THE JAMAICA PUBLIC SERVICE CO. LTD.

ANNUAL TARIFF ADJUSTMENT SUBMISSION FOR 2016

May 3, 2016

Preamble

This submission is made in relation to the annual Performance-Based Rate-Making (PBRM) tariff adjustment filing for 2016, in accordance with the 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, 2014 Determination Notice and Determination Notice Addendum 1 and the OUR's 2015 Annual Tariff Adjustment Determination Notice, the 2016 annual non-fuel tariff adjustment will incorporate changes in relation to the annual inflation adjustment, the resetting of the new foreign exchange rate but will not include any adjustments for either the Q factor or the Z factor.

The 2016 Annual Adjustment filing is set against the background of a new Electricity Licence that was established in January 2016 following negotiations between JPS, the Ministry of Science, Energy and Technology, and the Energy Sector Enterprise Team. Several new parameters were introduced in the Licence. In the absence of a consensus between the OUR and JPS on the values of these parameters, the JPS is proposing its position on the setting of these parameters.

JPS' position is informed by its interpretation of the new Licence, by due consideration to past precedence that has been set by Determinations of the OUR, as well as consideration to the impact on our customers and the energy sector at large.

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.

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"

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

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

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

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

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.

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

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

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.

The Z-Factor

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

1.2 Interpretation of Exhibit 1 Parameters

The Electricity License introduced several parameters which were not considered in previous rate filings or Determinations of the OUR. In the ensuing sections of this document, JPS will outline its position on the establishment of these parameters in the context of our interpretation of the Electricity Licence and remaining conscious of the potential impact on our customers.

1.2.1 The Revenue Cap for 2016 (RC_{2016})

The amended Electricity Licence moves JPS from a Price Cap to a Revenue Cap regulatory framework. Under the price cap, JPS prices were capped in real terms over the rate review period, allowing for annual adjustments to account for inflation but not allowing for adjustments for changes in sales volumes. Explicit performance based incentive mechanisms where included through the efficiency improvement (X factor) and reliability performance factor (Q factor).

The revenue cap introduces a cap on real revenues (the aggregate of volumes multiplied by prices) with annual adjustments made for inflation. In the context of the Licence amendment, the explicit performance based incentive for reliability is retained while the efficiency (X) factor has been removed from the annual adjustment formula. The removal of the X factor from the annual adjustment formula does not remove the incentive for JPS to improve efficiency as this will be factored into the 5 year business plan which will inform the establishment of the revenue cap for each year of the rate review period.

The Electricity License, describes the parameter RC_y as the revenue cap for year "y" which is to be established in the last rate review. Given that the last rate determination did not contemplate a revenue cap regulation, a revenue cap, RC_y, specific to the 2016/2017 annual adjustment filing has not been established for the 2016/2017. JPS' position however, is 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. The efficiency improvement factor must be included in setting the revenue cap target in this case since it was explicitly removed from the annual adjustment formula. It is JPS' position that the X factor that was set by the OUR in the 2014-2019 Tariff Determination should be used as the proxy for the efficiency improvement factor which would have been implicitly built into RC_y in the revenue cap determination at rate review.

The Licence contemplates that for each year of the rate review period, the parameter RCy will be established without factoring inflation. During the annual adjustments, the inflation between the base year and the current adjustment period would be factored in through the dI parameter. JPS is proposing that the revenue cap for 2016, RC2016, should be determined as follows:

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

where X is the efficiency factor that was set at 1.1% in the 2014-2019 Tariff Determination. The factor (1-X) is squared to account for the two adjustment years from the establishment of the revenue requirement (that is, for the 2015/2016 and 2016/2017 adjustment years).

1.2.2 True Up for Volumetric Adjustments

JPS' position is that the true-up for volumetric adjustments (TUVol) cannot be applied in the 2016/2017 tariff adjustment period. JPS' revenue requirement as determined in the 2014-2019 Determination is US383.65M inclusive of EEIF. The revenue requirement for the tariff basket, which excludes the EEIF, is US$370.65M. During the 2015/2016 tariff adjustment period when the price cap was applied, the tariff basket determined by the OUR (in the 2015 Annual Tariff Adjustment Determination) was US$361.4M[1]. Thus, applying the TUVol mechanism to the 2015 revenue target would be erroneous as the revenue target does not represent that which JPS should have obtained under revenue cap regulation.

It is important to note that the anomaly introduced by the application of the price cap in 2015/2016 would not have occurred had the revenue cap been in place since rate reset in 2014 (applied in 2015). It is therefore JPS' position that the volumetric adjustment cannot be applied in the 2016/2017 period as per the Licence but rather should be considered for the 2017/2018 period when the determined revenue requirement would have been re-established.

1.2.3 Targets for FX Losses and Interest Charges

In its 2014-2019 Determination Notice, the OUR determined that FX Losses should be excluded from the revenue requirement. The OUR also determined that JPS was not allowed to charge interest income to commercial customers that were in arrears, however, the OUR had previously allowed JPS to collect a late payment fee on residential customer accounts where bills were not settled by the due date. The late payment fees and the corresponding early payment incentive were not included in the revenue requirements of the 2014-2019 Determination.

The Electricity Licence has made provisions for the inclusion of FX losses as a part of the revenue requirement and has granted JPS the right to charge interest on commercial and GOJ customer accounts that are past due. The Licence states that a target interest income in relation to interest charged to customers and late payment fees should be included in the revenue requirement of the Base Year. The variation between the target interest income (expense) and the actual interest income (expense) is to be included as an offset to FX losses. Since these charges were not contemplated in the last rate case determination the target interest income and late payment charges (TIC) and the target FX losses should be set at zero.

That is,

[1] J$41,740,623,421 @ JMD115.50 to USD1

$$\mathrm{TFX} = 0$$
$$\mathrm{TIC} = 0$$

1.2.4 WACC

The WACC that is stipulated in the annual adjustment formula is the pre-tax WACC that is determined in the Base year. In the context of the 2016 Annual Adjustment Filing, the base year was 2013 and it is JPS' position that the WACC should be the pre-tax WACC as determined by the OUR in the 2014-2019 Determination.

1.2.5 Computation of dI

The format of the inflation adjustment (as shown in Section 1.1 "Overview") has changed in the new Electricity Licence; however, in effect it is similar to the formula in OUR's 2014-2019 Determination Notice, which is stated as follows:

$$\mathrm{dI} = \mathrm{USP} \times \left(\frac{\mathrm{EX_n} - \mathrm{EX_b}}{\mathrm{EX_b}}\right)(1 + \mathrm{USAF} \times \mathrm{INF_{US}}) + \mathrm{USP} \times \mathrm{USAF} \times \mathrm{INF_{US}} + (1 - \mathrm{USP}) \times \mathrm{INF_J}$$

where

$\mathrm{EX_b}$	=	Base US exchange rate.
$\mathrm{EX_n}$	=	Applicable US exchange rate at Adjustment Date.
$\mathrm{INF_{US}}$	=	The US inflation rate
$\mathrm{INF_J}$	=	The Jamaican inflation rate
USP	=	US portion of the total non-fuel expenses as determined from the Base Year.
USAF	=	Portion of the US portion of non-fuel expenses that is subject to US inflation

It can be shown that each formula could be reformulated in terms of the other (as is shown in Appendix 1) but there are some changes in how the formula is actually applied and interpreted.

In the new Electricity Licence, the inflation factors, $\mathrm{INF_{US}}$ and $\mathrm{INF_J}$, should not be computed annually as was the case previously. Instead, these factors measure the inflation rate between the current year and the base year, that is, at the start of the rate review period. Thus, for 2016, these will measure the inflation between 2016 and 2014 (the assumed based year for the last rate review). Similarly, the interpretation of $\mathrm{EX_b}$ is different from what was previously applied. In the context of the new Licence, $\mathrm{EX_b}$ refers to the exchange rate in the base year, that is, the value determined by the OUR in its last rate review (J$112:US$1).

The change in interpretation was necessary due to the way $\mathrm{RC_y}$ is established. $\mathrm{RC_y}$ will be established from the business plan and will be set in advance for each year of the five years of the rate review period. It will be determined at the Base Exchange rate in the Base year and the inflation index in the base year. Thus, in carrying out the annual adjustments, $\mathrm{RC_y}$ will need to be adjusted with respect to the base year.

In the context of the OUR 2014-19 Determination, USAF refers to the fraction of the non-fuel revenue which is subject to US inflation – this excludes debt service, return on equity, depreciation expenses and financing costs. The OUR derived values for USP and USAF was based on the test year financials as shown in Table 1-1.

Table 1-1 shows that the OUR classified depreciation, net financing costs, return on debt on pre-tax return on equity as debt related expenses. In addition, the computation was done on the basis on JPS' test year expenses rather than on the proposed revenue requirement. JPS had indicated in previous communications with the OUR that the computation of USP and USAF should have been based on the approved revenue requirement rather than the test year financials, however, given that we are interpreting the Electricity Licence in the context of the OUR's 2014 – 2019 Rate Determination, we will proceed with the OUR's approach. In future Rate Reviews, we urge to the OUR to revisit the methodology used in computing these two parameters.

In the case of the new Electricity Licence, $USDS_b$ is defined as the debt service portion of the non-fuel revenue requirement so it covers a smaller portion of JPS' non fuel revenue requirement than 1-USAF. $USDS_b$ is the part of the US portion of non-fuel revenue (USP_b) that is for debt service and thus not subject to US inflation, thus, USP_b - $USDS_b$ is subject to US inflation.

If the derivations of the two dIs in Appendix 1 are compared and USP and USPb are assumed to have the same interpretation in both Licences, USDSb can be interpreted in the context of USAF and USPb as shown below:

$$\mathrm{USP} \times (1 + \mathrm{USAF} \times \mathrm{INF_{US}}) = \{\mathrm{USP_b} + (\mathrm{USP_b} - \mathrm{USDS_b}) \times \mathrm{INF_{US}}\}$$

$$\mathrm{USAF} \times \mathrm{USP} = (\mathrm{USP_b} - \mathrm{USDS_b})$$

$$\text{Then } \mathrm{USDS_b} = \mathrm{USP_b}(1 - \mathrm{USAF})$$

The relation derived above would only hold if USAF and USDSb covered the same expense items however, as mentioned previously, 1-USAF covers a broader category than the intent of the new Electricity Licence. To obtain an exact relationship, USAF would have to be redefined to exclude only return on debt as the part of the US portion of non-fuel revenue that is not subject to US inflation. The table below shows USAF and USP recomputed with USAF excluding only the debt service portion of expenses (that is, return on debt).

Using the redefined definition of USAF, then $USDS_b$=80%*8.57%=6.88%

It is JPS' position that USP_b =80% (see Table 1-2), $USDS_b$ = 6.88% and EX_b =J$112:US$1 (the base exchange rate established at the 2014-2019 rate review).

Table 1-1: OUR Proposal for USP and USAF in its 2014 – 2019 Determination Notice

Non-Fuel Expenses	Actual Costs	US$ Component of Actual Costs
Total Non-Fuel Expenses	**456,040**	**366,307**
Power Purchased (non-fuel)	104,111	104,111
O &M Expenses	143,265	54,081
Sinking (Self-insurance) fund contribution	7,500	7,500
Debt Related Expense	**201,164**	**200,615**
Depreciation	49,168	49,168
Interest on Customer Deposits	549	-
Net Financing costs	29,547	29,547
Return on Debt	31,383	31,383
Pre-tax Return on Equity	90,517	90,517
Fuel Expenses	**728,745**	
Total Expenses	**1,184,785**	
Non-fuel Component of Total Expenses	**38.5%**	
US Component of Non-fuel Costs (USP)	**80%**	
1-USAF	**55%**	

Table 1-2: JPS' Proposal for USP and USAF based on Interpretation of the New Licence

Non-Fuel Expenses	OUR Approved Revenue Requirement	US$ Component of OUR Revenue Requirement
Total Non-Fuel Expenses	**456,040**	**366,307**
Power Purchased (non-fuel)	104,111	104,111
O &M Expenses	143,265	54,081
Sinking (Self-insurance) fund contribution	7,500	7,500
Depreciation	49,168	49,168
Interest on Customer Deposits	549	-
Net Financing costs	29,547	29,547
Pre-tax Return on Equity	90,517	90,517
Debt Service		
Return on Debt	31,383	31,383
Fuel Expenses	**728,745**	
Total Expenses	**1,184,785**	
Non-fuel Component of Total Expenses	**38.5%**	
US Component of Non-fuel Costs	**80%**	
1-USAF	**8.57%**	

1.2.6 System Losses Targets

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.

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

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

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

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 Licencee, having regard to the (i) nature and root cause of losses; (ii) roles of the Licencee 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 Licencee; (v) actual cooperation by the Government; and (vi) change in external environment that affected losses.

JPS would like to highlight that there was a typographical error in the new Licence which we are proposing should be corrected in application to the annual tariff filing. The formulae for computing Ycy-1 should actually have been:

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

Applying the incorrect formulae would adversely impact our customers so it is in the best interest of the OUR and JPS to apply this correction.

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:

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

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

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

Taking the above into consideration, JPS has disaggregated its losses for the year 2015 into the three components stipulated in the Licence. While it is straightforward to separate technical from non-technical losses, the division of non-technical losses into those totally within JPS’ control and those not totally within JPS’ control required considerably more thought. JPS considered the nature and the root cause of the losses and also the extent that it has control over certain types of system losses. Using this approach, Table 1-3 summarizes JPS’ proposal for the disaggregation of system losses into TL, JNTL and GNTL and also proposes a value for the responsibility factor, RF, to be applied in the tariff.

Table 1-3: Computation of TL, JNTL, GNTL and RF

Description/Category		No. of Cust.	Bill Sales (MWH)	Energy Loss (MWH)	% Loss	JNTL	GNTL	Responsibility Factor
Billed Customers	Streetlight/Stoplight/Interchange (R60)	398	93,273	3903	0.09%	0.09%	0.00%	N/A
	Large C&I (Rate 40 & 50)	1,913	1,378,867	19,093	0.45%	0.37%	0.08%	TBA
	Medium C&I (rate 20)	4,061	280,872	12,957	0.31%	0.21%	0.10%	TBA
	Small C&I (rate 20)	56,530	303,856	13,331	0.32%	0.10%	0.21%	TBA
	Residential (rate 10)	533,705	1,016,807	298,147	7.08%	3.08%	4.00%	TBA
Sub-Total		**596,607**	**3,073,675**	**347,430**	**8.25%**	**3.85%**	**4.40%**	**TBA**
Unquantified				22,387	**0.53%**	0.53%	0.00%	N/A
Illegal users (non-customers)		**180,000**		**403,920**	**9.60%**	0.00%	9.60%	TBA
TOTAL		**776,607**	**3,073,675**	**773,737**	**18.38%**	**4.38%**	**14.00%**	**TBA**

	Energy Loss (MWH)	TL Target %Loss
TECHNICAL LOSS (TL)	**362,010**	**8.60%**

The following section summarizes JPS' assumptions in computing the values in Table 1-3and also provides the justification for the proposed values of JNTL, GNTL and RF.

1.2.6.1 Justification for System Losses Disaggregation

<u>Losses Associated with Rate 40 and 50 Customers</u>

In 2015, 1,913 of JPS' customers belonged to either the Rate 40 or Rate 50 Class. They contributed 0.45% to system losses in 2015. The sources and disaggregation of these sources are highlighted in Figure 1-1 and Figure 1-2 below.

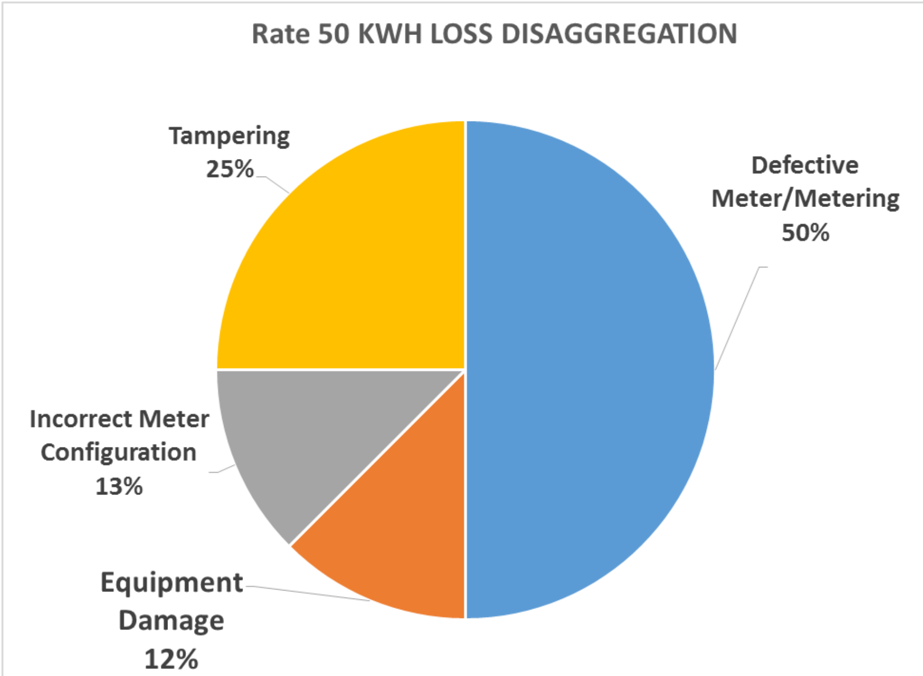


Figure 1-1: Rate 50 Loss Disaggregation

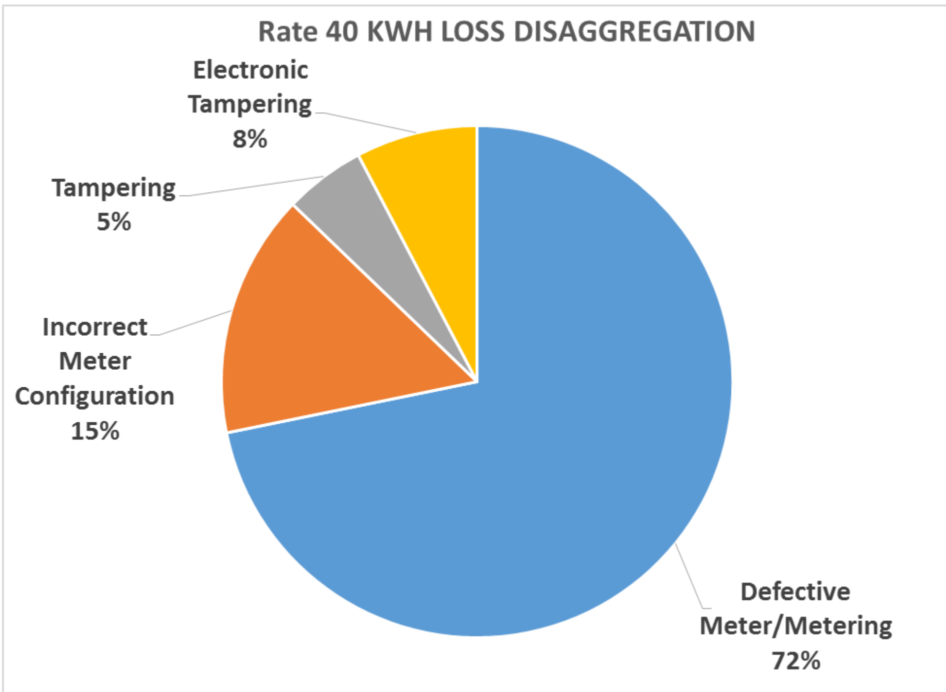


Figure 1-2: Rate 40 Loss Disaggregation

The sources of losses and the contribution of each source was obtained from information gathered from the annual audits that JPS conducts on these meters.

JPS' position is that the losses incurred by this group of customers are not totally within JPS' control given the clear evidence of meter tampering in some cases. It must be noted that though these customers are equipped with AMI meters, they continue to display unrelenting efforts towards new methods of tampering. We believe that assigning two thirds of the losses related to this customer group to the category of losses JPS has control over is reasonable given the prevalence of tampering.

JPS believes the responsibility factor related to this customer group should be the product of consultation with the OUR given the various factors that the licence required be taken into consideration in deriving the factor.

<u>Losses Associated with Large Rate 20 Customers</u>
The sources and contribution of losses from these sources for large Rate 20 Customers is shown in Figure 1-3 below:

Similar to the R40 & R50 customers, the large Rate 20 customers are equipped with smart meters which are audited annually. The results from the audit show that 37% of the irregularities found were "Line Tap". It is JPS' position that line taps are due to the pervasive and criminal efforts of some customers which ultimately are due to socio-economic factors which are not totally within the control of JPS. This type of irregularity is of a similar nature to meter tampering and contributes to 20% of the losses attributed to this group of customers. JPS posits that customers' are cunningly devising ways to abstract electricity using methods and means that are uncommon and difficult to detect.

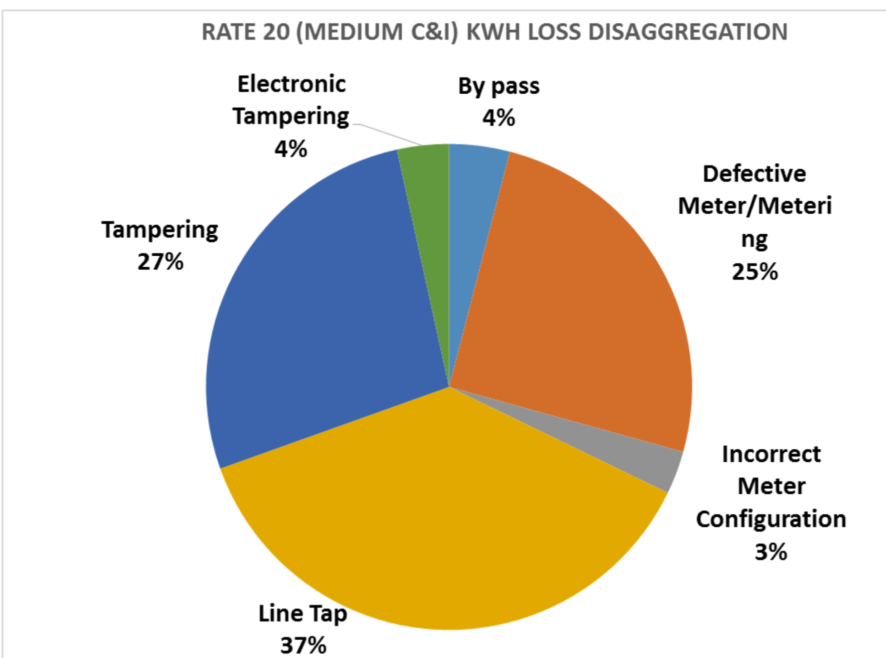


Figure 1-3: Rate 20 Loss Disaggregation

JPS believes the responsibility factor related to this customer group should be the product of consultation with the OUR given the various factors that the licence required be taken into consideration in deriving the factor.

Losses Associated with Rate 10 and Small Rate 20 Customers

Residential and small commercial customers account for over 95% of JPS' customer base. Rate 10 customers and small commercial customers contribute 7.08% and 0.32% respectively to system losses.

Figure 1-4 to Figure 1-7 below represent the disaggregation of losses for this group of customers. The data used to prepare the graph was obtained from investigations and audits. The results of our audits and investigations indicate, as illustrated in Figure 1-5 below, only 39% of the losses attributed to Rate 10 Customers are totally within JPS' control. The corresponding value for Rate 20 customers is 30% as in Figure 1-4.

JPS carries out approximately 100,000 investigations each year on all small accounts (R10/R20). From these investigations, an average of 30,000 irregularities is found. As shown in Figure 1-4 and Figure 1-5 respectively, 66% of the irregularities found were deemed to be customer related for small Rate 20 customers, while 52% of the R10 irregularities were deemed to be customer related.

Unlike the Rate 40 and 50 customers whose meter sockets are of the current transformer (CT) rated types that are installed on the Company's Distribution poles and are a part of the JPS owned metering facility, the meter socket used for Rate 10 and small Rate 20 customers utilizing under 100 and 200 amperes respectively, are not owned by JPS and it is the responsibility of the customer to ensure that they are maintained and kept in good working order. JPS' responsibility in the case of these customer groups stops at the pothead. All other infrastructural work to be done on the customer's premises is the responsibility of the customer. Where JPS audits and investigations reveal loss impacting defects with customer owned infrastructure, the losses are attributed to the customers. These defects include: Meter Tampering, Burnt Wire, Tampering, Defective Meter Socket, Defective Wiring, Illegal Abstraction, and Incorrect Wiring. The losses dictionary provided in Appendix VI provides a definition of these categories. JPS' standard operating practice dictates that whenever irregularities are found, a letter is sent to the customer explaining the irregularity, the correction needed and any actions that may be taken if the irregularity is not corrected within a stipulated time frame.

JPS believes the responsibility factor related to this customer group should be the product of consultation with the OUR given the various factors that the licence required be taken into consideration in deriving the factor.

