for this component of JPS' claim will therefore be addressed via a revision of the rate base and the revenue requirement of the revenue-cap mechanism, and the resultant adjustment of the tariff going forward. This is stated in paragraph 6.3 of the Extraordinary Rate Review Determination Notice as follows:

> In order to effect the rate revision to address the expected increase in depreciation expenses, the following steps are required:
>
> - an adjustment of the rate of return on investment in the revenue requirement approved in the 2014 - 2019 Determination, so as to reflect the changes derived from a forward looking rate base for the period 2016 – 2019, including consideration of the impact of asset impairments already incurred and accelerated depreciation of certain assets as provided in the Licence 2016.
> - an adjustment to the approved depreciation expense component of the revenue requirement in the 2014 -2019 Determination by an amount equivalent to the average annual increase in depreciation expenses expected in 2017 and 2018.

Table 1-2 below provides a summary of the revenue requirement approved by the OUR in the 2014 – 2019 Rate Determination. In keeping with the OUR's approach described above, adjustments to the rate base would be necessary to incorporate any forward looking rate base investments in 2017 and 2018 and to account for the impact of asset impairment adjustments already incurred. The sum of the return on equity, long term debt and gross up for taxes represents JPS' return on investments (ROI) which is obtained by multiplying the approved cost of capital (WACC) times the approved rate base. Any revision to the approved rate base would require automatic adjustments to each of these components of the ROI which will subsequently be reflected in the adjusted revenue requirement.

JPS does not agree with the OUR, however, that the adjustment to be included in the revenue requirement for increased depreciation expenses should be "an amount equivalent to the average annual increase in depreciation expenses expected in 2017 and 2018". The OUR's directive to use the average annual increase appears to stem from its interpretation of Schedule 3, Paragraph 6 of the Licence which states that:

> *"The Licensee shall file with the Office proposed non-fuel rate schedules and shall demonstrate that the non-fuel rates proposed for the various rate categories will generate the non-fuel revenue requirement on average over the five year rate review process."*

The OUR may have interpreted that only one revenue cap will be applied over the rate review period. JPS' interpretation is that separate revenue caps for each year of the review period is required – this interpretation is consistent with the descriptions and terminologies used in Exhibit 1 of the Licence. JPS' interpretation is predicated on paragraph 46 d(ii) of the Licence 2016 which states:

> *"where the Licensee's capital and special program expenditure are delayed and such delay results in the variation of 5% or more of the annual expenditure, the Z-factor adjustment will take into consideration the over-recovery of such expenditure plus a surchage at the WACC;"*

The application of the average revenue cap to paragraph 46 d(ii) would prove problematic as an average value could naturally lie above or below the annual values therefore, the 5% variation could occur despite JPS delivering everything agreed in the five year business plan. Thus, rather than computing one revenue cap which covers 2017 and 2018, JPS' proposes separate revenue caps, RC_{2017} and RC_{2018}, for 2017 and 2018 respectively.

Table 1-3 shows the rate base that was approved by the OUR in the 2014 – 2019 Determination while Table 1-3 shows the fixed asset portion of the rate base as of December 31, 2016. Note that Construction Work in Progress (CWIP) was not removed from the rate base for 2016 which was the case in the 2014 – 2019 Determination as Schedule 3, paragraph 29 of the new Licence states that CWIP should be included in the calculation of the rate base. It is important to note that the asset impairment cost of US$13.4M is already factored in the NBV of the assets in Table 1-4.

Table 1-2: Approved Revenue Requirement for 2014 - 2019

Revenue Requirement	US$'000
Purchased Power	104,111
Operating Expense	147,736
Total Operational Expenses	**251,847**
Net Finance Costs (excl. long term debt)	
Interest on short term loans	1,403
Interest on customer deposits	549
Interest - Bank Overdraft and other	1,990
Int. capitalised during construction (AFUDC)	1,450
Debt Issuance cost and expenses	3,202
Finance income	(1,615)
	6,979
Depreciation	47,412
FX Losses	-
Other Income	(1,785)
Other Expenses	3,000
Self-insurance Fund (SIF) contribution	2,000
Gross up taxes on SIF	1,000
Return on Equity	31,837
Taxation (Gross Up)	15,918
Long Term Interest Expenses	20,985
Revenue Requirement	376,194
Less Carib Cement Revenue	(4,936)
JPS Managed IPP Expenses	(604)
Loss Reduction Fund (incl. taxes)	**13,000**
Adjusted Revenue Requirement	383,654

Table 1-3: Approved Rate Base in the 2014 – 2019 Determination Notice

Items		OUR Approved US$'000
Property, Plant and Equipment		698,571
Add		
Intangible Assets		9,877
Rural Electrification Assets		-
Other Asset		
Long-term receivables		1,447
Exclusions		
Retired Plants and Assets not in use and/or useful		(9,495)
Construction Work in Progress (CWIP)		(14,516)
Capital Reserve (Revaluation Surplus)		(19,901)
JPS managed IPP Assets		(43,319)
EEIF Assets		(31,125)
Net Fix Assets		**591,540**
Offsets		
Customer Deposits		(26,827)
Employee Benefit Obligations		(6,908)
Deferred Expenditure (Tax)		(39,917)
Deferred Revenue		(1,654)
Adjustments		
Asset Impairment Cost on Assets existing as of Dec 2013		
Incremental Accumulated Depreciation		
Total Long Term Assets		**516,234**
Add		
Net Current Assets (Working Capital):	**US$'000**	**3,657**
Add **Current Assets:**	**232,022**	
Cash and Short Term Deposits	3,854	
Repurchase Agreements/Restricted Cash	-	
Receivables	186,877	
Tax Recoverable	420	
Inventories	40,871	
Subract **Current Liabilities:**	**228,365**	
Bank Overdraft	1,938	
Short term loans plus current maturity	37,492	
Payables	189,385	
Corporation Tax Payable	(1,148)	
Related Companies Balances	698	
Total Net Assets (RATE BASE)		**519,891**

Table 1-4: Net Fixed Assets as of December 31, 2016

Items	Net Fixed Assets as of December 31, 2016 US$'000
Property, Plant and Equipment	678,065
Add	
Intangible Assets	21,479
Rural Electrification Assets	-
Other Asset	
Other Assets (House wiring)	89
Long-term receivables	-
Exclusions	
Retired Plants and Assets not in use and/or useful	(3,596)
Capital Reserve (Revaluation Surplus)	(4,145)
JPS managed IPP Assets	(40,576)
EEIF Assets	(48,381)
Customer Funded portion of Bogue Reconfiguration Fund Assets	(9,847)
Net Fix Assets	**593,087**

The incremental change in ROI is shown in Table 1-5Table 1-5. The table shows the ROI that JPS obtained on its fixed assets in the 2014 – 2019 Rate Determination as opposed to what it would receive on the 2016 fixed assets which, we are proposing should replace the fixed asset values determined in the 2014 rate review and serve as a proxy to the 2017 and 2018 rate base. The incremental change represents one part of the adjustments required to determine the revenue cap for 2017. In making the adjustment the time value of money and the efficiency improvement factor applied to the revenue cap were factored by using the following formula:

$$\mathrm{Value}_{2016} = \mathrm{Value}_{2013}\frac{\mathrm{EX_b} \times (1 + \mathrm{dI})(1 - X)^3}{\mathrm{EX_n}}$$

Where EX_b is the exhange rate for the base year (2014), EX_n is the proposed base exhange rate for 2017, dI is the escalation factor on the revenue target and X is the efficiency improvement factor. The second part of the adjustment is the incremental change in depreciation expenses. The depreciation expense that was approved in the 2014 – 2016 Determination Notice was US$47.412M. The depreciation expense in 2016 was US$77.607M – this includes the 2016 asset impairment cost of US$13.4M which the OUR has allowed JPS to recover through the Z factor mechanism, depreciation expense of US$4,125,040 on EEIF and JPS Managed IPP assets and depreciation expense on customer funded portion of the Bogue LNG conversion assets. To develop the proxy for the 2017 depreciation expense, these costs have to be removed from the 2016 depreciation and amortisation expense and US$4,108,088.42 of accelerated depreciation expense for 2017 would be added. This is illustrated below in Table 1-6:

Table 1-5: Incremental Change in ROI

Item	2014 - 2019 Approved ROI	2014 - 2019 Approved ROI Adjusted for 2016 currency	2017 Adjusted ROI Expressed in 2016 currency	Incremental Change in ROI Values
Cost of Debt	8.07%	8.07%	8.07%	
Rate of Return on Equity(ROE)	12.25%	12.25%	12.25%	
Tax Rate	33.33%	33.33%	33.33%	
Gearing Ratio (Deemed)	50%	50%	50%	
Post-tax WACC	8.81%	8.81%	8.81%	
Pre-tax WACC	13.22%	13.22%	13.22%	
	US$'000	**US$'000**	**US$'000**	**US$'000**
Rate Base	**591,540**	**580,121**	**593,087**	**12,967**
Return on Equity	**36,222**	**35,523**	**36,317**	**794**
Taxation (Gross Up)	**18,111**	**17,761**	**18,158**	**397**
Long Term Interest Expenses	**23,869**	**23,408**	**23,931**	**523**

Table 1-6: Projected 2017 Depreciation Expense

2017 Depreciation Expense	
2016 Depreciation Expense	77,607,000
- 2016 Asset Impairment Cost	(13,378,012)
- EEIF and JPS IPP Managed Assets Depn. Expense	(4,125,040)
- Customer Funded portion of Bogue RF Assets Depn. Expense	(192,238)
+ 2017 Accelerated Depreciation Expense	4,108,088
Proxy 2017 Depreciation Expense	64,019,798

After factoring the time value of money and the efficiency improvement, the incremental change in depreciation expense amounts to U$17.523M. The total adjustments to the revenue target for 2017 is the sum of the incremental depreciation expenses, incremental return on equity, incremental taxes and incremental long term interest expense. These amount to US$19.237M (J$2,520,849,791).

Using the proposed formula for RC_{2017}, that is,

$$RC_{2017} = (\text{Revenue Requirement Established in 2014} - \text{2019 rate review}) \times (1 - X)^3 + \frac{\text{Adjustments}}{(1+\text{dPCI})}$$

the revenue cap for 2017 is:

Computation of Revenue Cap for 2017	
Approved 2014 - 2019 Revenue Requirement	41,512,909,469
dPCI (dI - Q + Z)	23.517%
Adjustments	2,520,085,974
RC_{2017}	42,198,264,249

1.2.3 True Up for Volumetric Adjustments

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

$$\mathrm{TUVol}_{y-1} = \left\{\frac{\text{kWh Target}_{y-1} - \text{kWh Sold}_{y-1}}{\text{kWh Target}_{y-1}}\right\} \times \text{Non Fuel Rev Target for Energy}$$

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

$$+ \left\{\frac{\text{\#Customer Charges Billed Target}_{y-1} - \text{\#Customer Charges Billed}_{y-1}}{\text{\# Customer Charges Billed Target}_{y-1}}\right\} \times$$

$$\text{Non Fuel Rev Target for Customer Charges}$$

The formula indicates that the volumetric adjustment for any year is dependent on the variance between the target billing determinants for that year and those that were actually achieved during the year. Schedule 3, paragraphs 44 and 45 of the Licence further clarifies how the target billing determinants should be determined and are outlined below:

"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 2017. Application of the formula in Exhibit 1 to compute ART_{2017} for the 2017/2018 Annual Adjustment requires the computation of $TUVol_{2016}$ (volumetric adjustment for 2016) which is a function of the billing determinants for 2016, that is,

$$\mathrm{TUVol}_{2016} = \left\{\frac{\text{kWh Target}_{2016} - \text{kWh Sold}_{2016}}{\text{kWh Target}_{2016}}\right\} \times \text{Non Fuel Rev Target for Energy}$$

$$+ \left\{\frac{\text{kVA Target}_{2016} - \text{kVA Sold}_{2016}}{\text{kVA Target}_{2016}}\right\} \times \text{Non Fuel Rev Target for Demand}$$

$$+ \left\{\frac{\text{\#Customer Charges Billed Target}_{2016} - \text{\#Customer Charges Billed}_{2016}}{\text{\# Customer Charges Billed Target}_{2016}}\right\} \times$$

$$\text{Non Fuel Rev Target for Customer Charges}$$

JPS' interpretation of Paragraphs 44 and 45 is that the targets for 2016 should be based on the actual billing determinants for 2015 barring any changes made by OUR to adjust the target billing determinants for known and measurable changes anticipated in relation to the following year. This adjustment by the OUR, by our interpretation of paragraph 45, should have been done in the 2016 Annual Adjustment Determination. No adjustments were made in the Determination therefore the billing determinant targets for 2016 would be the prior year's (2015) actual billing determinants.

Given the forgoing, the billing determinant targets for 2016 are given as follows:

$$\text{kWh}_{\text{Target}_{2016}} = \text{kWh}_{\text{Sold}_{2015}}$$
$$\text{kVA}_{\text{Target}_{2016}} = \text{kVA}_{\text{Sold}_{2015}}$$
$$\text{\# Customers Charges Billed}_{\text{Target}} = \text{\# Customers Charges Billed}_{2015}$$

where:
$\text{kWh}_{\text{Sold}_{2015}} = \text{kWh billed in 2015}$
$\text{kVA}_{\text{Sold}_{2015}} = \text{kVA billed in 2015}$
$\text{\# Customers Charges Billed}_{2015} = \text{\# Customers Charges Billed in 2015}$

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 2016 are the actual billing determinants for 2015, the non-fuel revenue targets for energy, demand and customer should be the product of the 2016 approved prices and the 2015 quantities for each revenue category. Therefore, the 2016 non-fuel revenue targets for energy, demand and customer charge should be based on those proposed in Table 5.7 of the OUR's 2016 Determination Notice and are described as "Total Energy Revenue", "Total Demand Revenue" and "12 Months Customer Revenue" respectively. A copy of Table 5.7 is shown below.

Table 5.7 Approved Annual Revenue Target: 2016-2017

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	1,083,661,233	4,514,321,729	0	0	0	0	5,279,468,298
Rate 10 LV	> 100	1,654,735,366	11,024,351,975	0	0	0	0	11,957,671,206
Rate 20 LV		693,510,460	10,673,776,545	-	-	-	-	10,720,509,832
Rate 40A		-	-	-	-	-	-	-
Rate 40 LV - Std		132,935,202	3,624,335,217	3,883,154,552	-	-	-	7,205,699,213
Rate 40 LV - TOU		9,622,439	636,486,225	-	24,457,781	246,494,686	248,378,861	1,099,128,655
Rate 50 MV - Std		10,026,743	2,183,888,674	1,783,387,119	-	-	-	3,751,001,529
Rate 50 MV - TOU		1,859,799	497,573,238	-	21,798,949	199,516,449	213,344,453	880,944,766
Rate 60 LV		12,846,438	1,653,646,649	-	-	-	-	1,571,672,776
TOTAL		3,599,197,680	34,808,380,252	5,666,541,670	46,256,730	446,011,134	461,723,314	45,028,110,780

It is important to note, however, that the tariffs approved by the OUR in 2016 are multiplied by the Billing Determinants does not compute to the Revenue Target depicted in Table 5.7 of the OUR's Determination due to rounding errors. JPS believes that the revenue targets should be set using the tariffs determined by the OUR, therefore when computed on this basis, the corrected approved revenue target is as illustrated in Table 1-7 below is $45,025,076,153.

Table 1-7: Corrected Approved Annual Revenue Target: 2016 - 2017

	Block/ Rate Option		12 Months 2011 Customer Revenue	Energy Revenue	Demand (KVA) revenue				Total Demand Revenue	Total Revenue
					Std.	Off-Peak	Part Peak	On-Peak		
Rate 10	LV	<100 -	1,083,669,454	4,514,594,493					-	5,598,263,947
Rate 10	LV	>100 -	1,654,747,919	11,024,542,293					-	12,679,290,213
Rate 20	LV	-	693,511,619	10,672,506,900					-	11,366,018,519
Rate 40	LV - Std	-	132,935,155	3,622,676,533	3,883,146,311				3,883,146,311	7,638,757,999
Rate 40	LV - TOU	-	9,622,435	636,194,936		24,458,307	246,495,331	248,379,668	519,333,306	1,165,150,677
Rate 50	MV - Std	-	10,026,739	2,183,454,954	1,783,388,334				1,783,388,334	3,976,870,027
Rate 50	MV - TOU	-	1,859,798	497,474,420		21,798,554	199,517,853	213,345,219	434,661,626	933,995,844
Rate 60	LV	-	12,846,449	1,653,882,477					-	1,666,728,926
TOTAL			3,599,219,569	34,805,327,007	5,666,534,645	46,256,861	446,013,185	461,724,887	6,620,529,577	45,025,076,153

Using Table 1-7 as the basis, the Non-fuel Energy, Customer Charge and Demand revenues would be computed as follows:

Component of Revenue	Target Value
Non Fuel Rev Target for Energy	$34,805,327,007
Non Fuel Rev Target for Customer Charges	$3,599,219,569
Non Fuel Rev Target for Demand	$6,620,529,577

$TUVol_{2016}$ can then be determined substituting the values determined above.

Table 1-8: Computation of Volumetric Adjustment

Volumetric Adjustment ($TUVol_{2016}$)			
Line	**Description**	**Formula**	**Value**
	Energy Surcharge		
L1	kWh $Target_{2016}$		2,972,549,058
L2	kWh $Sold_{2016}$		3,083,667,744
L3	Revenue Target for Energy		34,805,327,007
L4	kWh Surcharge	(L1-L2)/L1*L3	(1,301,079,347)
	Demand Surcharge		
L5	kVA $Target_{2016}$		5,194,994
L6	kVA $Sold_{2016}$		5,233,851
L7	Revenue Target for Demand		6,620,529,577
L8	kVA Surcharge	(L5-L6)/L5*L7	(49,519,476)
	Customer Count Surcharge		
L9	#Customer Charges Billed $Target_{2016}$		594,284
L10	#Customer Charges $Billed_{2016}$		623,982
L11	Revenue Target for Customer Charges		3,599,219,569
L12	Customer Charges Surcharge	(L9-L10)/L9*L11	(179,864,379)
L13	**$TUVol_{2016}$**	**L4+L8+L12**	**(1,530,463,202)**

1.2.4 FX and Interest Surcharges

FX losses and interest charges were not included in the revenue requirement that was set by the OUR in the 2014 – 2019 Rate Determination Notice however, Schedule 3, paragraph 31 of the new 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. In the 2016 Annual Tariff Determination Notice, the OUR allowed JPS to recover a provisional sum of J$603,295,228 in the 2016 tariffs – this provisional sum is in effect the target for FX losses/gains. The OUR also included a provisional sum for interest income which will also serve as the target for the interest income. On that basis, the calculation of the FX surcharge net of the interest surcharge is given in the table below.

Table 1-9: Computation of FX and Interest Surcharges

FX and Interest Surcharge for 2016 (SFX_{2016} - SIC_{2016})			
Line	**Description**	**Formula**	**Value**
	FX Surcharge		
L1	TFX		603,295,228
L2	AFX_{2016}		627,883,000
L3	**SFX_{2016}**	**L2-L1**	**24,587,773**
	Interest Surcharge		
L4	Actual net interest expense/(income) in relation to interest charged to customers for 2016		-
L5	Actual Net Late Payment fees for 2016		49,780,000
L6	AIC_{2016}	L4+L5	49,780,000
L7	TIC_{2016}		37,500,000
L8	**SIC_{2016}**	**L6-L7**	**12,280,000**
L9	**SFX_{2016} - SIC_{2016}**	**L3-L8**	**12,307,773**

1.2.5 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 Rate Determination Notice.

1.2.6 System Losses and the Computation of $TULos_{2016}$

The annual non-fuel adjustment formula proposed in the new Electricity Licence incorporates an incentive mechanism for system losses performance. This incentive mechanism is included in the revenue surcharge through TULos. 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 that would be set by the OUR as shown in the following equations.

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

The Licence stipulates that the responsibility factor is to 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 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 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:

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

Taking the above into consideration, JPS has disaggregated its losses for the year 2016 into the three components stipulated in the Licence. While it is straightforward to separate technical from non-technical losses (see Table 1-10), the division of non-technical losses into those totally within JPS' control and those not totally within JPS' control is a more complex evaluation. JPS first determined the losses spectrum by allocating the losses to the various customer classes and then for each rate class, considered the nature and the root cause of the losses and the extent to which the company has control over the different causal factors to determine the proportions that fall into the JNTL and GNTL buckets. Using this approach, Table 1-11 shows the allocation of losses to customer classes, while Figure 1-2 finalises the spectrum by showing JPS' proposal for the disaggregation of system losses into JNTL and GNTL using the methodology that was included in the 2016 Annual Tariff Adjustment Filing.

JPS is proposing that the disaggregation of system losses for the purpose of computing $TULos_{2016}$ be based on the same methodology that was proposed in the 2016 Annual Adjustment Filing as this was the basis on which the OUR established the targets for TL, JNTL and GNTL. In the 2016 Annual Tariff submission, the apportionment of losses to various casual factors or type of loss was based on the distribution of the relative incidence of each factor identified during audits carried out in relation to loss impacting service orders. The Losses Spectrum shown in Figure 1-2 was generated by using the proportions for JNTL and GNTL that was determined by the OUR in its 2016 Annual Tariff Determination Notice except for the Rate 10 Class. JPS' most recent audit data for Rate 10's indicate that the proportions are significantly different from that determined by the OUR and thus, the proportions were determined from Figure 1-3. JPS believes that Open Circuit, Burnt Meter, Short Circuit and Idle Service are factors that are within its control so these, which represents 45% of the losses allocated to Rate 10 were assigned to JNTL.

JPS has, however, recognized some deficiencies in the use of the relative incidence of each factor methodology and is proposing an improved method for the OUR's consideration in setting the targets for the 2017/2018 annual adjustment period. The improved disaggregation method is described in the ensuing section.