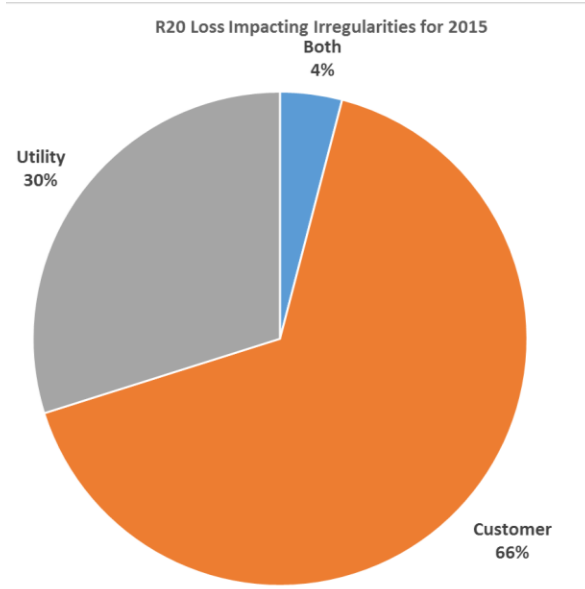


Figure 1-4: Attribution of Losses for Small Rate 20 Customers

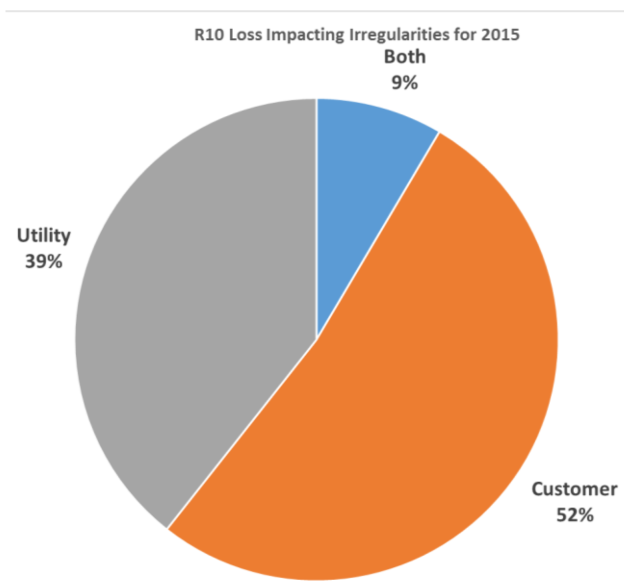


Figure 1-5: Attribution of Losses for Rate 10 Customers

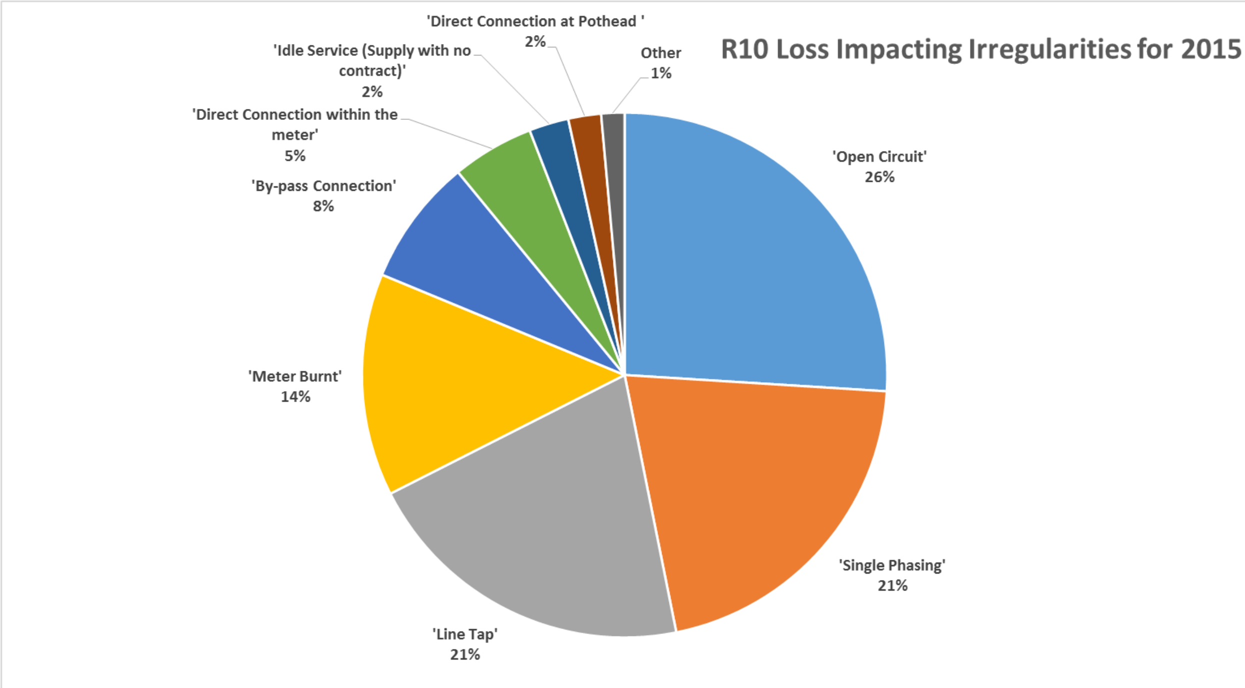


Figure 1-6: Disaggregation of customer related losses for Rate 10 Customers

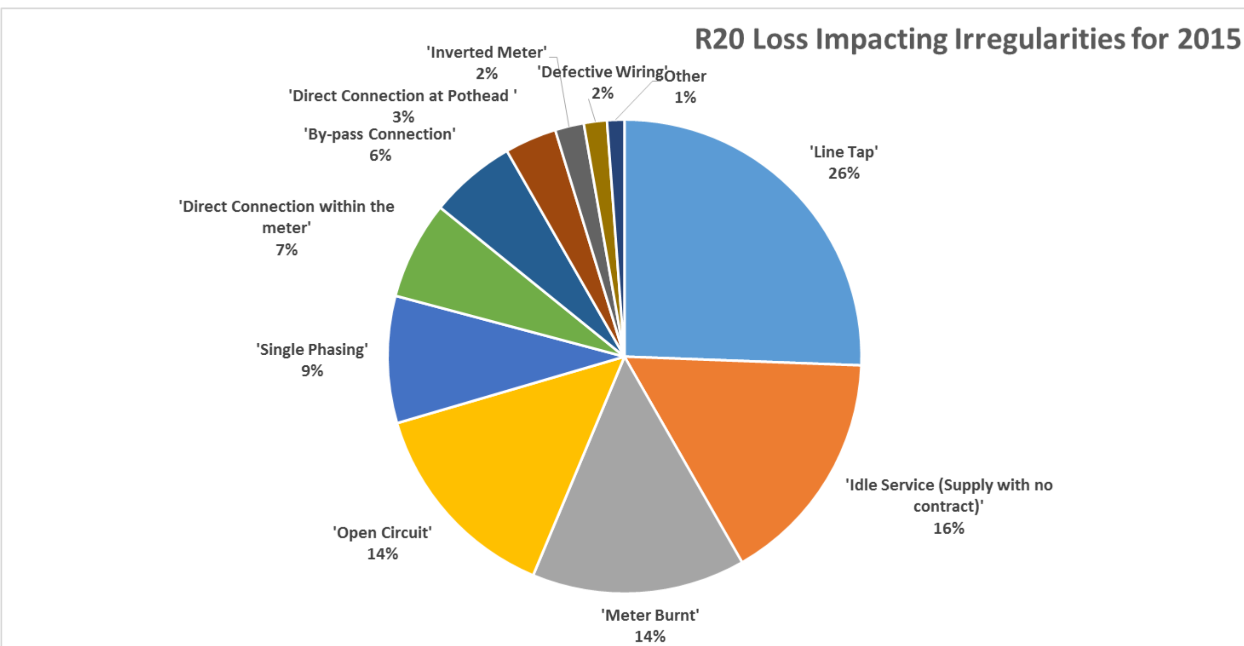


Figure 1-7: Disaggregation of customer related losses for Small Rate 20 Customers

<u>Unquantified Losses</u>

This represents any losses incurred due to the utility's own internal operations as well as any margin of error within our estimates.

JPS' position is that we accept full responsibility for this category of loss noting that a proactive and targeted approach is required to mitigate or control this type of energy loss.

Losses Associated with Rate 60 Customers

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 working street lights.

Losses due to Illegal Users

JPS is asserting that system losses associated with illegal users is mainly due to socioeconomic conditions which are largely outside of the purview of the electric utility. 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 Loss. 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 Quantum in 2013 benchmarked non-technical energy loss or electricity theft between 2004 and 2011, of several electric utilities in countries with similar socio-economic conditions. These countries were: Jamaica, Brazil, Dominican Republic, Argentina, Guatemala, Bolivia and El Salvador. In total 53 distribution utilities were included. The objective of the study was to determine whether there is a strong relationship between non-technical losses (NTL) and the social conditions of the population living in the study areas. 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 1-8 below, which highlights energy losses in parishes with a high population density of inner city and squatter settlements.

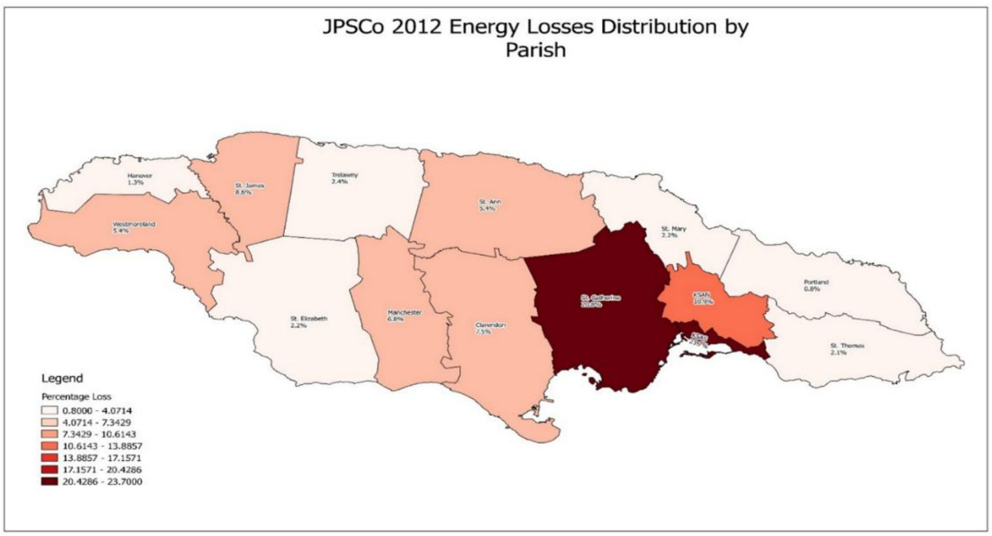


Figure 1-8: JPS Energy Loss Distribution

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 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.

JPS believes the responsibility factor related to this customer group should be the product of consultation with the OUR given the various factors that the licence required be taken into consideration in deriving the factor.

1.2.6.2 Targets for TL, GNTL and JNTL and Proposed Responsibility Factor for the Year 2015

The recognition of a true-up calculation for system losses in the 2016 annual tariff filing adjustment requires the prior establishment of targets for the year 2015 for the three components of system losses as defined in the Licence. These would not have been previously defined, however, JPS has already incurred US$37.5M fuel impairment in 2015 as a result of the system losses incentive scheme that was included in the fuel cost recovery mechanism under the price cap regime. This mechanism remains in force up to July 2016. Since these targets were not previously established and the alternate loss recovery mechanism was in force heretofore, there is no basis for the inclusion of the losses true-up in the 2016 tariff filing. Instead JPS proposes that the baseline targets be set for the tariff period commencing July 2016 in order to facilitate assessment and adjustment in tariff periods commencing in 2017. JPS is proposing that $TUlos_{2015}$ be set to zero and this can be achieved by setting the 2015 losses target to the actual losses performance for these targets in 2015. That is,

$$\text{Target System Loss “a” Rate\%}_{2015} = \text{Actual System Loss “a” Rate\%}_{2015}$$

$$\text{Target System Loss “b” Rate\%}_{2015} = \text{Actual System Loss “b” Rate\%}_{2015}$$

$$\text{Target System Loss “c” Rate\%}_{2015} = \text{Actual System Loss “c” Rate\%}_{2015}$$

1.2.6.3 Targets for TL, GNTL and JNTL and Proposed Responsibility Factor for the Year 2016

The following tables reflect the 2016 targets that JPS is proposing for each of the three losses components. These targets were set based on loss reduction initiatives to be executed in 2016. Details of these are described in Section 1.7.1.

Figure 1-9: Proposed Losses Targets for 2016

Description/Category		Target %Loss	Target JNTL	Target GNTL
Billed Customers	Streetlight/Stoplight/Interchange (R60)	0.00%	0.00%	0.00%
	Large C&I (Rate 40 & 50)	0.35%	0.20%	0.15%
	Medium C&I (rate 20)	0.28%	0.19%	0.09%
	Small C&I (rate 20)	0.28%	0.09%	0.19%
	Residential (rate 10)	6.82%	2.97%	3.85%
Sub-Total		**7.73%**	**3.45%**	**4.28%**
Unquantified		0.48%	0.48%	0.00%
Illegal users (non-customers)		9.59%	0.00%	9.59%
TOTAL		**17.80%**	**3.93%**	**13.87%**

	Target TL %Loss
TECHNICAL LOSS (Y_a)	**8.40%**

1.2.7 JPS Position on the Heat Rate Target

Prior to the new 2016 Licence, the recovery of the fuel cost was subject to two efficiency measures: Heat Rate and System Losses. In its 2014-2019 Determination notice, the OUR proposed a change to the fuel recovery mechanism that existed previously. In its determination the OUR proposed that:

- Net generation from non-combustible renewables such as wind, hydro and solar shall not be included in the JPS' generating units heat rate calculation; and
- The Independent Power Producers' (IPPs) fuel cost shall only be adjusted for efficiency by the system losses factor: $\frac{(1-\text{System Losses Actual})}{(1-\text{System Losses Target})}$

Consequently, the fuel cost formula that was applied by JPS in the Fuel Rate Adjustment Mechanism was:

$$\text{Pass Through Cost} = \left[\text{IPPs Fuel Cost} + \left(\text{JPS Fuel Cost} \times \left(\frac{\text{JPS Heat Rate Target}}{\text{JPS Heat Rate Actual}}\right)\right)\right] \times \left(\frac{1-\text{Losses Actual}}{1-\text{Losses Target}}\right)$$

The OUR also determined that:

- JPS' generating heat rate target shall be 12,010 kJ/kWh for the period January 2015 – May 2019.
- The indicative technical losses ceiling for period January 2015 – May 2019 shall be 8.4%.
- JPS' non-technical loss target ceiling for the period January 2015 – May 2019 shall be 10.8%.

- The technical and non-technical losses and heat rate target will be reviewed by the Office at each Annual Tariff Adjustment during the price cap period, 2015 – 2019

JPS began applying this new fuel rate adjustment mechanism in its March 2015 billing.

1.2.7.1 Changes introduced in the New Electricity Licence

Exhibit 2 of the Electricity Licence specifies that the applicable heat rate could either be the JPS thermal heat rate, the system heat rate or it could be based on any other mechanism determined by the OUR. Regardless of heat rate utilized, the fuel rate calculation proceeds as follows:

The fuel cost portion of the monthly bill computed under the appropriate rate schedule will be calculated in the following manner:

$$\mathbf{F = F_m/S_m}$$

Where:

Billing Period = The billing month during the effective period for which the 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)
S_m	=	Total kWh sales for the period

Where :

F_m = $FAct_{m-1}$ +over/under billing $_{m-1}$ + H

To drive optimal dispatch and minimize fuel cost and related losses the Licensee is incentivized to improve the Heat rate as reflected in the fuel pass through, the H-factor.
The monthly Heat Rate Incentive or **H-factor** will be calculated as follows:

H	=	$\{(HR\ T - HR\ Act_{m-1})/HR\ T\} * FAct_{m-1}$
HRT	=	Heat Rate Target per year as established during the rate setting process
HR Act	=	Actual Heat-Rate prior month, corrected for items outside the Licensee's control; meaning higher than anticipated forced outages[2] at the IPP's or 3rd party generators that were part of the original HR target setting.
$FAct_{m-1}$	=	The Actual energy cost incurred in the previous month (fuel, fuel additives, IPP and Take or Pay charges).

[2] Where the Licensee gets to correct the heat rate for higher than anticipated forced outages the potential Liquidated damages of the IPP's become an off-set against the fuel charges (preferred solution), where the licensee would not get the heat rate relief the Licensee should be able to retain the Liquidated Damages paid by the (virtual) IPPs.

JPS Position on Heat Rate
A system heat rate target that includes renewables sends a clear and unambiguous signal of improving fuel conversion and replacement that is resulting in lower fuel cost to customers. JPS invested over US$40M between 2010 to 2014 in Wind and Hydro Renewables. The impact of renewables on fuel cost to customers weighed heavily in JPS' decision to invest in the renewable capacity. The company remains committed to the national goal of increased generation from renewables and believes the use of the JPS heat rate provides a strong incentive for the utility to continue its investments in renewables.

The heat rate target should continue to include and be modified by the inclusion of renewable capacity. This factor weighed heavily in JPS' decision to invest in renewable capacity.

System modelling of the current and future unit availability and dispatch suggest a target JPS Heat Rate, which is the combination of JPS Thermal and JPS Renewables, at 10,710 kJ/kWh.

Request for Reconsideration
We are requesting the OUR's reconsideration of the heat rate applied in the fuel cost recovery formula. JPS is proposing that the JPS Heat Rate be used instead and that the target for 2016/2017 be set at 10,710 kJ/kWh. Section 2 details the modelling assumptions used in projecting the 2016 JPS Heat Rate which guided the determination of the proposed target.

1.3 Application of the Annual Revenue Cap Adjustment Formula

The annual adjustment in the new Licence allows JPS to adjust its rates 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, and system losses incentive mechanism and a FX surcharge offset by income received for interest paid by customers.

The following outlines JPS' proposal in relation to the components of the non-fuel electricity prices adjustment factor (dPCI) and its application to the non-fuel tariffs for 2016.

The application of the annual escalation adjustment formula dPCI will result in an increase of 9.53% 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 2016 and March 2014 of 7.05%, derived from the CPI data[3] published by Statin (see Appendix I);
- U.S. point-to-point inflation rate (INFUS) between March 2016 and March 2014 of 0.78%, derived from the U.S. Department of Labor statistical data[4] (see Appendix I); and
- The 9.38% increase in the Base Exchange Rate $\left(\frac{EX_n - EX_b}{EX_b}\right)$ from J$112: US$1 to J$122.50: US$1.

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

The table below sets out the details of the annual adjustment factor, dPCI that amounts to a 9.53% increase to RC_{2016}.

Table 1-4: Escalation Factor (dPCI)

Annual Adjustment Clause Calculation			
ESCALATION FACTOR (dI) based on point to point data as at March 2016			
Line	Description	Formula	Value
L1	Base Exchange Rate		112.00
L2	Proposed Exchange Rate		122.50
L3	Jamaican Inflation Index		
L4	CPI @ Mar 2016		229.3
L5	CPI @ Mar 2014		214.2
L6	US Inflation Index		
L7	CPI @ Mar 2016		238.1
L8	CPI @ Mar 2014		236.3
L9	Exchange Rate Factor	(L2-L1)/L1	9.38%
L10	Jamaican Inflation Factor	(L4-L5)/L5	7.05%
L11	US Inflation Factor	(L7-L8)/L8	0.78%
L12	Escalation Factor	L9*{0.8+(0.8-0.0688)*L11}+(0.8-0.0688)*L11+(1-0.8)*L10	9.53%
L13	**Escalation Factor net of Q**	**dI - Q**	9.53%

1.3.1 Computation of the Revenue, FX and Interest Surcharges and RC_{2016}

The computed value of RC_{2016} using JPS' proposal outlined earlier in Section 1.2.1 is indicated in Table 1-5.

Table 1-5: Computed Value of RC_{2016}

dI adjusted for Q factor	**9.53%**
WACC (pre-tax)	**13.22%**
RC_{2016}	**40,604,648,523**
RS_{2015}	**-**
SFX_{2015} - SIC_{2015}	**526,670,865**

Table 1-5 also shows the computed values of FX and interest surcharges (SFX_{2015} – SIC_{2015}) which were obtained by applying the targets proposed in the previous sections of this document. The details of the calculations are provided in Table 1-6.

The application of the computed values of RC_{2015}, SFX_{2015} and SIC_{2015} to the annual adjustment formula

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

results in a revenue requirement of 45,070,568,280, an increase of 6.13% over the 2015 actual revenue.

An annual adjustment factor of 6.13% will be applied to the 2015 actual revenue. The approved tariff basket, shown in Table 1-7 below, is derived using the 2014 billing determinants and the approved non-fuel tariffs arising from the OUR's 2015 Determination Notice. The 2015 actual revenue is derived from the 2015 billing determinants and the approved non-fuel tariffs (see Table 1-9).

Table 1-6: Computed FX and Interest Surcharges (SFX_{2015} and SIC_{2015})

FX and Interest for 2015 (SFX_{2015} - SIC_{2015})			
Line	**Description**	**Formula**	**Value**
	FX Surcharge		
L1	TFX		-
L2	AFX_{2015}		603,295,228
L3	**SFX_{2015}**	**L2-L1**	**603,295,228**
	Interest Surcharge		
L4	Actual net interest expense/(income) in relation to interest charged to customers for 2015		**-**
L5	Actual Net Late Payment fees for 2015		76,624,363
L6	AIC_{2015}	L4+L5	76,624,363
L7	TIC_{2015}		-
L8	**SIC_{2015}**	**L6-L7**	**76,624,363**
L9	**SFX_{2015} - SIC_{2015}**	**L3-L8**	**526,670,865**

Table 1-7: 2015 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	1,119,893,221	4,218,090,152					0	5,337,983,373
Rate 10	LV	>100	1,531,243,204	9,858,081,966					0	11,389,325,169
Rate 20	LV		671,897,996	9,975,953,642					-	10,647,851,638
Rate 40	LV - Std		123,998,760	3,349,037,071	3,684,087,085				3,684,087,085	7,157,122,916
Rate 40	LV - TOU		8,922,420	610,839,596		23,603,697	235,599,911	239,192,611	498,396,219	1,118,158,235
Rate 50	MV - Std		9,456,240	2,011,454,983	1,623,727,413				1,623,727,413	3,644,638,636
Rate 50	MV - TOU		1,830,240	460,327,450		21,420,545	198,537,714	195,115,009	415,073,269	877,230,959
Rate 60	LV		9,481,250	1,551,905,877					-	1,561,387,127
TOTAL			3,476,723,331	32,035,690,737	5,307,814,498	45,024,242	434,137,625	434,307,621	6,221,283,986	41,733,698,054

Table 1-8: 2015 Actual Revenues

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	1,022,002,955	4,257,465,344	-	-	-	-	5,279,468,298
Rate 10	LV	> 100	1,560,584,048	10,397,087,158	-	-	-	-	11,957,671,206
Rate 20	LV		654,051,024	10,066,458,808	-	-	-	-	10,720,509,832
Rate 40A	LV		-	-	-	-	-	-	-
Rate 40	LV - Std		125,371,440	3,418,117,385	3,662,210,388	-	-	-	7,205,699,213
Rate 40	LV - TOU		9,074,940	600,271,360	-	23,066,179	232,469,603	234,246,573	1,099,128,655
Rate 50	MV - Std		9,456,240	2,059,629,531	1,681,915,758	-	-	-	3,751,001,529
Rate 50	MV - TOU		1,753,980	469,262,260	-	20,558,630	188,164,340	201,205,556	880,944,766
Rate 60	LV		12,115,500	1,559,557,276	-	-	-	-	1,571,672,776
TOTAL			**3,394,410,126**	**32,827,849,122**	**5,344,126,146**	**43,624,809**	**420,633,943**	**435,452,129**	**42,466,096,275**

Table 1-9: 2015 Billing Determinants[5]

Class		Block/ Rate Option	Average 2015 Customer	Energy kWh Std.	Demand-KVA			
					Std.	Off-Peak	Part Peak	On-Peak
Rate 10	LV	<100	210,351	494,479,134	-	-	-	-
Rate 10	LV	>100	321,203	518,557,963	-	-	-	-
Rate 20	LV		60,426	606,048,092	-	-	-	-
Rate 40	LV - STD		1,644	659,868,221	2,256,751	-	-	-
Rate 40	LV - TOU		119	115,882,502	-	337,077	325,574	256,220
Rate 50	MV -STD		124	412,751,409	1,156,910	-	-	-
Rate 50	MV -TOU		23	94,040,533	-	317,116	297,446	247,900
Rate 60	STREETLIGHTS		394	70,921,204	-	-	-	-
TOTAL			594,284	2,972,549,058	3,413,661	654,193	623,020	504,120

Table 1-10: Approved Non-Fuel Tariffs for 2015

Class		Block/ Rate Option	Customer Charge	Energy-J$/kWh	Demand-J$/KVA			
					Std.	Off-Peak	Part Peak	On-Peak
Current Rates								
Rate 10	LV	<100	404.88	8.61				
Rate 10	LV	>100	404.88	20.05				
Rate 20	LV		902.0	16.61				
Rate 40	LV - Std		6,355.00	5.18	1,622.78			
Rate 40	LV - TOU		6,355.00	5.18		68.43	714.03	914.24
Rate 50	MV - Std		6,355.00	4.99	1,453.80			
Rate 50	MV - TOU		6,355.00	4.99		64.83	632.60	811.64
Rate 60	LV		2,562.50	21.99				
EEIF				0.4998				

The weights of each tariff, relative to the 2015/2016 actual revenues shown in

[5] The 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%.

Table 1-8 are shown in Table 1-11 below.