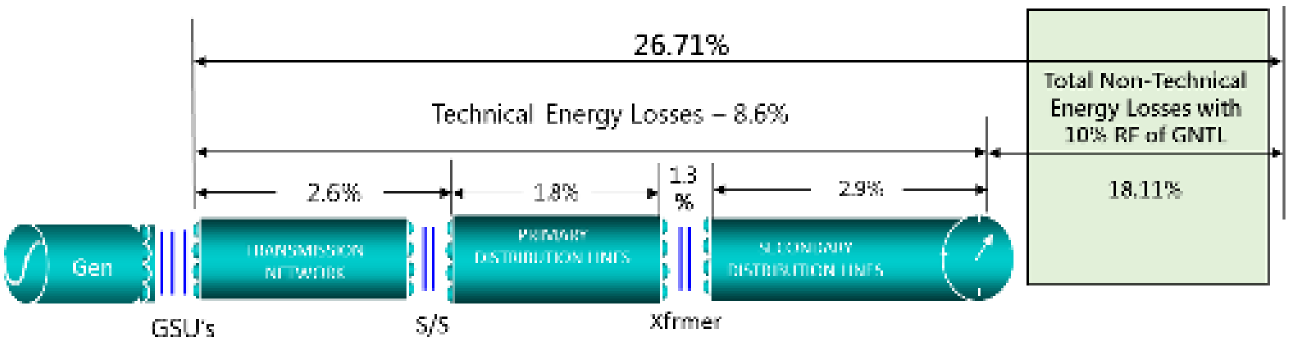
Table 1-10: 2016 System Losses

	MWh	% of Net Generation
System Losses		
Technical Losses	0	8.60%
Non-Technical Losses	786,524	18.11%
Sub-total Losses	**1,160,093**	**26.71%**
Billed Energy	3,183,732	73.29%
Net Generation	**4,343,824**	**100.00%**

Table 1-11: JPS' 2016 Allocation of System Losses

Description	Average Monthly Customers	Billed Energy (MWh)	Energy Loss (MWh)	Energy Loss %
Billed Customers				
Streetlight, Stoplight, Interchange (RT60)	409	96,273	3,917	0.09%
Large Commercial (RT40&50)	1,938	1,410,093	19,511	0.45%
Medium Commercial (RT20)	4,755	350,018	16,450	0.38%
Small Commercial (RT20)	59,196	248,577	11,751	0.27%
Residential (RT10)	556,883	1,078,771	325,075	7.48%
Subtotal	623,181	3,183,732	376,704	8.67%
Internal Losses	N/A	N/A	5,900	0.14%
Illegal Users	180,000	N/A	403,920	9.30%
Grand Total	803,181	3,183,732	1,539,932	35.45%

Figure 1-2: 2016 Losses Spectrum showing Disaggregation in JNTL and GNTL



Description/Category		No. of Customers	Bill Sales (MWh)	Energy Loss (MWh)	% Loss	JNTL	GNTL
Billed Customers	Streetlight/Stoplight/Interchange (460)	408	96,273	3,517	0.09%	0.09%	0.00%
	Large C&I (Rate 40 & 50)	1,938	1,410,093	19,511	0.45%	0.45%	0.00%
	Medium C&I (rate 20)	[illegible]	[illegible]	[illegible]	[illegible]	0.24%	0.14%
	Small C&I (rate 20)	59,196	248,577	11,751	0.27%	0.19%	0.08%
	Residential (rate 10)	556,893	1,078,771	325,075	7.48%	3.38%	4.11%
Sub-Total		623,180	3,183,731	376,704	8.67%	4.34%	4.33%
Unquantified				5,500	0.14%	0.14%	0.00%
Illegal users (non-customers)		180,000		403,920	9.30%	0.00%	9.30%
TOTAL		803,180	3,183,731	786,524	18.11%	4.48%	13.63%

Figure 1-3: Rate 10 Losses Distribution using Relative Frequency Approach

Irregularity	Relative Frequency
Open Circuit	36%
Burnt Meter	7%
By-pass	10%
Line Tap	24%
Tampering	6%
Short Circuit	1%
Throw Up	10%
Idle Service	1%
Inverted Meters	5%
Total	**100.00%**

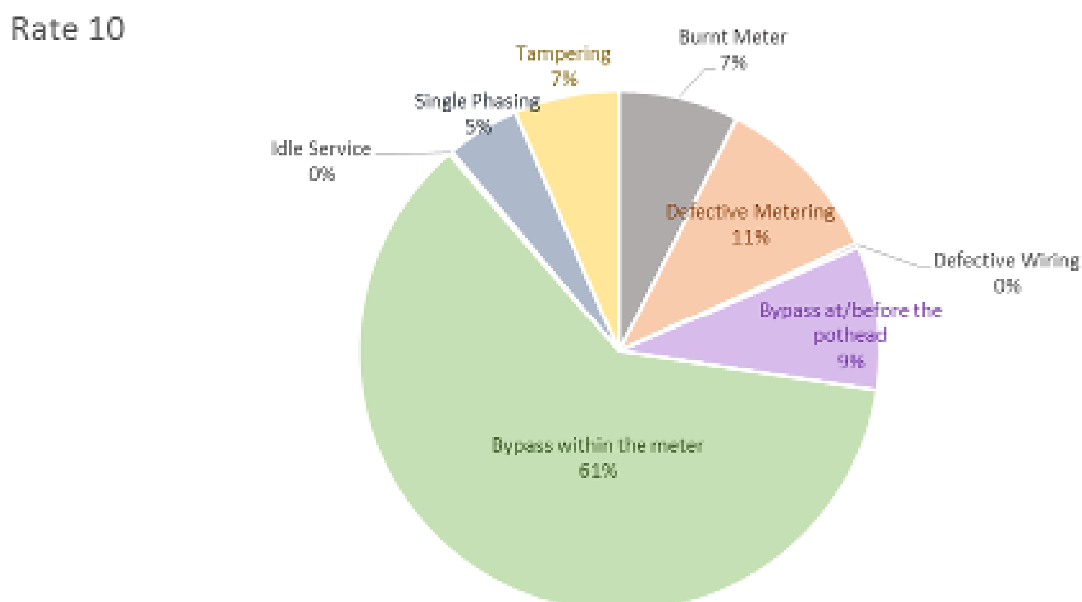
The following section summarizes JPS' proposal for the disaggregation of system losses for the 2017/ 2018 period and also provides the justification for the proposed values of JNTL and GNTL for the period.

1.2.6.1 Justification for System Losses Disaggregation Proposed for 2017/2018 Tariff Period

Rate 10

Approximately 89% of the accounts billed in 2016 were Residential and based on the Losses Spectrum presented in Table 1-11, the contribution of this rate class to system losses was 7.48%. In the 2016 Annual Tariff submission, the apportionment of losses to various casual factors or type of loss was based on the distribution of the relative incidence of each factor identified during audits carried out in relation to loss impacting service orders. In this submission, the findings were based on service orders generated for all customer field work whether they were loss impacting or not. This reduces the degree of bias in the analysis since the audits were more randomly generated. The average energy loss sustained for each mode of loss is also considered. The figure below shows the energy distribution.

Figure 1-4: 2016 Loss distribution by mode of loss for Rate 10



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 as illustrated in the Table below:

Mode of Loss	Relative Incidence	Average Recovery	Weight	Percentage
Burnt Meter	3.72%	2,918	108	7.43%
Defective Metering	20.69%	756	156	10.72%

Defective Wiring	0.77%	543	4	0.29%
Bypass at/before Pothead	9.73%	1,345	131	8.97%
Bypass within the meter	49.97%	1,789	894	61.29%
Idle Service	0.51%	623	3	0.22%
Single Phasing	12.10%	551	67	4.57%
Tampering	2.52%	3,779	95	6.52%

Figure 1-4 shows that 77% of the losses in this rate class is due casual factors emanating from unauthorized customer actions to illegally abstract or otherwise directly under register consumption — through bypasses and tampering. This is equivalent to the energy consumed by 130,000 average residential households. Over 400,000 service orders were completed in 2016 including orders for connections, disconnections and meter changes. Approximately 64,000 or 16% of these service orders were audits performed specifically to detect losses. These audits were conducted on 55,112 premises or approximately 10% of the Rate 10 customer base and detected loss impacting irregularities at approximately 6,900 service points. JPS recovered 6.3 GWh of energy based on these audits. Despite the significant effort JPS expends each year in conducting audits, the large majority of customers in this rate class goes unaudited each year. This is to a large extent the result of the size of the customer base; resources involved in conducting audits, which require thorough physical inspection of the premise and metering facilities; low penetration of AMI infrastructure; and also the consumption of audit resources by repeat offenders, which accounted for about 15% of our audits.

Additionally, although audits continue to be an important tool in detecting losses, they confer limited visibility into this rate class as the premise is only effectively monitored for the duration of the audit. This limits the amount of recovery. The data supports this as we recovered only 2% of the losses attributed to this rate class in the 2016 loss spectrum:

Table 1-12: Recovery rate for residential rate class

	RT10
Recoveries	6.3 GWh
Losses Attributed to class	325.1 GWh
Recovery Rate	2%

JPS continues to increase its efforts to address losses in this rate class. Notably, the Smart Grid AMI initiative is a huge investment in detection infrastructure. Approximately 937 Smart Total Meters and 20,000 Smart Revenue Meters were installed in 2016 affecting just under 4% of the Rate 10 customer base. The SMART Grid AMI initiative will provide real-time and near constant monitoring in the areas in which it is deployed. Currently, most of our visibility into this class is through audits which are guided by tips, history of loss incidences and billing analysis. Despite

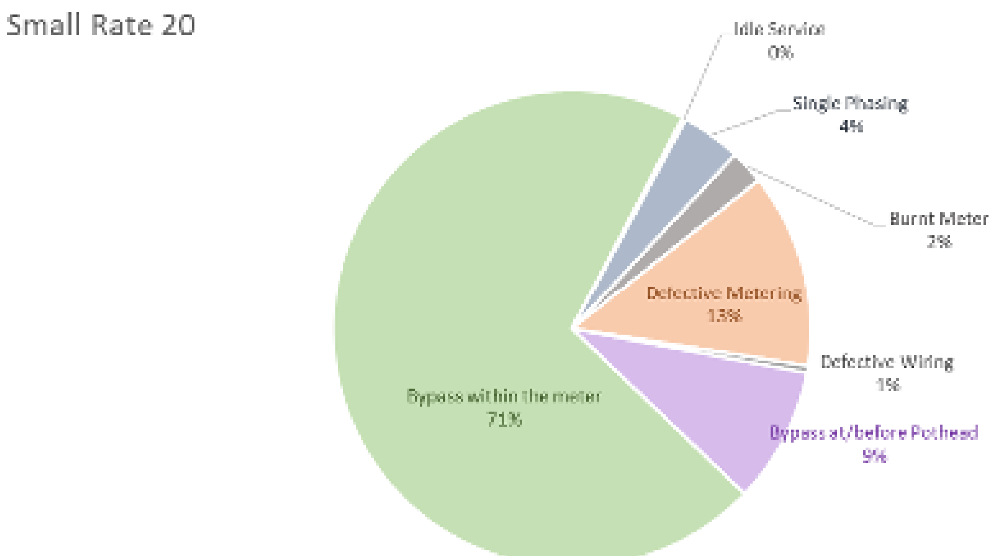
JPS' efforts to monitor and recover from the rate class, the size of the customer base represents a big challenge. JPS plans to continue our rollout of 100,000 AMI type revenue meters over the next 5 years. JPS also acquired an analytical tool to complement the Smart Grid AMI devices. The tool promises to bring advanced analytics capabilities, one of which is the transformer energy balance. In this solution, the system sums the energy delivered to customers on a transformer and compares this with the energy delivered by the transformer in intervals as small as 15 minutes. This increases the confidence and granularity of JPS' losses detection capability. The connectivity mapping of the SMART Grid AMI revenue meters to total meters is essential to this and the mapping of the 20,000 revenue meters installed in 2016 is scheduled to be finished in mid Q2 2017.

This methodology established customer culpability for 77% of the losses sustained from this rate class which occurs despite the significant effort that we are making to detect and prevented losses for Rate 10 customers. Consequently, GNTL and JNTL proposed for this class are 5.76% and 1.72% respectively.

<u>Small Rate 20</u>

Rate 20 accounts that consume less than 3 MWh monthly are further classified as small Rate 20 accounts. Based on the Losses Spectrum in Table 1-11, 0.27% as system losses was due to the small rate 20 class, which is accounted for by approximately 59,000 premises. The energy loss distribution for this rate class is shown in Figure 1-5:

Figure 1-5: 2016 Loss distribution by mode for small Rate 20



The proportions in Figure 1-5 above are based on weights derived from the product of the relative incident rate and the average recovery from audits for each mode of loss as illustrated in the table below:

Table 1-13: Loss distribution data for Small Rate 20

Mode of Loss	Relative Incidence	Average Recovery	Weight	Percentage
Burnt Meter	6.34%	564	36	2.33%
Defective Metering	21.04%	966	203	13.22%
Defective Wiring	0.56%	1,328	7	0.48%
Bypass at/before Pothead	10.37%	1,359	141	9.17%
Bypass within the meter	51.17%	2,118	1,084	70.52%
Idle Service	0.45%	846	4	0.25%
Single Phasing	8.39%	739	62	4.03%
Tampering	1.68%	N/A	N/A	N/A

The data above came from analysis of over 80,000 service orders that were conducted on the small Rate 20 accounts. Of these, 9,556 or 12% were audits for loss oriented service orders performed on 8,092 premises, which represents 14% of the customer base. These audits revealed 901 premises with irregularities with the large majority due to bypasses. JPS recovered 1.3 GWh from these activities. Like the residential rate class, 15% of the audits were performed on premises that were audited at least once previously during the year. This is in response to the recurring anomalies in some accounts indicative of repeat offenders, and theft techniques that are elaborate and difficult to detect.

JPS' ability to recover from this rate class is better when compared with the residential rate class but not significantly. There is still a significant challenge in maintaining visibility into the rate class due to low AMI penetration. Audits remain the most effective tool in detecting losses for these accounts. JPS recovered 11% of the losses allocated to this class as shown in Table 1-14:

Table 1-14: Recovery rate for small rate 20

	Small RT20
Recoveries	1.3 GWh
Losses Attributed to class	11.8 GWh
Recovery Rate	11%

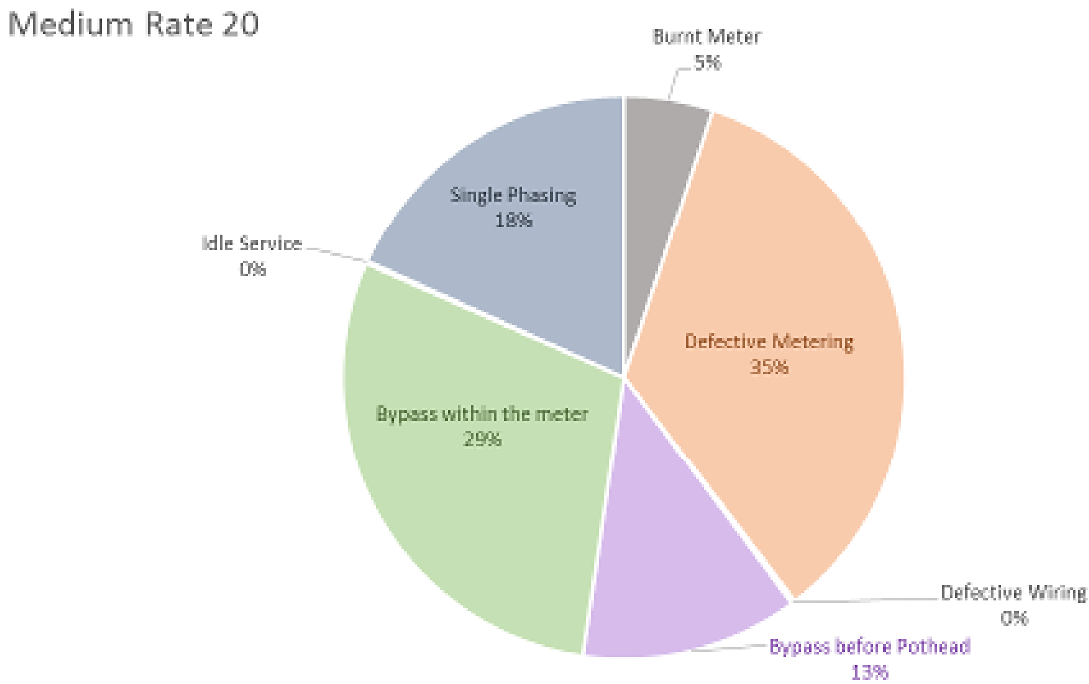
The Smart Grid AMI and Analytical initiatives described previously, is the primary initiative to assist JPS in augmenting its ability to monitor this rate class. With the ability to monitor consumption in 15 minute intervals, detect events indicative of losses and the advanced analytical capabilities being deployed over a period of 5 years to prioritized areas, JPS believes that we will significantly improve our visibility and losses recovery rate within the rate class.

The data shows that 80% of the losses for this group of customers was directly due to customer actions to illegally abstract or otherwise directly under register consumption.

Medium Rate 20

There were 4,755 accounts in the medium Rate 20 category. These are services that consume more than 3 MWh of energy per month. Based on the 2016 Loss Spectrum, the losses due to this category was 0.38% or 16.5 GWh. This is an average loss of 3.5 MWh per account. The figure below shows the distribution of losses by mode:

Figure 1-6: Loss distribution by mode of loss for medium Rate 20



The proportions in Figure 1-6 are based on weights derived from the product of the relative incident rate and the average recovery for each mode of loss as illustrated in the table below:

Table 1-15: Loss distribution data for medium Rate 20

Mode of Loss	Relative Incidence	Average Recovery	Weight	Percentage
Burnt Meter	19.19%	3,084	592	5.12%
Defective Metering	38.38%	10,397	3,991	34.52%
Defective Wiring	0.40%	6,225	25	0.22%
Bypass at/before Pothead	4.04%	35,743	1,444	12.49%
Bypass within the meter	26.87%	12,592	3,383	29.26%

Idle Service	0.40%	4,154	17	0.15%
Single Phasing	10.10%	20,893	2,110	18.25%
Tampering	0.61%	N/A	N/A	N/A

JPS conducted 8,830 service orders on 2,645 medium Rate 20 premises. Audits carried out for loss targeted service orders amounted to 855 or 10% of the total service orders. These audits were performed on 687 services, which represents 14% of the number of accounts in this category of customers.

There are just over 3,000 AMI meters installed giving an AMI penetration of over 60%. Though these AMI meters aid JPS' ability to monitor this group, a significant portion of the losses are sustained from bypasses, which these meters are not equipped to detect. JPS recovered 1.3 GWh from our activities in 2016 as summarized in the table below:

Table 1-16: Recovery rate for medium Rate 20

	Medium RT20
Recoveries	1.3 GWh
Losses Attributed to class	16.5 GWh
Recovery Rate	10%

JPS has been making investments in advanced analytics especially with the planned acquisition of a Business Intelligence (BI) tool that will help us to detect losses via consumption pattern analysis.

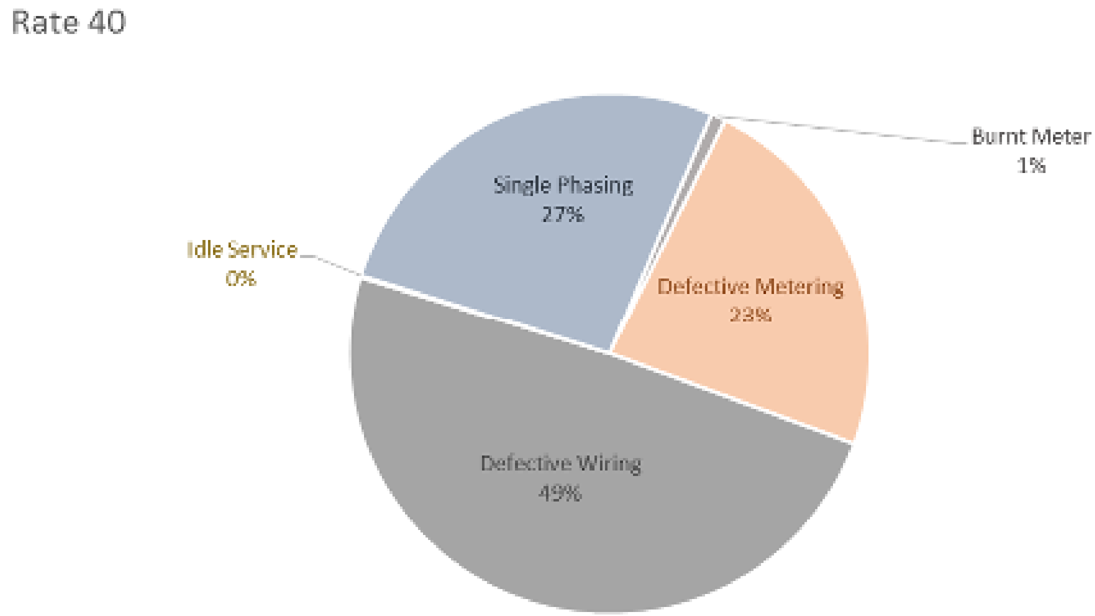
The data shows that 42% of the losses in this category is due to varying kinds of bypass. AMI meters have little ability to detect these types of losses and our visibility into this rate class suffers as a result, however, with the total meter mapping project and the acquisition of the BI tool, detection rates should improve. JPS continues to invest in improving our audit capabilities for this category and also to improve our analytical ability, which will help to guide the audits.

Until then, losses incurred through meter bypassing, must be allocated to customers as it represents a clear intent of the customer to defraud. Consequently, since 42% of losses is due to bypassing of the meter, JPS is proposing that JNTL for this group should be 58% of the losses sustained while GNTL should be 42%.

<u>Rate 40 and 50</u>

Based on the losses spectrum, these rate classes contributed 0.45% to system losses. The loss distribution is based on the data from regular audits and adjustments performed on these accounts.

Figure 1-7: Loss distribution by mode of loss for Rate 40



The proportions in Figure 1-7 above and Figure 1-8 below, are derived from weights, which are the product of the relative incident rate and the average recovery for each mode of loss as seen in Table 1-17 and Table 1-18.

Table 1-17: Loss distribution data for medium Rate 40

Mode of Loss	Relative Incidence	Average Recovery	Weight	Percentage
Burnt Meter	4.27%	13,070	558	0.94%
Defective Metering	51.22%	27,151	13,907	23.32%
Defective Wiring	21.34%	137,353	29,313	49.15%
Bypass at/before Pothead	0.61%	N/A	N/A	N/A
Bypass within the meter	1.83%	N/A	N/A	N/A
Idle Service	0.61%	11,818	72	0.12%
Single Phasing	19.51%	80,955	15,796	26.48%
Tampering	0.61%	N/A	N/A	N/A

Figure 1-8: Loss distribution by mode of loss for Rate 50

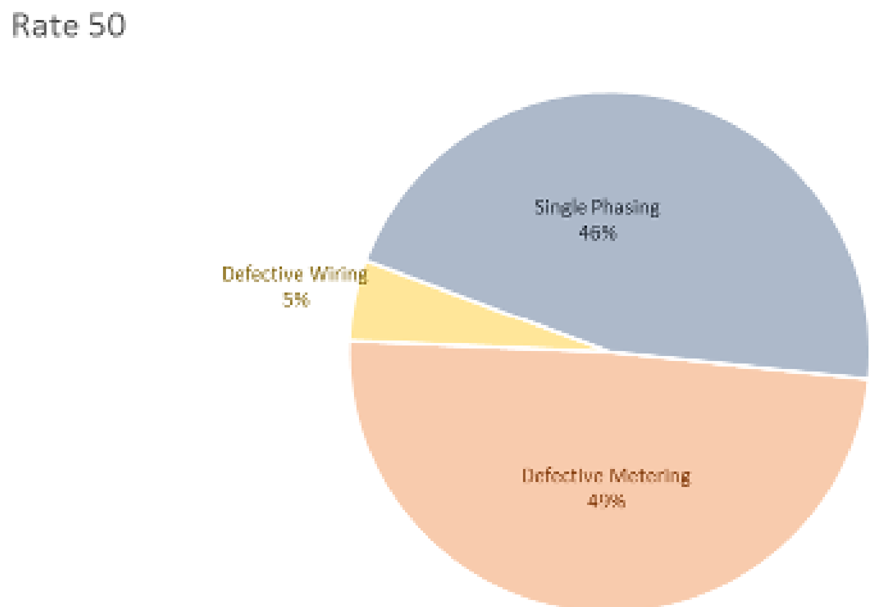


Table 1-18: Loss distribution data for medium rate 50

Mode of Loss	Relative Incidence	Average Recovery	Weight	Percentage
Burnt Meter	0.00%	0	0	0.00%
Defective Metering	27.27%	588,853	160,596	49.00%
Defective Wiring	45.45%	36,639	16,654	5.08%
Bypass at/before Pothead	9.09%	N/A	N/A	N/A
Bypass within the meter	0.00%	2,058	N/A	N/A
Idle Service	N/A	N/A	N/A	N/A
Single Phasing	18.18%	827,564	150,466	45.91%
Tampering	N/A	N/A	N/A	N/A

Our Large Commercial customers represented 44% of our billed energy sales in 2016 though they represent only 1,938 accounts. A single incident of loss from any of these customers could have significant impact on system losses therefore, the company employs several strategies to increase our visibility of these accounts.