Table 1-11: Non-Fuel Weights for 2015 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	2.41%	10.03%	0.00%	0.00%	0.00%	0.00%	12.43%
Rate 10	LV	>100	3.67%	24.48%	0.00%	0.00%	0.00%	0.00%	28.16%
Rate 20	LV		1.54%	23.70%	0.00%	0.00%	0.00%	0.00%	25.24%
Rate 40	LV - Std		0.30%	8.05%	8.62%	0.00%	0.00%	0.00%	16.97%
Rate 40	LV - TOU		0.02%	1.41%	0.00%	0.05%	0.55%	0.55%	2.59%
Rate 50	MV - Std		0.02%	4.85%	3.96%	0.00%	0.00%	0.00%	8.83%
Rate 50	MV - TOU		0.00%	1.11%	0.00%	0.05%	0.44%	0.47%	2.07%
Rate 60	LV		0.03%	3.67%	0.00%	0.00%	0.00%	0.00%	3.70%
TOTAL			7.99%	77.30%	12.58%	0.10%	0.99%	1.03%	100.0%

Table 1-12 below shows how JPS proposes to apply the 2016 revenue adjustment factor of 6.13% to the individual non-fuel revenue components in the 2015 approved tariff basket.

Table 1-12: 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	6.1331%	6.1331%				
Rate 10	LV	> 100	6.1331%	6.1331%				
Rate 20	LV		6.1331%	6.1331%				
Rate 40A	LV							
Rate 40	LV - Std		6.1331%	6.1331%	6.1331%			
Rate 40	LV - TOU		6.1331%	6.1331%		6.1331%	6.1331%	6.1331%
Rate 50	MV - Std		6.1331%	6.1331%	6.1331%			
Rate 50	MV - TOU		6.1331%	6.1331%		6.1331%	6.1331%	6.1331%
Rate 60	LV		6.1331%	6.1331%				

Proof that the weighted adjustment factor proposed by JPS is equal to 6.13% is shown in

Table 1-13 below.

Table 1-13: 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	0.15%	0.61%	0.00%	0.00%	0.00%	0.00%	0.76%
Rate 10	LV	> 100	0.23%	1.50%	0.00%	0.00%	0.00%	0.00%	1.73%
Rate 20	LV		0.09%	1.45%	0.00%	0.00%	0.00%	0.00%	1.55%
Rate 40A	LV		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 40	LV - Std		0.02%	0.49%	0.53%	0.00%	0.00%	0.00%	1.04%
Rate 40	LV - TOU		0.00%	0.09%	0.00%	0.00%	0.03%	0.03%	0.16%
Rate 50	MV - Std		0.00%	0.30%	0.24%	0.00%	0.00%	0.00%	0.54%
Rate 50	MV - TOU		0.00%	0.07%	0.00%	0.00%	0.03%	0.03%	0.13%
Rate 60	LV		0.00%	0.23%	0.00%	0.00%	0.00%	0.00%	0.23%
TOTAL			0.49%	4.74%	0.77%	0.01%	0.06%	0.06%	6.13%

The proposed revenue and the corresponding proposed rates for 2016/2017 arising from the application of the annual adjustment formula are given in Table 1-14 and
Table 1-15 respectively.

Table 1-14: Proposed Revenues for 2016/2017

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	1,084,683,029	4,518,578,332	-	-	-	-	- 5,603,261,361
Rate 10	LV	> 100	1,656,295,635	11,034,746,958	-	-	-	-	12,691,042,592
Rate 20	LV		694,164,379	10,683,840,966	-	-	-	-	11,378,005,345
Rate 40A	LV		-	-	-	-	-	-	-
Rate 40	LV - Std		133,060,548	3,627,752,643	3,886,816,021	-	-	-	7,647,629,211
Rate 40	LV - TOU		9,631,512	637,086,375	-	24,480,842	246,727,108	248,613,060	1,166,538,897
Rate 50	MV - Std		10,036,197	2,185,947,887	1,785,068,694	-	-	-	3,981,052,778
Rate 50	MV - TOU		1,861,553	498,042,405	-	21,819,504	199,704,575	213,545,617	934,973,654
Rate 60	LV		12,858,551	1,655,205,890	-	-	-	-	
TOTAL			**3,602,591,403**	**34,841,201,455**	**5,671,884,715**	**46,300,346**	**446,431,683**	**462,158,678**	**45,070,568,280**

Table 1-15: Proposed 2016/2017 Tariff

Class		Block/ Rate Option	Customer Charge	Energy-J$/kWh	Demand-J$/KVA			
					Std.	Off-Peak	Part Peak	On-Peak
Rate 10	LV	--100	429.71	9.14				
Rate 10	LV	> 100	429.71	21.28				
Rate 20	LV		957.32	17.63				
Rate 40A	LV							
Rate 40	LV - Std		6,744.76	5.50	1,722.31			
Rate 40	LV - TOU		6,744.76	5.50		72.63	757.82	970.31
Rate 50	MV - Std		6,744.76	5.30	1,542.96			
Rate 50	MV - TOU		6,744.76	5.30		68.81	671.40	861.42
Rate 60	LV		2,719.66	23.34				

While there is an overall 6.13% increase in the non-fuel revenues compared to 2015 actual, this includes the impact of resetting the Base Exchange rate from J$112: US$1 to J$122.50: 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 1.32%.

We are proposing that the EEIF rate remain at J$0.4998/kWh for all rate classes. This is to ameliorate the impact of the 4.1% fuel tariff increase that results from the removal of the losses incentive mechanism from fuel cost recovery.

A detailed analysis of the non-fuel tariff adjustment for 2016/17 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 2.2%. Additionally, it shows that for commercial customers there will be a range of adjustments from an increase of 2.1% for Rate 20 customers and to an increase of 2.5% for Rate 50 TOU customers.

Section 1.4 discusses some additional requested changes as part of the annual tariff adjustment application. This includes a proposed adjustment to the 2014/2015 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. In Section 1.6, JPS discusses its proposal for treating with the LED Street Lighting tariff.

The 2015 performance of system losses, the community renewal program and other factors that impact the non-fuel rate determination such as FX losses/gains and net late payment fees revenues are presented in Section 1.7. It also describes the 2016 system losses initiatives and plans for the Community Renewal Programme.

In Section 1.8, we present our proposal for OUR's consideration of an Extraordinary Rate Review in the 2017/2018 period. Section 1.9 concludes Part 1 of this document and presents a proposal for the treatment of the 2016 losses impairment cost from the fuel rate mechanism.

1.4 Pre-paid Rates

1.4.1 Rate 10 Prepaid Rates

JPS' pre-paid pilot programme ended in December 31, 2015 and as of end of December 2015, there were 294 customers on the programme from whom revenues for 2015 of J$4,794,884.00 were obtained. In its 2015 Annual Adjustment Filing, JPS indicated that the two tiered pre-paid tariff structure for Rate 10 customers could threaten JPS' financial position as the tariff structure is not revenue neutral with respect to the post-paid tariffs. While the revenues generated from PAYG customers is still very small compared to revenues from post-paid customers and the resulting financial fallout that arises from the lack of revenue neutrality for pre-paid customers is still relatively small, JPS remains strongly opposed to any rate structure that would seem to favour over one customer group relative to another. The current rate structure presents a clear arbitrage opportunity for prepaid customers relative to their post-paid counterparts. JPS believes that whatever rate structure is implemented the principles of fairness and non-discrimination should be present allowing all customers in the same class to be treated in a similar manner. JPS' analysis indicates that a three tiered PAYG rate structure more accurately captures the essence of the equivalent post-paid rates. JPS is therefore proposing that the three tiered structure be implemented for the 2016/2017 period. This will remove the mischief of having to right this wrong at a later date when PAYG would have become accustomed to paying the lower rates than their post-paid counterparts and therefore expectant of its continuation.

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 Table 1-15 is described in the following.

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

- $200.9558/kWh for the first 2kWh in a 30 day cycle
- $10.2539/kWh for the next 99 kWh in a 30 day cycle
- $21.7714/kWh for every kWh above 101kWh in a 30 day cycle

Table 1-16 provides an illustration of the analysis for the proposed rate. This shows that JPS could suffer a potential shortfall of approximately J$33.8M annually if all customers in the 0-100kWh band were to switch to pre-paid service but is revenue neutral for other consumption levels. This obviously is a much more sustainable position for JPS than if the two tiered structure was used. Use of the two structure would have resulted in a revenue shortfall of approximately J$286.7M as shown in Table 1-17.

Table 1-16: 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	79,074	22,457	23.67	27.79	26.37	52,014,031.11	49,356,243.26	(2,657,787.85)	(31,893,454.20)
50-100 kWh	105,616	97,278	76.75	15.24	15.22	123,535,866.72	123,373,746.16	(162,120.56)	(1,945,446.72)
100-200 kWh	192,771	335,134	144.88	16.37	16.37	457,192,204.80	457,192,204.80	-	-
200-300 kWh	76,070	220,429	241.48	18.53	18.53	340,384,678.11	340,384,678.11	-	-
300-400 kWh	26,291	108,015	342.37	19.49	19.49	175,434,356.07	175,434,356.07	-	-
400-500 kWh	10,639	56,673	443.91	20.01	20.01	94,502,397.38	94,502,397.38	-	-
500- 1000 kWh	11,961	94,617	659.20	20.59	20.59	162,345,791.81	162,345,791.81	-	-
>1000 kWh	3,471	89,133	2,139.95	21.41	21.41	159,028,479.69	159,028,479.69	-	-
Total						**1,512,423,775**	**1,512,261,654**	**(2,819,908)**	**(33,838,901)**

Table 1-17: Analysis of Rate 10 Pre-paid with 2 Tier Tariff Structure

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	79,074	22,457	23.67	27.79	15.20	52,014,031.11	28,449,560.02	(23,564,471.09)	(282,773,653.08)
50-100 kWh	105,616	97,278	76.75	15.24	15.20	123,535,866.72	123,211,625.60	(324,241.12)	(3,890,893.44)
100-200 kWh	192,771	335,134	144.88	16.37	16.37	457,192,204.80	457,192,204.80	-	-
200-300 kWh	76,070	220,429	241.48	18.53	18.53	340,384,678.11	340,384,678.11	-	-
300-400 kWh	26,291	108,015	342.37	19.49	19.49	175,434,356.07	175,434,356.07	-	-
400-500 kWh	10,639	56,673	443.91	20.01	20.01	94,502,397.38	94,502,397.38	-	-
500- 1000 kWh	11,961	94,617	659.20	20.59	20.59	162,345,791.81	162,345,791.81	-	-
>1000 kWh	3,471	89,133	2,139.95	21.41	21.41	159,028,479.69	159,028,479.69	-	-
Total						**1,512,423,775**	**1,512,099,533**	**(23,888,712)**	**(286,664,547)**

1.4.2 Rate 20 Prepaid Rates

As for 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 1-15, the prepaid Rate 20 tariff is descried as follows:

- $113.874/kWh for the first 10kWh in a 30 day cycle
- $18.131/kWh for every kWh above 10kWh in a 30 day cycle

The analysis of this proposal is shown in
Table 1-18 below. This tariff structure retains revenue neutrality for JPS for the Rate 20 customer class.

Table 1-18: Analysis of JPS Proposed Prepaid Rate 20 Customers

Customer Bands	Customer Count	Test Year Demand (MWh)	Average Consumption (kWh/month)	Post-paid Rate	Pre-paid Rate	Monthly Post-paid Revenue	Monthly Pre-paid Revenue	Monthly Variance	Annual Variance
(0-50] kWh	10,236	2,664	21.69	62.27	62.27	13,825,113.17	13,825,113.17	-	-
(50-100] kWh	7,405	6,643	74.76	30.94	30.94	17,128,315.93	17,128,315.93	-	-
(100-1000] kWh	26,680	119,640	373.69	20.69	20.69	206,280,317.95	206,280,317.95	-	-
(1000-7500] kWh	9,279	278,824	2,504.08	18.51	18.51	430,086,482.50	430,086,482.50	-	-
>7500 kWh	1,013	203,568	16,746.30	18.19	18.19	308,575,194.56	308,575,194.56	-	-
Total						**962,070,310.94**	**962,070,310.94**	-	-

1.5 Community Renewal Rate

In the 2015/2016 Annual Tariff Adjustment Determination, the OUR approved a rate for eligible participants of the community renewal programme. The eligibility criteria that was proposed in

JPS' 2015/2016 Annual Adjustment Filing was that participants should be beneficiaries of the PATH programme and that they should be new customers or customers who had been inactive for more than twelve (12) months. Since submitting that proposal, further field work in the communities indicate that there were only a limited number of people who were enrolled on the PATH programme and thus, the Community Renewal programme will be not be as effective if this criteria is not expanded to be more inclusive.

JPS has been consulting with the PIOJ to finalise a selection criteria and will submit a separate proposal on this to the OUR by May 31, 2016. In the interim, 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 with high levels of unemployment and with a large percentage of people earning minimum wage. JPS is proposing that the Community Renewal rate for the 2016/2017 period for both post-paid and pre-paid customers be $9.14/kWh for up to 150kWh of consumption per month. This rate will not attract a customer charge or the EEIF tariff as long as consumption remains below 150kWh in a billing cycle.

Persons consuming above 150kWh will pay the same rate as for post-paid (including customer charge and EEIF) or prepaid customers (whichever is applicable) for excess consumption above 150kWh.

1.6 Tariffs for LED Street Lighting

In its 2014 – 2019 Determination, the OUR requested that JPS submit a proposal for tariffs for LED Street Light within six (6) months of the effective date of the Determination. JPS subsequently submitted its proposal to the OUR on August 7, 2015. In its proposal, JPS offered a technical, economic and tariff evaluation of replacing the existing street lighting system with LED. JPS indicated that given the uncertainty in the timing and final outcome of the programme, it was prudent to wait until the LED replacement proposal is finalised before the tariff is prescribed.

The OUR's response in the 2015 Annual Tariff Filing Adjustment was to give JPS sixty (60) additional days to allow for further negotiations between the Ministry of Local Government and JPS. JPS was mandated to meet with all the stakeholders (including ESET) to finalise the terms and conditions of the replacement so that a definitive tariff proposal could be submitted to the OUR for LED Street Lights. The OUR further offered its assistance to facilitate and expedite the discussions and negotiations among the stakeholders. Following the publication of the 2015 Determination Notice, JPS wrote to the OUR indicating the difficulty of finalising the terms and conditions within the stipulated time asking for a further extension.

JPS in the interim negotiated a Licence amendment with the Ministry of Science, Energy, and Technology which concluded in December 2015. The responsibility and ownership for the Street Lighting Replacement project was addressed in Condition 28 of Electricity Licence 2016. Condition 28 states:

"The Licensee shall, by December 30, 2016, commence a programme for the implementation of smart LED lighting technology, that has intelligence capable of remotely reading the consumption of each lamp; provides a unique identifier; allows for the identification of out-of-service lamps; provides for the dimming of lights when necessary; can accommodate video surveillance and other

smart features and is designed in line with international best practices. This programme is hereinafter referred to as the "Smart Streetlight Programme". The Office shall utilise a Fund or the System Benefit Fund (as defined in the EA), to allow the Licencee to recover the costs of implementing the Smart Streetlight Programme."

Given the changes introduced in the Licence and the intent to establish a Fund for the progamme JPS believes it is prudent for us to delay the implementation of the LED tariff until the 2017/2018 filing where we are requesting OUR's consideration for an Extraordinary Rate Review (see Section 1.8). Also, although JPS is at an advanced stage of the selection process for the Contractor to implement the Smart LED street lighting replacement project, this has not been finalised and until then, the final cost and economic evaluation of the project cannot be established. It is our intent to finalise the selection process by October 1, 2016

1.7 Factors Impacting the Non-Fuel Tariff

1.7.1 System Losses

System energy losses, especially non-technical losses (NTL), remain a chronic problem for JPS despite a number of initiatives and investments made to reduce the problem. In 2015, JPS incurred a revenue loss of US$37.5M due to system loss impairment. Concurrently, capital investments of US$8M was made in system loss reduction initiatives.

1.7.1.1 Summary of 2015 Losses Performance

The rolling system losses total for 2015 was 26.98%. This represents an increase of 0.34% in the level of system losses when compared to December 2014 result of 26.64%.
Figure 1-10 provides an illustration of the JPS' system loss performance over the past 5 years and

Figure 1-12 presents the energy loss spectrum as at December 2015. Although there was no evident point to point change in system losses for December 2015 compared to January 2015, the trend analysis shown in Figure 1-11 shows the general decline in monthly losses which reflects the efforts being made to reduce system losses.

Figure 1-10: JPS' System Loss Performance for past 5 years

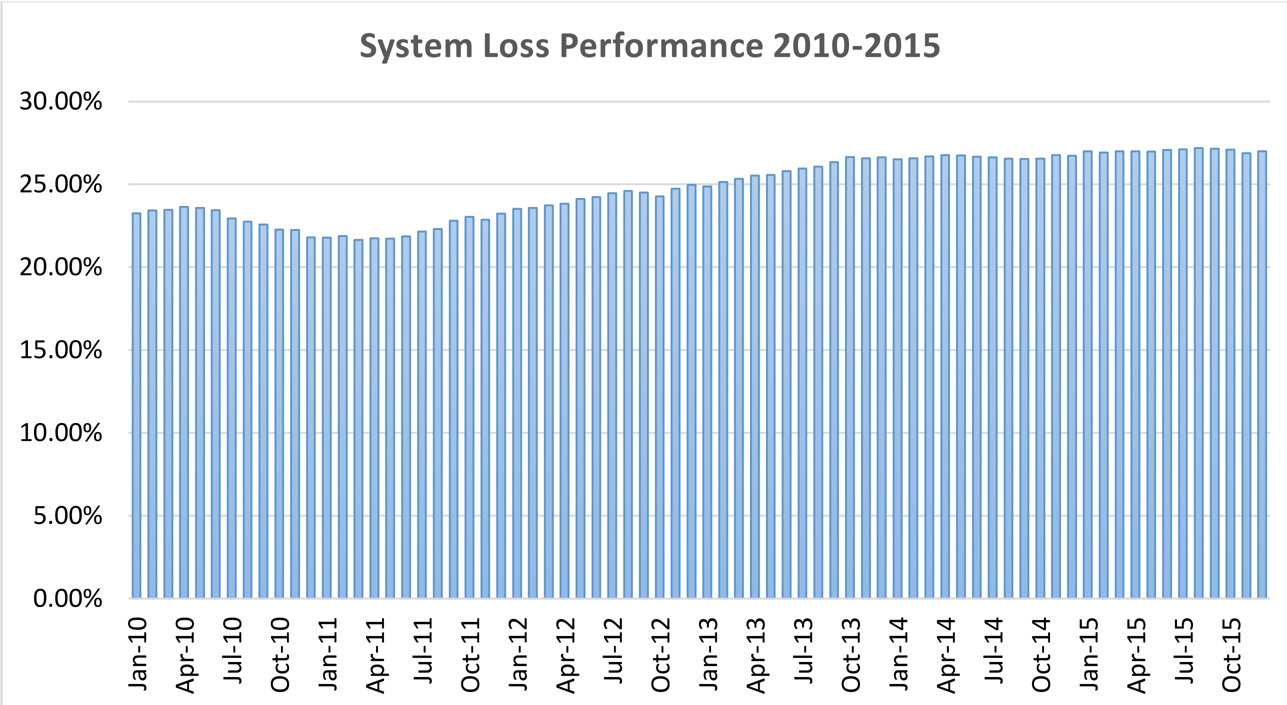
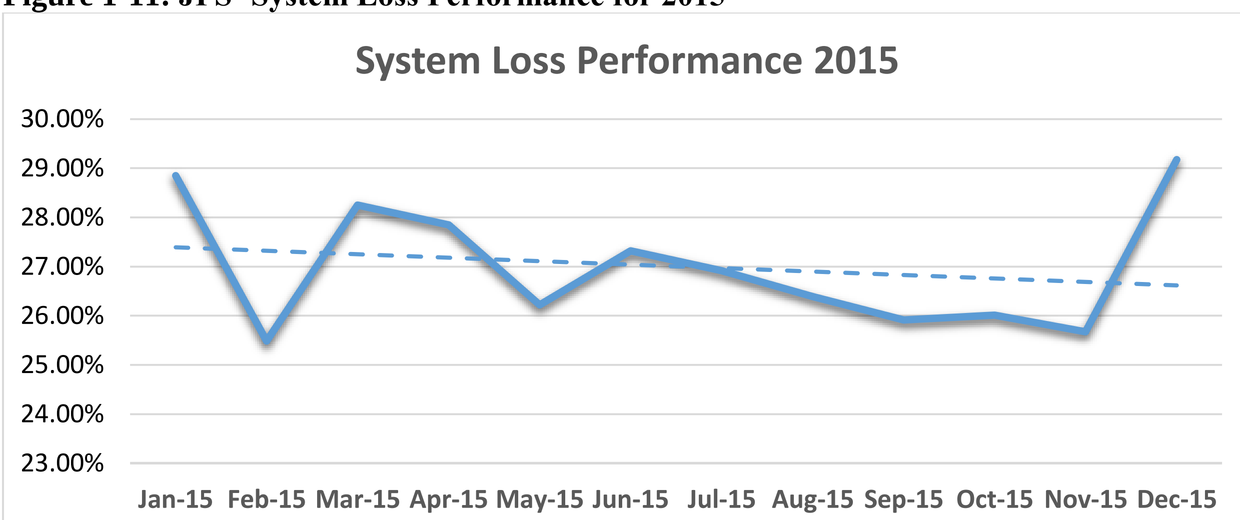


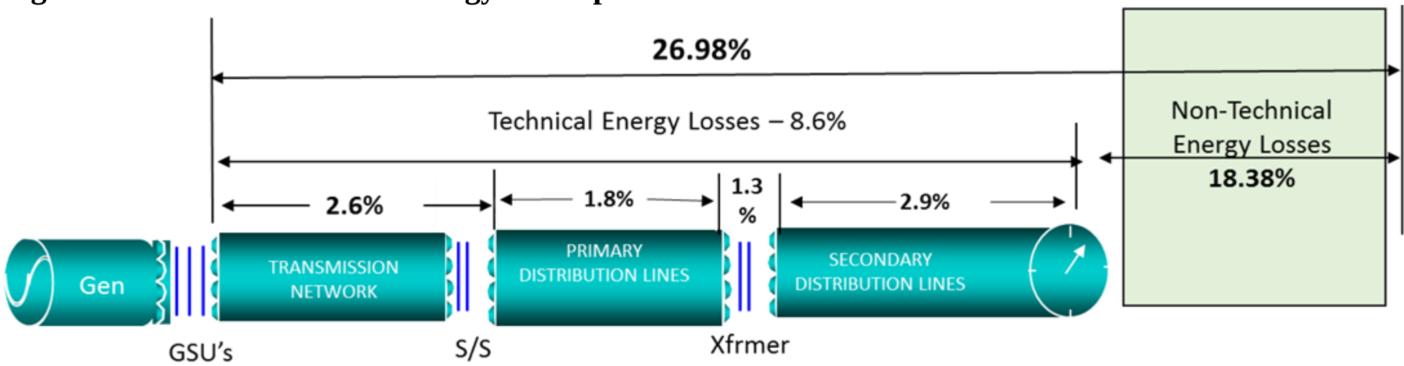
Figure 1-11: JPS' System Loss Performance for 2015



The energy loss spectrum as of December 2015 is shown in

Figure 1-12.

Figure 1-12: December 2015 Energy Loss Spectrum



Description/Category		No. of Cust.	Bill Sales (MWH)	Energy Loss (MWH)	% Loss
Description/Category		No. of Cust.	Bill Sales (MWH)	Energy Loss (MWH)	% Loss
Billed Customers	Streetlight/Stoplight/Interchange (R 60)	398	93,273	3903	0.09%
	Large C&I (Rate 40 & 50)	1,913	1,378,867	19,093	0.45%
	Medium C&I (rate 20)	4,061	280,872	12,957	0.31%
	Small C&I (rate 20)	56,530	303,856	13,331	0.32%
	Residential (rate 10)	533,705	1,016,807	298,147	7.08%
Sub-Total		**596,607**	**3,073,675**	**347,430**	**8.25%**
Internal Bleeds/Unquantified				22,387	**0.53%**
Illegal users (non-customers)		**180,000**		**403,920**	**9.60%**
TOTAL		**776,607**	**3,073,675**	**773,737**	**18.38%**

1.7.1.2 Technical Loss

Technical energy loss is inherently a part of every electric utility operation and as such is unavoidable. However, for each electric utility there is an optimal technical losses level at which it should operate and this is dependent on its geography, customer density, T&D voltage levels, economic conditions and the general network characteristic defined by each customers' supply point.

JPS' existing 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 diligently work towards its optimal technical loss level through several economically feasible initiatives with the application of systems to more accurately measure and quantify technical energy loss at all levels throughout the T&D network. In summary the two main technical loss reduction initiatives are (1) primary distribution feeder power factor correction (2) primary distribution feeder phase balancing.

It must be noted that over the past three decades JPS has made significant investments in technical loss reduction projects to move it towards its optimal level. These projects include but were not limited to (1) upgrade of over 75% of the primary distribution network voltages from 12 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.

<u>Power Factor (PF) Correction</u>

Over 240 MVARs or 400 pole-mounted capacitor banks are presently installed on the 110 feeders island-wide 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 VAR demands during peak and off peak periods, respectively.

A total of 81 feeders are at or above 0.95 power factor. A total of thirteen (13) feeders were corrected and improved during 2015 in order to bring these feeders within acceptable power factor levels. The plan for the next five years is to correct and maintain 90-95% of all feeders above 0.95 power factor.

<u>Feeder Phase Balancing</u>

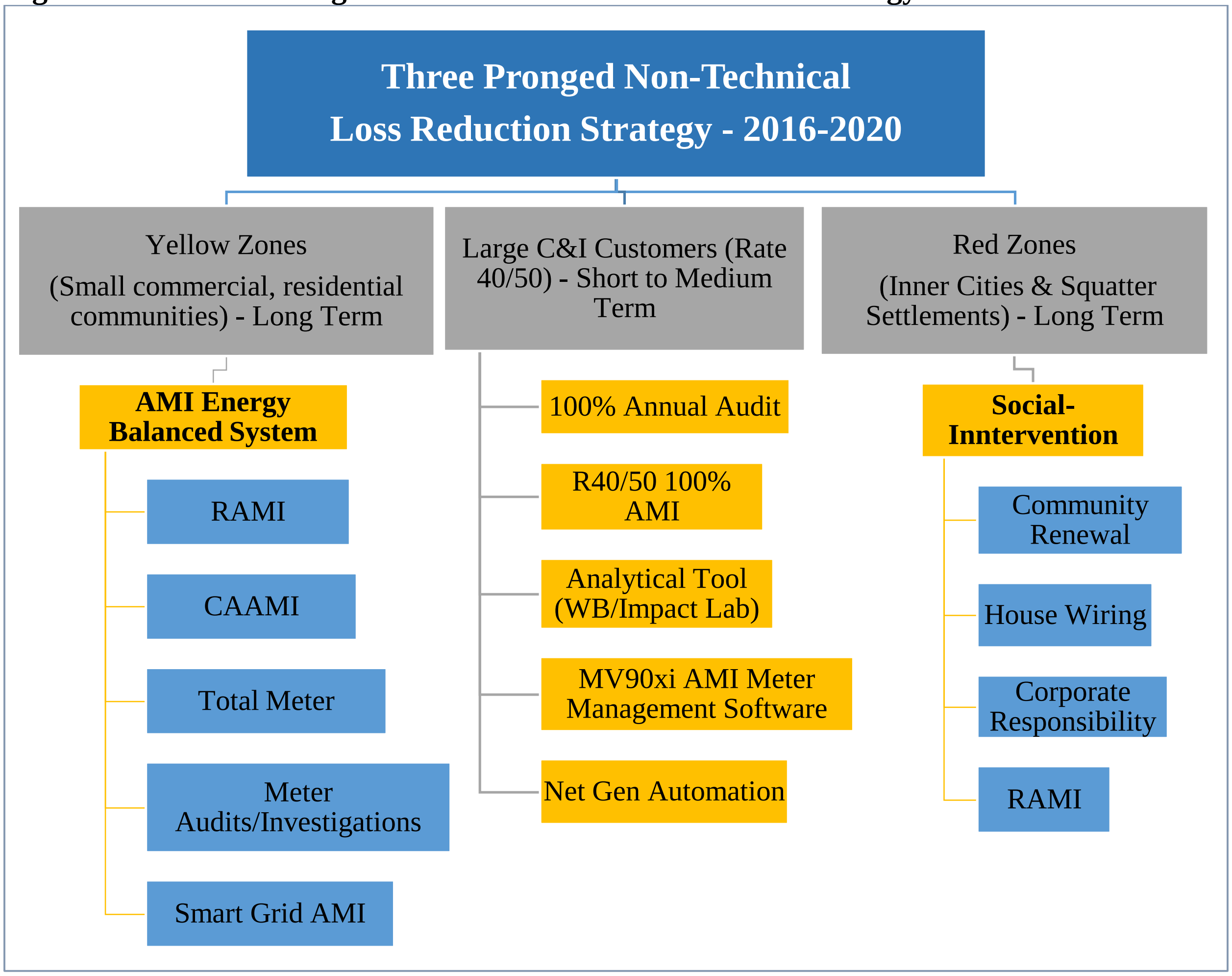
Feeder phase balancing is essential to maintaining good voltage quality and reliability of supply. This is achieved by ensuring the neutral current for the 3-phase system is less than 10% of the feeder average current. Phase imbalance above 20% translates into energy loss due to increased line current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

In 2015, the focus continued to be on identifying feeders with phase imbalance above 20% to economically improve and maintain them within acceptable phase balanced levels. For 2016-2020, emphasis will be placed on the continuation of this effort as part of our routine operation to maintain the phase imbalance of the corrected feeders within acceptable levels.

1.7.1.3 Non-Technical Losses

JPS non-technical energy loss reductions strategy is based on several years of studies, project implementation, reviews, analytics, lessons learnt and recommendations from both local and international consultants. The following outlines the JPS 2016 – 2020 non-technical energy loss reduction three pronged strategy namely (1) 'Yellow Zone' AMI technology and account audit solutions, (2) Large commercial and industrial customers' solutions, and (3) Infrastructure Reconfiguration & Social intervention for 'Red Zone communities. The primary objective is to demonstrate through the strategy, prioritized initiatives and solutions the incremental gains to be realized towards reducing energy loss.

Figure 1-13: Three Pronged Non-Technical Loss Reduction Strategy



Yellow Zone Initiatives

Yellow Zone initiatives are non-technical loss reduction projects implemented in communities characterised by low to high income earning customers that display low or no visible evidence of electricity theft in the form of throw-ups. Illegal abstraction in these communities is done through more sophisticated means, such as meter bypass and meter tampering. Residents in yellow zones are for the most part employed with a steady income stream and represent majority middle class. This strategy involves a continuation of routine revenue meter audits with improved data analytics, to increase the strike rate while applying technology through AMI, which is prioritized around areas with relatively high energy loss.

The Residential and Commercial Anti-Theft AMI solutions (RAMI & CAAMI) complemented by the use of 'Total (transformer) Meters' have been primarily implemented in this zone for the 2014 and 2015 periods. Over 15,000 RAMI & CAAMI solutions have been installed in Yellow Zone communities to date.

Smart Grid AMI revenue meters (i.e. smart AMI meters on customers' premises) combined with Advanced Automated Theft Detection Data Analytical tools are the industry trend that provide far greater benefits for both customer and utility. The plan for 2016 is to take advantage of these tools by transferring over 20,000 customers to this system, prioritized around feeders within Yellow Zone with high levels of energy loss. In summary, this will be the primary initiative for the loss reduction program as a more sustainable and longer term solution. This is depicted in Table 1-19.

The table below shows the comparison over a range of key considerations between the Yellow Zone RAMI and that of the Smart Grid AMI meter solution.

Table 1-19: RAMI and Smart Grid AMI meter comparison

No.	Description	RAMI	Smart Grid AMI
1	Average Cost/Customer (US$)	500	200
2	Energy Loss Benefit/customer (KWh)	96	77
3	Telecommunication infrastructure	3rd Party	JPS
4	Annual Deployment Worldwide (Qty)	< 0.5 million	>10 million
5	JPS Annual Deployment Capacity (Qty)	≈8,000	>20,000
6	Communication Reliability	≈70%	≥98%
8	JPS Installation capacity /Year	≈8,000	>20,000
9	Discount Payback Period (Years)	5.1	3.1
10	Internal Rate of Return (IRR)	30%	55%
11	Relative ease of installation & maintenance	Complex	Plug 'n' play

RAMI has had and continues to have an impact on loss reduction since its deployment. However, there are limitations such as the prohibitive cost per installation, field deployment constraints in terms of maintenance and service expansion, and the unreliability of third party communication services. Smart Grid AMI is a more cost effective, flexible and value-added solution contributing far beyond that of RAMI for both JPS and the customer. The ease of installation for the Smart Grid AMI solution allows for a faster deployment period and consequently a more immediate impact on losses.

RAMI/CAMI and Total Meters

The RAMI and CAAMI project involves the installation of anti-theft AMI solutions for residential and small commercial customers prioritized in Yellow Zones with high levels of energy loss. These non-technical energy loss solutions are designed to prevent customers from gaining access to the meter or pot-head where over 90% of electricity theft takes place in Yellow Zones. The installation of RAMI and CAAMI in Yellow Zones as a loss reduction solution commenced in 2014 with a total deployment of approximately 15,000 to date.

'Total Meters' are energy meters installed at pole-mounted transformer locations that are utilized to measure the energy delivered to customers via the secondary network. The 'Total Meters' are therefore used to compute the energy loss at each transformer circuits and prioritize for RAMI/CAAMI solution interventions. This project commenced in 2014 with a total installation to date of over 2,500 at transformer locations island-wide covering approximately 50,000 customers. For the 2016-20 period the plan is to integrate the 'Total Meters' as part of the Smart Grid AMI metering solution. With an average of 20 customers per transformer location, it is projected that approximately 900 total meters will be installed for the first year of the plan in 2016.

Table 1-20: 2015 RAMI, CAAMI and Total Meter Installation

Regions	RAMI Target	RAMI Actual	CAMI Target	CAMI Actual	Total Meter Target	Total Meter
East	1800	1839	500	524	400	472
West	2160	2299	600	609	460	488
Central	2040	2121	400	370	340	360
Total	**6000**	**6259**	**1500**	**1503**	**1200**	**1320**

<u>Meter Site Audit and Investigations</u>

JPS is scheduled to complete over 350,000 audits and investigations, or an average of 75,000 per annum for the period 2016 – 2020. This is one of the main sources of energy loss reduction in the recovery of losses and the resultant incremental increase in sales from irregularities identified and corrected. Based on historical trends it is estimated that approximately 20% of these premises investigated will be identified with irregularities contributing to energy loss.

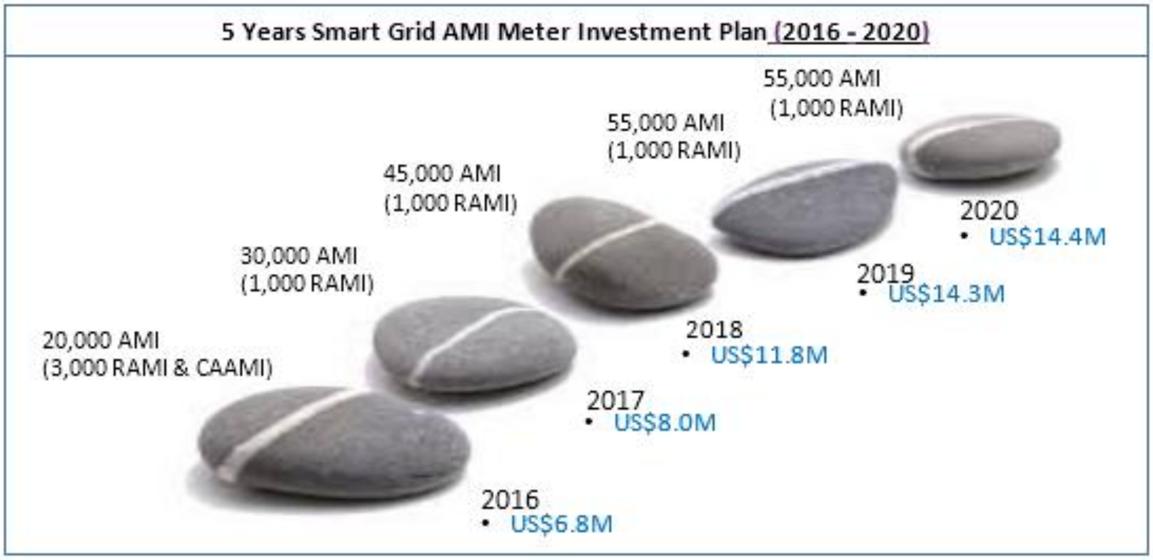
<u>Smart Grid AMI Smart Meters</u>

The Smart Grid AMI project, in summary, involves the replacement of existing 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 pin point customer premises contributing to energy loss. This revamped solution will revolutionize the way in which technology, human resources, systems, analytics and energy measurements are integrated towards realizing both utility and customer expectations.

The implementation of the Smart Grid AMI will include the replacement of the customer meters, the installation of transformer meters (Total Meter) and the building out of a smart grid communication network that will support the remote and automated connectivity to these meters. A variety of communication solutions are currently being reviewed with the ultimate aim of achieving self-sufficiency with respect to communication (using the JPS-owned network), reliability and self-healing capacity. The telecommunication infrastructure network will also provide communication support to the Distribution Automation and other needs of the business.

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

- 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).
- Automating the detection of fraudulent activities by use of meter events and tamper flags.
- A total of 205,000 Smart Grid AMI meters are projected to be installed for the period 2016-2020 with an intended impact of 2.81% reduction in losses. The average cost per customer is estimated at US$250 with a total investment of US$52M for the planning period. The figure below illustrates JPS' Smart Grid AMI investment plan.



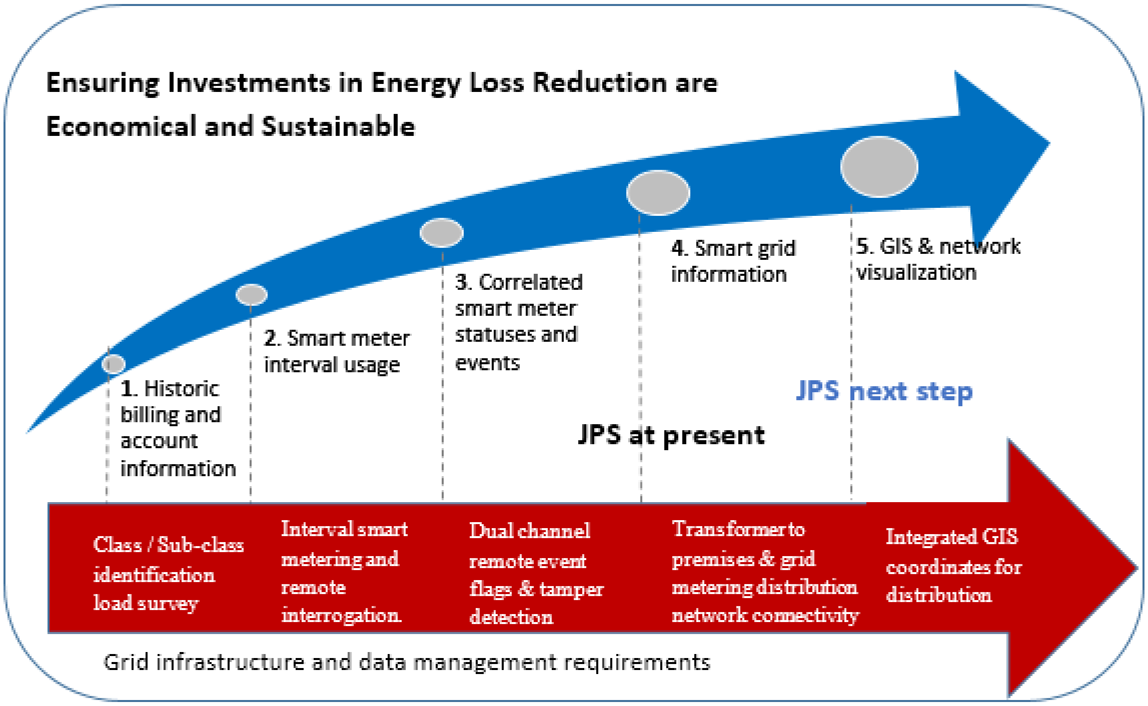
Advanced Automated Theft Detection Tool

While theft through energy diversion continues to be a challenge, the evolution of smart grid technologies has brought about better ways to analyse and identify potential diversion in a more deliberate and sustainable way. Smart meters and grid devices provide the type of data that can be leveraged by back-office analytics and software techniques to detect theft and support the next steps of revenue protection—prosecution and payment collection. Leveraging smart grid devices for revenue protection enables utilities to achieve powerful payback benefits from their smart grid investments.

Figure 1-14 illustrates the general viewpoint on a capability model for revenue diversion analysis, starting with basic analytics on customer, account and billing data and progressing through analytics based on data from smart grid feeder and transformer meters. Note that the highest level, Level 5, represents an aggregation of capabilities of the prior levels, with an emphasis on utilizing geographic information systems (GIS) and network visualization to apply geospatial analytics to the problem of energy diversion.

The five levels of the model correlate the required level of maturity in grid infrastructure, smart metering, modelling of distribution network connectivity and back-office capabilities to levels of maturity in energy diversion identification and analysis. Since the model is structured in the context of grid infrastructure and back-office data management capabilities as a frame of reference, it also provides a framework that can be used to develop a roadmap for a revenue diversion analytics solution aligned with smart meter and smart grid implementation activities. This is illustrated in the Figure 1-14 below.

Figure 1-14: Grid infrastructure and data management requirements



The next step for JPS is the integration of the Smart Grid AMI metering system, theft detection analytics and GIS distribution network model visualization. The four main objectives to be established by the Advanced Automated Theft Detection Analytical tool are listed below:

1. Automate and quantify energy loss per network segment
    a) Feeder, sub-feeder and transformer
    b) Network segment energy loss progress reports (daily, weekly, monthly)
    c) GIS reporting tools that identify geographic locations and transformers with "High Losses"
    d) Provision of technical and non-technical energy loss
2. Automate and detect fraudulent activities
    a) Meter events and tamper flags
    b) Transformer hourly loss versus fraudulent customers' usage analysis
    c) Controls and accountability for field investigations and meter replacement.
3. Automate and quantify energy diversion per premises
    a) Energy diversion KWh per month with supporting documentation
4. Automate primary and secondary distribution network technical loss measurement and simulation

Figure 1-15 and Figure 1-16 below illustrate a pictorial view of the Smart Grid AMI meter energy balance loss model and energy balance calculations respectively.

Figure 1-15: Energy Balance Feeder Loss Model

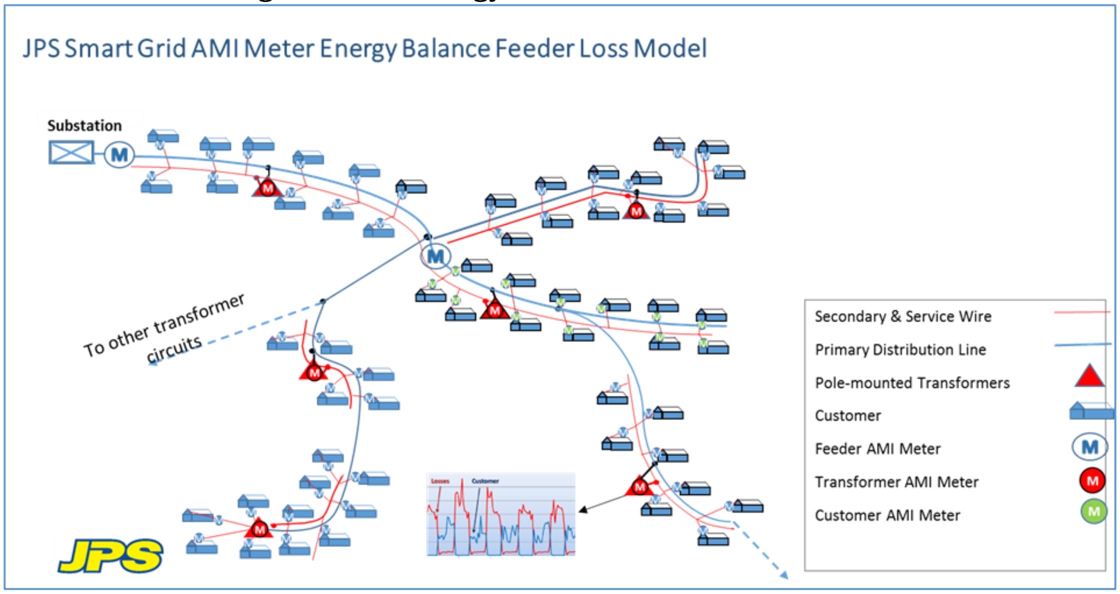
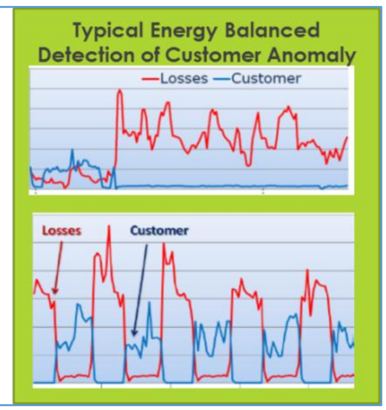


Figure 1-16: Energy Balance Calculation

$$\text{Feeder Energy Loss} = M - (M_{p1} + M_{p2} + M_{p3} + \cdots M_{pn})$$

$$\text{Feeder Technical Energy Loss} = M - (M_1 + M_2 + M_3 + \cdots M_p)$$

$$\text{Transformer Energy Loss} = M_p - (M_{p1} + M_{p2} + M_{p3} + \cdots M_{pn})$$



The Advanced Automated Analytical Theft Detection 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 through the utilization of 15 minutes and hourly energy interval data
- 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.

The Advanced Automated Theft Detection Analytical tool is estimated to cost US$270K with recurring costs of US$0.50 per meter or US$50K for each 100k meters. The tool will be implemented in 2016.

Large C&I (R40/50) Customers

This group of customers represent 0.3% of the total customer base, however they contribute to 45% of annual sales. Priority is therefore given to this group, which is evident through investments in the application of Advanced Metering Infrastructure (AMI) for the automation of meter reading and theft detection. Among other initiatives, we conduct annual meter audit for all Rate 40 and Rate 50 meters, which is geared towards limiting energy loss in this group to an absolute minimum.

Annual Meter/Site Audits (RT 40, 50 and High Consumption RT 20s)

As part of JPS' routine operation 100% of rate 40 and 50 customers' metering facilities are investigated annually. In addition, a further 4,000 rate 20 customers utilizing 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 account for approximately 50% of sales. JPS continues to perform 100% audit of all 1,920 Rate 40 and 50 accounts and plans to audit an additional 4,000 Rate 20 accounts, with monthly consumption greater than 3MWh annually.

Technological & Process Support Solutions - Automation of the Collection & Reporting of Net Generation Metering Data

Resulting from a review conducted in 2014, it was concluded that for both JPS and IPP plants the need for greater controls and accountability in the reporting of Net Generation meter data is critical. This project therefore leveraged the MV90xi automated meter reading application to automate the collection of net generation readings, create reports and to notify users of the meter status. This project also ensures the synchronizing of all generating plants hourly energy data across the power grid. All JPS' twenty eight (28) and IPP's fourteen (14) net generation metering points were completed in 2015.

Figure 1-17 illustrates a typical IPP net generation AMI meter communication infrastructure.

Technological & Process Support Solutions – Sub Feeder Metering

The application of sub feeder meters is a major shift in the use of measurement and empirical data to be more efficient and effective in our loss reduction efforts. This information is readily utilized to target loss reduction solutions and to monitor the performance of initiatives and interventions to reduce energy loss on a sustained basis.

These are primary meters installed downstream on feeders at the 24kV medium voltage level. A shift in approach was made, reducing the number of sub feeder (primary) meters and significantly increasing the number of sub feeder 'Total' meter at the low voltage level (220V) of pole-mounted transformers. A total of approximately 830 'Total' meters at an estimated cost of US$500K is budgeted for 2016.

The measurements from the 'Total' meters guide efficiency improvements in the investigations and implementation of RAMI/CAAMI solutions. Of even greater importance is the ability to track and monitor energy losses throughout the period to detect when there is a breach in the solution implemented. This will ensure that the loss reduction efforts are sustainable using measurements and analysis.

Figure 1-17: Typical IPP Net Generation AMI Communication Architecture

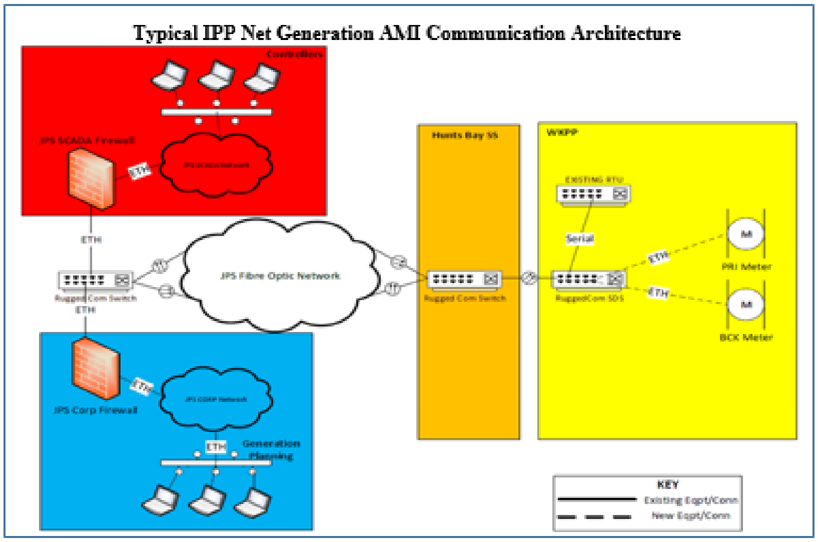


Table 1-21: Annual Plan for 2016

	2016			Q1			Q2			Q3			Q4		
Initiatives	**Qty**	**Impact**	**Budget (US$ '000)**	**Qty**	**Impact**	**Budget (US$ '000)**	**Qty**	**Impact**	**Budget (US$'000)**	**Qty**	**Impact**	**Budget (US$'000)**	**Qty**	**Impact**	**Budget (US$'000)**
NON-TECHNICAL															
RAMI new installation	2000	0.03%	1,000.00	1200	0.02%	600	700	0.01%	350	100	0.00%	50	0	0.00%	0
CAAMI new installation	1000	0.03%	500	500	0.02%	250	400	0.01%	200	100	0.00%	50	0	0.00%	0
Smart Grid AMI (Residential)	20000	0.27%	5,000.00	0	0.00%	0	1000	0.01%	250	9000	0.12%	2250	10000	0.14%	2500
Advanced Automated Theft Detection Analytical Tool	1	0	280	1	0	140	1	0	140	0	0	0	0	0	0
Feeder/Sub-feeder/transformer metering	833	0.04%	500	0	0.00%	0	42	0.00%	25	375	0.02%	225	417	0.02%	250
RAMI and CAAMI Rehabilitation	0	0.08%	450		0.00%	112.50		0.03%	112.50		0.03%	112.50		0.01%	112.50
RAMI and CAAMI Reliability Improvement	6000		425	0		-	2500		177	2500		177	1000		71
Small Account Audits	75000	0.16%	150	18933	0.04%	37.87	19176	0.04%	38.35	19175	0.04%	38.35	17716	0.04%	35.43
Large Account Audits	All	0.17%	200	1966	0.04%	51.82	1975	0.04%	52.05	1990	0.04%	52.44	1658	0.04%	43.69
Community Renewal (RAMI)	4,000	0.01%	4,000.00	1087.00	0.00%	1087.00	1,387	0.00%	1,387	1,204	0.00%	1,204	322	0.00%	322
Total Non-Technical			***12,505.00***			***2,279.19***			**2,731.90**			**4,159.29**			**3,334.62**
TECHNICAL															
Power Factor Correction	Maintain 90% of feeders above 0.95 PF	0.06%	250		0.02%	100		0.02%	100		0.03%	50		0.00%	
Phase Balancing	Maintain 90% of feeders below 20% phase imbalance	0.02%	100		0.00%	20		0.01%	30		0.01%	50		0.00%	
Total Technical			***350***			***120***			**130**			**100**			**0**
Total			**12,855.00**			**2,399.19**			**2,861.90**			**4,259.29**			**3,334.62**

Note: The sum of energy loss reduction impact based on the respective loss reduction initiatives represents the arithmetic sum and not the net projected reduction in system energy loss for 2016 year.