The accounts have full AMI Meter coverage and JPS performs audits on every rate 40 and 50 customer at least once a year. These audits aid the detection of deteriorations in the metering facilities that arise from environmental factors like corrosion. Data from the AMI meters and audit history is analysed to help detect defects in metering and wiring as quickly as possible as these are the most significant modes of loss for 2016. The BI tool will expand our analytical capabilities. The primary goal of JPS' losses effort for these rate classes is to identify, correct and recover from loss events as quickly as possible given the potential for significant losses due to the high usage patterns of these customers.

Based on data in Figure 1-7 and Table 1-18 for 2016, the energy loss is primarily due to meter defects and single phasing. During 2016, there is little evidence to suggest that the losses are due to the customer interfering with JPS energy meter and consequently JPS allocates 100% of these losses to that within JPS' control (JNTL). The information presented for Rate 40 and 50 customers is based on the annual audit which represents a single point in time snapshot of irregularities so while no evidence was found of customer theft, there is still the possibility that this may have occurred. The analytical tool will give JPS improved capabilities to identify and detect incidence of theft on a more continuous basis.

Rate 60

JPS' position on losses related to this rate class has not changed since the 2016 Annual Tariff submission 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 are 9,150 streetlights that are currently 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 additional funds may be unfair. JPS is also concerned about the growing arrears for streetlight service which peaked with the GOJ having approximately 20 months usage outstanding. These concerns have resulted in numerous meetings between JPS and the GOJ in an attempt to resolve the issues JPS has continued to work with the Ministry of Local Government to resolve the matter, and we are confident that we will come to an agreement with the MLG on the billing of all operational street lights by July 2016.*

In this regard, JPS takes full responsibility of 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.

Internal Losses

The internal losses represent our 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 due to Illegal Users (Non-customers)

With regards to illegal users, JPS' argument remains the same as it was in the 2016 Annual Tariff Filing. No new information is yet available to aid JPS to revisit its position on the responsibility factor that should be assigned to the Company for this category of system losses. For completeness, the arguments presented in last year's annual filing will be repeated to reiterate our firm belief that the responsibility factor should be set at 10% which we are once again proposing for the targets in the 2017/2018 tariff period.

Data from the 2011 Census conducted by STATIN and when compared to the number of customers billed through JPS' Customer Information System indicate that over 200,000 households may be connected illegally to JPS' grid. We recognize that a segment of the population resides in tenement housing facilities and therefore we cannot say definitively, without further information, that all 200,000 households are illegally connected. Our conservative assessment indicates that there are approximately 180,000 illegal consumers.

The Community Renewal Programme (CRP) aims to increase customer on-boarding and retention through the provision of energy solutions to high-need, socially vulnerable communities which will contribute to the reduction of Non-Technical Losses. The model integrates technical solutions with social initiatives through strategic partnerships. JPS recognises the importance of partnership in addressing the socio-economic challenges in the targeted communities.

A study conducted by consultants to JPS, Quantum, in 2013 benchmarked non-technical energy loss or electricity theft between 2004 and 2011, for several electric utilities in countries with socio-economic conditions similar to Jamaica with the objective of determining whether there is a strong relationship between non-technical losses (NTL) and the social conditions of the population living in the study areas. The countries included in the study were: Jamaica, Brazil, Dominican Republic, Argentina, Guatemala, Bolivia and El Salvador. In total 53 distribution utilities were included. The socio-economic conditions included in the study were:

- Demographic characteristics, violence, education, income inequality, infrastructure, labour informality, poverty rate, market characteristics (% of residential customers) of the electric utility and electricity price.
- The model considered the NTL to low voltage index, poverty index, the average residential rate, GDP per capita index and the violence index (murder rate per 100,000).

The study clearly demonstrated a very strong correlation between electricity theft and the socio-economic and political conditions existing within the study areas. The report made the following conclusions:

- 90% of the variability in the NTL is explained by socio-economic variables.
- NTL depend positively on the poverty level, on the payment capabilities of the population and the degree of violence present in the environment.
- For each 1% increase in the proportion of the population that lives in conditions of poverty, the NTL level increases by 0.63%.
- The result confirms the importance of the social dimension on the performance of the electric utilities. This task requires social intervention and cannot be performed by JPS

alone, but requires the joint efforts of the Regulator, GOJ, customers and other stakeholders.

A breakdown of the energy losses island wide can be seen in Figure 1-9 below. The figure highlights energy losses in parishes with a high population density of inner city and squatter settlements.

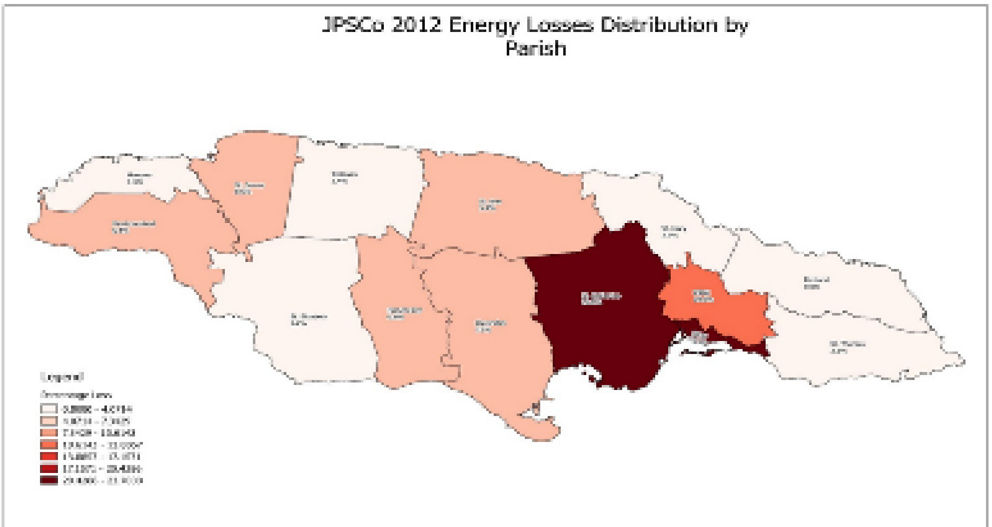


Figure 1-9: JPS Energy Loss Distribution

The Jamaica Social Investment Fund (JSIF) carried out a baseline survey between 2009 and 2011 that shows evidence of the socio-economic factors in the model associated with inner city communities. The survey was conducted in over 40 communities across the island. The baseline survey showed the following:

- Income levels in inner city areas are low and range between JM$6,000 to JM$20,000 per month.
- The areas are underdeveloped and lacks access to basic infrastructure such as roads, drainage and piped water. There is a lack of proper disposal systems such as garbage collection and sewage lines.
- Poverty levels are generally high, above the national average of 16.9% (ESSJ, 2009).
- High crime levels with the presence of gang warfare is present in these communities.

Given that many of the illegal users are associated with inner city communities and squatter areas, and that 89.9% of the non-technical losses are due to socio-economic conditions that are out of JPS control, the responsibility factor should be set to 10%

1.2.6.2 Proposed Losses Target for 2017/2018 Tariff Period

Using the discussion in the previous Section of this document as the basis, JPS is proposing that the disaggregation of System Losses for the 2017/2018 tariff period should be based on the following spectrum:

Table 1-19: Losses Spectrum to be used as the basis for setting targets for the 2017/2018 Regulatory Period

Description	Customers	Billed Energy (MWh)	Energy Loss (MWh)	Energy Loss %	JNTL %	GNTL %
Billed Customers						
Streetlight, Stoplight, Interchange (RT60)	409	96,273	3,917	0.09%	0.09%	0.00%
Large Commercial (RT40 & 50)	1,938	1,410,093	19,511	0.45%	0.45%	0.00%
Medium Commercial (RT20)	4,755	350,018	16,450	0.38%	0.27%	0.11%
Small Commercial (RT20)	59,196	248,577	11,751	0.27%	0.05%	0.22%
Residential (RT10)	556,883	1,078,771	325,075	7.48%	1.72%	5.76%
Subtotal	**623,181**	**3,183,732**	**376,704**	**8.67%**	**2.58%**	**6.09%**
Internal Losses	N/A	N/A	5,900	0.14%	0.14%	0.00%
Illegal Consumers	180,000	N/A	403,920	9.30%	0.00%	9.30%
Grand Total	**803,181**	**3,183,732**	**1,539,932**	**35.45%**	**2.72%**	**15.39%**

To summarize, the spectrum was derived by allocating losses to JNTL and GNTL as follows:

Category	JNTL %	GNTL %
Streetlight, Stoplight, Interchange (RT60)	100%	0%
Large Commercial (RT40&50)	100%	0%
Medium Commercial (RT20)	58%	42%
Small Commercial (RT20)	20%	80%
Residential (RT10)	23%	77%
Internal Inefficiencies	100%	0%
Illegal Consumers	0%	100%

JPS is proposing that for the 2017/2018 period, the targets be set as follows:

- TL = 8.4%
- JNTL = 2.5%
- GNTL = 14%
- RF = 10%

1.2.6.3 $TULos_{2016}$

In its 2016 Annual Tariff Submission, JPS used the following nomenclature:

Target System Loss "a" Rate%y-1 = TL = Technical Losses
Target System Loss "b" Rate%y-1 = JNTL
JNTL = Portion of Non-technical losses which is completely within JPS' control

Target System Loss "c" Rate%y-1 = GNTL
GNTL = Portion of Non-technical losses which is not completely within JPS' control

JPS' procedure for computing TULos2016 is to disaggregate its losses for the year 2016 into the three components stipulated in the License using similar procedures to that outlined in its 2016 Annual Tariff Filing where JPS considered the nature and the root cause of the losses and the extent that it control certain types of system losses. The OUR established the 2016 targets for TL, GNTL, JNTL and RF in its 2016 Annual Tariff Adjustment determination and we applied those targets in computing Ya_{y-1}, Yb_{y-1}, Yc_{y-1} and consequently $Y_{y-1.}$

JPS' position is that the ART_{y-1} value for the computation of $TULos_{2016}$ should be one half the revenue target that was set for 2016, that is, between July 2016 and December 2016, as the company incurred a losses penalty between January 2016 and June 2016 under the incentive mechanism that operated under the price cap regime in which the losses penalty was applied to fuel cost. Thus, we are proposing that TULos be computed by the following formula.

$$TULos_{y-1} = \frac{1}{2} Y_{y-1} * ART_{y-1}$$

Using the Losses Spectrum shown in Figure 1-2, the computation of $TULos_{2016}$ is shown in Table 1-20 below:

Table 1-20: Computation of $TULos_{2016}$

Revenue Surcharge for 2015 ($RS_{2015} = TUVol_{2015} + TULos_{2015}$)			
Line	**Description**	**Formula**	**Value**
	Losses Surcharge		
L14	Actual TL_{2016}		8.60%
L15	Target TL_{2016}		8.20%
L16	Ya_{2016}	(L15-L14)	-0.40%
L17	Actual $JNTL_{2016}$		4.48%
L18	Target $JNTL_{2016}$		3.50%
L19	Yb_{2016}	(L18-L17)	-0.98%
L20	Actual $GNTL_{2016}$		13.63%
L21	Target $GNTL_{2016}$		9.80%
L22	RF		20.00%
L23	Yc_{2016}	(L21-L20)*L22	-0.7660%
L24	Y_{2016}	L16+L19+L23	-2.15%
L25	ART_{2016}		45,025,076,153
L25	**$TULos_{2015}$**	**0.5*L24*L25**	**(483,119,067)**

1.2.7 The 2017 Revenue Target (ART_{2017})

The application of the computed values of RC_{2017}, $RS_{2016} = TUVol_{2016} + TULos_{2016}$, SFX_{2016} and SIC_{2016} to the annual adjustment formula:

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

results in a revenue requirement of J$49,856,384,730 an increase of 6.42% over the actual 2016 revenue.

1.3 Proposed 2017 Tariff Basket

An annual adjustment factor of 6.42% will be applied to the actual 2016 revenue. The approved tariff basket for 2016, shown in Table 1-21 below, is derived using the product of the 2015 billing determinants and the approved non-fuel tariffs arising from the OUR's 2016 Annual Tariff Adjustment Determination Notice. The actual revenue for 2016 is derived from the 2016 billing determinants and the approved non-fuel tariffs (see Table 1-22).

Table 1-21: 2016 Approved Non-Fuel Tariff Basket

	Block/ Rate Option		12 Months 2011 Customer Revenue	Energy Revenue	Demand (KVA) revenue				Total Demand Revenue	Total Revenue
					Std.	Off-Peak	Part Peak	On-Peak		
Rate 10	LV	<100 -	1,083,669,454	4,514,594,493					-	5,598,263,947
Rate 10	LV	>100 -	1,654,747,919	11,024,542,293					-	12,679,290,213
Rate 20	LV	-	693,511,619	10,672,506,900					-	11,366,018,519
Rate 40	LV - Std	-	132,935,155	3,622,676,533	3,883,146,311				3,883,146,311	7,638,757,999
Rate 40	LV - TOU	-	9,622,435	636,194,936		24,458,307	246,495,331	248,379,668	519,333,306	1,165,150,677
Rate 50	MV - Std	-	10,026,739	2,183,454,954	1,783,388,334				1,783,388,334	3,976,870,027
Rate 50	MV - TOU	-	1,859,798	497,474,420		21,798,554	199,517,853	213,345,219	434,661,626	933,995,844
Rate 60	LV	-	12,846,449	1,653,882,477					-	1,666,728,926
TOTAL			3,599,219,569	34,805,327,007	5,666,534,645	46,256,861	446,013,185	461,724,887	6,620,529,577	45,025,076,153

Table 1-22: Actual 2016 Revenues

	Block/ Rate Option		12 Months 2011 Customer Revenue	Energy Revenue	Demand (KVA) revenue				Total Demand Revenue	Total Revenue
					Std.	Off-Peak	Part Peak	On-Peak		
Rate 10	LV	<100 -	1,111,313,583	4,767,199,582					-	5,878,513,165
Rate 10	LV	>100 -	1,761,219,804	11,876,154,274					-	13,637,374,078
Rate 20	LV	-	734,817,486	10,981,035,454					-	11,715,852,940
Rate 40	LV - Std	-	134,794,954	3,649,417,376	3,852,860,257				3,852,860,257	7,637,072,587
Rate 40	LV - TOU	-	9,541,574	653,980,100		24,338,099	246,130,412	249,123,120	519,591,631	1,183,113,306
Rate 50	MV - Std	-	10,431,043	2,294,728,970	1,931,569,388				1,931,569,388	4,236,729,401
Rate 50	MV - TOU	-	1,859,798	478,168,228		21,700,946	198,300,983	183,169,444	403,171,373	883,199,399
Rate 60	LV	-	14,118,052	1,662,706,908					-	1,676,824,960
TOTAL			3,778,096,295	36,363,390,892	5,784,429,645	46,039,045	444,431,394	432,292,564	6,707,192,649	46,848,679,836

Table 1-23: 2016 Billing Determinants[3]

Class		Block/ Rate Option	Average 2016 Customer	Energy kWh Std.	Demand-KVA Std.	Demand-KVA Off-Peak	Demand-KVA Part Peak	Demand-KVA On-Peak
Rate 10	LV	<100	215,717	522,146,723	-	-	-	-
Rate 10	LV	>100	341,870	558,614,971	-	-	-	-
Rate 20	LV		64,025	623,568,169	-	-	-	-
Rate 40	LV - STD		1,667	664,739,048	2,239,150	-	-	-
Rate 40	LV - TOU		118	119,122,058	-	335,420	325,092	256,987
Rate 50	MV -STD		129	433,786,195	1,253,037	-	-	-
Rate 50	MV -TOU		23	90,390,969	-	315,696	295,632	212,837
Rate 60	STREETLIGHTS		433	71,299,610	-	-	-	-
TOTAL			623,982	3,083,667,744	3,492,187	651,116	620,724	469,824

Table 1-24: Approved Non-Fuel Tariffs for 2016

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	429.31	9.13				
Rate 10	LV	>100	429.31	21.26				
Rate 20	LV		956.4	17.61				
Rate 40	LV - Std		6,738.40	5.49	1,720.68			
Rate 40	LV - TOU		6,738.40	5.49		72.56	757.11	969.40
Rate 50	MV - Std		6,738.40	5.29	1,541.51			
Rate 50	MV - TOU		6,738.40	5.29		68.74	670.77	860.61
Rate 60	LV		2,717.10	23.32				

The weights of each tariff, relative to the 2016/2017 actual revenues shown in Table 1-22 are shown in Table 1-25 below.

[3] The energy data corresponds exactly to the earnings sheet value for Rate 20 and 60 Customers. For Rate 10, 40 and 50 the data is derived from CIS data obtained between October 2015 and January 2016. Since the CIS system is an open item system, there were minor variances from the earning sheet total in the order of 0.1%. Customer count was determined using the best available method for counting billed customers.

Table 1-25: Non-Fuel Weights for 2016 Actual Revenues

Class		Block/ Rate Option	Customer Charge	Energy-J$/kWh	Demand-J$/KVA				Total
					Std.	Off-Peak	Part Peak	On-Peak	
Rate 10	LV	<100	2.37%	10.18%	0.00%	0.00%	0.00%	0.00%	12.55%
Rate 10	LV	>100	3.76%	25.35%	0.00%	0.00%	0.00%	0.00%	29.11%
Rate 20	LV		1.57%	23.44%	0.00%	0.00%	0.00%	0.00%	25.01%
Rate 40	LV - Std		0.29%	7.79%	8.22%	0.00%	0.00%	0.00%	16.30%
Rate 40	LV - TOU		0.02%	1.40%	0.00%	0.05%	0.53%	0.53%	2.53%
Rate 50	MV - Std		0.02%	4.90%	4.12%	0.00%	0.00%	0.00%	9.04%
Rate 50	MV - TOU		0.00%	1.02%	0.00%	0.05%	0.42%	0.39%	1.89%
Rate 60	LV		0.03%	3.55%	0.00%	0.00%	0.00%	0.00%	3.58%
TOTAL			8.06%	77.62%	12.35%	0.10%	0.95%	0.92%	100.0%

1.3.1 Proposal for a Wholesale Rate to Improve Economic Competitiveness

The introduction of LNG into the Jamaican market has been a major game changer for the industry as many of our larger customers are now seriously contemplating self-generating using gas as the fuel of choice. JPS' analysis indicates that the best alternative option (BAO) is at a cost which is lower than the grid cost for our larger customers and there is a real possibility of significant grid defection. The impact of grid defection by the larger customers would be significant for other rate classes in that it could cause a significant increase in tariffs and it is because of this that JPS is proposing, the introduction of a new rate class for customers whose peak demand at a single location is at or above 2MVA.

JPS' analysis indicates that the best alternative self-generation option for several of our large industrial customers is at a cost of US$0.1683/kWh. JPS' must be able to offer electricity at a cost which is competitive with the BAO for large industrial customers to ensure that the cost of electricity does not rise too significantly for smaller customers. A steep rise in the cost of electricity for some customers could adversely impact economic growth and development especially on the small and medium enterprise sector which is a major growth engine for Jamaica. The proposed "wholesale" rate (Rate 70) will also allow large customers to improve their international competitiveness by helping to reduce the cost of production thereby driving economic growth. The Amended OUR Act of 2015 advises the OUR in Subsection 4 to take the following into consideration when setting rates:

(i) the interest of consumers in respect of matters, including the cost, safety and quality of the services;
(ii) Jamaica's economic development
(iii) the best use of indigenous resources
(iv) the possibility of including specific tariffs to encourage the regularization of the payment for electricity usage by consumers who are unable to pay for the full cost of the services provided
(v) the possibility of including specific tariffs for special economic zones, wholesale rates for large consumers, to enhance their competitiveness and Jamaica's economic development;

JPS believes that conditions (i), (ii) and (v) are applicable in this circumstance and there are sufficient grounds for the OUR to approve the introduction of the proposed rate class.

The revenue requirement for the proposed Rate 70 was set to ensure that the non-fuel rate for the average customer in this class is less than US3c/kWh so that the total cost of electricity for the average customer in the class will be no more than $0.165c/kWh (assuming March 2017 fuel rates). The revenue requirement for all other rate classes is determined by the difference between the 2017 revenue target and the Rate 70 revenue requirement.

The billing determinants for the proposed Rate 70 class were determined from the billing data of accounts with peak demand at or above 2MVA. These included both Rate 40 and Rate 50 standard and TOU customers. The billing determinants for the remaining Rate 40 and 50 customers is adjusted to account for the removal of the billing determinants for the proposed Rate 70 Customers. The billing determinant given in Table 1-23 can therefore be restated in the Table below which separates the billing determinant of the proposed Rate 70 customers from the Rate 40 and Rate 50 buckets.

Table 1-26: Billing Determinant with proposed Rate 70 Separated

Class		Block/ Rate Option	Average 2016 Customer	Energy kWh Std.	Demand-KVA Std.	Demand-KVA Off-Peak	Demand-KVA Part Peak	Demand-KVA On-Peak
Rate 10	LV	<100	215,717	522,146,723	-	-	-	-
Rate 10	LV	>100	341,870	558,614,971	-	-	-	-
Rate 20	LV		64,025	623,568,169	-	-	-	-
Rate 40	LV - STD		1,663	661,052,032	2,220,365	-	-	-
Rate 40	LV - TOU		117	114,887,570	-	314,816	304,817	241,975
Rate 50	MV -STD		109	182,528,823	560,146	-	-	-
Rate 50	MV -TOU		19	47,274,641	-	171,029	153,913	119,012
Rate 70	MV -STD		24	254,944,388	711,676			
Rate 70	MV -TOU		5	47,350,816		165,271	161,994	108,837
Rate 60	STREETLIGHTS		433	71,299,610	-	-	-	-
TOTAL			623,982	3,083,667,744	3,492,187	651,116	620,724	469,824

The separation of the proposed Rate 70 revenue requirement from the Rate 40 and Rate 50 revenue requirement is shown in Table 1-27. The weights of each tariff, relative to the 2016/2017 actual revenues shown in Table 1-26 are shown in Table 1-28.