1.7.2 Community Renewal

In 2015, JPS launched a pilot project for the implementation of a community renewal programme in seven communities in the parishes of Kingston and St Andrew. The aim of the project was to gather necessary information to inform the full scale roll-out of the programme across Jamaica. The programme targeted two thousand customers in these communities and at the end of the pilot, JPS intends to develop an effective deployment strategy that would on-board 4,000 customer for 2016. We will review our plans as we further develop our five year business strategy for the Community Renewal Programme to be incorporated in our business plan for a rate review submission (possible an Extraordinary Rate Review). A successful implementation of the pilot project will result in billed sales increasing by approximately 480Wh for 2016. The aim of the programme ultimately is to convert one hundred thousand customers who are currently consuming electricity illegally to registered customers paying for their consumption on a monthly basis.

The communities targeted in the pilot project are:

1. McGregor Gardens
2. Denham Town
3. Payne Land
4. Majesty Gardens
5. Bayfarm Villa
6. Whitfield Town
7. Arnette Gardens

Figure 1-18 below shows the status of connection of consumers that have been converted to customers.

Figure 1-18: Breakout of customers signed up that have been connected vs. waiting to be connected

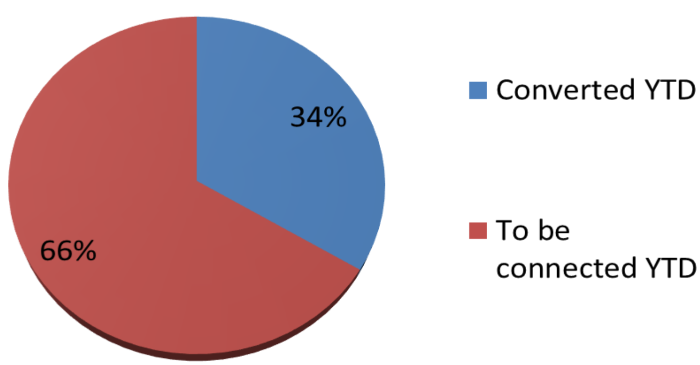


Table 1-22: Customer on-boarded per Community (target vs. actual)

Community	Target	Actuals	Variance
McGregor Gardens	218	200	(18)
Majesty Gardens	150	241	91
Whitfield Town	352	196	(156)
Payne Land	320	21	(299)
*Arnette Gardens	320	-	(320)
*Denham Town	320	-	(320)
Tower Hill/Bayfarm Villa	320	18	(302)
Total	**2000**	**676**	**(1326)**

While we connected only 325 of the 2000 customers targeted for 2015 at the end of the year the programme has already began to show signs of success. One such success story is the implementation of the project in McGregor Gardens where 200 customers were on-boarded using JPS' STS type prepaid meters (Pay as You go). The electricity infrastructure implemented in the community was deliberately selected to encourage energy management and mitigate the propensity to illegally abstract electricity in the area. The pole line construction incorporated PVC insulated cables and stand-alone prepaid meters was installed at each customer location. The community also benefited from the installation of LED street lighting. JPS also completed a YPP AMI installation in Majesty Gardens to facilitate 250 connections of which 125 were completed in 2015. Pole line construction to facilitate the conversion of 210 customers in the Whitfield town community was also done in 2015. The line configuration in both of these areas was based on the RAMI model where meter enclosures were connected to the primary electric circuit and mounted on the distribution pole

Working in conjunction with JSIF who implemented the house wiring component of the project, JPS completed the upgrading of 600 households to the reregulated eligibility code for safe electric consumption as determined by the JS21 and the National Building Code. This was to enable the facilitation of legal connection to JPS' distribution lines across communities such as McGregor Gardens, Majesty Gardens and Payne Land.

Our experience to date has not been without its fair share of challenges in on-boarding customers 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;
- Developing an appropriate implementation structure on the ground; and

- Technical limitations of the metering infrastructure (or device).

We have taken instruction from our lessons learnt and will be implementing several measures to combat the above mentioned challenges, such as

- Increased community engagement
- Introduction of a new AMI metering system (Hexing) with both Prepaid and Post-paid capabilities
- Improving the robustness of the locks for the Energy Guards
- Use of more versatile and technically resilient metering infrastructure

To date, JPS has spent a total of US$248,900 to connect the 325 customers. As at April 28th 2016 we have connected 857 customers. It should be noted that most of the funding was used to build infrastructure in the project areas as most areas did not previously have electricity. Table 1-23 below shows the breakdown of the actual monies spent versus the budgeted amount for each project area in 2015.

Table 1-23: Budget and Project Status for 2015 Pilot Project

Project	2015 Budget (US'000)	Actuals (US'000)	% Spend	% Complete
McGregor Gardens	54.2	17.9	33	91.7
Majesty Gardens	271.1	123.1	45.4	96.4
Whitfield Town	177.4	92.4	52.1	55.7
Payne Land	55.9	9.9	17.7	6.6
Arnette Gardens	81.1	3.5	4.3	0
Denham Town	81.1	2.1	2.5	0
Tower Hill	55.9	-	0	5.6
Total	**776.7**	**248.9**		

1.7.2.1 Methodology

The launch of the Project in each community begins with community outreach through community meetings and other means of engagement. A number of social intervention programmes were offered to residents in the project areas and these programmes were offered free of cost to residents. A list of the interventions offered under the Pilot in 2015 can be seen in Table 1-24 below:

Table 1-24: List of Social Interventions offered under 2015 Pilot

House Wiring	Recertification
Energy Audits	Conservation Sessions
Community Facilitation	Service Centres
Capacity Building	Wellness Fairs
Light Bulb Swap	Refrigerator Seal Management

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

Wellness Fairs

In 2015, the Community Renewal Department hosted three (3) Wellness Fairs. The Wellness Fairs were hosted in Payne Land, Whitfield Town and McGregor Gardens. The objective of the Fairs is to sign up for 10% of patrons from each Fair and to improve the Company's image. For 2015, over 500 residents received medical attention including general medical examinations from General Practitioners, Optical checks, Gynaecological examination and pharmaceutical supplies at a cost of US$23, 839. A total of 147 persons were signed up for JPS Service and will be connected in 2016.

Capacity Building

JPS through the partnership with JSIF in 2015, enrolled four (4) persons from McGregor Gardens in the HEART NTA Electrical programme. This programme ran for 18 months and cost US$754. Of the four (4) persons that entered the programme, only two (2) completed. The other two (2) persons were unable to complete based on personal challenges including difficulty in managing the commute to the institution.

To improve success of this initiative for 2016, there will be more screening to determine the eligibility and commitment to the programme before selection of the beneficiaries for the skills training programme is made. To mitigate the concern of high commuting cost, JPS is minded to recommend shorter tenure programmes with a maximum of six (6) months and training opportunities will be offered in other fields such as BPO operations, hair dressing, and similar skills.

Service Centres and Community Facilitators

In 2015, 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 answer simple bill queries and advise persons in their community of the offerings under the programme. Community Facilitators work in their community at the local JPS Service Centre where they are able to meet with customers and provide the JPS experience in a setting that is more convenient to customers. The facilitators are trained to conduct energy audits and energy sessions to assist persons in managing their consumption.

House Wiring and Recertification

For 2015, part of the programme offerings was to offer house wiring and recertification at minimal or no cost to customers. The purpose of this was to assist in the conversion process to make it easier for customers to come onto the grid as house wiring not affordable for some residents. For some projects completed so far and going forward in 2016, JPS has asked residents to make a contribution to show their commitment to the programme and to ensure the customers understand and appreciate the value of the service.

Refrigerator Seal Replacement Programme

This initiative was developed as an energy conservation initiative to help persons reduce their consumption by replacing the seal on their refrigerator to improve the refrigerator efficiency. However, this was not implemented in 2015 due to concerns of JPS' Partner, JSIF, on the implementation process as this would have been implemented though JSIF.

Community Relations Meeting

There was also on-going dialogue with customers through community outreach meetings across the communities.

1.7.2.2 2016 Plans for the Community Renewal Programme

As a means of building on the progress made last year, the Community Renewal and Customer Solutions strategies for 2016 are as follows. Extend the pilot to on-board up to 4000 customers with an expected 480MWh recovery. This will be accomplished through the following initiatives:

1. High Loss communities on Feeders such as Hope 510 and Tredegar 410 will be targeted.
2. 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. JSIF presently has projects in 5 of the 10 communities being targeted by JPS for the 2016 programme. There is a 30% consumer compliant rate in red zones (community profile). JPS believes that by partnering with JPS 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 our project areas. This will allow participants to have easy access to JPS. Our facilitators become the bridge between the community and JPS and have easy access to solutions for issues that may require greater assistance.
4. As a part of the programme, JPS has retained Community Facilitators who will undertake education and promotional activities, promote positive relationship 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 done in 2015 and as such have been newly introduced to the customers in the project areas for 2016. Along with the energy audits, the community facilitators will also be conducting small group sessions as a means of educational and promotional activities and relationship building.

5. Through the Community Renewal Programme, JPS also offers Energy Management /Customer Education. This is also being carried over from 2015 and incorporates several new elements for 2016. This is being done through: bulb distribution (LED/Fluorescent bulbs exchange of incandescent bulbs), house wiring, and refrigerator swap. During walk through of several communities with our International partners from USAID it was recognised that several households had defective our energy inefficient refrigerators. In an effort to improve energy management it was recommended that a refrigerator swap program be introduced. This program has been implemented in other countries with high system losses such as Brazil. The refrigerator swap initiative will be a partnership between the USAID and JPS. This program will be piloted in two communities before any wide-scale implementation.
6. The programme will also offer several Billing Method & Payment Options to JPS customers in the project areas. These options are as follows: post-paid or pre-paid metering, flexible payment arrangements or bad debt write off, first deposit paid in instalments which are all coming over from 2015. Plans are being put in place for the implementation of the proposed community renewal rate (special tariff for 150kwh) for 2016. This will be informed by advancing discussions with PIOJ and PATH.
7. Through the Community Renewal Programme, as a part of the 2016 initiatives, JPS wants to contribute to the ability of the community members to earn an income through job creation - Building Capacity to Pay will be pursued through the provision of training opportunities in: electrical training/apprenticeship, customer services, tutorial sessions, ambassadorship (compensate for customer on boarding while you learn – CCL), entrepreneurship workshops e.g. Small business, Food Handlers Permits, Cosmetology
8. In an effort to properly assess and address the specific needs of each community, Customer Base Line surveys are being conducted. One such survey is a Needs Assessment done through SALISES UWI. This was done based on JSIF's recommendations who are the social experts. This is also a 2016 initiative for which work began in the latter part of 2015.
9. To ensure that JPS is equipped to properly analyse the effectiveness of the interventions a proper Data management System is needed. This is being implemented as part of an initiative commissioned in collaboration with World Bank/University of Chicago with a target completion date of April 2016.
10. 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 in the following areas: Lineman Training, Non-Governmental Organisation Partnership and Environmental Preservation (clean up drive).

Table 1-25: Summary of Proposed plans for 2016:

Communities	HSE WRG	RC	YER Prog	ST	ESW	IP	S	SC	SM	RB	RS	ECS	BS	F	WF	CE
McGregor Gardens	x		X		x			x	X			X	x	x		
Majesty Gardens	X		X					x	X	x	x	X	x	x		
Whitfield Ave/ Maxfield Ave	X	X		x		X		x	X			X	x	x		x
Ellerslie Pen / Tawes Pen	X	X	X	x	x	X	X	x	X		x	X	x	x	x	
Russia	X	X	X	x	x	X		x	X			X	x	x	x	
Retirement	X	X	X	x	x	X			X			X	x	x	x	
Denham Town			X		x		X	x	X			X	x	x	x	
Payne Land		X	X		x			x	X			X	x	x		
Arnett Gardens		X			x		X	x	X			X	x	x		
Bayfarm Villa		X			x				X			X	x			
Goldsmith Villa									X			X				
Nessberry Grove									x			X				

Key:

HSE WRG- House wiring	ESW- Entrepreneur Workshop	IP-Intern Prog	RC – Recertification
S-Scholarship	SC-Service Centre	SM-Social Marketing	ST- Skills Training
RB-Ready Board	RS-Fridge Swap	ECS- Enrg Cons Session	BS- Bulb Swap
F-Facilitator	WF-Wellness Fair	CE-Career Expo	

The 2016 initiatives are broken down as follows:

- Host four (4) Wellness Fairs with a view to on-board a minimum of 10% of attendees in selected communities such as Ellerslie (Tawes) Meadows , Retirement , Denham Town and Russia - to reduce each household consumption by 10%.
- Train 200 persons in areas including Hospitality Management, Business Process Operations and Electrical Technology. JSIF is to advise of Communities to target after results from their needs assessments.
- Entrepreneurship Workshops targeting 50 persons between ages 25 -35 in Russia, Retirement, Ellerslie Gardens\Tawes Meadows, and McGregor Gardens.Three month Internship Programme for 28 trainees in area of speciality (Selected after Training is completed in assigned communities).
- Youth Education & Recreational Project - GSAT Centres/ High School Leavers Skills Training Programme (targeting 200 students).
- Wire 1,000 houses in 6 targeted communities, such as Majesty Gardens, Whitfield/Maxfield, Ellerslie Gardens, Tawes Pen Meadows, Russia and Retirement.

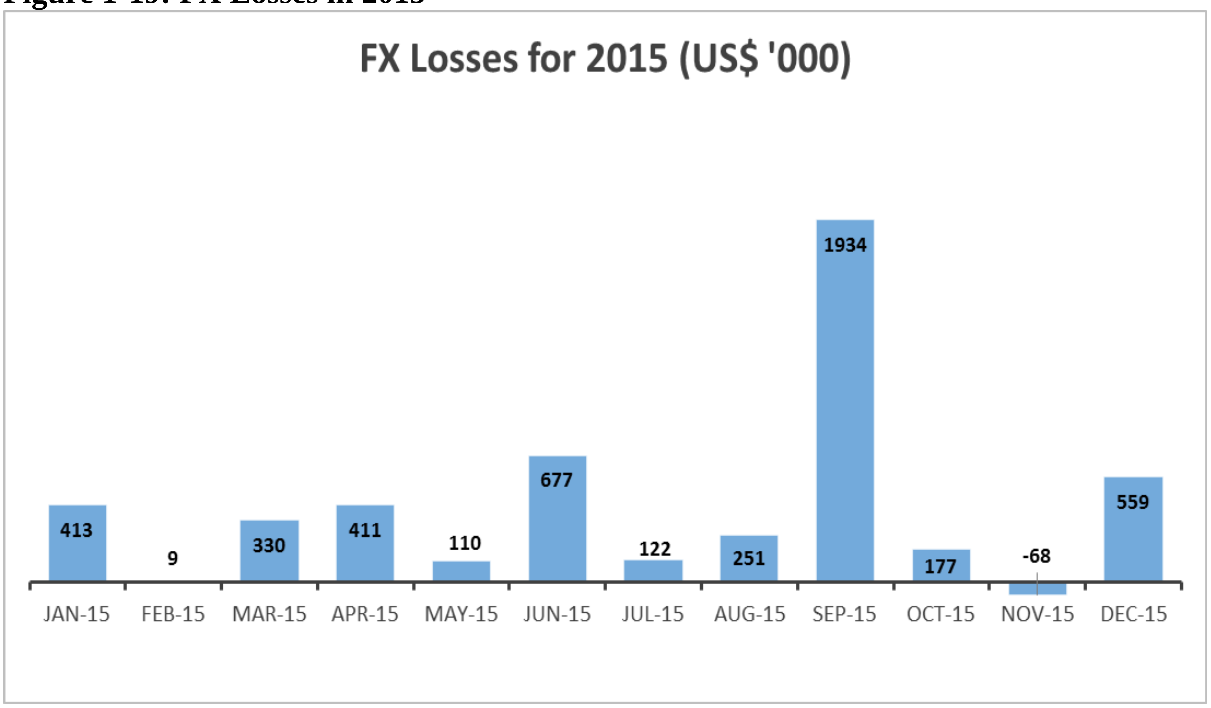
- Facilitate the recertification of 900 homes in targeted communities namely, Whitfield/Maxfield, Ellerslie Gardens, Tawes Pen Meadows, Russia, Retirement, Payne Land, Arnett Gardens and Denham Town.
- On Board 400 consumers using Ready Boards (house wiring solution) in Majesty Gardens.
- Conduct 36 energy management sensitization sessions to approx. 6000 residents across all project areas
- Match payments on arrears that fall within $100k to $150k for 100 customers -to reduce the level of long outstanding debt on their account prior to joining the program. This is effectively a debt forgiveness program in which JPS forgives an amount equivalent to the amount paid by the customer. These amounts in the main have already been provided for in JPS' accounts and as such will not represent an additional expense to the business.
- Recognize 1,600 prepaid customers who have successfully maintained purchase of prepaid tokens quarterly.
- Expanding partnership with the CSJP for 45 youth at risk from high risk communities.
- Offer on the job training to 30 youths across the island in JPS Parish offices for 1 year. Tentative start date is May 9th
- Linesman training and internship of 15 lines men for 5 week training and internship for up to 6 months . Assessment for linesmen training is April 28th and 29th with a tentative start date of May 9th 2016.

1.7.3 FX Losses in 2015

JPS is seeking to recover foreign exchange losses incurred during 2015 in this annual filling per Schedule 3 of the Amended Operating Licence.

Figure 1-19 shows JPS' FX losses in 2015. The total FX loss for 2015 was US$4, 924,859

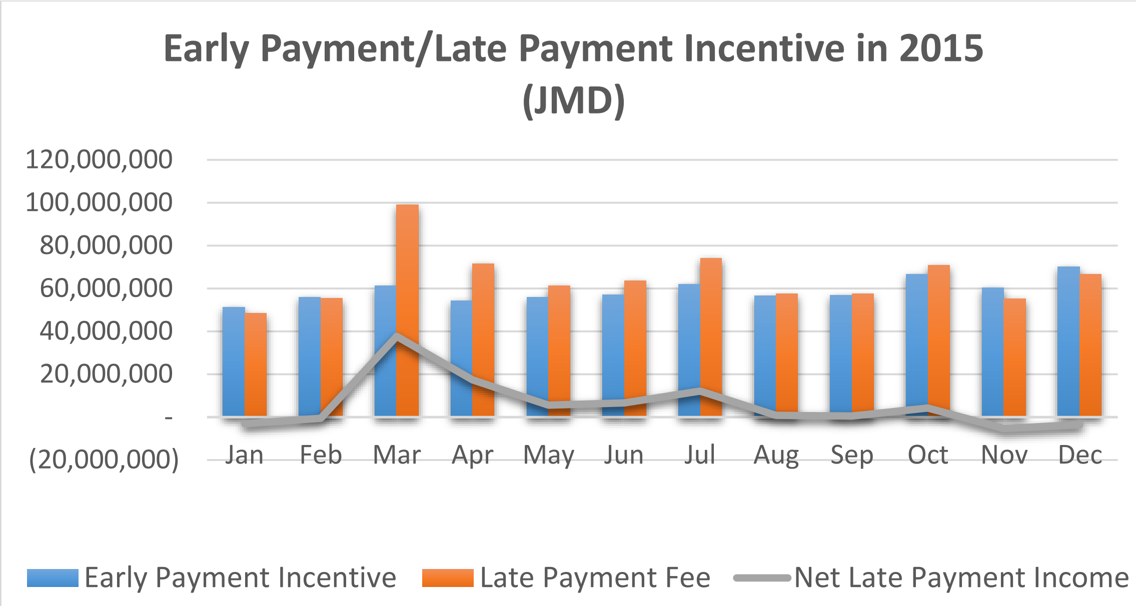
Figure 1-19: FX Losses in 2015



1.7.4 Customer Interest Income/Expenses in 2015

The early payment incentive expense incurred by JPS and the late payment income received from residential customers in 2015 is highlighted in Figure 1-20. The net late payment/ fee income remaining after the payment of early payment incentive income is also shown in the Figure. The net late payment income was US$625,505.00.

Figure 1-20: Net Late Payment Income in 2015



1.8 Request for Extraordinary Rate Review for the 2017/2018 Filing

Paragraph 59 of Schedule 3 of the Licence specifies that:

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

JPS is requesting the OUR's consideration for an Extraordinary Rate Review in the 2016/2017 tariff period. The request comes against the backdrop of the exceptional circumstances necessitated by the need to operationalization of the new Electricity Licence. The Licence allows for the inclusion of certain key items which has a significant impact on JPS' revenue requirement (more than J$50 million) and its ability to make the necessary investments to provide the service that our customers require. These include:

- The inclusion of the current portion of long term debt (CPLTD) in the rate base which is addressed in Paragraph 29 of Schedule 3of the Licence.
- Changes to the depreciation schedule which need to be brought into effect as soon as possible.
- Allowance for Smart Street Lighting investments.
- The incorporation of the new IPPs into the non-fuel tariff.
- Review of the ROE

These items could have been included in an annual tariff filing through the Z factor adjustment mechanism which was expanded in the Licence, however, given the need to address Wheeling, Net Billing and standby rates in a comprehensive, cost reflective and non-discriminatory manner, we believe that it is prudent for us to reset the tariffs based on cost of services studies. These studies are currently being conducted and will be used to inform the new tariff design.

1.9 Request for Re-imbursement of Losses Related Fuel Impairment Costs for 2016

Between January and March 2016, JPS incurred US$5.4M in fuel cost impairment directly attributable to system losses. The financial impairment is likely to grow until the end of July 1 2016 when the system losses efficiency mechanism is removed from the fuel rate calculation. The true-up mechanism for system losses in the 2017/2018 filing period could also result in JPS being penalised for system losses performance in 2016. This would result in JPS being penalised twice for the fuel losses performance from January to June 30, 2016. We are therefore requesting OUR's consideration of a mechanism to allow JPS to recover the fuel impairment cost for the first half of the year.

2 Overview of Fuel Efficiency Mechanism

2.1 Introduction

The Electricity Licence 2016 introduced a major change in the fuel cost recovery mechanism that has existed since 2001. Previously, fuel cost recovery was subject to two efficiency measures: heat rate and system losses. The system losses incentive has now been removed from the fuel cost recovery mechanism and is now applicable to the annual revenue cap non-fuel adjustment formula. This means that the fuel cost recovery is now only dependent on JPS' heat rate performance.

Paragraph 40 of Schedule 3 of the operating licence makes provision for the heat rate performance to be based on the system average, JPS thermal, individual generating units of JPS or some other mechanism which the OUR determines. In its 2014-2019 Determination notice, the OUR proposed a change from the use of the system heat rate to JPS thermal heat rate with only JPS' fuel cost subject to the heat rate efficiency incentive. The fuel cost formula that was determined by OUR in the 2014-2019 Determination Notice was given by the following formula,

$$\text{Pass Through Cost} = \left[\text{IPPs Fuel Cost} + \left(\text{JPS Fuel Cost } \times \left(\frac{\text{JPS Heat Rate Target}}{\text{JPS Heat Rate Actual}}\right)\right)\right] \times \left(\frac{1 - \text{Losses Actual}}{1 - \text{Losses Target}}\right)$$

Net generation from non-combustible renewables such as wind, hydro and solar was not included in the JPS' generating units' heat rate calculation. The OUR also determined that JPS' generating heat rate target shall be 12,010 kJ/kWh for the period January 2015 – May 2019.

JPS is proposing that the heat rate target be set with respect to the JPS system (including JPS controlled renewable plants) for the 2016/2017 tariff period rather than the JPS thermal heat rate that is currently applicable.

JPS is proposing the use of the JPS system heat rate rather than the JPS thermal due to the characteristics of the JPS plants. The average heat rates for JPS' thermal plants ranged from 9,151 kJ/kWh to 15,822 kJ/kWh in 2015. Due to the wide spread in the heat rates of the plants, the loss of a single generating unit due to forced outages or even due to maintenance outages could have a significant impact on the JPS thermal heat rate. It is therefore difficult to maintain a steady average value for the JPS thermal heat rate. The impact of JPS' hydro units is to smooth the heat rate performance to give a more steady heat rate curve. On this basis, setting a target on JPS' heat rate rather than its thermal heat rate would be more system with the nature of our units.

A JPS system heat rate target that includes renewables sends a clear and unambiguous signal of improving fuel conversion and replacement that is resulting in lower fuel cost to customers. JPS invested over US$40M between 2010 to 2014 in Wind and Hydro Renewables. The impact of renewables on fuel cost to customers weighed heavily in JPS' decision to invest in the renewable capacity. The company remains committed to the national goal of increased generation from renewables and believes the use of the JPS heat rate provides a strong incentive for the utility to continue its investments in renewables.

Given the changes introduced in the Licence and the incentive that the use of JPS heat rate provides, JPS' proposal is therefore for the fuel recovery mechanism to be based on the following formula:

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

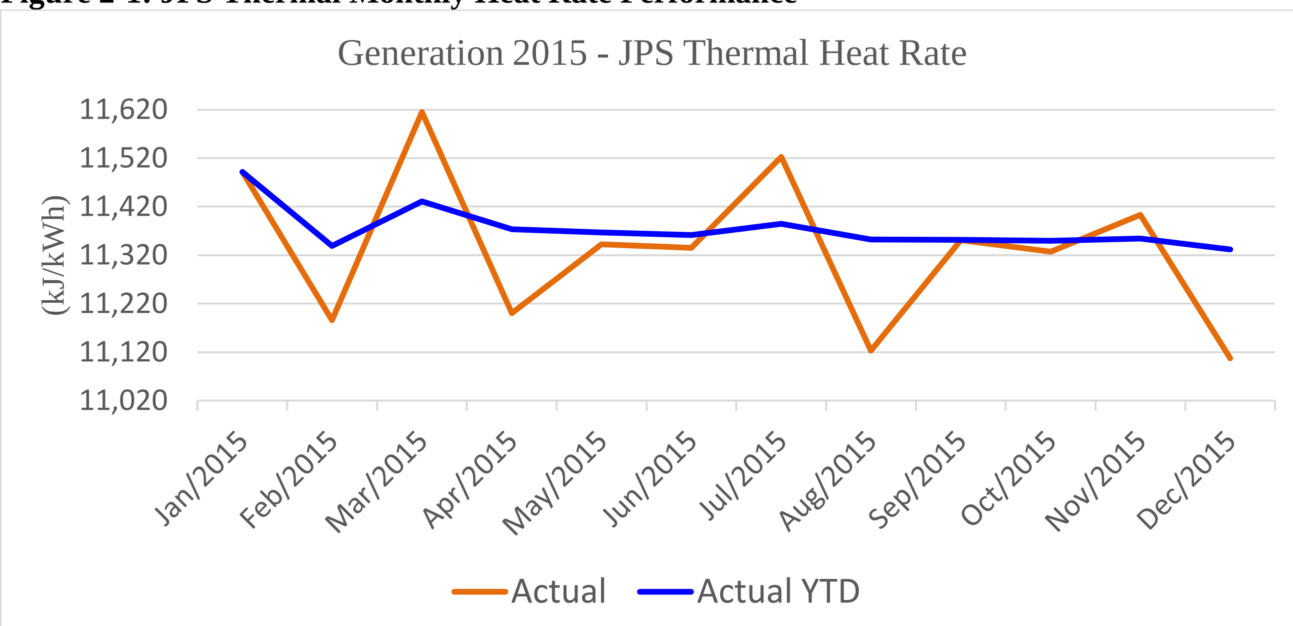
where the heat rate to be applied is JPS' heat rate (thermal and renewables). We further propose that the target for the 2016/2017 adjustment period should be 10,710 kJ/kWh.

The following outlines JPS heat rate performance in 2015 and provides the forecast of performance for 2016/2017.

2.2 JPS System Heat Rate Performance –2015

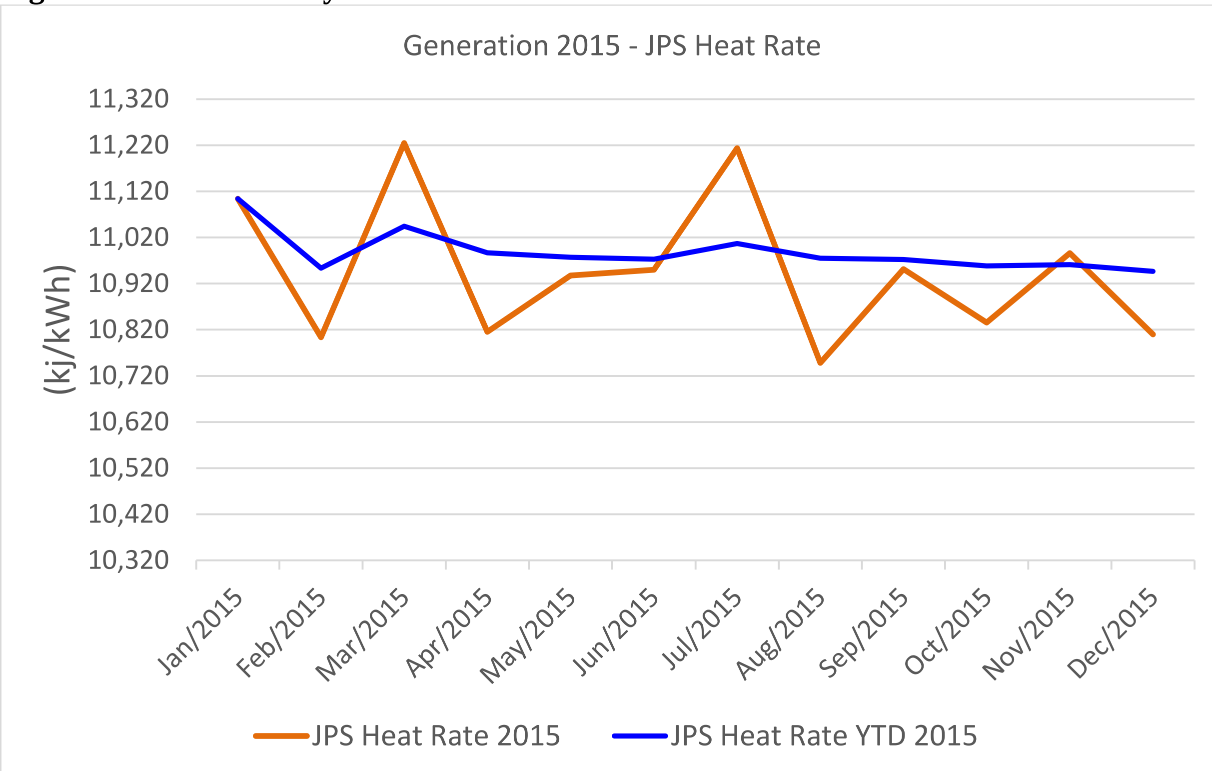
The JPS system heat rate has improved during the current tariff period. The heat rate fell by 125 kJ/kWh over the period from January 2015 to present. The major drivers of this improved efficiency was due to US$20M in major maintenance investments in 2015 along with routine maintenance activities including, steam turbine overhaul on Old Harbour Unit #3, improved efficiency from Bogue CC after hot gas path works on GT#13 and Rockfort Engine #1 overhaul. The JPS thermal and JPS system heat rate performances are illustrated in Figure 2-1 and Figure 2-2 below:

Figure 2-1: JPS Thermal Monthly Heat Rate Performance



JPSCO THERMAL Heat Rate (kj/kWh)	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
Actual	11,492	11,186	11,615	11,200	11,343	11,335	11,523	11,123	11,351	11,327	11,403	11,107
Actual YTD	11,492	11,339	11,431	11,373	11,367	11,362	11,385	11,352	11,352	11,349	11,354	11,332

Figure 2-2: JPS Monthly Heat Rate Performance



JPSCO Heat Rate (kj/kWh)	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
JPS Heat Rate 2015	11,104	10,803	11,225	10,816	10,938	10,950	11,214	10,748	10,951	10,836	10,986	10,810
JPS Heat Rate YTD 2015	11,104	10,954	11,044	10,987	10,977	10,973	11,007	10,975	10,972	10,958	10,961	10,947

2.3 Heat Rate Forecast for 2016

2.3.1 Model Assumptions

JPS heat rate forecast for 2016 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 2016 are outlined in the ensuing.

<u>Projected Maximum Capacity Rating (MCR)</u>

- Rockfort's maximum capacity rating is forecasted to remain at 20MW x 2 for the period 2016.
- Hunts Bay's maximum capacity rating will remain at 122.5MW for the period 2016.
- Old Harbour's maximum capacity rating will remain at 193.5MW for the period 2016.
- Bogue's maximum capacity rating is forecasted to remain at 173.5MW for the period 2016.
- JPS Renewables MCR is forecasted at 32.52MW for the period 2016.

- IPP's MCR forecasted to 366MW in 2016, this includes 96MW Wind and 20MW Solar.

Forecasted Capacity Factor

- Rockfort's capacity factor is forecasted to average 86% for 2016. This is inclusive of major maintenance outage on Engine #2.
- Hunts Bay's #B6 capacity factor is forecasted to average 64% for 2016. The capacity factor of Hunts Bay's gas turbines is projected to average 1%, for 2016.
- Old Harbour's capacity factor is forecasted to average 52% for 2016.
- Bogue's capacity factor is forecasted to average 51.3% for 2016. Capacity factor for the peaking units is <1% for 2016. This is inclusive of major maintenance outage and dual fuel conversion on GT#12 & GT#13.
- JPS Hydro Renewables capacity factor forecasted to average 62% for 2016. Capacity factor for Wind farms, Wigton 34% and Munro 3%.
- IPP's capacity factor forecasted to average 60% for 2016. This is inclusion of major maintenance outage for the entire WKPP facility for 30 days.
- The overall system capacity factor is forecasted at 50% for 2016.
- The capacity factors of each plant is provided in Table 2-1 at the end of the Section.

Forecasted Energy Production

- Rockfort's energy production is forecasted at 302GWh for 2016. This is inclusive of major maintenance outage on Engine #2.
- Hunts Bay's #B6 energy production is forecasted at 391GWh for 2016. The energy production forecasted for Hunts Bay's gas turbines projected at 6GWh for 2016.
- Old Harbour's energy production is forecasted at 877GWh for 2016.
- Bogue's energy production is forecasted at 808GWh for 2016. Energy production for the peaking units is forecasted at 2GWh for 2016. This is inclusive of major maintenance outage and dual fuel conversion on GT#12 & GT#13.
- JPS Hydro Renewables energy production is forecasted at 176GWh for 2016. The Energy production for the wind farms are Wigton 181GWh and Munro 0.74GWh.
- IPP's energy production forecasted at 1,342GWh for 2016. This is inclusive of major maintenance outage for the entire WKPP facility for 30 days.
- The overall system demand is forecasted remain flat for 2016 vs 2015, largely due to most new customers expected to come from the small commercial and residential classifications.
- The forecasted energy production of each plant for 2016 is shown in Table 2-2 at the end of the Section.

2.4 System Heat Rate Model Results

The model used to derive the forecast for system heat rate was predicated on the following additional assumptions for fuel rates and variable operation and maintenance costs.

HFO #6 Fuel price for 2016 was modelled at US$56.18/barrel average for JPS Plants. The forecasted average HFO #6 price for the IPPs is US$56.16/barrel while the forecast for ADO #2 for 2016 is US$81.28/barrel. The 2016 (variable operation and maintenance) VOM for the IPPs averaged US$15.61/MWh in the model. The top ten plants in the merit order for 2016 are projected to be RF#2, RF#1, JPPC, HB #B6, OH#4, WKPP, OH #3, JEP, BG CCGT, OH#2.

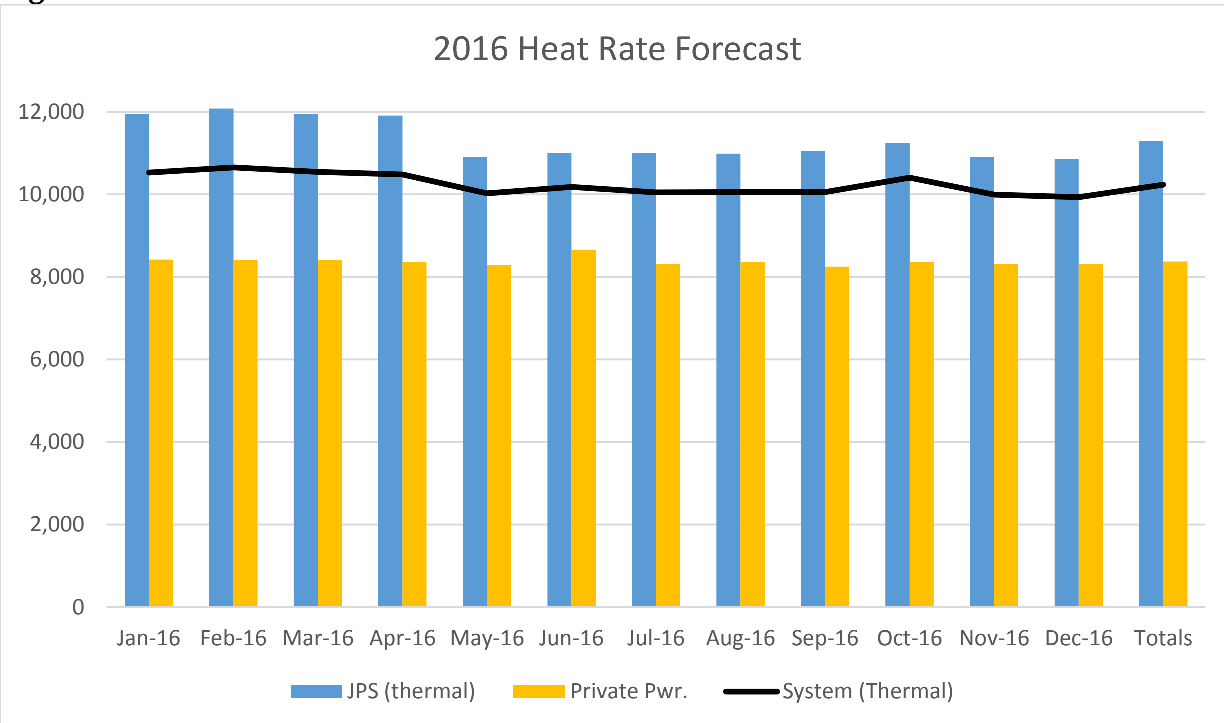
The forecasted heat rate by plant for 2016 is as follows.

- Rockfort is forecasted at 9,251kj/kWh with planned major outage intervention on RF#2.
- Old Harbour plant heat rate is forecasted at 13,317kj/kWh, largely due to deteriorated performance of OH#2 with cycling duties enabled.
- Hunts Bay HB#B6 forecasted at 12,621kj/kWh. Hunts Bay gas turbines forecasted at 15,575kj/kWh which is reflective of their peaking duties.
- Bogue gas turbine GT#3-GT#11 are forecasted at 18,399kj/kWh as per their peaking duties. Bogue CCGT is forecasted at 9,152kj/kWh with major maintenance outage and dual fuel conversion on GT#12 & GT#13.
- IPPs are forecasted at 8,371kj/kWh with major overhaul JPPC engine #2 and major maintenance outage for the entire WKPP facility for 30 days.
- JPS Thermal heat rate is forecasted at 11,284 kj/kWh

The 2016 system heat rate is forecasted at 10,231kj/kWh. The forecasted energy production of each plant for 2016 is shown in Table 2-3 at the end of the Section.

Avg. Heat Rate (kJ/kWh)	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Totals
JPS (thermal)	11,943	12,080	11,941	11,903	10,902	11,002	10,996	10,983	11,046	11,240	10,905	10,861	11,284
Private Pwr.	8,415	8,407	8,411	8,353	8,288	8,660	8,320	8,364	8,250	8,364	8,318	8,307	8,371
System (Thermal)	10,528	10,651	10,541	10,478	10,020	10,181	10,044	10,054	10,056	10,400	9,993	9,928	10,231

Figure 2-3: Heat Rate Forecast 2016



2.5 Proposal for Heat Rate Target

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

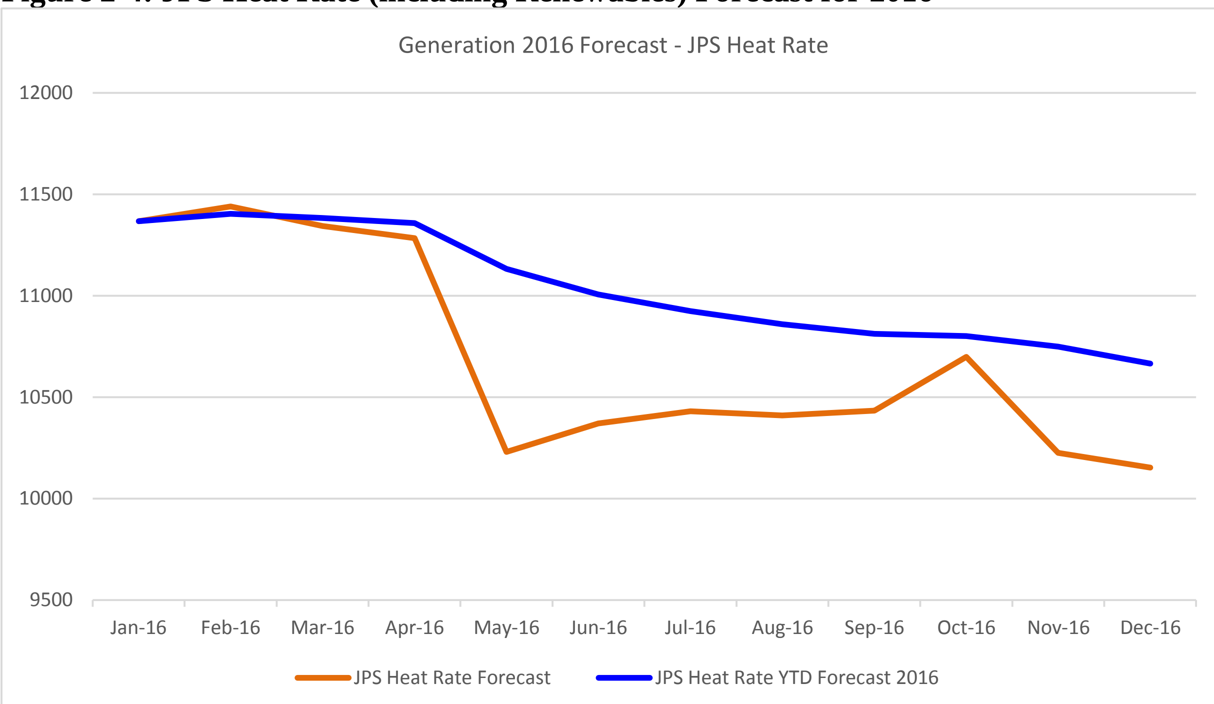
- Growth in system demand
- Addition of new generating units and the installed reserve margin (OUR);
- Heat rate improvements made to existing generating units (JPS);
- Availability and reliability of JPS generators (JPS);
- Availability and reliability of IPP generators (IPPs);
- Absolute and relative fuel prices for JPS and the IPPs and the impact on economic dispatch;
- Spinning reserve policy (JPS & OUR); and
- 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.

System modeling of the current and future unit availability and dispatch suggest a JPS Heat Rate target, which is the combination of JPS Thermal and Renewable plants, of 10,710 kJ/kWh. JPS' view is that the heat rate target must consider the effect that the likely changes to the influencing factors, which are outside JPS' control, would have on the actual monthly heat rate value. Based on the planned mix of generating units, including IPPs, their projected availability and dispatch, and the foregoing discussion of heat rate influencing variables and the possible variation in heat rate performance for reasons beyond JPS' control, JPS proposes the following:.

- JPS Heat Rate target to include JPS Renewable production of 10,710kj/kWh
- Annual review of the Heat Rate target and adjustment for the known impact of new generation added to the grid.
- An assessment of the total generation system, the structure of the system and the efficacy of a system heat rate target after the implementation of the 190MW LNG project.

Figure 2-4: JPS Heat Rate (including Renewables) Forecast for 2016



JPSCO Heat Rate (kj/kWh)	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16
JPS Heat Rate Forecast	11,368	11,441	11,344	11,284	10,231	10,371	10,430	10,411	10,434	10,699	10,225	10,152
JPS Heat Rate YTD Forecast 201	11,368	11,404	11,384	11,359	11,133	11,006	10,924	10,860	10,812	10,801	10,749	10,666

Table 2-1: Projected Capacity Factors

(76% System Availability)		Capacity Factor Projections												
	Capacity	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Totals
HYDRO & Purchases	**160.5**	**29%**	**30%**	**25%**	**35%**	**35%**	**48%**	**39%**	**36%**	**35%**	**26%**	**29%**	**35%**	**34%**
Old Harbour Steam	**193.5**	**59.9%**	**60.6%**	**59.2%**	**58.8%**	**43.1%**	**47.2%**	**47.7%**	**47.6%**	**45.6%**	**59.8%**	**45.7%**	**44.4%**	**52%**
OH-4	68.5	75.1%	71.7%	72.5%	73.0%	69.8%	70.3%	72.0%	72.8%	50.0%	76.2%	75.8%	72.2%	71%
OH-3	65	58.1%	55.0%	55.2%	54.8%	39.6%	55.1%	55.2%	55.0%	56.4%	63.0%	53.9%	54.0%	55%
OH-2	60.0	44.4%	53.9%	48.2%	47.0%	16.3%	12.3%	11.8%	10.8%	28.8%	37.7%	2.6%	2.4%	26%
OH-1	30													
Hunts Bay Steam	**68.5**	**68%**	**66%**	**66%**	**67%**	**65%**	**65%**	**63%**	**63%**	**66%**	**68%**	**67%**	**43%**	**64%**
HB-B6	68.5	67.5%	66.2%	66.1%	67.1%	64.5%	64.8%	62.8%	63.4%	66.5%	68.1%	67.5%	42.6%	64%
Rockfort	**40**	**56%**	**72%**	**89%**	**89%**	**87%**	**89%**	**94%**	**94%**	**92%**	**88%**	**94%**	**87%**	**86%**
RF-B1	20	89.4%	74.6%	89.4%	89.4%	87.5%	89.4%	94.4%	94.4%	92.8%	81.1%	94.4%	89.3%	89%
RF-B2	20	22.8%	68.7%	89.4%	89.4%	87.1%	89.4%	94.4%	94.4%	91.5%	94.4%	94.4%	85.3%	83%
Hunts Bay Gas Turbines	**54**	**0%**	**3%**	**3%**	**1%**	**0%**				**3%**	**6%**			**1%**
HBGT10	32.5	0.5%	4.5%	3.7%	2.1%	0.6%				3.4%	10.0%			2%
HBGT5	21.5	0.2%	1.0%	0.9%	0.1%					1.5%				0%
HBGT4														
HB-Combined Cycle_2														
Bogue Gas Turbines	**179.5**									**0%**	**1%**			**0%**
BOGT3	21.5									0.7%	3.9%			0%
BOGT9	20									0.3%	0.9%			0.11%
BOGT7	18									0.3%	2.9%			0.28%
BOGT6	18									0.3%	1.5%			0.15%
BOGT8	14													
BOGT11	20													
BOG-Combined Cycle	120	48.3%	38.3%	39.9%	41.2%	95.0%	93.3%	92.0%	92.6%	94.3%	94.3%	94.8%	92.7%	76.5%
		32.3%	25.6%	26.6%	27.5%	63.5%	62.3%	61.5%	61.9%	63.2%	64.0%	63.4%	61.9%	51.3%
Private Power	**249.86**	**65%**	**61%**	**64%**	**65%**	**55%**	**60%**	**62%**	**62%**	**62%**	**51%**	**62%**	**59%**	**60%**
JEP (Plant Total)	124.36	46.0%	36.4%	38.9%	43.5%	23.5%	50.0%	35.1%	38.2%	35.5%	15.9%	30.2%	26.3%	35%
JPPC	60	84.4%	83.7%	84.4%	92.0%	93.8%	56.7%	93.6%	89.0%	84.3%	84.5%	94.1%	93.7%	86%
WKPP	65.5	82.7%	85.8%	93.9%	84.0%	83.7%	85.9%	85.5%	84.0%	93.7%	90.8%	93.9%	92.9%	88%
	1													
Total (MWh) less Hydro & Pur	785.4													54%
Total	**945.8**	**48%**	**46%**	**47%**	**49%**	**50%**	**54%**	**53%**	**53%**	**53%**	**52%**	**52%**	**49%**	**50%**
Non-dispatchable Units	**160.5**	**29%**	**30%**	**25%**	**35%**	**35%**	**48%**	**39%**	**36%**	**35%**	**26%**	**29%**	**35%**	**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	50.0%	49.1%	52.8%	56.3%	42.8%	52.8%	53.6%	40.9%	56.3%	41.8%	77.3%	56.3%	52%
L.W.RIVER	4.7	77.7%	79.4%	78.5%	82.8%	82.6%	80.2%	65.7%	71.5%	70.0%	50.2%	85.3%	86.2%	76%
U W.RIVER	3.1	84.9%	92.0%	86.5%	91.3%	76.1%	86.1%	83.6%	84.5%	77.1%	71.3%	92.9%	81.3%	84%
MAGGOTY	6.0					88.8%	82.7%	61.3%	74.2%	89.0%	87.0%	91.2%	83.3%	55%
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%	20.1%	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%	27.2%	54.0%	43.3%	35.2%	32.8%	17.5%	18.0%	33.3%	31%
Wigton II	18	36.2%	34.3%	23.7%	42.2%	37.7%	68.0%	53.2%	45.1%	38.3%	22.2%	25.1%	43.1%	39%
Wigton III	24	28.5%	27.0%	18.6%	33.2%	29.7%	53.5%	41.9%	35.5%	30.2%	17.5%	19.8%	34.0%	31%
JPS Munro Wind Farm	3	1.7%	2.0%	3.3%	4.4%	12.3%	3.3%	3.3%	0.7%	1.0%	0.3%	0.3%	1.0%	3%
BM Wind	34	18.6%	17.8%	13.5%	22.1%	17.2%	34.1%	27.3%	22.2%	20.7%	11.1%	11.4%	21.1%	20%
WRG Solar	20	15.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	15.0%	15.0%	15.0%	18%