Table 1-27: 2016 Actual Revenues showing Separation of Proposed Rate 70 Revenue Requirement

	Block/ Rate Option		12 Months 2016 Customer Revenue	Energy Revenue	Demand (KVA) revenue				Total Demand Revenue	Total Revenue
					Std.	Off-Peak	Part Peak	On-Peak		
Rate 10	LV	<100 -	1,111,313,583	4,767,199,582					-	5,878,513,165
Rate 10	LV	>100 -	1,761,219,804	11,876,154,274					-	13,637,374,078
Rate 20	LV	-	734,817,486	10,981,035,454					-	11,715,852,940
Rate 40	LV - Std	-	134,471,510	3,629,175,655	3,820,537,077				3,820,537,077	7,584,184,243
Rate 40	LV - TOU	-	9,460,714	630,732,761		22,843,073	230,779,855	234,570,487	488,193,415	1,128,386,890
Rate 50	MV - Std	-	8,813,827	965,577,473	863,470,534				863,470,534	1,837,861,834
Rate 50	MV - TOU	-	1,536,355	250,082,851		11,756,543	103,240,435	102,422,521	217,419,500	469,038,706
Rate 70	MV -STD	-	1,940,659	1,349,393,218	1,100,422,034				1,100,422,034	2,451,755,911
Rate 70	MV -TOU	-	404,304	251,332,717		11,439,429	110,411,104	95,299,555	217,150,089	468,887,109
Rate 60	LV	-	14,118,052	1,662,706,908					-	1,676,824,960
TOTAL			3,778,096,295	36,363,390,892	5,784,429,645	46,039,045	444,431,394	432,292,564	6,707,192,649	46,848,679,836

Table 1-28: Non-Fuel Weights for Actual 2016/2017 Tariff Basket – Proposed Rate 70 shown explicitly

Class		Block/ Rate Option	Customer Charge	Energy- J$/kWh	Demand-J$/KVA				Total
					Std.	Off-Peak	Part Peak	On-Peak	
Rate 10	LV	<100	2.37%	10.18%	0.00%	0.00%	0.00%	0.00%	12.55%
Rate 10	LV	>100	3.76%	25.35%	0.00%	0.00%	0.00%	0.00%	29.11%
Rate 20	LV		1.57%	23.44%	0.00%	0.00%	0.00%	0.00%	25.01%
Rate 40	LV - Std		0.29%	7.75%	8.16%	0.00%	0.00%	0.00%	16.19%
Rate 40	LV - TOU		0.02%	1.35%	0.00%	0.05%	0.49%	0.50%	2.41%
Rate 50	MV - Std		0.02%	2.06%	1.84%	0.00%	0.00%	0.00%	3.92%
Rate 50	MV - TOU		0.00%	0.53%	0.00%	0.03%	0.22%	0.22%	1.00%
Rate 70	MV -STD		0.00%	2.88%	2.35%	0.00%	0.00%	0.00%	5.23%
Rate 70	MV -TOU		0.00%	0.54%	0.00%	0.02%	0.24%	0.20%	1.00%
Rate 60	LV		0.03%	3.55%	0.00%	0.00%	0.00%	0.00%	3.58%
TOTAL			8.06%	77.62%	12.35%	0.10%	0.95%	0.92%	100.0%

Table 1-29 below shows how JPS proposes to apply the 2016 revenue adjustment factor of 6.42% to the individual non-fuel revenue components in the adjusted 2016 approved tariff basket with the Rate 70 class separated from the Rate 40 and Rate 50 customer class.

Proof that the weighted adjustment factor proposed by JPS is equal to 6.42% is shown in Table 1-30 below.

Table 1-29: Proposed Annual Non-Fuel Revenue Adjustment per tariff

Class		Block/Rate Option	Customer Charge	Energy-J$/kWh	Demand-J$/KVA			
					Std.	Off-Peak	Part Peak	On-Peak
Rate 10	LV	--100	14.426%	9.874%				
Rate 10	LV	> 100	14.426%	9.874%				
Rate 20	LV		14.426%	9.890%				
Rate 40A	LV							
Rate 40	LV - Std		14.426%	9.390%	9.951%			
Rate 40	LV - TOU		14.426%	9.390%		9.951%	9.951%	9.951%
Rate 50	MV - Std		14.426%	8.933%	9.951%			
Rate 50	MV - TOU		14.426%	8.933%		9.951%	9.951%	9.951%
Rate 70	MV -STD		14.426%	-40.039%	-60.000%			
Rate 70	MV -TOU		14.426%	-40.039%		-60.000%	-60.000%	-60.000%
Rate 60	LV		14.426%	7.207%				

Table 1-30: Weighted Non-Fuel Adjustment

Class		Block/Rate Option	Customer Charge	Energy-J$/kWh	Demand-J$/KVA				
					Std.	Off-Peak	Part Peak	On-Peak	
Weighted increase									TOTAL
Rate 10	LV	--100	0.34%	1.00%	0.00%	0.00%	0.00%	0.00%	1.35%
Rate 10	LV	> 100	0.54%	2.50%	0.00%	0.00%	0.00%	0.00%	3.05%
Rate 20	LV		0.23%	2.32%	0.00%	0.00%	0.00%	0.00%	2.54%
Rate 40A	LV		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 40	LV - Std		0.04%	0.73%	0.81%	0.00%	0.00%	0.00%	1.58%
Rate 40	LV - TOU		0.00%	0.13%	0.00%	0.00%	0.05%	0.05%	0.23%
Rate 50	MV - Std		0.00%	0.18%	0.18%	0.00%	0.00%	0.00%	0.37%
Rate 50	MV - TOU		0.00%	0.05%	0.00%	0.00%	0.02%	0.02%	0.09%
Rate 70	MV -STD		0.00%	-1.15%	-1.41%	0.00%	0.00%	0.00%	-2.56%
Rate 70	MV -TOU		0.00%	-0.21%	0.00%	-0.01%	-0.14%	-0.12%	-0.49%
Rate 60	LV		0.00%	0.26%	0.00%	0.00%	0.00%	0.00%	0.26%
TOTAL			1.16%	5.80%	-0.41%	-0.01%	-0.07%	-0.05%	6.42%

The proposed revenue and the corresponding proposed rates for 2017/2018 arising from the application of the annual adjustment formula are given in Table 1-31 and Table 1-32 respectively.

Table 1-31: Proposed Revenues for 2017/2018

Class		Block/ Rate Option	Customer Charge	Energy-J$/kWh	Demand-J$/KVA				Total Revenue
					Std.	Off-Peak	Part Peak	On-Peak	
Rate 10	LV	--100	1,271,631,693	5,237,891,161	-	-	-	-	- 6,509,522,853
Rate 10	LV	> 100	2,015,293,392	13,048,751,666	-	-	-	-	15,064,045,058
Rate 20	LV		840,822,264	12,067,099,276	-	-	-	-	12,907,921,540
Rate 40A	LV		-	-	-	-	-	-	-
Rate 40	LV - Std		153,870,372	3,969,963,187	4,200,731,111	-	-	-	8,324,564,671
Rate 40	LV - TOU		10,825,516	689,959,947	-	25,116,261	253,745,507	257,913,357	1,237,560,588
Rate 50	MV - Std		10,085,310	1,051,828,040	949,397,287	-	-	-	2,011,310,637
Rate 50	MV - TOU		1,757,990	272,421,595	-	12,926,475	113,514,225	112,614,919	513,235,204
Rate 70	MV -STD		2,220,619	809,116,278	440,168,814	-	-	-	1,251,505,711
Rate 70	MV -TOU		462,629	150,702,842	-	4,575,772	44,164,442	38,119,822	238,025,506
Rate 60	LV		16,154,722	1,782,538,241	-	-	-	-	
TOTAL			4,323,124,506	39,080,272,232	5,590,297,212	42,618,508	411,424,174	408,648,098	49,856,384,730

Table 1-32: Proposed 2017/2018 Tariff

Class		Block/ Rate Option	Customer Charge	Energy-J$/kWh	Demand-J$/KVA			
					Std.	Off-Peak	Part Peak	On-Peak
Rate 10	LV	–100	491.24	10.03	-	-	-	-
Rate 10	LV	> 100	491.24	23.36	-	-	-	-
Rate 20	LV		1,094.39	19.35	-	-	-	-
Rate 40A	LV		-	-	-	-	-	-
Rate 40	LV - Std		7,710.48	6.01	1,891.91	-	-	-
Rate 40	LV - TOU		7,710.48	6.01	-	79.78	832.45	1,065.87
Rate 50	MV - Std		7,710.48	5.76	1,694.91	-	-	-
Rate 50	MV - TOU		7,710.48	5.76	-	75.58	737.52	946.25
Rate 70	MV -STD		7,710.48	3.17	618.50	-	-	-
Rate 70	MV -TOU		7,710.48	3.18	-	27.69	272.63	350.25
Rate 60	LV		3,109.07	25.00	-	-	-	-

It should be noted that the tariff proposed in
Table 1-32 using the same level of precision as shown in the table generates a revenue requirement of J$49, 856, 822,473, which is J$437,743 in excess of the computed revenue target. This is shown in Table 1-33.

Table 1-33: Revenue Requirement Generated with Tariffs as shown in Table 1-32

	Block/ Rate Option		12 Months 2016 Customer Revenue	Energy Revenue	Demand (KVA) revenue				Total Demand Revenue	Total Revenue
					Std.	Off-Peak	Part Peak	On-Peak		
Rate 10	LV	<100 -	1,271,625,829	5,237,131,633					-	6,508,757,462
Rate 10	LV	>100 -	2,015,284,099	13,049,245,712					-	15,064,529,811
Rate 20	LV	-	840,819,837	12,066,044,068					-	12,906,863,905
Rate 40	LV - Std	-	153,870,339	3,972,922,712	4,200,730,119				4,200,730,119	8,327,523,170
Rate 40	LV - TOU	-	10,825,514	690,474,298		25,116,047	253,744,753	257,913,808	536,774,608	1,238,074,420
Rate 50	MV - Std	-	10,085,308	1,051,366,019	949,396,918				949,396,918	2,010,848,245
Rate 50	MV - TOU	-	1,757,989	272,301,932		12,926,383	113,514,149	112,614,670	239,055,201	513,115,123
Rate 70	MV -STD	-	2,220,618	808,173,711	440,171,860				440,171,860	1,250,566,189
Rate 70	MV -TOU	-	462,629	150,575,596		4,576,351	44,164,354	38,120,236	86,860,942	237,899,167
Rate 60	LV	-	16,154,728	1,782,490,253					-	1,798,644,981
TOTAL			4,323,106,890	39,080,725,935	5,590,298,897	42,618,781	411,423,257	408,648,714	6,452,989,649	49,856,822,473

While there is an overall 6.42% increase in the non-fuel revenues compared to 2016 actual, this includes the impact of resetting the Base Exchange rate from J$112: US$1 to J$131.00: US$1. The increase attributable to the resetting of the Base Exchange rate is already reflected in customer bills through the foreign exchange adjustment clause. Accordingly, the incremental impact of the annual revenue adjustment factor is an average increase of 5.01% in non-fuel rates.

In keeping with the OUR's proposal in the 2016 Annual Tariff Adjustment Determination Notice, we are proposing that the EEIF be discontinued. JPS is proposing that the System Benefit Fund described in Electricity Act 2015 be implemented in its place. Given that today, JPS is in a better position to raise funding to implement power delivery infrastructure the need for the EEIF as it was proposed is not as severe as in time past. The challenge that we are facing now is that customers in targeted communities are unable to afford the wiring of their houses. Based on surveys and needs assessments carried out by JPS, the majority of residents stealing electricity earn less than minimum wage or are at minimum wage making it difficult for them to afford house wiring which has an average cost of approximately $70,000. We believe that among its various objectives, the system benefit fund could assist in this addressing this issue. This should improve the effectiveness of the overall program. It is our experience that customers are challenged to find funds to wire their homes.

A detailed analysis of the non-fuel tariff adjustment for 2017/18 and the total bill impact for the typical JPS customer in each rate class has been provided in Appendix IV. This demonstrates that the total bill impact of the proposed tariff increase for the typical JPS residential customer will result in an increase of 1.64%. Additionally, it shows that for commercial customers there will be a range of adjustments from an increase of 0.47% for Rate 50 customers and to an increase of 1.63% for Rate 20 customers. Conversely, Rate 70 Standard Customers previously on Rate 50 would experience a decline of 20.4%.

Section 1.4 discusses some additional requested changes as part of the annual tariff adjustment application. This includes a proposed adjustment to the 2016/2017 approved prepaid rates for Rate 10 and 20 Customers. Proposed post-paid and pre-paid rates for customers enrolled in the community renewal programme will also be presented.

The 2016 performance of system losses and the community renewal program are described in Section 1-6. It also describes the 2017 system losses initiatives and plans for the Community Renewal Programme.

In Part 2, we present our proposal for the OUR's consideration of an Extraordinary Rate Review in the Annual Filing which will allow JPS to recover the returns associated with the current portion of long term debt (CPLTD) for 2016 and 2017 which the amended Licence recognizes as a legitimate cost that JPS should be allowed to recover in the company's revenue requirement. The impact of the inclusion of CPLTD in the revenue requirement will also be presented.

1.4 Pre-paid Rates

1.4.1 Rate 10 Prepaid Rates[4]

In the 2016 Annual Tariff Adjustment Filing, JPS proposed that the structure of the Rate 10 prepaid tariff should be changed to a three tiered one to avoid a potentially significant shortfall in the revenue requirement if a significant number of customers switched to the prepaid tariff. The OUR approved the proposal and consequently, the Rate 10 prepaid rates were changed to a three-tiered structure when the 2016/2017 rate schedule came into effect.

Almost immediately after the implementation of the three-tiered structure, the company faced significant backlash from customers who were previously introduced to the program particularly its existing pre-paid customers. The customers indicated that the tariff structure lacked simplicity and was extremely difficult to understand. The major challenge was that payments for the same amount of electricity could significantly vary throughout the month. The frequency of the complaints led JPS to conduct a focus group discussion with some of the customers. The feedback from the focus group indicated that we must address the issue even if it meant a reversal of our previous proposal to the OUR. JPS is therefore requesting that the OUR consider approving the

[4] Only the accounts of post-paid customers were factored into analysis.

re-introduction of the two-tiered structure in the interim until the 2019 Rate Case Filing when a cost of service study could serve to potentially delink the revenue requirement of the post-paid customers from the pre-paid customers. The Company understands the implication of a shortfall in the revenue requirement but given the small number of pre-paid customers at this time, believes that it is risk that it can manage.

The design of the prepaid tariff is based on the approved post-paid rates. The proposal for the pre-paid tariff assuming the acceptance of JPS' tariff proposal in Section 1.3 is described below.

We are proposing that the non-fuel tariff for Rate 10 prepaid customers should be as follows:

- $16.2917/kWh for the first 119kWh in a 30-day cycle
- $23.3592/kWh for every kWh above 119kWh in a 30-day cycle

Table 1-34: 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	77,560	21,733	23.35	31.07	16.29	56,268,577.82	29,501,613.54	(26,766,964.28)	(321,203,571.36)
50-100 kWh	104,156	96,715	77.38	16.38	16.29	132,016,105.17	131,290,741.95	(725,363.22)	(8,704,358.64)
100-200 kWh	200,835	350,207	145.31	17.57	17.57	512,751,175.74	512,751,175.74	-	-
200-300 kWh	83,182	241,171	241.61	19.88	19.88	399,540,348.04	399,540,348.04	-	-
300-400 kWh	29,266	120,275	342.48	20.90	20.90	209,481,111.31	209,481,111.31	-	-
400-500 kWh	11,979	63,818	443.96	21.46	21.46	114,128,504.19	114,128,504.19	-	-
500- 1000 kWh	13,067	199,976	1,275.32	22.70	22.70	378,286,566.19	378,286,566.19	-	-
>1000 kWh	3,697	87,961	1,982.71	22.94	22.94	168,152,009.28	168,152,009.28	-	-
Total						**1,914,355,820**	**1,913,630,457**	**(27,492,328)**	**(329,907,930)**

1.4.2 Rate 20 Prepaid Rates

As with the design of pre-paid rates for Rate 10 Customers, the pre-paid design for Rate 20 customers is dependent on the approved post-paid tariffs. Assuming the acceptance of JPS' tariff proposal in Table 1-32, the prepaid Rate 20 tariff is descried as follows:

- $128.7895/kWh for the first 10kWh in a 30-day cycle
- $19.3496/kWh for every kWh above 10kWh in a 30-day cycle

The analysis of this proposal is shown in Table 1-35 below. This tariff structure retains revenue neutrality for JPS for the Rate 20 customer class.

Table 1-35: Analysis of JPS Proposed Prepaid Rate 20 Customers

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
10,515	2,690	21.32	70.68	70.68	15,845,028.26	15,845,028.26	-	-
7,582	6,803	74.77	33.99	33.99	19,269,139.70	19,269,139.70	-	-
30,470	127,255	348.03	22.49	22.49	238,494,622.51	238,494,622.51	-	-
9,488	283,849	2,493.05	19.79	19.79	468,113,815.74	468,113,815.74	-	-
1,035	206,590	16,633.66	19.42	19.42	334,331,575.90	334,331,575.90	-	-
					1,060,209,153.85	**1,060,209,153.85**	**-**	**-**

1.5 Community Renewal Rate

The Community Renewal Rate has been in effect since July 2016 when the OUR initially approved the tariff. It has not been implemented however as the eligibility criteria has not yet been approved by the OUR. In the 2016 Annual filing, JPS indicated that its field work showed that PATH was too restrictive as only a limited number of people in the targeted communities were enrolled on the PATH programme. JPS had been working with the PIOJ and other stakeholders to assess the feasibility of implementing a more inclusive set of criteria but was unable to determine one with a reasonable administrative cost. JPS wrote to the OUR November 2016 to request its approval to begin implementing the rates for those person that were enrolled on PATH until the company is able to finalise an expanded eligibility criteria that could be implemented cost effectively.

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. In acknowledgement of this, JPS is proposing that the Community Renewal rate for the 2017/2018 period for both post-paid and pre-paid customers be $10.03/kWh for up to 150kWh of consumption per month. This rate will not attract a customer charge or any other charges as long as consumption remains below 150kWh in a billing cycle.

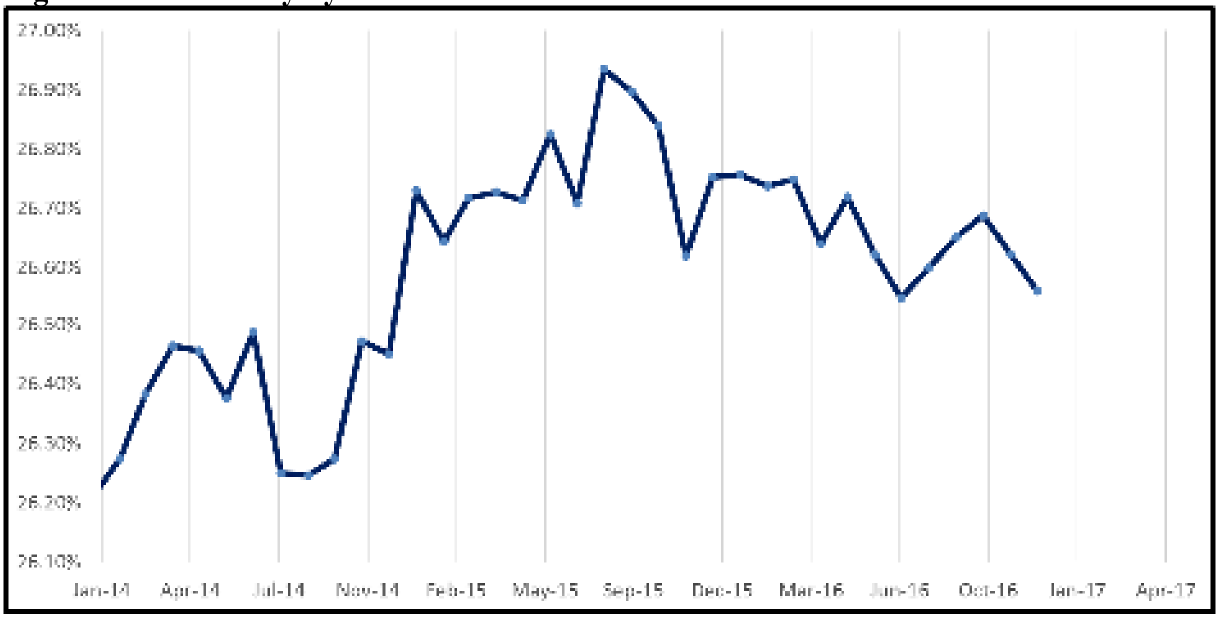
Customers qualifying for this rate who consume more than 150kWh per month will pay the same rate as post-paid or prepaid customers (whichever is applicable), including the customer charge, for the excess consumption.

1.6 Performance and Initiatives for Factors Impacting Non-Fuel Tariffs

1.6.1 System Losses

The 12-month rolling system losses for 2016 was 26.71% compared to 26.98% in 2015. This represents a decline of 0.27 percentage points. Figure 1-10 shows the monthly performance system losses between January 2014 and December 2016. The diagram shows that since July 2015, system losses has generally trended downwards and this is a direct result of the losses strategy that JPS has been employing.

Figure 1-10: Monthly System Losses Performance



1.6.2 2017 Loss Reduction Initiatives

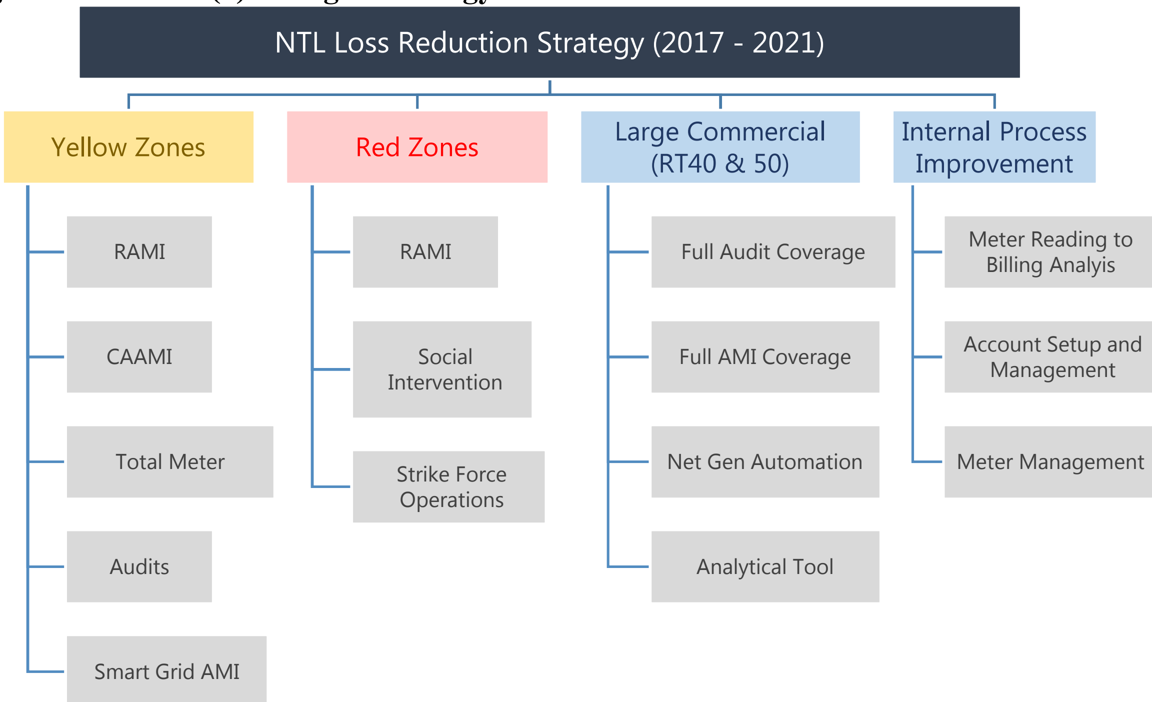
The Strategies to be employed over the 2017/2018 period are broken into two major components: Technical Loss Reduction and Non-Technical Loss Reduction.