Table 2-2: Projected Unit Energy (MWh)

Total Energy Projections

(76% System Availability)	Capacity	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Totals
HYDRO & Purchases	160.5	**35,176**	**33,027**	**29,774**	**40,060**	**41,389**	**55,000**	**47,095**	**43,116**	**40,667**	**31,434**	**33,724**	**42,065**	**472,527**
Old Harbour Steam	193.5	**86,189**	**81,584**	**85,166**	**81,919**	**62,015**	**65,752**	**68,665**	**68,494**	**63,462**	**86,117**	**63,725**	**63,950**	**877,038**
OH-4	68.5	38,276	34,165	36,949	35,988	35,551	34,657	36,680	37,080	24,652	38,840	37,370	36,799	427,007
OH-3	65	28,114	24,895	26,681	25,627	19,174	25,787	26,713	26,590	26,384	30,447	25,239	26,095	311,746
OH-2	60.0	19,799	22,524	21,536	20,304	7,290	5,308	5,272	4,824	12,426	16,830	1,116	1,056	138,285
OH-1														
Hunts Bay Steam	68.5	**34,418**	**31,584**	**33,697**	**33,079**	**32,897**	**31,965**	**31,993**	**32,305**	**32,797**	**34,711**	**33,271**	**21,686**	**384,403**
HB-B6	68.5	34,418	31,584	33,697	33,079	32,897	31,965	31,993	32,305	32,797	34,711	33,271	21,686	384,403
Rockfort	40	**16,691**	**19,945**	**26,606**	**25,748**	**25,981**	**25,748**	**28,094**	**28,094**	**26,542**	**26,121**	**27,188**	**25,979**	**302,737**
RF-B1	20	13,303	10,379	13,303	12,874	13,014	12,874	14,047	14,047	13,360	12,074	13,594	13,281	156,150
RF-B2	20	3,388	9,566	13,303	12,874	12,967	12,874	14,047	14,047	13,182	14,047	13,594	12,698	146,587
Hunts Bay Gas Turbines	54	**145**	**1,170**	**1,040**	**500**	**150**				**1,036**	**2,427**			**6,468**
HBGT10	32.5	120	1,020	900	480	150				801	2,427			5,898
HBGT5	21.5	25	150	140	20					235				570
HBGT4														
HB-Combined		**34,563**	**32,754**	**34,737**	**33,579**	**33,047**	**31,965**	**31,993**	**32,305**	**33,833**	**37,138**	**33,271**	**21,686**	390,871
Bogue GT#3 - GT#11	179.5									**232**	**1,357**			**1,589**
BOGT3	21.5									102	621			723
BOGT9	20									45	141			186
BOGT7	18									45	391			436
BOGT6	18									40	204			244
BOGT8	18													
BOGT11	20													
BOG-Combined Cycle	120	43,152	31,995	35,585	35,585	84,816	80,579	82,113	82,687	81,510	84,179	81,946	82,725	806,872
Bogue Gas Turbines		**43,152**	**31,995**	**35,585**	**35,585**	**84,816**	**80,579**	**82,113**	**82,687**	**81,742**	**85,536**	**81,946**	**82,725**	**808,461**
Private Power	249.86	**120,579**	**105,592**	**119,427**	**118,287**	**104,373**	**109,776**	**115,936**	**116,012**	**112,346**	**96,684**	**111,970**	**111,425**	**1,342,407**
JEP (Plant Total)	124.36	42,603	31,501	35,984	38,929	21,709	44,749	32,495	35,337	31,742	14,744	27,062	24,295	381,150
JPPC	60	37,670	34,961	37,677	39,738	41,866	24,503	41,762	39,730	36,396	37,713	40,648	41,846	454,510
WKPP	65.5	40,306	39,130	45,766	39,620	40,798	40,524	41,679	40,945	44,208	44,227	44,260	45,284	506,747
Total (MWh) less Hydro & Pur	785.4	301,174	271,870	301,521	295,118	310,232	313,820	326,801	327,592	317,925	331,596	318,100	305,765	3,721,514
Total (Net Gen)	**945.8**	**336,350**	**304,897**	**331,295**	**335,178**	**351,621**	**368,820**	**373,896**	**370,708**	**358,592**	**363,030**	**351,824**	**347,830**	**4,194,041**
JPS (thermal+hydro)		192,521	177,735	193,783	190,402	223,330	220,027	225,031	226,535	221,492	250,686	223,770	210,098	2,555,410
Private (JEP + JPPC)		120,579	105,592	119,427	118,287	104,373	109,776	115,936	116,012	112,346	96,684	111,970	111,425	1,342,407
Total (less purchases)		313,100	283,327	313,210	308,689	327,703	329,803	340,967	342,547	333,838	347,370	335,740	321,523	3,897,817
Hydro		11,926	11,457	11,689	13,571	17,471	15,983	14,166	14,955	15,913	15,774	17,640	15,758	176,303
Purchases		23,250	21,570	18,085	26,489	23,918	39,017	32,929	28,161	24,754	15,660	16,084	26,307	296,224
Total Hydro & Purchases		35,176	33,027	29,774	40,060	41,389	55,000	47,095	43,116	40,667	31,434	33,724	42,065	472,527
	160.5	**11,926**	**11,457**	**11,689**	**13,571**	**17,471**	**15,983**	**14,166**	**14,955**	**15,913**	**15,774**	**17,640**	**15,758**	**176,303**
RIO - A	2.5	1,339	1,462	1,406	1,490	1,548	1,246	1,272	1,071	1,181	1,548	1,541	1,451	16,555
RIO - B	1.1	409	376	432	446	350	418	439	335	446	342	612	461	5,066
L.W.RIVER	4.7	2,716	2,596	2,745	2,801	2,887	2,714	2,299	2,500	2,369	1,756	2,887	3,013	31,283
U W.RIVER	3.1	1,957	1,984	1,994	2,038	1,756	1,922	1,927	1,949	1,721	1,644	2,074	1,875	22,841
MAGGOTY	**6.0**					**3,966**	**3,571**	**2,738**	**3,311**	**3,845**	**3,884**	**3,938**	**3,720**	**28,973**
ROARING RIV	4.1	2,671	2,610	2,656	2,599	2,723	2,426	2,701	2,411	2,189	2,381	2,621	2,745	30,733
CONSTANT SPRING	0.8	37	271	365	338	275	115	52	67	317	335	29	298	2,499
Magg-B	**7.2**	**2,797**	**2,158**	**2,091**	**3,859**	**3,966**	**3,571**	**2,738**	**3,311**	**3,845**	**3,884**	**3,938**	**2,195**	**38,353**
JAMALCO	11.0	372	348	372	360	372	360	372	372	360	372	360	372	4,392
ROPECON	0.5	74	70	74	72	74	72	74	74	72	74	72	74	876
BROILERS	12.0	1,488	1,392	1,488	1,440	1,488	1,440	1,488	1,488	1,440	1,488	1,440	1,488	17,568
Wigton	20.0	4,390	3,912	3,184	5,033	4,047	7,776	6,436	5,238	4,723	2,604	2,592	4,955	54,890
Wigton II	18	4,851	4,301	3,169	5,465	5,044	8,813	7,120	6,034	4,968	2,969	3,254	5,773	61,761
Wigton III	24	5,096	4,517	3,326	5,738	5,297	9,252	7,477	6,339	5,220	3,117	3,420	6,064	64,863
JPS Munro Wind Farm	3	37	42	74	94	275	72	74	15	22	7	7	22	741
BM Wind	34	4,710	4,204	3,422	5,407	4,345	8,352	6,912	5,625	5,069	2,797	2,779	5,327	58,949
WRG Solar	20	2,232	2,784	2,976	2,880	2,976	2,880	2,976	2,976	2,880	2,232	2,160	2,232	32,184

Table 2-3: Total System Thermal Heat Rate

(76% System Availability)	kJ/kWh Heat Rate Projections												
Avg. Heat Rate (kJ/kWh)	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Totals
Old Harbour Steam	**13,362**	**13,480**	**13,441**	**13,429**	**13,254**	**13,276**	**13,250**	**13,236**	**13,450**	**13,225**	**13,129**	**13,187**	**13,317**
OH-4	12,531	12,589	12,574	12,565	12,628	12,618	12,594	12,576	12,557	12,518	12,515	12,585	12,570
OH-3	13,796	13,922	13,916	13,934	13,923	13,918	13,912	13,924	13,866	13,626	13,971	13,968	13,885
OH-2	14,353	14,342	14,339	14,324	14,543	14,447	14,453	14,513	14,338	14,129	14,656	14,871	14,346
OH-1													
Hunts Bay Steam	**12,585**	**12,604**	**12,605**	**12,588**	**12,636**	**12,631**	**12,674**	**12,661**	**12,599**	**12,579**	**12,578**	**12,762**	**12,621**
HB-B6	12,585	12,604	12,605	12,588	12,636	12,631	12,674	12,661	12,599	12,579	12,578	12,762	12,621
Rockfort	**9,269**	**9,259**	**9,258**	**9,258**	**9,278**	**9,259**	**9,228**	**9,228**	**9,245**	**9,229**	**9,228**	**9,287**	**9,251**
RF-B1	9,277	9,277	9,277	9,277	9,302	9,278	9,222	9,222	9,239	9,222	9,222	9,280	9,257
RF-B2	9,238	9,239	9,238	9,239	9,255	9,239	9,234	9,235	9,252	9,234	9,235	9,294	9,245
Hunts Bay Gas Turbines	**16,051**	**15,883**	**15,890**	**15,606**	**15,457**				**15,741**	**15,193**			**15,575**
HBGT10	15,502	15,479	15,468	15,480	15,457				15,205	15,193			15,322
HBGT5	18,685	18,635	18,598	18,635					17,567				18,188
HBGT4													
HB-Combined	**12,599**	**12,721**	**12,704**	**12,633**	**12,649**	**12,631**	**12,674**	**12,661**	**12,695**	**12,750**	**12,578**	**12,762**	**12,669**
Bogue GT#3 - GT#11									**18,714**	**18,345**			**18,399**
BOGT3									18,751	18,319			18,380
BOGT9									18,261	18,075			18,120
BOGT7									18,585	18,307			18,336
BOGT6									19,272	18,685			18,781
BOGT8													
BOGT11													
BOG-Combined Cycle	9,615	9,615	9,615	9,615	8,999	9,057	9,061	9,059	9,054	9,054	9,053	9,059	9,152
Bogue Gas Turbines	**9,615**	**9,615**	**9,615**	**9,615**	**8,999**	**9,057**	**9,061**	**9,059**	**9,082**	**9,202**	**9,053**	**9,059**	**9,170**
Private Power	**8,415**	**8,407**	**8,411**	**8,353**	**8,288**	**8,660**	**8,320**	**8,364**	**8,250**	**8,364**	**8,318**	**8,307**	**8,371**
JEP1	8,614	8,614	8,614	8,614	8,615	8,613	8,614	8,614	8,614	8,614	8,614	8,614	8,614
JPPC	8,017	8,030	8,017	7,872	7,836	8,884	7,833	7,921	7,534	8,017	7,838	7,836	7,939
WKPP	8,567	8,567	8,567	8,568	8,568	8,568	8,567	8,567	8,567	8,567	8,568	8,568	8,568
Avg. System Heat Rate (kJ/kWh) no hydros or purchases	**10,529**	**10,652**	**10,542**	**10,479**	**10,021**	**10,182**	**10,045**	**10,054**	**10,056**	**10,401**	**9,993**	**9,929**	**10,232**
JPS (thermal)	11,943	12,080	11,941	11,903	10,902	11,002	10,996	10,983	11,046	11,240	10,905	10,861	11,284
Private Pwr.	8,415	8,407	8,411	8,353	8,288	8,660	8,320	8,364	8,250	8,364	8,318	8,307	8,371
System (Thermal)	10,528	10,651	10,541	10,478	10,020	10,181	10,044	10,054	10,056	10,400	9,993	9,928	10,231
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 & Br	**9,482**	**9,555**	**9,651**	**9,278**	**8,891**	**8,708**	**8,826**	**8,932**	**8,963**	**9,551**	**9,084**	**8,778**	**9,129**

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, that is, 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.

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

(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.

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

(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).

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

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

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

The OUR, in its 2015 Annual Tariff Adjustment Determination stated that the implementation of the Q-factor in the PBRM has been greatly hindered due to "significant issues with JPS' service quality performance data necessary to establish the Q factor baseline and the incentive scheme." JPS acknowledges the OUR's concern but does not share the view that there are any significant issues with the quality performance data and would like to indicate clearly that JPS is of the opinion that the data is of sufficient quality to be used to establish the Q-factor baseline notwithstanding our acknowledgement that are a few issues to be addressed.

JPS will show that the quality of the reliability data is consistent with industry standards and that the effective management of reliability data is not characterised by the identification of an error event or a series of isolated error events, but rather, must take a lifecycle approach. We will describe JPS' efforts to ensure that the data quality is continuously improved and maintained over time.

3.2.1 Reliability Data Quality in the Utility Industry

Maintaining data quality can be challenging for the electric utility due to the sheer volume of data and the means by which data quality can be compromised. Data quality challenges are pervasive throughout the industry regardless of utility size or ownership structure (municipal, IOU, cooperatives, etc.). In fact, the utility which has totally solved its data quality issues remains an aberration in the industry. Poor data quality stems principally from two sources:

- Initial data quality
- Maintenance-induced and ongoing deterioration.

Even when initially good, data quality can deteriorate over time due to data erosion and other factors so, maintaining and improving data quality is an ongoing lifecycle effort.

The implementation of OMS significantly improves the utility's management of its reliability data, but due to vast amounts of data, errors in the automation process can lead to errors in the calculation of the reliability indices. An IEEE research paper[6] shows that most utilities with OMS have some process for verifying outage events prior to it being used for reliability reporting. Less aggressive processes sample a portion of outage events based on an established criteria including:

- Computer generated exceptions report
- Outages impacting more than a threshold number of customers
- All feeder level outages and random sampling, etc.

As such, event verification and calibration is generally considered an important part of the reliability reporting with utilities classified for verification of events as[1]:

- Best : All events are examined daily
- Good: Most events are examined daily
- Fair: Exception report logic generate a list of suspicious events, which are than reviewed
- Poor: Events are reviewed on an ad-hoc basis at the time that reports are generated
- Worst: Events are not reviewed.

The Survey of Reliability Reporting Practices indicates that only the worst utilities do not review their events and the best utilities do so every day. This indicates that JPS' practice of reviewing its events data on an ongoing basis is consistent with the best practices in the industry and is not an indication that JPS' reliability data is being compromised.

3.2.2 Quality of JPS' OMS Data

The implementation of an automated outage management and reporting system (OMS) is dependent on:

- Accurate GIS network data which provides the source for building the OMS electrical network model;
- Ability of the GIS Spatial model to seamlessly and accurately represent network electrical topology in real-world scenario and;
- Business processes and practices alignment to network operational requirements

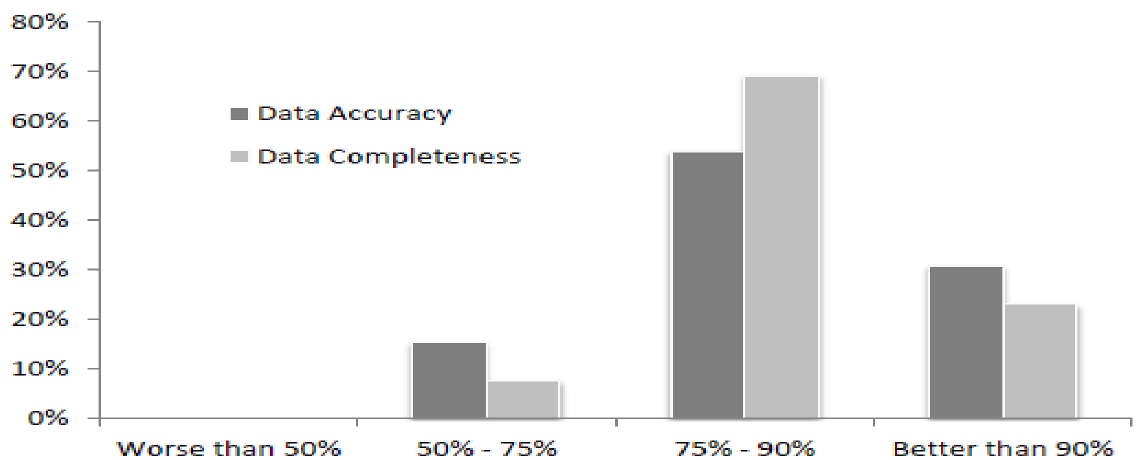
As stated in an article from Schneider Electric[7], "the foundational concept of every OMS is its ability to understand the relationship between customers and the network, in order to analyze the location and extent of an outage. Outage prediction capabilities are enabled by a detailed

[6] R.E. Brown and J.H. Spare, "A Survey of Reliability Reporting Practices," IEEE Paper, 2006.
[7] Dirkman, J (2014). Enhancing Utility Outage Management Performance.

representation of the transmission and distribution network. A model that represents the network's current topology and connection to the end consumer is essential to determine the location of the problem." This means that to a very large extent, the accuracy of the GIS model has the most significant impact on the accuracy of the OMS data. GIS data quality is measured by two quality 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. In the context of GIS, accuracy refers to how much the GIS model represents the actual system in the field, inclusive of circuit 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. Electric Power Research Institute (EPRI) carried out a Smart Grid Assessment study in 2012[8] in which the completeness and accuracy of GIS data for US utilities was assessed. The majority of utilities fell in the very functional and acceptable range of 75% - 90% data quality. Only a few utilities indicated a higher level of accuracy. Figure 3-1 shows the results that were observed in the EPRI study. Figure 3-2 shows the current status of JPS' data quality as measured by its completeness and accuracy.

Figure 3-1: Expressed Level of Data Quality



[8] EPRI Smart Grid Assessment Report – Nov. 2012 (1024303)

Figure 3-2: Current Status of JPS' Data Quality

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

The table shows that JPS is better than 90% of the utilities included in the EPRI survey for most components of the GIS and is at least as good as the average utility for its weakest area which is the customer to transformer. In its 2014 rate review filing JPS had erroneously indicated that all but 9,000 customers were correctly mapped to their service transformers with full location data and phase of power serving them. This was an error on our part and we would like to point out this correction for the record.

Prior to OMS, JPS' GIS focused on cartographic data for map production. We worked to improve the accuracy of the model before commissioning of the OMS implementation; however, immediately following the deployment of the OMS, JPS identified spatial errors in the GIS electrical model leading to erroneous prediction or even failure of the OMS. Most of these errors were corrected in the GIS during the testing phase of the system, for example, we corrected issues associated with the integration of SCADA enabled devices and implemented freezing of outages on subfeeders to prevent rollup, which eliminated the problem of a later outage on a feeder section with a subsection previously out assuming the start time of the original subsection outage..

Distribution systems undergo daily changes due to operational configuration, growth, and network additions, as well as routine switching for maintenance. To illustrate, JPS, as part of its normal operations, is often required to do energized (live line) feeder transfers and to utilize mobile transformers when carrying out certain maintenance activities. These activities do not result in customer outages, however, the removal of a feeder recloser device from the grid will be picked up by the SCADA and this will be seen in the OMS as an outage when in fact, none occurred. These activities are normally managed by our system operators to prevent erroneous OMS reporting. However, in cases where this is not done, extensive incorrect outages will be reported in OMS. To circumvent these types of problems, JPS established Rule Base Management of "Unique System Challenges" which includes rules for:

i. Use of mobile transformers

ii. Feeder Transfers
iii. Protection and SCADA Systems maintenance and functional checks
iv. Excessive overloading of transformers.

The initiation of these rules aid in the calibration process, which also involve ensuring customer related issues such as disconnections, and behind the meter non JPS outages are tagged as non-reportable.

3.2.3 Clarification of Points made in 2015 Annual Tariff Adjustment Determination

It is important for us to clarify some of the points raised by the OUR in its 2015 Annual Tariff Adjustment Determination as these are germane to the OUR's conclusions on the validity and integrity of the submitted dataset. We hope that our clarifications will shed more light on the issues raised by the OUR.

These points addressed by the OUR are raised and clarified in the following numbered list (1-11).

1. **Period of Outage Data**
   - **OUR's Concern**: The outage data presented by JPS covered the period of Jan. 1 – Dec. 31 2014, which includes data from the post cut-over period which was indicated to be completed in March 2014. Outage data for April & May 2014 were included though it was previously assessed by the OUR as not considered reliable. The OUR also cited JPS' indication that it needed more time to fix system glitches and improve GIS data to arrive at the desired improvements needed to guarantee accurate reliability reporting as a significant cause for concern.
   - **JPS' Response**: We note the concerns raised by the OUR, however, we would like to state that it is normal for system glitches and inconsistencies in data reported by the OMS to be corrected post system implementation. GIS Data Set Improvement is a continuous process and requires Life Cycle Data Improvement Management as is accepted within the industry. System modifications are particularly important to correcting the root cause for system related errors. We therefore do acknowledge that outages over the period were reviewed and the dataset properly calibrated, consistent with utility best practice. Even after the elimination of all system glitches, data validation will remain part of the life cycle data improvement management process. We believe that greater emphasis should be place on the causes of modification and the process by which modifications are effected to determine the quality of the data presented to the OUR. The availability of 24 months of data improves quality of information available to the Regulator to set the baseline.

2. **Planned Outages**
   - **OUR Position**: Dataset includes planned outages. However, the Q-factor only involves unplanned interruptions of service.
   - **JPS Response**: Accepted. Planned Outages will be submitted separately for monitoring purposes only and not included in Q-factor reporting.

4. **Customer Count**
   - **OUR's Concern**: Total number of customer served at time of interruption, which is fundamental to the computation of the reliability indices was not provided. OUR also queried whether a single annual value was used customer count since customer count changes throughout the year.
   - **JPS' Response**: A fixed annual customer count was utilized since the daily values were not yet implemented. This fact was inadvertently omitted from the submission, however, a validation of the data would indicate that the values are the same.

5. **Recalibration of Outage Data**
   - **OUR's Concern**: It appears that JPS has made significant alteration to the raw outage data by adjusting and disaggregating the data into categories denoted as "reportable" and "non reportable" outage data. There **was no** explanation as to the determination of what is meant by "non reportable". There was uncertainty as to whether adjustments are made according to a standardized process and also if they are automated or manual.
   - **JPS' Response**: The categorization of outages as "reportable" and "non reportable" is a fundamental part of OMS. This option is utilized in situations where clear errors are obtained. An automated rule based data dictionary is used to define "non-reportable" issues.

6. **Outages with negative durations**
   - **OUR's Concern**: 25 outages were found with negative durations. OUR wanted to establish whether negative duration outages were accounted for.
   - **JPS' Response**: These were errors directly found in the base OMS system to which no modifications were made and is being investigated by the vendor. These outages were not related to reliability complaints as they were less than five minutes duration. No alteration was made to the raw dataset in computing the reliability figures.

7. Annex B – Summary of OMS Raw Data
   - **OUR's Concern**: Whether or not outage events occurring during days referred to as "Major Event Days" were accounted for.
   - **JPS' Response**: Consistent with the 2.5 beta definition, days with SAIDI values in excess of the MED values were highlighted and excluded from the report.

8. **Annex C – Reportable Outage Data**
   - **OUR's Concern**: The need to alter the OMS data by means of approximations and adjustments without any clear process as to how this is done can only serve to nullify or negate the purpose of having an OMS.
   - **JPS' Response**: All data Calibration is Rule Based. Rules are established to identify and eliminate errors that are technically incorrect such as assignment of loads to a transformer in excess of 50% greater than its capacity. The initiation of

these rules also initiate field validation, results of which is included to improve data quality and aid in the life cycle improvement process.

9. **Annex C – Reportable Outage Data Cont.**
   - **OUR's Concern**: The percentage of customer restored within 24hrs of forced outages is 99.91% which is in conformance of EOS9 standards. Data questionable due to alterations to Reportable dataset. The OUR also identified two record IDs in Annex C which were not in Annex A.
   - **JPS' Response**: Data alterations are properly documented by a rules-based system and can be audited if necessary. The two records in Annex C were carried over from 2013owing to an error in the parameters used to generate the dataset.

10. **Annex C – Reportable Outage Data Cont.**
    - **OUR's Position**: Adjustments were made to outage events right throughout the year, with a noticeable increase in the number of adjustments made per month in the second half of the year.
    - **JPS's Response**: Historically the number of outages increases in the second half of the year which is associated with the hurricane season). With this increase in outages, an increase number of issues emerge.

3.3 2015 Reliability Performance

Figure 3-3, Figure 3-4, Figure 3-5 and the data in, highlights JPS 2015 reliability performance. In 2015, JPS attained a 10.9% and 30.3% improvement over 2014 in the SAIDI and SAIFI performance statistics respectively.