Technical Loss Reduction is geared primarily at correcting three (3) major issues: Power Factor Correction, Feeder Phase Balancing and Voltage standardization program. Non-Technical Loss Reduction is more complex due to the multifaceted nature of the issues 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.

Red zones are areas/communities 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 at assisting the community at large. These are described later in the Community Renewal Section.

Yellow zones are classified as areas/communities where the majority of the population can afford electricity but some choose to steal. Illegal abstraction in these communities is in most cases, 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 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.

Figure 1-11: Four (4) Pronged Strategy for Loss Reduction



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 several business processes and is aimed at identifying root causes and developing mitigating activities.

1.6.3 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 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). It should be noted that over the past three decades, JPS has made significant investments in technical loss reduction projects towards achieving its optimal level.

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.

  A total of 78 feeders are at or above 0.95 power factor. 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 where three feeders were targeted and converted to 24kV. 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 are Greenwood Substation 110 feeder (100% completed), Martha Brae Substation feeder 110 and Duncan's Substation 110 feeder (95% and 60% respectively were completed).

  For 2017 the following four feeders are targeted for upgrade:
  1. Hope Substation 510
  2. Roaring River Substations 210, 310 and 410 feeders.

1.6.4 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.

1.6.4.1 Red Zone Communities

Communities that exhibit energy loss in excess of 70% 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 as a result 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 170,000 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.

1.6.4.2 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, 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.

1.6.4.3 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 2016 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 228,647 throw-ups removed, 3,264 idle services removed, 725 arrests, 142 court summons along with 576 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.

1.6.4.4 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 in which there is a majority of customers that have a higher propensity to pay than found 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.

1.6.4.5 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. This project commenced in 2014 with a total installation to date of over 3,233 at transformer locations island-wide measuring energy delivered to approximately 50,000 customers.

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 a total of 933 Transformer Total Meters were installed in the field and these were Aclara Smart meters. The 933 Transformer Total Meters would be associated with 19,000 Revenue Meters to create an energy balance for the transformer circuit. The table below shows the deployment across Jamaica in 2016.

Parish	Total Meters
KSAN	85
KSAS	74
Clarendon	161
St. James	182
St. Mary	63
Portmore	63
Westmoreland	57
St. Catherine	106
St. Ann	142
Total	933

During 2017, a total of 20,000 Revenue Meters are to be installed in 2017 along with a further 1,602 Transformer Total Meters.

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, however, the energy balance algorithm will be implemented in the second quarter of 2017.

1.6.4.6 Smart Grid AMI and Smart Meters

The Smart Grid AMI project, in summary, involves the replacement of existing ANSI type analog 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 19,200 smart meters in eight (8) parishes island-wide. The primary objectives of the project are to identify and reduce losses on the network and to further evolve the company's network into a Smarter Grid that will improve reliability and responsiveness for both utility and customers, provide more data points for grid analysis and stability, prepare the grid for demand response and eventually lead to revenue diversification for JPS. The Smart AMI meters being deployed also has the capability of addressing the needs of pre-paid metering within the system.

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 energy loss progress reports (daily, weekly, monthly).
2. Automating the detection of fraudulent activities by use of meter events and tamper flags.

A total of 100,000 Smart Grid AMI meters are projected to be installed for the period 2017-2021 with 20,000 earmarked for installation in 2017 with an intended impact of 2.81% reduction in losses over the five years.

1.6.4.7 Advanced Automated Theft Detection Analytical Tool (AATDAT)

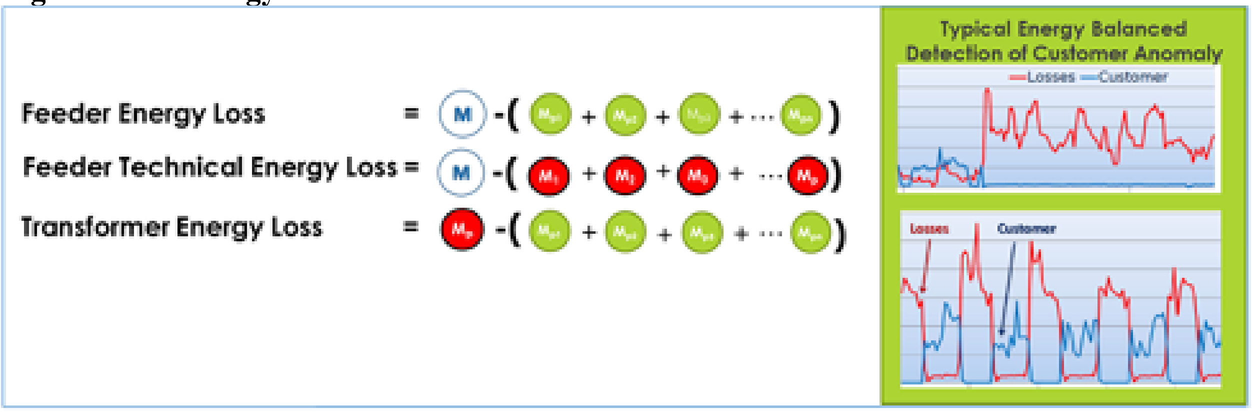
The AATDAT tool is a business intelligence tool designed to utilize metering data from AMI meters and other utility data sources to identify with a high degree of precision, the services or locations of possible theft or loss.

For phase 1 of this implementation, the tool is expected to accurately and reliably identify and report theft among smart metered customers by utilizing load profile interval data matched against similar data from Transformer Total Meters along with events within the meters. Specific use cases will then be developed to zoom in on account which 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 achieve the following:

- The detection of customers' energy loss-impacting irregularities based on correlation of customers' energy usage and transformer energy loss.
- The detection of customers' energy loss-impacting irregularities based on correlation between transformer meter and customer meter interval voltage information.
- The detection of customers' energy loss-impacting irregularities based on correlation between AMI meter event flags and transformer energy loss.
- The detection of a customer's anomaly contributing to less than a 1% change in transformer energy loss.

Figure 1-12: Energy Balance within AATDAT



1.6.4.8 <u>Frontier Metering</u>

Frontier Meters are a category of total meters that are installed at parish boundaries in order to segment and precisely calculate the losses attributed to each parish as feeders cross from one parish into another. This is in order to measure the impact of any loss related activities within each parish boundary. Losses per parish are tracked on a monthly basis and are assessed based on their performance in reducing losses. The impact of Parishes in tackling losses can be better validated once Frontier Meters have been installed.

There are an estimated five (5) metering points to be metered in 2017. Site visits and planning are currently underway to complete this project.

1.6.4.9 <u>Annual Meter/Site Audits (Rate 40, 50 and High Consumption 20s)</u>

As part of JPS' routine operation, 100% of Rate 40 and 50 customers' metering facilities are audited annually. In addition, a further 4,000 rate 20 customers consuming greater than 3MWh per month are now equipped with AMI smart meters. This represents approximately 6,000 customers or 1% of JPS' customer base. This category of customers is referred to as our Priority Industrial and Commercial (PIC) customers and accounts for approximately 50% of sales. JPS continues to perform 100% audit of all 1,973 (as at December 2016) Rate 40 and 50 accounts and plans to audit an additional 4,000 Rate 20 accounts in 2017.

1.6.5 Community Renewal Programme

In 2015, JPS launched a pilot project for the implementation of a community renewal programme in seven communities in Kingston and St Andrew. 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 2016. In 2016, the programme targeted the regularization of 3,675 customers in the following communities:

1. McGregor Gardens
2. Denham Town

6. Whitfield Town
7. Arnette Gardens

11. Goldsmith Villa
12. Naseberry Grove

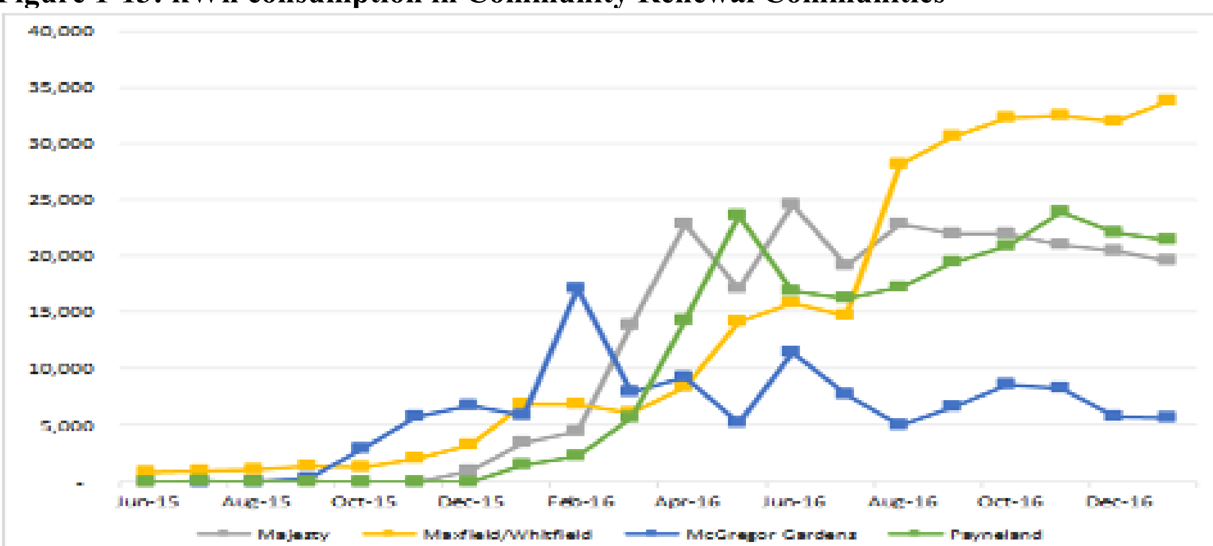
3. Payne Land
4. Majesty Gardens
5. Bayfarm Villa
8. Ellerslie Gardens/ Tawes Meadows
9. Russia Phase 1
10. Granville

JPS intends to develop an effective deployment strategy that would on-board 2,500 customers by the end of 2017. A successful implementation of the project will result in billed sales increasing by approximately 300 MWh for 2017. The ultimate aim of the programme is to convert 27,000 consumers who are currently illegally abstracting electricity to registered customers paying for their consumption on a monthly basis over a 5-year period. We will review the plans as we further develop our five-year business strategy for the Community Renewal Programme.

1.6.5.1 Status of 2016 Initiatives

The programme has had 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 inception in 2015. Figure 1-13 shows the kWh consumption in a sample of these communities. For customers that were on-boarded through the CRP initiative, a total of 835 MWh of billed sales was recorded between June 2015 and January 2017.

Figure 1-13: kWh consumption in Community Renewal Communities



In addition to increased billed sales, the company has collected over J$12.6 million from these customers over a 13-month period, from January 2016 to January 2017.
Figure 1-14 shows revenues collected over a one (1) year period in these communities.

Figure 1-15 shows the losses in those same communities. Losses in Payne Land and Whitfield Town/Maxfield have decreased over the period whilst losses in Majesty Gardens and McGregor Gardens fluctuated over the same period.

Figure 1-14: Collections (J$) in Community Renewal Communities

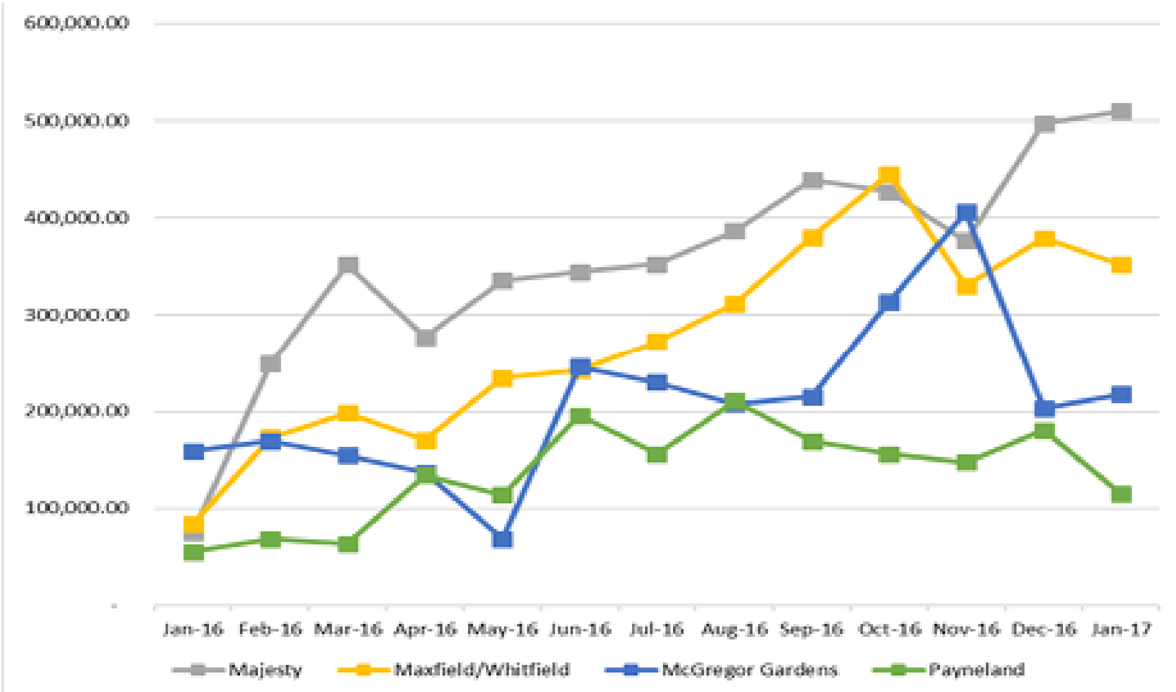
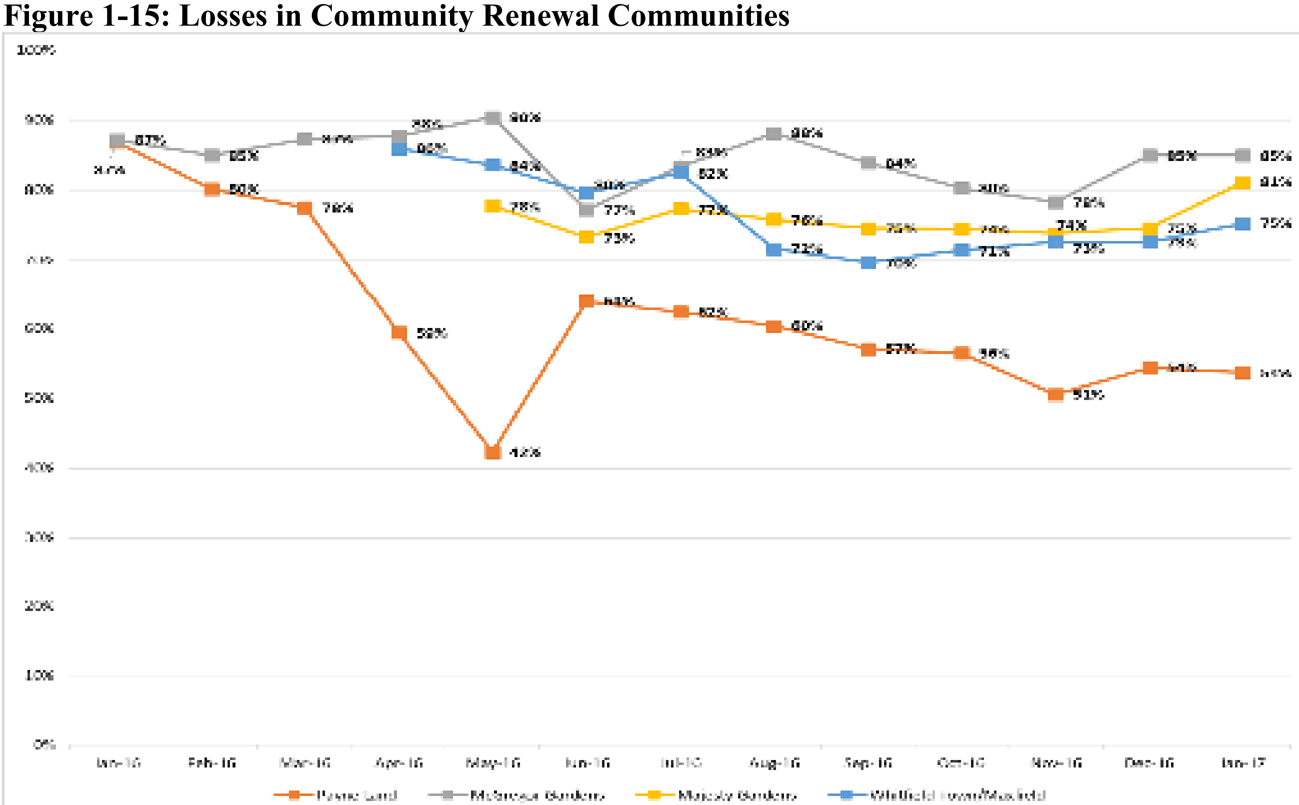


Figure 1-15: Losses in Community Renewal Communities



While the billed sales have increased, the losses are still relatively high which indicates that more social intervention needs to be done. Surveys done in these communities by the World Bank, USAID and JPS indicate that one of the primary reasons for non-payment of bills or refusal to sign up for JPS' Service was the lack of income. High levels of unemployment exist in these communities and until this social issue is addressed, JPS will continue to face challenges with system losses. Based on these lessons learnt, for 2017, the Programme will be focusing on employment oriented initiatives that will provide work experience that give community members an avenue to enter the workforce.

While only 617 of the 3,675 customers targeted were connected in 2016, JPS was able to identify a promising metering solution for these communities through the provision of AMI Prepaid service using Hexing meters. A prepaid solution was selected as it has proven to be best for the targeted communities especially for new customers that are not accustomed to paying a monthly bill. It assists the customer to afford paying for electricity consumed in small increments as cash flow permits. This is in contrast to post-paid where the entire month's bill becomes due at once presenting a challenge for the customer to satisfy the obligation.

In July, the meters were approved to be piloted in the communities beginning in October, however, due to delays on the supplier side the meters were not received until December 2016.

Working in conjunction with JSIF who implemented and also funded some of the house wiring components of the project, a total of 839 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 communities such as McGregor Gardens, Majesty Gardens, Whitfield Town/Maxfield, Goldsmith Villa, Ellerslie Meadows/Tawes Gardens and Russia.

Our experience to date in on-boarding customers has not been without its fair share of challenges and this resulted in delays in our scheduled implementation in several communities. These include:

- Violence encountered in some communities;
- Damage to the Energy Guard Boxes shortly after implementation;
- Bridging of the energy guards;
- Lack of communication of meters in the Quadlogic Meter Boxes from existing projects e.g. Denham Town and Arnett Gardens;
- 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.

1.6.5.2 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 2016 can be seen in Table 1-36 below:

Table 1-36: **List of Social Interventions offered under 2016 Programme**

House Wiring	Recertification	Youth Education & Recreation Programme
Energy Audits	Energy Conservation Sessions	Social Marketing
Community Facilitation	Service Centres	Ready Board
Skills Training	Wellness Fairs	
Light Bulb Swap	Internship Programme	

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.

Wellness Fairs

In 2016, the JPS hosted two (2) Wellness Fairs in the communities of Ellerslie Meadows/ Tawes Gardens and Granville. The objective of the Fairs is to sign up 10% of patrons from each Fair and to improve the Company's image. For 2016, the Wellness Fairs received over 1,000 patrons. A total of 147 persons were signed up for JPS Service and will be connected in 2017.

Capacity Building

JPS through the partnership with JSIF in 2016, enrolled 51 persons from HEART NTA programmes skills training and Internship programmes.

Service Centres and Community Facilitators

In 2016, 10 community facilitators were hired from each of the project areas. The community facilitator's role is to act as a JPS customer service representative in the communities to respond to simple bill queries and advise persons on the offerings under the programme. The facilitators are trained to conduct energy audits and energy management sessions to assist persons in controlling their consumption. In 2017, there will only be seven (7) community facilitators as some project areas will be handed over to the Parish Council.

House Wiring, Recertification and Ready Board

In 2016, the programme offered house wiring and recertification at minimal or no cost to customers. JPS has asked residents to make a contribution as a show of commitment to the programme and to ensure the customers understand and appreciate the value of the service.

In Majesty Gardens, there are some houses that cannot be traditionally wired and as a result JPS has partnered with USAID and UTECH to implement the ready board solution through JSIF. This project began in 2016 with installations of the ready board beginning in November and continuing in 2017 to meet the target of 400 ready board connections.

Energy Conservation Competition

This initiative was developed as an energy conservation initiative to promote energy conservation and efficiency. In 2016, energy conservation sessions were conducted and an energy conservation competition saw communities competing against each other. Feedback on the initiative was solicited through a survey. Residents generally felt that the sessions were useful and they saw reductions in their energy bill. This initiative will be continued in 2017.

Career Expo

In 2016, JPS hosted a Career Expo in Whitfield Community. Over 500 persons were present at the Expo and after completion, a survey was conducted to which respondents noted that the forum was very informative and useful to their professional development.

Best Practice Symposium

JPS in collaboration with PIOJ, NHT, and SDC hosted a Best Practice Symposium on November 30, 2016 at the Knutsford Court Hotel. The focus of the symposium was on best practices that exist in Jamaica for community Renewal in the specific areas of 1) community entry & mobilization, 2) youth development and 3) social enterprise. Over 100 persons attended the Symposium and there was an overall positive review of the event as everyone was pleased with the material shared and the quality of the presentations. The top recommendations from the conference were to involve more community persons and to work with more agencies. Another symposium focusing on determining when a community is ready for intervention and when a community is considered 'renewed' is intended for 2017.

Community Relations Meeting/Community Engagement

There was also on-going dialogue with customers through community outreach meetings across the communities. In addition to community meetings, JPS invested in the creation and implementation of a social marketing campaign which was conducted by JSIF. This campaign is aimed at finding creative ways of influencing customer attitudes towards electricity theft and energy conservation. The social marketing campaign will be launched in 2017.

1.6.5.3 2017 Plans for the Community Renewal Programme

The Community Renewal and Customer Solutions strategies for 2017 aims to on-board up to 2,500 customers with an expected 300MWh recovery. 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 for implementing the program. Several of the communities in the CRP programme 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 being offered and the strong emphasis on social upliftment.

3. JPS Service Centres, operated by our 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.

4. JPS has retained Community Facilitators who 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 energy audits, though forming a part of the general programme offerings, were not conducted in 2016 and as such have been newly introduced to the customers in the project areas for 2017. The community facilitators will also be conducting small group sessions to educate and promote and build relationships.

5. JPS also offers Energy Management and Customer Education. This was also carried over from 2016 and incorporates several new elements for 2017. The programme includes bulb distribution (LED/Fluorescent bulbs exchanged for incandescent bulbs), house wiring and an appliance swap program to be introduced in 2017. The appliance swap program is expected to improve energy management and will be implemented through the energy competition scheduled for 2017. This program has been implemented in other countries with high system losses such as in Brazil. In addition to energy management we will roll out another series of the energy conservation competitions as persons were happy to participate in the 2016 programme as they experienced significant reductions in their energy bills.

6. 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, first deposit paid in instalments.

7. JPS hopes to contribute to the income earning potential of the community members through job creation – "Building Capacity to Pay" will be pursued through the provision of internship programmes and entrepreneurship workshops. Based on our experience in 2016, many communities already have several existing skills training programmes so JPS assisted in placing those trained persons in internship programmes to aid their professional development.

8. In an effort to properly identify where the illegal consumers are located and also to assess and address the specific needs of each community, a validation exercise will be carried out in 2017. 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 versus illegal users. In addition to this, in 2016, JPS began carrying out surveys. Periodically (or state an interval) to access the effectiveness of the programmes.

9. 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, provision of educational scholarships (First Year Secondary Level), establishment of the JPS Academy to facilitate training in the areas of Lineman Training, Non-Governmental Organisation Partnership and Environmental Preservation (clean up drive).

Table 1-37 summarizes the slate of programmes we are planning to implement in 2017.

Table 1-37: **Summary of Proposed plans for 2017:**

Communities		IP	YER	CM	F	WF	BS	ESW	ES	HW	SC	ECS
Handed Over	Denham Town											
	Payne Land			x								x
	Arnett Gardens											
	McGregor Gardens			x								x
	Bayfarm Villa											
Existing	Majesty Gardens			x	x						x	x
	Ellerslie Pen / Tawes Pen	x		x	x			x	x		x	x
	Russia Phase 1	x		x								x
	Whitfield Ave / Maxfield Ave			x					x		x	x
	Goldsmith Villa			x								x
New	Granville	x	x	x	x		x	x				x
	Russia (Phase 2)			x	x		x			x		x
	Red Pond			x	x	x	x			x	x	x
	Rose Town	x	x	x	x		x	x	x	x		x
	Canon Heights		x	x	x	x	x				x	x

Key:

HW- House wiring	ESW- Entrepreneur Workshop	IP-Intern Prog
BS- Bulb Swap	SC-Service Centre	YER – Youth Education & Recreation Programme
F-Facilitator	ES-Employment Seminar	ECS- Enrg Cons Session
WF-Wellness Fair	CM-Community Meetings	

2 Extraordinary Rate Review: Current Portion of Long-term Debt (CPLTD)

As JPS indicated to the OUR in a discussion paper submitted in September 2016, the returns associated with the CPLTD which were excluded from the revenue requirement in the 2014 - 2019 rate review is recognised as a legitimate component of the cost structure of the business in the amended Licence. JPS should be allowed the opportunity of recovering this cost item prospectively as of the application date of the Amended Licence. Given that JPS' revenue target established in the 2016 Annual Tariff Filing was set using the 2014 – 2019 Revenue Requirement (which excluded the CPLTD in the amount of US$37.49M) as the basis, the Company is of the view that an adjustment is now required to the non-fuel rates to correct this exclusion and is requesting that the OUR consider it as an extraordinary rate review request in the 2017 Annual Tariff Adjustment Filing.

The ROI associated with the CPLTD which was excluded from the 2014 – 2019 Revenue Requirement is shown in Table 2-1.

Table 2-1: ROI for Current Portion of Long Term Debt for 2013

Cost of Debt	2016 Net Fixed Assets
Cost of Debt	8.07%
Rate of Return on Equity(ROE)	12.25%
Tax Rate	33.33%
Gearing Ratio (Deemed)	50%
Post-tax WACC	8.81%
Pre-tax WACC	13.22%
	US$'000
Rate Base	**37,492**
Return on Equity	**2,296**
Taxation (Gross Up)	**1,148**
Long Term Interest Expenses	**1,513**
Total	**4,956**

Given that the Licence came into effect in July 2016, JPS is proposing that only half of the ROI associated with the CPLTD for 2016 be recovered by JPS. As this amount should have been included in the 2016 revenue requirement, JPS will convert to Jamaican dollars using the base exchange rate for 2014, inflating it by the 2016 inflation factor and finally adjusting it by the WACC to determine the retroactive amount owing in 2017. It is important to note that the amount recovered in 2016 should also have been adjusted by the efficiency improvement factor between 2014 and 2016, $(1 - X)^2$, as was applied to the 2014 – 2019 revenue requirement to derive the revenue cap (RC). That is, the ROI associated with the CPLTD to be recovered retroactively for 2016 is given by the following:

$$\mathrm{ROI}_{2013}(1-\mathrm{X})^2(1+\mathrm{dI}_{2016})(1+\mathrm{WACC})$$

Where dI_{2016} is the annual escalation factor for 2016 which was 9.53%. This amounts to the recovery of J$336,671,933. The amount to be recovered for 2017 is the equivalent of US$4.96M (expressed in 2014 base year currency) which after conversion to Jamaican dollars should be subjected to the 2017 escalation adjustment factor dI and adjusted for efficiency improvement as follows:

$$\mathrm{ROI}_{2013}(1-\mathrm{X})^3(1+\mathrm{dI})$$

Where dI is the 2017 adjustment factor. The amount to be recovered for 2017 is J$636,757,042. The total amount of recovery for returns associated with CPLTD that JPS is proposing should be recovered is $973,428,975. When added to the revenue requirement for 2016 as reflected in Table 1-31 of Section 1.3.1, JPS is proposing an adjusted value of revenue requirement for 2017 of J$50,829,813,705.

In recovering the cost associated with the CPLTD for 2017, JPS did not utilize the CPLTD for 2016 as the OUR's Extraordinary Review Determination that allowed JPS to recover future cost associated with the fixed assets was not extended to the other aspects of the Rate Base and as such, only costs that would have been applicable at the time of the 2014 – 2019 Rate Determination was considered applicable.

The recovery of costs associated with the CPLTD will result in a further 2.08% increase in revenues for 2017 revenues over 2016 actual revenues. This will result in the Rate 10 bills rising by a further 1.20% compared to the base case without the inclusion of the CPLTD. Similarly, Rate 20, Rate 40 and Rate 50 bills will increase by a further 1.0%, 1.01% and 0.72% respectively.

The proposed revenue basket and tariff are shown in the Appendix. Also shown are the bill impacts for each rate class.

3 Ensuring Quality of Service - The Q-Factor

3.1 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's control, such as those due to disruptions by the independent power producers; natural disasters; and other *Force Majeure* events, as defined under the licence; and
- It should be symmetrical in application, as stipulated in the Licence.

In the 2004 Tariff Review Determination the OUR stipulated that the Q-factor should be based on three quality indices:

- 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.

$$SAIDI = \frac{(\Sigma \text{ Customer interruption durations})}{\text{Total number of customers served}}$$

(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).

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

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

The OUR had previously considered including MAIFI in the Q factor but in its January 7, 2015 Determination Notice stipulated that while MAIFI will not be a part of the Q factor, JPS should commence monthly reporting of MAIFI.

MAIFI measures the average frequency of momentary interruptions per customer over a predefined area. Momentary interruptions are interruptions with duration less than or equal to 5 minutes.

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

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

The OUR has determined that 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.

The OUR further stated, that, 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%

3.2 Adequacy of JPS' OMS Data for Reliability Baseline

In its 2016 Annual Tariff Filing, JPS established that 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. This was in response to the OUR's statement in the 2015 Annual Adjustment

Determination Notice that there were "significant issues with JPS' service quality performance data necessary to establish the Q factor baseline and the incentive scheme".

JPS showed that the quality of reliability is measured on two dimensions, accuracy and completeness. Accuracy refers to the ability of the data to represent the "real world" values that they are expected to model while completeness measures the availability of all the relevant information required to create the model. To a large extent, the GIS data quality has the most significant impact on the quality of the OMS data. In the context of GIS, accuracy refers to how much the GIS model represents the actual system in the field, inclusive of circuitry and customer to transformer connectivity by phase. The completeness on the other hand, indicates the extent to which all the network assets inclusive of switching devices are included in the GIS model.

In the 2016 Filing, JPS showed the status of its OMS data quality as reproduced here in Table 3-1.

Table 3-1: Status of JPS' Data Quality up to May 2016

ITEM	ACCURACY	COMPLETENESS	RANKING WRT UTILITY BEST PRACTICE
FEEDER MAPPING	98%	99%	Better than 90%
TRANSFORMER MAPPING	98%	99%	Better than 90%
TRANSFORMER TO FEEDER MAPPING	98%	99%	Better than 90%
CUSTOMER TO TRANSFORMER MAPPING!	84%	91%	75% - 90%
REPORTING PRACTICE			Best/Good

At that time the accuracy and completeness of the feeder mapping, the transformer mapping and the transformer to feeder mapping was well above the utility best practice. The accuracy of the customer to transformer mapping scored the lowest even though it was still within the range of utility best practice.

As stated previously, achieving high quality OMS data is a life cycle process as the T&D grid undergo daily changes due to operational configuration, growth, and network additions, as well as routine switching for maintenance. This therefore introduces many challenges in achieving a 100% accuracy. JPS is continuing its efforts to improve the quality of the data and with the revision of the GIS Update Policy and the acquisition of ArcFM software, the Company is better equipped to achieve and maintain a very high level of data accuracy and quality.

JPS also noted that contrary to the OUR's position in the 2015 Determination Notice that calibration of the dataset is an indication of poor data, event verification and calibration are generally considered important aspects of the reliability reporting. Outage validation and adjustment are daily processes for JPS. Additionally, data calibration is done when outage characteristics are abnormal. The calibration process is done via a Rules Base Dictionary which is shown in Figure 3-1.

Figure 3-1: Rules 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. daily/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. Where 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 completion/restoration time is automatically adjusted to crew completion time as recorded by mobile tablet.

	RULE	CONDITION	ACTION
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 to 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.

	RULE	CONDITION	ACTION
4	Operator Error	If outage mismanagement results in an outage greater than 50% of actual SAIDI, the outage is made non reportable. Triggers: • 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.

With respect to the 2016 dataset that was submitted with the annual filing, JPS has noted the OUR's concerns regarding errors that were identified in the initially provided dataset. JPS regrets that the OUR was unable to review the re-submitted dataset as it would have clarified that these inaccuracies were not present in the resubmitted dataset. The Company, however, welcomed the OUR's intent to continue discussions with JPS in relation to the Q-Factor and to intensify its monitoring of the periodic reported system outage data with the aim of ensuring that the Q-Factor mechanism can be implemented at the commencement of the next tariff review period. JPS and the OUR has met to clarify issues related to the establishment of the Q Factor baseline and have agreed that JPS will continue improving its data quality with the objective of ensuring that the Q Factor can be established for the 2019 Rate Case filing.

In keeping with the OUR's intent to intensify monitoring of the reliability data, in the next Sections, JPS will highlight its reliability performance and describe the initiatives that it will put in place to continue improving reliability.

3.3 2016 Reliability Performance

Figure 3-2, Figure 3-3 and the data in Table 3-2, highlights JPS 2016 reliability performance. In 2016, JPS attained a 9% and 15% improvement over 2015 in the SAIDI and SAIFI performance indices respectively.

The improvement in reliability performance was the direct result of the strategies and initiatives undertaken during the year.

Figure 3-2: SAIDI Performance in 2016 – (inclusive of Generation, Transmission and Distribution)

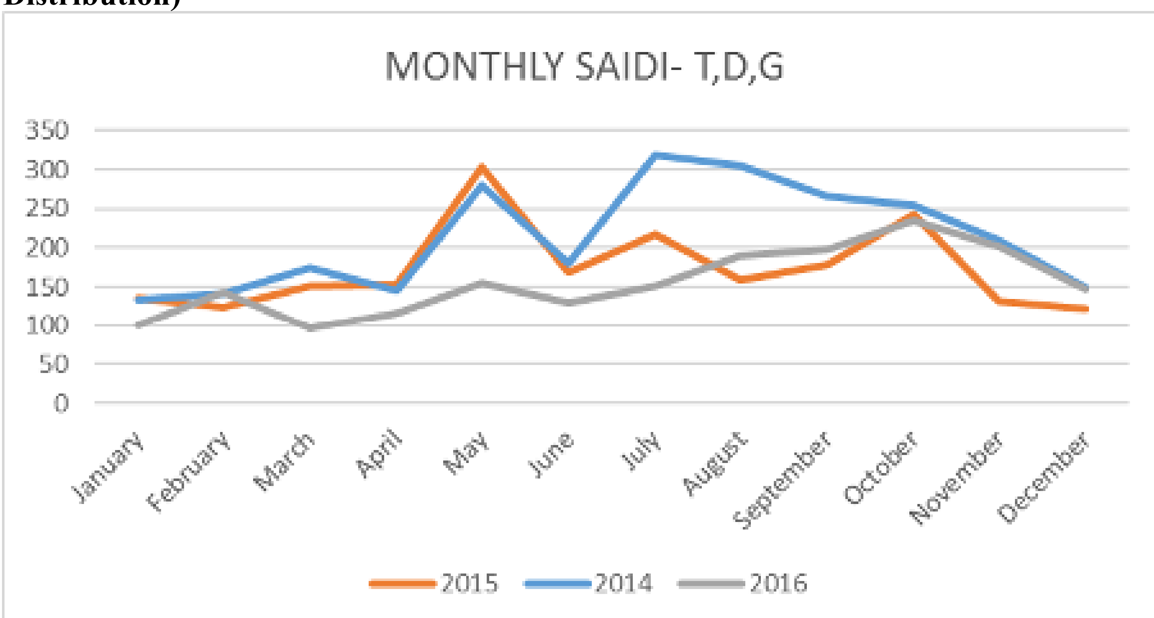


Figure 3-3: SAIFI Performance in 2016 – (inclusive of Generation, Transmission and Distribution)

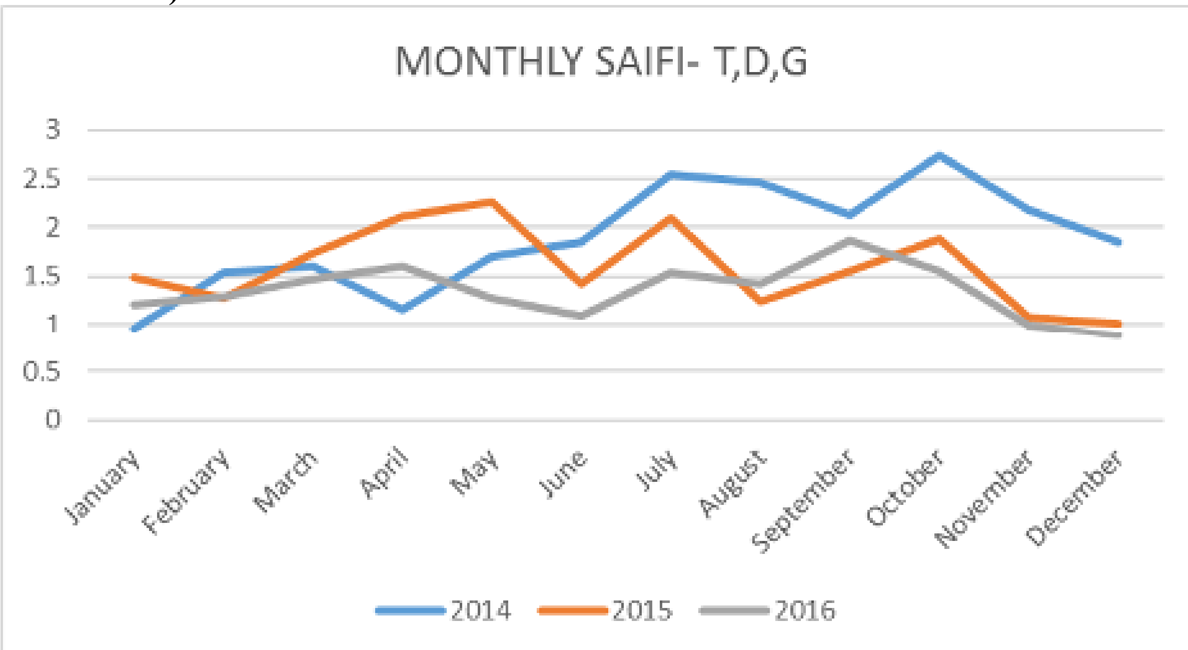


Table 3-2: Summary of Reliability Performance in 2016

Indicators	Unit	Category	Generation	Transmission	Distribution	Force Majeure/Major Event day	Total
SAIDI	Minutes/Customer	Forced	100.945	64.185	1,609.158	218.903	1,993.191
		Planned	0.000	10.143	75.395	1.727	87.266
		Total	100.945	74.328	1,684.554	220.630	2,080.457
SAIFI	Interruptions/Customer	Forced	5.307	0.939	9.408	1.893	17.548
		Planned	0.000	0.089	0.411	0.027	0.528
		Total	5.307	1.029	9.819	1.921	18.075
CAIDI	Minutes/Customer	Forced	19.021	68.324	171.039	115.629	113.588
		Planned	0.000	113.666	183.477	62.957	0.000
		Total	19.021	72.258	171.560	178.586	115.100
MAIFI	Interruptions/Customer	Forced	6.421	0.833	17.681	0.665	25.600
		Planned	0.000	0.647	1.109	0.024	1.780
		Total	6.421	1.480	18.790	0.689	27.381

3.4 2016- 2017 Reliability Performance Improvement Strategy

The 2016 reliability performance improvement strategy continued to pivot around four (4) major initiatives, as follows:

1. Employment of automated grid management approaches through the use of technology on the T&D network;
2. Lifecycle maintenance of outage data quality and processes;

3. Use of traditional methods including vegetation management, lightning mitigation, routine line inspection/maintenance and the application of the appropriate solutions to problem areas; and
4. Entrenching a Reliability Culture within the organization.

3.4.1 Automated Approaches

As part of its plan to develop a smart-self healing grid, JPS is employing various grid technologies to improve T&D System reliability. During 2017, a number of smart initiatives will be implemented on the system, including the following:

- 50 Distribution Automated (DA) Switches
- 45 Smart Fault Circuit Indicators
- 82 Dropout Reclosers (TripsaverII).
- 20,000 Smart Meters

The Distribution Automated Switches were installed to limit faulted sections of a distribution feeder and allow for faster response and restoration of affected circuits at the primary distribution level. These devices are pivotal to our self-healing grid strategy. Since 2014, one hundred and thirty-eight (138) DA Switches have been installed on the network, broken down by year as follows:

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

This automated solution, which remotely monitors the status of the distribution network, also provides power flow information to our system control and dispatch teams enabling them to optimally direct the trouble-shooting and repair crews.

Two Hundred and Eighty (280) Fault Circuit Indicators were installed on the distribution network in 2016, adding to the one hundred and thirty (130) previously installed. These devices enable us to reduce outage troubleshooting time, thereby improving our outage response time.

One hundred and twenty (120) DropOut Reclosers (TripsaverII) were installed on the distribution network in 2016. These were installed on targeted line sections to minimize the number of transient events translating into sustained outages due to fuse blowing.

Twenty Thousand (20,000) Smart Meters were installed in 2016 as part of our roadmap to a smarter grid.

3.4.2 Traditional 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
- Targeted focus on the worst performing circuits areas

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

3.5 2017 Reliability Improvement Plan

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 2016, US$6.7M was invested in these types of projects and JPS has budgeted US$17.3M for investment in similar projects in 2017.

3.5.1 2017 System Reliability Objectives:

Figure 3-4 below, provides an illustration of JPS 2017 initiatives geared towards improving reliability and measurement in 2017. Specifically, our objectives are detailed as follows:

SAIFI:

- Reduction in the number of outages through cost effective approaches
- 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
- Faster outage trouble shooting - Optimize use of Fault Circuit Indicators
- Implementing automatic call-out of crews/trouble-shooters for faster outage restoration
- Increasing crew availability and hours of coverage
- Institutionalizing a culture of “restore before repair”

Figure 3-4: JPS Reliability Initiatives for 2016-2020

3.6 2017 Reliability Baseline

The OUR and JPS have agreed that no baseline should be established for 2017 and thus, we will not be proposing one at this time. Consequently, JPS is proposing that the Q factor be set to 0 for the 2017/2018 tariff period.

4 Overview of Fuel Efficiency Mechanism

4.1 Introduction

Regarding the monthly adjustment to JPS fuel rates, Exhibit 2 of Schedule 3 of the New 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 New 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 New 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 Licence 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.

4.2 JPS' Heat Rate Performance

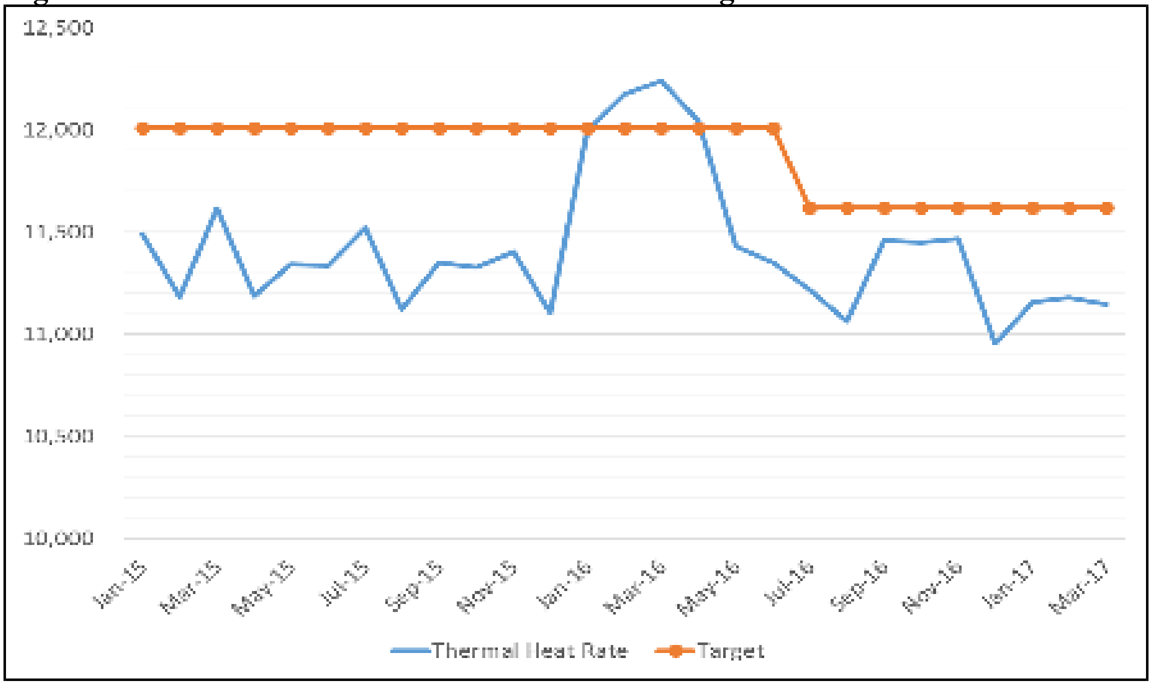
Table 4-1 summarizes JPS' heat rate performance versus target from January 2015 to March 2017.

Table 4-1: JPS Thermal Heat Rate Performance

Month	JPS Thermal Heat Rate (kJ/kWh)	JPS Thermal Heat Rate Target (kJ/kWh)	Variance from Target (kJ/kWh)
Jan-15	11,492	12,010	- 518
Feb-15	11,186	12,010	- 824
Mar-15	11,615	12,010	- 395
Apr-15	11,190	12,010	- 820
May-15	11,343	12,010	- 667
Jun-15	11,335	12,010	- 675
Jul-15	11,523	12,010	- 487
Aug-15	11,124	12,010	- 886
Sep-15	11,351	12,010	- 659
Oct-15	11,327	12,010	- 683
Nov-15	11,403	12,010	- 607
Dec-15	11,107	12,010	- 903
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

The heat rate of JPS' thermal plants deteriorated during the 2016 when compared to the 2015 period. Compared to 2015, the heat rate deteriorated by 238 kJ/kWh or 2.1% in 2016. The major factors contributing to the decline in efficiency were the Combined Cycle Plant Dual Fuel Conversion at the Bogue Power Station, Old Harbour Unit #3 boiler tube leaks, JPPC Complex engine and turbocharger failure and forced outages on other steam turbines at Old Harbour. The Figure 4-1 shows the thermal heat rate performance versus target. In 2016, JPS' thermal heat rate performance was better than target between April and December and the variance of the heat rate from target was much less than it was in 2015.

Figure 4-1: Thermal Heat Rate Performance vs Target



4.3 Heat Rate Forecast for 2017

JPS heat rate forecast for 2017 is based on the assumptions on 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 2017 are outlined in the ensuing.

4.3.1 Model Assumptions

Projected Maximum Capacity Rating (MCR)

- Rockfort's maximum capacity rating is forecasted to remain at 20MW x 2 for the period 2017.
- Hunts Bay's maximum capacity rating will remain at 122.5MW for the period 2017.
- Old Harbour's maximum capacity rating will remain at 193.5MW for the period 2017.
- Bogue's maximum capacity rating is forecasted to remain at 173.5MW for the period 2017.
- JPS Renewables MCR is forecasted at 32.52MW for the period 2017.
- IPP's MCR forecasted at 366MW in 2017, this includes 96MW Wind and 20MW Solar.

Forecasted Capacity Factor

- Rockfort's capacity factor is forecasted to average 88% for 2017. This is inclusive of major maintenance outage on Engine #1.

- Hunts Bay's #B6 capacity factor is forecasted to average 62% for 2017. The capacity factor of Hunts Bay's gas turbines are projected to average 2%, for 2017.
- Old Harbour's capacity factor is forecasted to average 55% for 2017.
- Bogue's capacity factor is forecasted to average 47% for 2017. Capacity factor for the peaking units is <1% for 2017. The Combined Cycle Plant forecasted at 77% capacity factor.
- JPS Hydro Renewables capacity factor forecasted to average 54% for 2017. Capacity factor for Wind farms, Wigton 35% and Munro 2%, Solar Farm 26%.
- IPP's capacity factor forecasted to average 59% for 2017. This is inclusive of major overhaul outage on JPPC Engine #1 for 27 days.
- The overall system capacity factor is forecasted at 55% for 2017.
- The capacity factors of each plant are provided in Table 1-1 at the end of the chapter.

<u>Forecasted Energy Production</u>

- Rockfort's energy production is forecasted at 307GWh for 2017. This is inclusive of major maintenance outage on Engine #1.
- Hunts Bay's #B6 energy production is forecasted at 372GWh for 2017. The energy production forecasted for Hunts Bay's gas turbines projected at 9GWh for 2017.
- Old Harbour's energy production is forecasted at 1,074GWh for 2017.
- Bogue's energy production is forecasted at 806GWh for 2017. Energy production for the peaking units is forecasted at 1GWh for 2017.
- JPS Hydro Renewables energy production is forecasted at 139GWh for 2017. Energy production for Wind farms, Wigton 192GWh and Munro 0.74GWh, Solar Farm 45GWh.
- IPP's energy production forecasted at 1,283GWh for 2017. This is inclusive of major overhaul outage on JPPC Engine #1 for 27 days.
- The overall system demand is forecasted remain flat for 2017 vs 2016, largely in part due to most new customers expected to come from small commercial and residential customers.
- The forecasted energy production of each plant for 2017 are shown in Table 4-4 at the end of the chapter.

4.3.2 System Heat Rate Model Results

HFO #6 Fuel prices for 2017 was modelled at US$45.62/barrel average for JPS Plants. HFO #6 price average for the IPPs US$45.66/barrel was forecasted. For ADO #2 the average for 2017 was forecasted at US$69.97/barrel. 2017 VOM for the IPPs averaged US$15.61/MWh in the model. The merit order top ten units / plant from the above for 2017 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 2017.

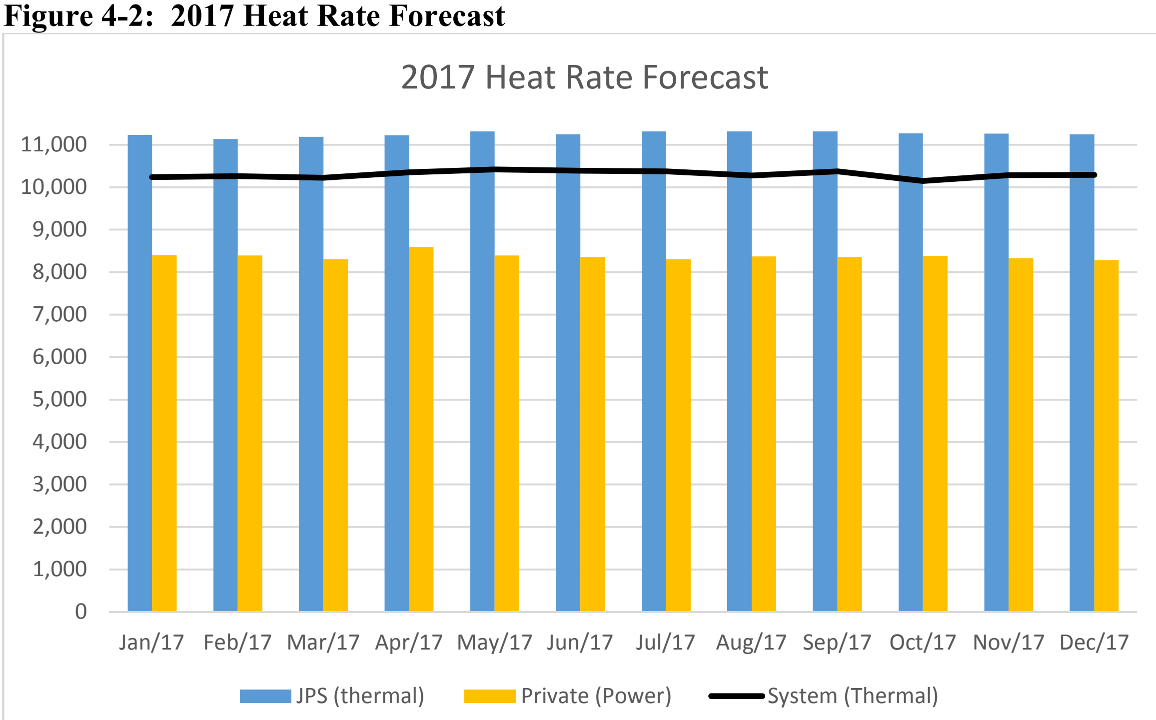
- Rockfort is forecasted at 9,237kj/kWh with planned major outage intervention on RF#1.
- Old Harbour plant heat rate is forecasted at 13,027kj/kWh with OH#2 with cycling duties enabled.
- Hunts Bay HB#B6 forecasted at 12,621kj/kWh. Hunts Bay gas turbines forecasted at 16,732kj/kWh which is reflective of their peaking duties.
- Bogue gas turbine GT#3-GT#11 are forecasted at 19,476kj/kWh as per their peaking duties. Bogue CCGT is forecasted at 9,014kj/kWh.
- IPPs are forecasted at 8,370kj/kWh with major overhaul JPPC engine #2. Major maintenance outage WKPP Total Plant for 30 days.

JPS Thermal heat rate is forecasted at 11,270 kJ/kWh. The 2017 System Thermal heat rate is forecasted at 10,302kj/kWh. The forecasted energy production of each plant for 2017 are shown in Table 4-5 at the end of the chapter.

Table 4-2: 2017 Heat Rate Forecast

Avg. Heat Rate (kJ/k	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Totals
JPS (thermal)	11,235	11,136	11,188	11,225	11,343	11,247	11,355	11,343	11,372	11,271	11,265	11,243	11,270
Private (Power)	8,398	8,392	8,301	8,595	8,390	8,357	8,299	8,370	8,352	8,388	8,323	8,278	8,370
System (Thermal)	10,239	10,258	10,220	10,352	10,420	10,390	10,377	10,273	10,374	10,145	10,285	10,290	10,302

Figure 4-2: 2017 Heat Rate Forecast



4.4 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)
9. Network constraints and contingencies (JPS).

While all the above factors influence the resultant system heat rate, JPS has sole direct control over only a few. JPS' view is that the heat rate target must consider the effect of a major failure of one of the key steam turbines in the fleet that are now at the end of life. The unreliability of some of these assets are beginning to show with Old Harbour Unit #3 having boiler tube leak incidents for at least eight times in 2016 and Unit #2 operating with turbine cracks.

Based on the planned mix of generating units, including IPPs, their projected availability and dispatch, and the foregoing discussion of heat rate affecting variables and the possible variation in heat rate performance for reasons beyond JPS' control, JPS proposes a new Thermal Heat Rate target which takes account of Forced Outage Outliers of 11,720kj/kWh for 2017.

Table 4-3: Projected Capacity Factor for 2017

		Capacity Factor Projections												
(76% System Availability)	Capacity	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Totals
HYDRO & Purchases	**160.5**	**30%**	**30%**	**26%**	**36%**	**36%**	**48%**	**40%**	**37%**	**36%**	**27%**	**30%**	**36%**	**34%**
Old Harbour Steam	**223.5**	**52.1%**	**53.1%**	**59.8%**	**56.2%**	**58.9%**	**57.9%**	**61.9%**	**49.6%**	**56.8%**	**45.0%**	**54.5%**	**52.4%**	**55%**
OH-4	68.5	79.2%	79.3%	82.8%	78.3%	78.6%	79.9%	80.7%	49.7%	73.6%	55.6%	80.4%	79.1%	75%
OH-3	65	78.1%	77.8%	89.2%	75.5%	84.6%	82.5%	80.0%	69.5%	68.3%	54.7%	69.2%	66.9%	75%
OH-2	60.0	19.0%	23.1%	31.7%	38.1%	38.0%	35.3%	51.9%	52.7%	53.5%	45.0%	36.3%	32.3%	38%
OH-1	30													
Hunts Bay Steam	**68.5**	**62%**	**66%**	**43%**	**42%**	**67%**	**68%**	**66%**	**67%**	**65%**	**70%**	**65%**	**64%**	**62%**
HB-B6	68.5	61.8%	65.9%	42.9%	42.1%	67.0%	67.9%	66.1%	67.3%	65.4%	69.6%	65.4%	63.7%	62%
Rockfort	**40**	**51%**	**78%**	**94%**	**94%**	**94%**	**94%**	**94%**	**93%**	**87%**	**86%**	**91%**	**94%**	**88%**
RF-B1	20	8.2%	71.8%	94.4%	94.4%	94.4%	94.4%	94.4%	93.1%	94.4%	88.4%	94.4%	94.4%	85%
RF-B2	20	93.3%	84.9%	94.4%	94.4%	94.4%	94.4%	94.4%	92.2%	79.3%	83.9%	88.4%	94.4%	91%
Hunts Bay Gas Turbines	**54**	**1%**	**0%**	**2%**	**5%**	**3%**		**1%**	**5%**	**2%**	**1%**	**2%**	**1%**	**2%**
HBGT10	32.5		0.3%	1.9%	7.0%	4.0%		1.4%	6.9%	3.3%	1.7%	2.9%	1.0%	3%
HBGT5	21.5	2.6%		1.0%	3.1%	0.8%			2.3%	0.7%	0.3%			1%
HBGT4														
HB-Combined Cycle_2														
Bogue Gas Turbines	**111.5**	**0%**			**0%**	**0%**			**0%**					**0%**
BOGT3	21.5	0.9%			1.1%	0.3%			0.7%					0%
BOGT9	20	0.2%												0.02%
BOGT7	18	0.4%							0.3%					0.06%
BOGT6	18	0.2%							0.1%					0.03%
BOGT8	14													
BOGT11	20													
BOG-Combined Cycle	120	81.7%	83.5%	73.5%	78.5%	73.5%	78.5%	73.5%	73.5%	78.5%	73.5%	78.5%	73.5%	76.6%
	197.5	49.8%	50.8%	44.7%	47.8%	44.7%	47.7%	44.7%	44.8%	47.7%	44.7%	47.7%	44.7%	46.6%
Private Power	**249.86**	**60%**	**55%**	**58%**	**57%**	**55%**	**52%**	**58%**	**64%**	**59%**	**69%**	**59%**	**54%**	**23%**
JEP (Plant Total)	124.36	32.7%	26.2%	27.0%	38.5%	26.9%	17.1%	24.8%	41.8%	28.8%	48.7%	28.3%	22.0%	30%
JPPC	60	84.2%	83.3%	94.1%	63.7%	83.5%	85.0%	93.9%	89.0%	88.8%	89.3%	88.1%	93.6%	86%
WKPP	65.5	89.7%	85.6%	85.3%	87.5%	83.4%	87.1%	89.3%	83.2%	90.4%	90.7%	92.3%	79.3%	87%
	249.86	60.0%	55.5%	58.4%	57.4%	55.3%	51.7%	58.3%	64.0%	59.4%	69.5%	59.4%	54.2%	58.6%
Total (MWh) less Hydro & Pur	747.4													59%
Total	**907.8**	**53%**	**53%**	**53%**	**54%**	**55%**	**57%**	**57%**	**56%**	**56%**	**54%**	**55%**	**53%**	**55%**
Non-dispatchable Units	**160.5**	**30%**	**30%**	**26%**	**36%**	**36%**	**48%**	**40%**	**37%**	**36%**	**27%**	**30%**	**36%**	**34%**
RIO - A	2.5	72.0%	84.0%	75.6%	82.8%	83.2%	69.2%	68.4%	57.6%	65.6%	83.2%	85.6%	78.0%	75%
RIO - B	1.1	25.5%	28.8%	28.3%	31.1%	24.4%	27.5%	29.2%	22.6%	31.1%	23.5%	39.4%	31.9%	29%
L.W.RIVER	4.7	49.1%	47.7%	49.9%	53.2%	54.0%	50.7%	37.1%	42.9%	40.5%	21.6%	55.8%	57.6%	47%
U W.RIVER	3.1	41.5%	43.9%	43.1%	46.5%	32.8%	41.3%	40.2%	41.1%	32.3%	27.9%	48.1%	37.9%	40%
MAGGOTY	6.0								74.2%	89.0%	87.0%	91.2%	83.3%	36%
ROARING RIV	4.1	87.6%	91.5%	87.1%	88.0%	89.3%	82.2%	88.5%	79.0%	74.2%	78.1%	88.8%	90.0%	85%
CONSTANT SPRING	0.8	6.5%	50.6%	63.7%	61.0%	48.0%	20.7%	9.1%	11.7%	57.2%	58.5%	5.2%	52.0%	37%
Magg-B	**7.2**	**52.2%**	**43.1%**	**39.0%**	**74.4%**	**74.0%**	**68.9%**	**51.1%**	**61.8%**	**74.2%**	**72.5%**	**76.0%**	**41.0%**	**61%**
JAMALCO	11.0	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	5%
ROPECON	0.5	19.9%	19.9%	19.9%	20.0%	19.9%	20.0%	19.9%	19.9%	20.0%	19.9%	20.0%	19.9%	20%
BROILERS	12.0	16.7%	16.7%	16.7%	16.7%	16.7%	16.7%	16.7%	16.7%	16.7%	16.7%	16.7%	16.7%	17%
Wigton	20.0	29.5%	28.1%	21.4%	35.0%	36.1%	62.3%	49.4%	35.2%	32.8%	17.5%	18.0%	33.3%	33%
Wigton II	18	36.2%	34.3%	23.8%	42.2%	47.5%	77.2%	60.0%	45.1%	38.3%	22.2%	25.1%	43.1%	41%
Wigton III	24	28.5%	27.0%	18.6%	33.2%	37.1%	60.4%	47.0%	35.5%	30.2%	17.5%	19.8%	34.0%	32%
JPS Munro Wind Farm	3	1.7%	2.0%	3.3%	4.4%	5.6%	3.3%	3.3%	0.7%	1.0%	0.3%	0.3%	1.0%	2%
BM Wind	34	27.3%	27.2%	22.2%	31.1%	25.7%	43.1%	36.0%	30.7%	29.7%	19.6%	20.7%	29.8%	29%
WRG Solar	20	23.0%	25.0%	27.0%	30.0%	28.0%	21.1%	28.0%	28.0%	27.0%	24.0%	24.0%	23.0%	26%

Table 4-4: Total Energy Projections (MWh)

(76% System Availability)	Capacity	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Totals
Total Energy Projections														
HYDRO & Purchases	160.5	**36,366**	**32,558**	**30,831**	**41,500**	**42,430**	**55,151**	**48,286**	**44,306**	**41,675**	**32,773**	**35,020**	**43,255**	**484,151**
Old Harbour Steam		**86,634**	**79,787**	**99,511**	**90,385**	**97,939**	**93,234**	**102,989**	**82,455**	**91,352**	**74,875**	**87,706**	**87,098**	**1,073,965**
OH-4		40,383	36,504	42,199	38,627	40,064	39,385	41,139	25,339	36,302	28,330	39,657	40,312	448,241
OH-3		37,766	33,978	43,154	35,317	40,917	38,588	38,699	33,587	31,948	26,445	32,363	32,352	425,114
OH-2		8,485	9,305	14,158	16,441	16,958	15,261	23,151	23,529	23,102	20,100	15,686	14,434	200,610
OH-1														
Hunts Bay Steam		**31,474**	**30,322**	**21,888**	**20,752**	**34,125**	**33,494**	**33,687**	**34,276**	**32,251**	**35,469**	**32,258**	**32,474**	**372,470**
HB-B6		31,474	30,322	21,888	20,752	34,125	33,494	33,687	34,276	32,251	35,469	32,258	32,474	372,470
Rockfort	40	**15,109**	**21,061**	**28,094**	**27,188**	**28,094**	**27,188**	**28,094**	**27,574**	**25,007**	**25,644**	**26,319**	**28,094**	**307,466**
RF-B1	20	1,222	9,648	14,047	13,594	14,047	13,594	14,047	13,859	13,594	13,160	13,594	14,047	148,453
RF-B2	20	13,887	11,413	14,047	13,594	14,047	13,594	14,047	13,715	11,413	12,484	12,725	14,047	159,013
Hunts Bay Gas Turbines	54	**420**	**60**	**625**	**2,107**	**1,094**		**330**	**2,043**	**895**	**440**	**670**	**240**	**8,924**
HBGT10	32.5		60	460	1,627	970		330	1,670	780	400	670	240	7,207
HBGT5	21.5	420		165	480	124			373	115	40			1,717
HBGT4	21.5													
HB-Combined	115	**31,894**	**30,382**	**22,513**	**22,859**	**35,219**	**33,494**	**34,017**	**36,319**	**33,146**	**35,909**	**32,928**	**32,714**	381,394
Bogue GT#3 - GT#11	111.5	**250**			**165**	**40**			**175**					**630**
BOGT3	21.5	145			165	40			115					465
BOGT9	20	30												30
BOGT7	18	50							40					90
BOGT6	18	25							20					45
BOGT8	**14**													
BOGT11	**20**													
BOG-Combined Cycle	114	72,965	67,361	65,651	67,853	65,651	67,853	65,651	65,651	67,853	65,651	67,853	65,649	805,642
Bogue Gas Turbines		**73,215**	**67,361**	**65,651**	**68,018**	**65,691**	**67,853**	**65,651**	**65,826**	**67,853**	**65,651**	**67,853**	**65,649**	**806,272**
Private Power	439.86	**111,540**	**93,141**	**108,531**	**103,219**	**102,780**	**93,076**	**108,360**	**118,917**	**106,795**	**129,105**	**106,921**	**100,790**	**1,283,175**
JEP (Plant Total)	124.36	30,234	21,882	24,980	34,472	24,851	15,307	22,925	38,653	25,782	45,050	25,333	20,400	329,869
JPPC	60	37,596	33,602	41,992	27,503	37,266	36,708	41,898	39,732	38,371	39,856	38,053	41,762	454,339
WKPP	65.5	43,710	37,657	41,559	41,244	40,663	41,061	43,537	40,532	42,642	44,199	43,535	38,628	498,967
Total (MWh) less Hydro & Pu	645.4	318,392	291,732	324,300	311,669	329,723	314,845	339,111	331,091	324,153	331,184	321,727	314,345	3,852,272
Total (Net Gen)	**805.8**	**354,758**	**324,290**	**355,131**	**353,169**	**372,153**	**369,996**	**387,397**	**375,397**	**365,828**	**363,957**	**356,747**	**357,600**	**4,336,423**
42	JPS (thermal+hydro)	216,578	207,502	225,258	219,821	238,298	231,981	239,979	224,979	231,071	215,703	230,146	227,113	2,708,429
504	Private (JEP + JPPC)	111,540	93,141	108,531	103,219	102,780	93,076	108,360	118,917	106,795	129,105	106,921	100,790	1,283,175
	Total (less purchases)	328,118	300,643	333,789	323,040	341,078	325,057	348,339	343,896	337,866	344,808	337,067	327,903	3,991,604
Hydro		9,726	8,911	9,489	11,371	11,355	10,212	9,228	12,805	13,713	13,624	15,340	13,558	139,332
Purchases		26,640	23,647	21,342	30,129	31,075	44,939	39,058	31,501	27,962	19,149	19,680	29,697	344,819
Total Hydro & Purchases		36,366	32,558	30,831	41,500	42,430	55,151	48,286	44,306	41,675	32,773	35,020	43,255	484,151
	160.5	**36,366**	**32,558**	**30,831**	**41,500**	**42,430**	**55,151**	**48,286**	**44,306**	**41,675**	**32,773**	**35,020**	**43,255**	**484,151**
RIO - A	2.5	1,339	1,411	1,406	1,490	1,548	1,246	1,272	1,071	1,181	1,548	1,541	1,451	16,504
RIO - B	1.1	209	213	232	246	200	218	239	185	246	192	312	261	2,753
L.W.RIVER	4.7	1,716	1,507	1,745	1,801	1,887	1,714	1,299	1,500	1,369	756	1,887	2,013	19,194
U W.RIVER	3.1	957	915	994	1,038	756	922	927	949	721	644	1,074	875	10,772
MAGGOTY	**6.0**								**3,311**	**3,845**	**3,884**	**3,938**	**3,720**	**18,698**
ROARING RIV	4.1	2,671	2,520	2,656	2,599	2,723	2,426	2,701	2,411	2,189	2,381	2,621	2,745	30,643
CONSTANT SPRING	0.8	37	262	365	338	275	115	52	67	317	335	29	298	2,490
Magg-B	**7.2**	**2,797**	**2,083**	**2,091**	**3,859**	**3,966**	**3,571**	**2,738**	**3,311**	**3,845**	**3,884**	**3,938**	**2,195**	**38,278**
JAMALCO	11.0	372	336	372	360	372	360	372	372	360	372	360	372	4,380
ROPECON	0.5	74	67	74	72	74	72	74	74	72	74	72	74	873
BROILERS	12.0	1,488	1,344	1,488	1,440	1,488	1,440	1,488	1,488	1,440	1,488	1,440	1,488	17,520
Wigton	20.0	4,390	3,777	3,184	5,033	5,369	8,966	7,349	5,238	4,723	2,604	2,592	4,955	58,180
Wigton II	18	4,851	4,153	3,184	5,465	6,366	10,003	8,033	6,034	4,968	2,969	3,254	5,773	65,053
Wigton III	24	5,096	4,361	3,326	5,738	6,619	10,442	8,390	6,339	5,220	3,117	3,420	6,064	68,132
JPS Munro Wind Farm	3	37	40	74	94	126	72	74	15	22	7	7	22	590
BM Wind	34	6,910	6,209	5,622	7,607	6,495	10,552	9,112	7,775	7,269	4,947	5,079	7,527	85,104
WRG Solar	20	3,422	3,360	4,018	4,320	4,166	3,032	4,166	4,166	3,888	3,571	3,456	3,422	44,987

Table 4-5: 2017 Heat Rate Forecast

(76% System Availability)	kJ/kWh Heat Rate Projections												
Avg. Heat Rate (kJ/kWh)	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Totals
Old Harbour Steam	**12,889**	**12,900**	**12,823**	**12,988**	**12,996**	**12,935**	**13,018**	**13,262**	**13,181**	**13,313**	**13,040**	**13,051**	**13,027**
OH-4	12,486	12,481	12,292	12,493	12,484	12,478	12,470	12,601	12,554	12,796	12,473	12,490	12,496
OH-3	13,015	13,019	12,964	13,070	13,103	12,930	12,977	13,214	13,246	13,267	13,224	13,285	13,097
OH-2	14,245	14,114	13,974	13,972	13,944	14,130	14,061	14,042	14,075	14,104	14,093	14,095	14,062
OH-1													
Hunts Bay Steam	**12,695**	**12,614**	**12,658**	**12,663**	**12,598**	**12,596**	**12,612**	**12,595**	**12,624**	**12,550**	**12,625**	**12,656**	**12,621**
HB-B6	12,695	12,614	12,658	12,663	12,598	12,596	12,612	12,595	12,624	12,550	12,625	12,656	12,621
Rockfort	**9,245**	**9,230**	**9,229**	**9,229**	**9,229**	**9,229**	**9,228**	**9,243**	**9,228**	**9,296**	**9,230**	**9,229**	**9,237**
RF-B1	9,290	9,223	9,223	9,223	9,222	9,222	9,222	9,237	9,222	9,289	9,221	9,222	9,230
RF-B2	9,241	9,236	9,235	9,235	9,235	9,235	9,234	9,249	9,235	9,304	9,238	9,235	9,243
Hunts Bay Gas Turbines	**18,965**	**17,334**	**18,342**	**16,015**	**19,343**		**15,827**	**16,184**	**15,991**	**16,154**	**15,590**	**15,794**	**16,732**
HBGT10		17,334	17,437	15,402	19,000		15,827	15,529	15,521	15,795	15,590	15,794	16,146
HBGT5	18,965		20,864	18,093	22,022			19,119	19,177	19,744			19,190
HBGT4													
HB-Combined	**12,778**	**12,624**	**12,816**	**12,972**	**12,807**	**12,596**	**12,643**	**12,797**	**12,715**	**12,595**	**12,686**	**12,679**	**12,717**
Bogue GT#3 - GT#11	**19,104**			**19,400**	**22,965**			**19,283**					**19,476**
BOGT3	19,332			19,400	22,965			19,459					19,700
BOGT9	18,358												18,358
BOGT7	18,742							18,649					18,701
BOGT6	19,400							19,537					19,461
BOGT8													
BOGT11													
BOG-Combined Cycle	8,981	8,971	8,990	9,070	8,990	9,070	8,990	8,990	9,070	8,990	9,070	8,990	9,014
Bogue Gas Turbines	**9,015**	**8,971**	**8,990**	**9,095**	**8,998**	**9,070**	**8,990**	**9,017**	**9,070**	**8,990**	**9,070**	**8,990**	**9,023**
Private Power	**8,398**	**8,392**	**8,301**	**8,595**	**8,390**	**8,357**	**8,299**	**8,370**	**8,352**	**8,388**	**8,323**	**8,278**	**8,370**
JEP1	8,614	8,614	8,615	8,615	8,614	8,614	8,614	8,614	8,614	8,614	8,615	8,616	8,614
JPPC	8,016	8,039	7,838	8,600	8,036	8,002	7,837	7,921	7,924	7,923	7,836	7,834	7,965
WKPP	8,568	8,568	8,569	8,567	8,568	8,567	8,568	8,568	8,568	8,568	8,568	8,568	8,568
Avg. System Heat Rate (kJ/kWh) no hydros or purchases	**10,240**	**10,259**	**10,220**	**10,353**	**10,421**	**10,391**	**10,377**	**10,274**	**10,375**	**10,146**	**10,286**	**10,291**	**10,303**
JPS (thermal)	11,235	11,136	11,188	11,225	11,343	11,247	11,355	11,343	11,372	11,271	11,265	11,243	11,270
Private (Power)	8,398	8,392	8,301	8,595	8,390	8,357	8,299	8,370	8,352	8,388	8,323	8,278	8,370
System (Thermal)	10,239	10,258	10,220	10,352	10,420	10,390	10,377	10,273	10,374	10,145	10,285	10,290	10,302
Jamalco	9,500.0	9,500.0	9,500.0	9,500.0	9,500.0	9,500.0	9,500.0	9,500.0	9,500.0	9,500.0	9,500.0	9,500.0	9,500.0
Total System (- Ropecon & Broilers)	**9,241**	**9,279**	**9,384**	**9,186**	**9,282**	**8,888**	**9,130**	**9,109**	**9,241**	**9,282**	**9,325**	**9,096**	**9,201**

5 Appendices

US Bureau of Labor CPI Index for March 2017

Table 1. Consumer Price Index for All Urban Consumers (CPI-U): U.S. city average, by expenditure category, March 2017
[1982-84=100, unless otherwise noted]

Expenditure category	Relative importance Feb. 2017	Unadjusted indexes			Unadjusted percent change		Seasonally adjusted percent change		
		Mar. 2016	Feb. 2017	Mar. 2017	Mar. 2016-Mar. 2017	Feb. 2017-Mar. 2017	Dec. 2016-Jan. 2017	Jan. 2017-Feb. 2017	Feb. 2017-Mar. 2017
All items	100.000	238.132	243.603	243.801	2.4	0.1	0.6	0.1	-0.3
Food	13.657	247.978	248.791	249.165	0.5	0.2	0.1	0.2	0.3
Food at home	7.877	240.329	237.918	238.256	-0.9	0.1	0.0	0.3	0.5
Cereals and bakery products	1.060	273.162	271.708	272.174	-0.4	0.2	-0.1	-0.4	0.3
Meats, poultry, fish, and eggs	1.735	250.837	243.057	244.306	-2.6	0.5	0.7	0.2	0.3
Dairy and related products	0.821	218.131	220.552	218.567	0.2	-0.9	0.8	0.8	-0.6
Fruits and vegetables	1.327	298.162	292.222	292.932	-1.8	0.2	-1.7	0.7	1.6
Nonalcoholic beverages and beverage materials	0.960	168.187	169.451	168.455	0.2	-0.6	-0.3	1.5	-0.1
Other food at home	1.974	209.743	208.914	210.002	0.1	0.5	0.2	-0.4	0.7
Food away from home[1]	5.780	260.883	266.626	267.055	2.4	0.2	0.4	0.2	0.2
Energy	7.153	179.017	198.195	198.597	10.9	0.2	4.0	-1.0	-3.2
Energy commodities	3.524	174.500	206.984	209.029	19.8	1.0	7.6	-2.8	-6.0
Fuel oil[1]	0.105	192.617	242.467	240.619	24.9	-0.8	3.5	-0.4	-0.8
Motor fuel	3.328	171.050	202.912	205.155	19.9	1.1	7.9	-2.9	-6.1
Gasoline (all types)	3.277	170.356	201.957	204.217	19.9	1.1	7.8	-3.0	-6.2
Energy services[2]	3.628	191.203	198.820	197.709	3.4	-0.6	0.3	1.0	-0.3
Electricity[2]	2.814	202.487	206.416	205.692	1.6	-0.4	0.0	0.8	-0.1
Utility (piped) gas service[2]	0.814	154.822	172.967	170.755	10.3	-1.3	1.5	1.5	-0.8
All items less food and energy	79.191	246.358	251.143	251.290	2.0	0.1	0.3	0.2	-0.1
Commodities less food and energy commodities	19.125	146.367	145.140	145.527	-0.6	0.3	0.4	0.0	-0.3
Apparel	3.092	127.427	126.100	128.250	0.6	1.7	1.4	0.6	-0.7
New vehicles	3.687	148.227	148.993	148.543	0.2	-0.3	0.9	-0.2	-0.3
Used cars and trucks	1.974	146.178	137.899	139.372	-4.7	1.1	-0.4	-0.6	-0.9
Medical care commodities	1.858	362.386	376.078	376.440	3.9	0.1	0.3	-0.2	0.2
Alcoholic beverages	0.948	242.230	244.622	244.978	1.1	0.1	0.2	-0.1	0.2
Tobacco and smoking products	0.660	953.512	984.756	987.910	3.6	0.3	0.1	0.4	0.5
Services less energy services	60.066	307.703	316.506	316.481	2.9	0.0	0.3	0.3	-0.1
Shelter	33.561	285.196	294.444	295.044	3.5	0.2	0.2	0.3	0.1
Rent of primary residence[2]	7.843	293.489	304.211	304.868	3.9	0.2	0.3	0.3	0.3
Owners' equivalent rent of residences[2, 3]	24.468	292.080	301.785	302.259	3.5	0.2	0.2	0.3	0.2
Medical care services	6.697	489.520	506.105	505.991	3.4	0.0	0.2	0.2	0.1
Physicians' services[2]	1.699	372.672	385.353	383.965	3.0	-0.4	0.0	0.1	-0.3
Hospital services[2, 4]	2.268	300.303	313.974	314.529	4.7	0.2	0.3	0.4	0.4
Transportation services	5.941	296.363	306.221	307.490	3.8	0.4	0.6	0.7	0.4
Motor vehicle maintenance and repair[1]	1.162	273.980	279.782	279.600	2.1	-0.1	0.5	0.1	-0.1
Motor vehicle insurance	2.501	478.644	513.469	517.619	8.1	0.8	0.8	0.5	1.2
Airline fares	0.654	283.584	280.517	283.583	0.0	1.1	2.0	2.4	0.4

[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.

STATIN CPI New Release - CPI Index for Jamaica, March 2017

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News Release
Consumer Price Index
March 2017

April 18, 2017

The Consumer Price Index for the month of March was 238.7 and represented an inflation rate of 0.4 per cent. This upward movement was mainly attributed to the 1.5 per cent increase in the index for the division 'Housing, Water, Electricity, Gas and Other Fuels'. This was largely due to higher rates for electricity as well as water and sewage which resulted in the index for the group 'Electricity, Gas and Other Fuels' increasing by 2.6 per cent and the group 'Water supply and Miscellaneous Services Related to the Dwelling' moving up by 1.1 per cent.'

The heaviest weighted division 'Food and Non-Alcoholic Beverages' index, moved up by 0.3 per cent. This was primarily due to the class index 'Vegetables and Starchy Foods' increasing by 0.4 per cent.

At the end of the first quarter for 2017, the calendar year-to-date inflation was 1.0 per cent, while the fiscal year recorded an inflation rate of 4.1 per cent.

The other divisions that recorded increases in the All Jamaica 'All Divisions' index were:
'Health' 0.2 per cent, 'Alcoholic Beverages and Tobacco' 0.1 per cent, 'Clothing and Footwear' 0.1 per cent, 'Furnishings, Household Equipment and Routine Maintenance' 0.1 per cent and 'Miscellaneous Goods and Services' 0.1 per cent. The divisions to record negligible movements in their index were: 'Recreation and Culture', 'Restaurants and Accommodation Services' and 'Communication'.

The regional index showed upward movements for all three regions: Greater Kingston Metropolitan Area up by 0.4 per cent, Other Urban Areas up by 0.4 per cent and Rural Areas up by 0.3 per cent.

The Consumer Price Index Bulletin March 2017 further outlines additional information and may be obtained from the Information Section of the Statistical Institute of Jamaica, 7 Cecelio Avenue, Kingston. CPI data are also published on the STATIN website at www.statinja.gov.jm

Bill Impact – Rate 10

	Before			After			Change	
	March 2017 Bill			March 2017 Bill			March 2017 Bill	
Description	Usage	Rate	Charges (J$)	Usage	Rate	Charges (J$)	Charges (J$)	%
Base/Exchange Rate	122.5	128.6672		131.00	128.6672			
Non-Fuel Charges								
Energy 1st	100	9.13	912.94	100	10.03	1,003.15	90.20	9.9%
Energy Next	61.52	21.26	1,307.97	61.52	23.36	1,437.14	129.17	9.9%
Customer Charge		429.31	429.31		491.24	491.24	61.94	14.4%
EEIF Charges	161.52	0.2499	40.36	161.52	-	-	(40.36)	-100.0%
Sub Total			2,690.58			2,931.52	240.94	9.0%
F/E Adjustment			108.36			(41.76)	(150.13)	
Total Non-Fuel Bill			2,798.95			2,889.76	90.81	3.2%
Fuel & IPP Charges	161.5235543	16.956	2,738.76	161.5235543	16.956	2,738.76	-	0.0%
Early Payment Incentive		-	-		-	-	-	0.0%
Bill Total			5,537.70			5,628.52	90.81	1.64%

Bill Impact – Rate 20

	Before			After			Change	
	March 2017 Bill			March 2017 Bill			March 2017 Bill	
Description	Usage	Rate	Charges (J$)	Usage	Rate	Charges (J$)	Charges (J$)	%
Base/Exchange Rate	122.5	128.6672		131.00	128.6672			
Non-Fuel Charges								
Energy	811.62	17.61	14,292.64	811.62	19.35	15,706.23	1,413.59	9.9%
Customer Charge		956.42	956.42		1,094.39	1,094.39	137.97	14.4%
EEIF Charges	811.62	0.2499	202.82	811.62	-	-	(202.82)	-100.0%
Sub Total			15,451.88			16,800.63	1,348.74	8.7%
F/E Adjustment			622.33			(239.34)	(861.68)	
Total Non-Fuel Bill			16,074.22			16,561.28	487.07	3.0%
Fuel & IPP Charges	811.62	16.956	13,761.65	811.62	16.956	13,761.65	-	0.0%
Bill Total			29,835.87			30,322.93	487.07	1.63%

Bill Impact – Rate 40 STD

Description	Usage	Rate	Charges (J$)	Usage	Rate	Charges (J$)	Charges (J$)	%
	Before March 2017 Bill			After March 2017 Bill			Change March 2017 Bill	
Base/Exchange Rate	122.50	128.6672		131.00	128.6672			
Non-Fuel Charges								
Demand	111	1,720.68	191,448.04	111	1,891.91	210,499.65	19,052	10.0%
Energy	33,125	5.49	181,858.87	33,125	6.01	198,935.82	17,077	9.4%
Customer Charge		6,738.40	6,738.40		7,710.48	7,710.48	972	14.4%
EEIF Charges	33,125	0.2499	8,278.06	33,125	-	-	(8,278)	-100.0%
Sub Total			388,323.37			417,145.95	28,823	7.4%
F/E Adjustment			15,639.95			(5,942.71)	(21,583)	
Total Non-Fuel Bill			**403,963.32**			**411,203.25**	**7,239.93**	**1.8%**
Fuel & IPP Charges	33125.47765	16.278	539,201.06	33125.47765	16.278	539,201.06	-	0.0%
Bill Total (J$)			943,164.38			950,404.31	7,240	0.8%

Bill Impact – Rate 50 STD

Description	Usage	Rate	Charges (J$)	Usage	Rate	Charges (J$)	Charges (J$)	%
	Before March 2017 Bill			After March 2017 Bill			Change March 2017 Bill	
Base/Exchange Rate	122.50	128.6672		131.00	128.6672			
Non-Fuel Charges								
Demand	428	1,541.51	660,145.67	428	1,694.91	725,838.90	65,693	10.0%
Energy	139,548	5.29	738,209.08	139,548	5.76	804,149.88	65,941	8.9%
Customer Charge		6,738.40	6,738.40		7,710.48	7,710.48	972	14.4%
EEIF Charges	139,548	0.2499	34,873.05	139,548	-	-	(34,873)	-100.0%
Sub Total			1,439,966.20			1,537,699.26	97,733	6.8%
F/E Adjustment			57,995.49			(21,906.23)	(79,902)	
Total Non-Fuel Bill			1,497,961.69			1,515,793.04	17,831	1.2%
Fuel & IPP Charges	139,548	16.278	2,271,497.67	139,548	16.278	2,271,497.67	-	0.0%
Bill Total (J$)			3,769,459.36			3,787,290.70	17,831	0.5%

Extraordinary Rate Review – Proposed Revenue Basket & Bill Impact

Revenue Basket

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	1,316,387,558	5,345,739,703	-	-	-	-	- 6,662,127,261
Rate 10	LV	> 100	2,086,222,893	13,317,426,368	-	-	-	-	15,403,649,261
Rate 20	LV		870,415,525	12,269,922,438	-	-	-	-	13,140,337,963
Rate 40A	LV		-	-	-	-	-	-	-
Rate 40	LV - Std		159,285,935	4,213,920,315	4,150,387,146	-	-	-	8,523,593,396
Rate 40	LV - TOU		11,206,527	732,358,488	-	24,815,254	250,704,475	254,822,376	1,273,907,120
Rate 50	MV - Std		10,440,269	1,100,153,161	938,019,167	-	-	-	2,048,612,597
Rate 50	MV - TOU		1,819,863	284,937,715	-	12,771,557	112,153,806	111,265,277	522,948,219
Rate 70	MV -STD		2,298,775	793,896,393	451,173,034	-	-	-	1,247,368,202
Rate 70	MV -TOU		478,911	147,868,045	-	4,690,166	45,268,553	39,072,818	237,378,493
Rate 60	LV		16,723,297	1,753,167,895	-	-	-	-	
TOTAL			**4,475,279,554**	**39,959,390,522**	**5,539,579,347**	**42,276,976**	**408,126,834**	**405,160,471**	**50,829,813,705**

Proposed Tariff

Class		Block/ Rate Option	Customer Charge	Energy-J$/kWh	Demand-J$/KVA Std.	Off-Peak	Part Peak	On-Peak
Rate 10	LV	--100	508.53	10.24	-	-	-	-
Rate 10	LV	> 100	508.53	23.84	-	-	-	-
Rate 20	LV		1,132.91	19.68	-	-	-	-
Rate 40A	LV		-	-	-	-	-	-
Rate 40	LV - Std		7,981.86	6.37	1,869.24	-	-	-
Rate 40	LV - TOU		7,981.86	6.37	-	78.82	822.48	1,053.09
Rate 50	MV - Std		7,981.86	6.03	1,674.60	-	-	-
Rate 50	MV - TOU		7,981.86	6.03	-	74.67	728.68	934.91
Rate 70	MV -STD		7,981.86	3.11	633.96	-	-	-
Rate 70	MV -TOU		7,981.86	3.12	-	28.38	279.45	359.00
Rate 60	LV		3,218.49	24.59	-	-	-	-

Extraordinary Rate Review Bill Impact

Rate 10

	Before			After			Change	
	April 2017 Bill			April 2017 Bill			April 2017 Bill	
Description	Usage	Rate	Charges (J$)	Usage	Rate	Charges (J$)	Charges (J$)	%
Base/Exchange Rate	122.5	128.6672		131.00	128.6672			
Non-Fuel Charges								
Energy 1st	100	9.13	912.94	100	10.24	1,023.80	110.86	12.1%
Energy Next	61.52	21.26	1,307.97	61.52	23.84	1,466.73	158.76	12.1%
Customer Charge		429.31	429.31		508.53	508.53	79.23	18.5%
EEIF Charges	161.52	0.2499	40.36	161.52	-	-	(40.36)	-100.0%
Sub Total			2,690.58			2,999.06	308.47	11.5%
F/E Adjustment			108.36			(42.72)	(151.09)	
Total Non-Fuel Bill			2,798.95			2,956.33	157.38	5.6%
Fuel & IPP Charges	161.52	16.96	2738.76	161.52	16.96	2738.76	-	0.0%
Early Payment Incentive		-	-		-	-	-	0.0%
Bill Total			5,537.70			5,695.09	157.38	2.84%

Rate 20

	Before			After			Change	
	April 2017 Bill			April 2017 Bill			April 2017 Bill	
Description	Usage	Rate	Charges (J$)	Usage	Rate	Charges (J$)	Charges (J$)	%
Base/Exchange Rate	122.5	128.6672		131.00	128.6672			
Non-Fuel Charges								
Energy	811.62	17.61	14,292.64	811.62	19.68	15,970.22	1,677.58	11.7%
Customer Charge		956.42	956.42		1,132.91	1,132.91	176.49	18.5%
EEIF Charges	811.62	0.2499	202.82	811.62	-	-	(202.82)	-100.0%
Sub Total			15,451.88			17,103.13	1,651.25	10.7%
F/E Adjustment			622.33			(243.65)	(865.99)	
Total Non-Fuel Bill			16,074.22			16,859.48	785.26	4.9%
Fuel & IPP Charges	811.62	16.956	13,761.65	811.62	16.956	13,761.65	-	0.0%
Bill Total			29,835.87			30,621.13	785.26	2.6%

Rate 40 STD

	Before			After			Change	
	April 2017 Bill			April 2017 Bill			April 2017 Bill	
Description	Usage	Rate	Charges (J$)	Usage	Rate	Charges (J$)	Charges (J$)	%
Base/Exchange Rate	122.50	128.6672		131.00	128.6672			
Non-Fuel Charges								
Demand	111	1,720.68	191,448.04	111	1,869.24	207,976.91	16,529	8.6%
Energy	33,125	5.49	181,858.87	33,125	6.37	211,160.57	29,302	16.1%
Customer Charge		6,738.40	6,738.40		7,981.86	7,981.86	1,243	18.5%
EEIF Charges	33,125	0.2499	8,278.06	33,125	-	-	(8,278)	-100.0%
Sub Total			388,323.37			427,119.33	38,796	10.0%
F/E Adjustment			15,639.95			(6,084.79)	(21,725)	
Total Non-Fuel Bill			**403,963.32**			**421,034.54**	**17,071.22**	**4.2%**
Fuel & IPP Charges	33125.47765	16.278	539,201.06	33125.47765	16.278	539,201.06	-	0.0%
Bill Total (J$)			943,164.38			960,235.60	17,071	1.8%

Rate 50 STD

	Before			After			Change	
	April 2017 Bill			April 2017 Bill			April 2017 Bill	
Description	Usage	Rate	Charges (J$)	Usage	Rate	Charges (J$)	Charges (J$)	%
Base/Exchange Rate	122.50	128.6672		131.00	128.6672			
Non-Fuel Charges								
Demand	428	1,541.51	660,145.67	428	1,674.60	717,140.04	56,994	8.6%
Energy	139,548	5.29	738,209.08	139,548	6.03	841,095.69	102,887	13.9%
Customer Charge		6,738.40	6,738.40		7,981.86	7,981.86	1,243	18.5%
EEIF Charges	139,548	0.2499	34,873.05	139,548	-	-	(34,873)	-100.0%
Sub Total			1,439,966.20			1,566,217.58	126,251	8.8%
F/E Adjustment			57,995.49			(22,312.50)	(80,308)	
Total Non-Fuel Bill			1,497,961.69			1,543,905.08	45,943	3.1%
Fuel & IPP Charges	139,548	16.278	2,271,497.67	139,548	16.278	2,271,497.67	-	0.0%
Bill Total (J$)			3,769,459.36			3,815,402.75	45,943	1.2%