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

Figure 3-3: SAIDI Performance in 2015 – (inclusive of Generation, Transmission and Distribution)

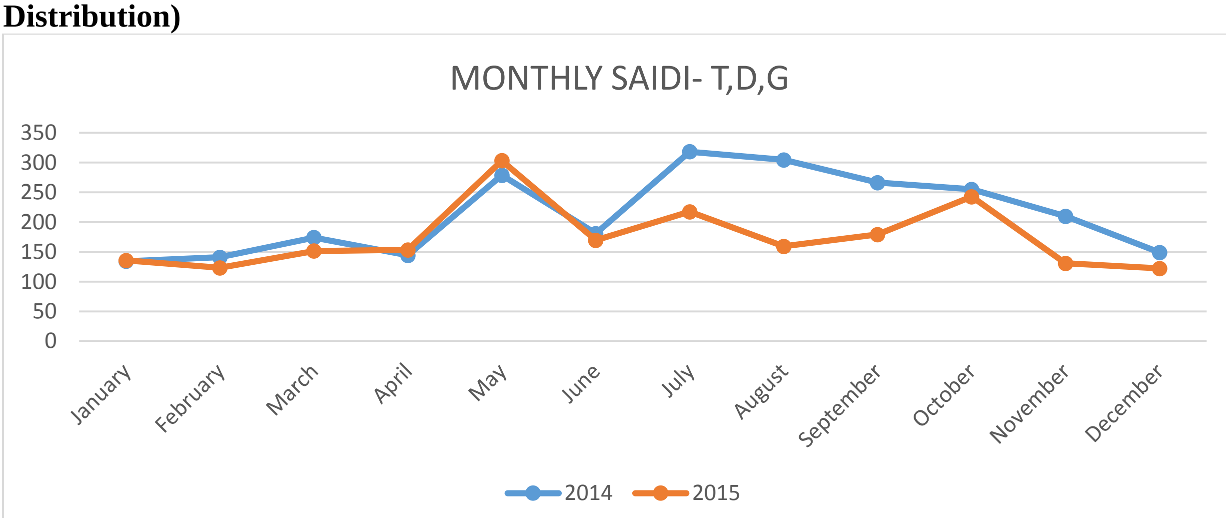


Figure 3-4: SAIFI Performance in 2015 – (inclusive of Generation, Transmission and Distribution)

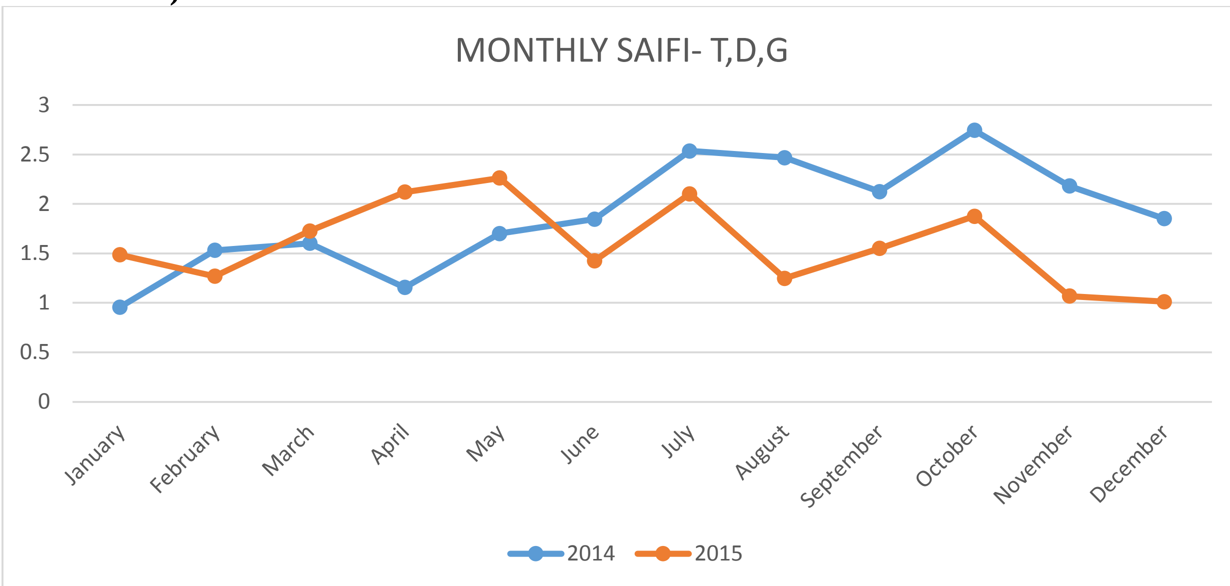


Figure 3-5: CAIDI Performance in 2015 – (inclusive of Generation, Transmission and Distribution)

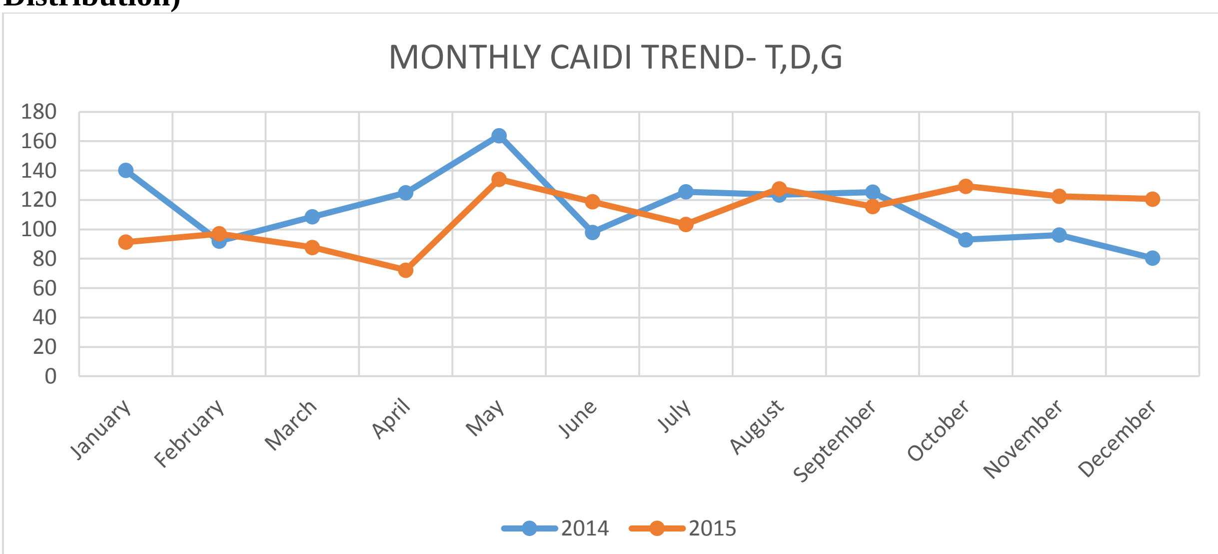


Table 3-1: Summary of Reliability Performance in 2015

SUMMARY OF 2015 RELIABILITY PERFORMANCE

Indicator	Unit	Category	Generation	Transmission	Distribution	Force Majeure	Total
SAIDI	Minutes/ Customer	Forced	110.192	154.557	1,718.975	0.000	1,983.724
		Planned	0.000	21.682	81.827	0.000	103.509
		Total	110.192	176.239	1,800.801	0.000	2,087.233
SAIFI	Interruptions / Customer	Forced	5.814	1.526	11.511	0.000	18.851
		Planned	0.000	0.069	0.223	0.000	0.292
		Total	5.814	1.594	11.734	0.000	19.143
CAIDI	Minutes/ Customer	Forced	18.953	101.295	149.333	0.000	105.232
		Planned	0.000	316.298	366.461	0.000	354.678
		Total	18.953	110.539	153.465	0.000	109.035
MAIFI	Interruptions / Customer	Forced	6.206	1.054	16.870	0.000	24.130
		Planned	0.000	0.210	0.274	0.000	0.484
		Total	6.206	1.264	17.144	0.000	24.614

3.4 2015 Strategy for Reliability Performance Improvement

2015 strategy for reliability performance improvement was pivoted around four (4) major initiatives outlined as follows:

1. Employment of automated approaches through the use of technology on the T&D network
2. Improvement of outage data quality and processes for computing the reliability indices
3. Use of traditional methods including vegetation management, lightning mitigation, routine line inspection/maintenance and the application of the appropriate solutions to problem areas.
4. Implementation of a Reliability Culture throughout the organization.

3.4.1 Employing Automated Approaches

As part of its plan to develop a smart-self healing grid, JPS is employing various technologies on its grid to improve T&D System reliability. In 2015, a number of smart devices as outlined below were installed on its distribution system:

- Distribution Automated Switches (DA)
- Fault Circuit Indicators
- Reclosing secondary switches (poor man re-closers)

The main function of these devices is to limit faulted section of a distribution feeder and allow for faster response and restoration of affected circuits at the primary and secondary distribution level. These devices are pivotal to our self-healing grid strategy. Since 2014, seventy six (76) DA devices were installation with the installations in 2014 and 2015 broken down as follows:

- 2014 – 41 devices
- 2015 – 35 devices

This automated solution, which remotely monitors the status of the distribution network, also provides more information to our system control and dispatch teams who direct the trouble-shooters and repair crews.

One hundred and thirty (130) Fault Circuit Indicators have also been installed on the distribution network of which eighty nine (89) were installed in 2015 to improve our outage troubleshooting time, thereby improving our outage response time.

3.4.2 Improving Outage Data Accuracy and Processes

Consistent with industry best practices, JPS has adopted a process for daily data calibration understanding that maintaining data quality is a life cycle endeavour and that the best utilities examine and verify all events on a daily basis.

Based on the above, JPS implemented a procedure to ensure each event is validated prior to outages being closed out in the Ventyx OMS. Additionally, rule based validation methods are employed for identification of non-reportable outages.

3.4.3 Traditional Reliability Improvement Methods

The approaches to improve service reliability included traditional methods that had previously being employed at 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
- 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.

3.4.4 Building a Reliability Culture throughout the Organization

JPS is working to transform the reliability culture within the organization. Some of the initiatives implemented in 2015 geared at improving the reliability culture are:

- Established Reliability Roles within Regional Operations
- Established Monthly Reliability Performance Recognition Programme
- Developed a lineman/OMS Appreciation Program to help Linemen appreciate their role in proper reliability reporting.

3.5 2016 Reliability Improvement Plan

JPS will continue its thrust towards improving the reliability of service to its customers. The continued process of lifecycle data management for the OMS and the increase use of automated technologies forms the backbone of our major initiatives geared at improving the reliability performance. We continue to invest in the rehabilitation and reinforcement of the T&D network. In 2015, US$15.626M was invested in a number of projects aimed at improving reliability performance. JPS has budgeted US$18.527M towards projects geared at reliability improvement for 2016.

3.5.1 2016 System Reliability Objectives:

Figure 2 below, provides an illustration of JPS 2016 initiatives t geared towards improving reliability and measurement in 2016. Specifically, our objectives are detailed as follows:

SAIFI:

- Reduction in the number of outages through cost effective approaches
    - Employ the use of Unmanned Aerial Devices (Drones) in distribution maintenance, incorporating other technology such as Infra-red scanning.
    - Extend the use of contamination monitors to allow for improved prediction of high contamination levels
    - Expand live line washing programme.
- Minimize the impact of outages (No. of customer affected per outage) through technological approaches.
    - Adopt "Single Phase Lockout" on Feeder Reclosers
    - Install "Trip Savers" isolating devices across the distribution network
    - Install in excess of 200 communication enabled fault indicators on distribution circuits.

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 3-6: JPS Reliability Initiatives for 2016-2020

In order to align ourselves to industry standards, based on the IEEE survey, JPS will work to continuously improve the accuracy of the GIS. JPS GIS/OMS data accuracy is in the best of class per industry best practice and is acceptable for successful OMS functionality and regulatory compliance.

3.6 Proposal for 2016 Reliability Baseline

Against the background described above, JPS is proposing that the submitted dataset for the reporting period Jan. 1st – Dec. 31st, 2015 be utilized for establishing the Q- factor benchmark. Our proposal is for the benchmarks outlined in Figure 3-7to be utilized by the OUR in establishing the Q factor targets in the PBRM.

Figure 3-7: Proposed Q Factor Targets for 2016

Item	2015 Actual – Calibrated Data	Proposed Q-Factor Baseline!
SAIDI	1,983.724	1,983.724
SAIFI	18.851	18.851
CAIDI	105.232	105.232

4 APPENDIX 1 – DERIVATIONS OF dI

To show that the formula in the new Electricity Licence can be reformulated in terms of the one established in the OUR's 2014-2019 determination, the following derivations will be useful.

Let $\Delta \mathrm{e} = \frac{\mathrm{EX_n} - \mathrm{EX_b}}{\mathrm{EX_b}}$

The non-fuel revenue at time t be noted as $\mathrm{ART_t}$. Using the definitions form the OUR's 2014-2019 determination, then

$$\mathrm{ART_t} = \left[(1 - \mathrm{USAF}) \times (1 + \Delta \mathrm{e}) \times \mathrm{USP} + \mathrm{USAF} \times (1 + \Delta \mathrm{e})(1 + \mathrm{INF_{US}}) \times \mathrm{USP} + (1 - \mathrm{USP}) \times (1 + \mathrm{INF_J})\right]\mathrm{ART_{t-1}}$$

This can be expanded to give:

$$\mathrm{ART_t} = \mathrm{ART_{t-1}}\left[(1 + \Delta \mathrm{e}) \times \mathrm{USP} \times (1 + \mathrm{USAF} \times \mathrm{INF_{US}}) + (1 - \mathrm{USP}) \times \left(1 + \mathrm{INF_J}\right)\right]$$

Further re-arranging eventually gives:

$$\mathrm{ART_t} = \mathrm{ART_{t-1}}[1 + \mathrm{USP} \times \Delta \mathrm{e} \times (1 + \mathrm{USAF} \times \mathrm{INF_{US}}) + \mathrm{USP} \times \mathrm{USAF} \times \mathrm{INF_{US}} + (1 - \mathrm{USP}) \times \mathrm{INF_J}]$$

$$\mathrm{ART_t} = \mathrm{ART_{t-1}}[1 + \mathrm{dI}]$$

So

$$\mathrm{dI} = \mathrm{USP} \times \left(\frac{\mathrm{EX_n} - \mathrm{EX_b}}{\mathrm{EX_b}}\right)(1 + \mathrm{USAF} \times \mathrm{INF_{US}}) + \mathrm{USP} \times \mathrm{USAF} \times \mathrm{INF_{US}} + (1 - \mathrm{USP}) \times \mathrm{INF_J}$$

as was determined by the OUR.

In the new formula, $\mathrm{USDS_b}$ is defined as the debt service portion of the non-fuel revenue requirement so it covers a smaller portion of JPS' non fuel revenue requirement than 1-USAF. $\mathrm{USDS_b}$ is the part of the US portion of non-fuel revenue ($\mathrm{USP_b}$) that is for debt service and thus not subject to US inflation, thus, $\mathrm{USP_b}$ - $\mathrm{USDS_b}$ is subject to US inflation.

The derivation of the dI formula in the context of the new Licence is shown below.

$$\mathrm{ART_t} = \left[\mathrm{USDS_b} \times (1 + \Delta \mathrm{e}) + (\mathrm{USP_b} - \mathrm{USDS_b}) \times (1 + \Delta \mathrm{e}) \times (1 + \mathrm{INF_{US}}) + (1 - \mathrm{USP}_b) \times (1 + \mathrm{INF_J})\right]\mathrm{ART_{t-1}}$$

$$\mathrm{ART_t} = \left[(1 + \Delta \mathrm{e}) \times (\mathrm{USDS_b} + \mathrm{USP_b} - \mathrm{USDS_b} + (\mathrm{USP_b} - \mathrm{USDS_b}) \times \mathrm{INF_{US}}) + (1 - \mathrm{USP_b}) \times (1 + \mathrm{INF_J})\right]\mathrm{ART_{t-1}}$$

$$\mathrm{ART_t} = \left[(1 + \Delta \mathrm{e}) \times (\mathrm{USP_b} + (\mathrm{USP_b} - \mathrm{USDS_b}) \times \mathrm{INF_{US}}) + (1 - \mathrm{USP_b}) \times (1 + \mathrm{INF_J})\right]\mathrm{ART_{t-1}}$$

$$\mathrm{ART_t} = \big[\Delta e(\mathrm{USP_b} + (\mathrm{USP_b} - \mathrm{USDS_b}) \times \mathrm{INF_{US}}) + (\mathrm{USP_b} + (\mathrm{USP_b} - \mathrm{USDS_b}) \times \mathrm{INF_{US}}) \\ + \ (1 - \mathrm{USP_b}) + (1 - \mathrm{USP_b})\mathrm{INF_J})\big]\mathrm{ART_{t-1}}$$

$$\mathrm{ART_t} = \big[1 + \Delta e\{\mathrm{USP_b} + (\mathrm{USP_b} - \mathrm{USDS_b}) \times \mathrm{INF_{US}}\} + (\mathrm{USP_b} - \mathrm{USDS_b}) \times \mathrm{INF_{US}} \\ + (1 - \mathrm{USP_b})\mathrm{INF_J})\big]\mathrm{ART_{t-1}}$$

So from this,

$$\mathrm{dI} = \left(\frac{\mathrm{EX_n} - \mathrm{EX_b}}{\mathrm{EX_b}}\right)\{\mathrm{USP_b} + (\mathrm{USP_b} - \mathrm{USDS_b}) \times \mathrm{INF_{US}}\} + (\mathrm{USP_b} - \mathrm{USDS_b}) \times \mathrm{INF_{US}} \\ + (1 - \mathrm{USP_b})\mathrm{INF_J})$$

5 APPENDIX II – CPI Data for March 2016

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

News Release
Consumer Price Index
March 2016

April 15, 2016

In March 2016 there was a 0.1 per cent decline in the All Jamaica 'All Divisions' Consumer Price Index which was **229.3.** The index for the highest weighted division, 'Food and Non-Alcoholic Beverages', moved downwards by 0.5 per cent. Mainly influencing this division were lower prices for 'Vegetables' and 'Starchy Foods' of -2.9 per cent and -3.1 per cent respectively. Also contributing to the downward movement in the 'All Jamaica' price index were the divisions 'Housing, Water, Electricity, Gas and Other Fuels' (-0.1 per cent) and 'Transport' (-0.4 per cent). Reduced rates for water and sewage were chiefly responsible for the movement within the 'Housing, Water, Electricity, Gas and Other Fuels' division, while the fall in airfares and petrol prices impacted the 'Transport' division. However, these movements were mitigated by an advancement in the index for the division 'Furnishings, Household Equipment and Routine Household Maintenance' of 2.3 per cent due mainly to the increase in the national minimum wage.

The All Jamaica 'All Divisions' CPI recorded **fiscal year and point-to-point inflation rates** of **3.0 per cent** each. The **calendar year-to-date inflation** was **–1.3 per cent.**

The movement in the index recorded for the other divisions for March 2016 were as follows: 'Alcoholic Beverages and Tobacco' 0.3 per cent, 'Clothing and Footwear' 0.1 per cent, 'Furnishings, Household Equipment and Routine Household Maintenance 2.3 per cent, 'Health 0.1 per cent, 'Recreation and Culture' 0.1 per cent, 'Restaurants and Accommodation Services' 0.1 per cent and 'Miscellaneous Goods and Services' 0.2 per cent.

The movements in the Index for all three regions were as follows: Greater Kingston Metropolitan Area (GKMA) -0.2 per cent, Other Urban Centres (OUC) -0.2 per cent and Rural Areas 0.0 per cent.

The **Consumer Price Index Bulletin - March 2016** further outlines additional information and is available at the Statistical Institute of Jamaica's Distribution Centre located at 7 Cecelio Avenue, Kingston 10. CPI data is also published on the STATIN website at www.statinja.gov.jm.

Table 3. Consumer Price Index for All Urban Consumers (CPI-U): U.S. city average, special aggregate indexes, March 2016

[1982-84=100, unless otherwise noted]

Special aggregate indexes	Relative importance Feb. 2016	Unadjusted indexes			Unadjusted percent change		Seasonally adjusted percent change		
		Mar. 2015	Feb. 2016	Mar. 2016	Mar. 2015-Mar. 2016	Feb. 2016-Mar. 2016	Dec. 2015-Jan. 2016	Jan. 2016-Feb. 2016	Feb. 2016-Mar. 2016
All items less food	85.969	234.580	235.295	236.602	0.9	0.6	0.0	-0.2	0.1
All items less shelter	66.692	223.014	221.229	222.363	-0.3	0.5	-0.1	-0.4	0.1
All items less food and shelter	52.661	217.015	214.168	215.747	-0.6	0.7	-0.1	-0.5	0.1
All items less food, shelter, and energy	46.282	221.558	224.171	224.802	1.5	0.3	0.3	0.3	0.0
All items less food, shelter, energy, and used cars and trucks	44.163	226.035	228.968	229.479	1.5	0.2	0.3	0.3	0.0
All items less medical care	91.512	226.093	226.494	227.545	0.6	0.5	0.0	-0.2	0.1
All items less energy	93.621	241.135	245.459	245.913	2.0	0.2	0.3	0.3	0.0
Commodities	36.565	182.318	177.049	178.437	-2.1	0.8	-0.4	-0.9	0.0
Commodities less food, energy, and used cars and trucks	17.627	147.574	146.712	147.024	-0.4	0.2	0.2	0.3	-0.2
Commodities less food	22.534	153.493	145.378	147.528	-3.9	1.5	-0.6	-1.5	0.1
Commodities less food and beverages	21.569	150.463	142.077	144.277	-4.1	1.5	-0.6	-1.6	0.1
Services	63.435	289.323	296.351	297.024	2.7	0.2	0.3	0.3	0.2
Services less rent of shelter[1]	30.477	313.483	319.366	319.935	2.1	0.2	0.1	0.3	0.2
Services less medical care services	56.781	275.388	281.727	282.437	2.6	0.3	0.2	0.2	0.2
Durables	9.681	109.587	108.252	108.525	-1.0	0.3	0.0	0.0	-0.1
Nondurables	26.884	218.297	210.749	212.806	-2.5	1.0	-0.7	-1.2	-0.4
Nondurables less food	12.853	194.444	179.008	183.308	-5.7	2.4	-1.2	-2.5	-0.3
Nondurables less food and beverages	11.888	191.634	175.116	179.677	-6.2	2.6	-1.4	-2.7	-0.3

6 APPENDIX III – FX Loss (Audited Financials)

JAMAICA PUBLIC SERVICE COMPANY LIMITED

Notes to the Financial Statements
Year ended December 31, 2015
(*Expressed in United States Dollars*)

25. Expenses (continued)

(c) Net finance costs

	2015 $'000	2014 $'000
Foreign exchange losses, net	(4,925)	(13,304)
Other finance costs:		
Long-term loans	(30,359)	(30,419)
Customer deposits	(606)	(553)
Bank overdraft and other	(2,146)	(6,354)
Preference dividends	(2,653)	(2,672)
Debt issuance costs and expenses	(4,218)	(4,018)
	(39,982)	(44,016)
Finance income:		
Interest income	1,062	1,598
Interest capitalised during construction [Note 5(d)]	1,368	524
	2,430	2,122
	(42,477)	(55,198)

Interest income arises materially from treasury transactions entered into in the ordinary course of business.

7 APPENDIX IV– Bill Impact Analysis

Bill Impact Rate 10

Enter your usage here	Energy (kWH)	158.8		
			Exchange Rate	121.8522 JMD/USD
			EEIF	0.4998 JMD
			EEIF (proposed	0.4998 JMD

	Before			After			Change	
	February 2016 Bill			February 2016 Bill			February 2016 Bill	
Description	**Usage**	**Rate**	**Charges (J$)**	**Usage**	**Rate**	**Charges (J$)**	**Charges (J$)**	**%**
Base/Exchange Rate	115.5	121.8522		122.50	121.8522			
Non-Fuel Charges								
Energy 1st	100	8.61	861.00	100	9.14	913.81	52.81	6.1%
Energy Next	58.82	20.05	1,179.34	58.82	21.28	1,251.67	72.33	6.1%
Customer Charge		404.88	404.88		429.71	429.71	24.83	6.1%
EEIF Charges	158.82	0.4998	79.38	158.82	0.4998	79.38	-	0.0%
Sub Total			2,524.60			2,674.57	149.97	5.9%
F/E Adjustment			111.08			(11.31)	(122.39)	
Total Non-Fuel Bill			2,635.68			2,663.25	27.57	1.0%
Fuel & IPP Charges	158.82	9.436	1,498.66	158.82	9.824	1,560.20	61.54	4.1%
Early Payment Incentive		-	-		-	-	-	0.0%
Bill Total			4,134.34			4,223.46	89.12	2.2%

Bill Impact Rate 20

Enter your usage here	Energy (kWH)	835.8

Exchange Rate	121.8522	JMD/USD
EEIF	0.4998	JMD
EEIF (proposed	0.4998	JMD

	Before			After			Change	
	February 2016 Bill			February 2016 Bill			February 2016 Bill	
Description	Usage	Rate	Charges (J$)	Usage	Rate	Charges (J$)	Charges (J$)	%
Base/Exchange Rate	115.5	121.8522		122.50	121.8522			
Non-Fuel Charges								
Energy	835.7992862	16.61	13,882.63	835.7992862	17.63	14,734.06	851.43	6.1%
Customer Charge		902.00	902.00		957.32	957.32	55.32	6.1%
EEIF Charges	835.7992862	0.4998	417.73	835.7992862	0.4998	417.73	-	0.0%
Sub Total			15,202.36			16,109.11	906.75	6.0%
F/E Adjustment			668.87			(68.15)	(737.02)	
Total Non-Fuel Bill			15,871.23			16,040.96	169.73	1.1%
Fuel & IPP Charges	835.80	9.436	7,886.80	835.80	9.824	8,210.66	323.86	4.1%
Bill Total			23,758.03			24,251.62	493.59	2.1%

Bill Impact Rate 40 STD

Enter your usage here	Energy (kWH)	33,135	Exchange Rate	121.8522	JMD/USD
	Demand kVA	116	EEIF	0.4998	JMD
	Load Factor	38%	EEIF (proposed)	0.4998	JMD

	February 2016 Bill						Change February 2016 Bill	
Description	**Usage**	**Rate**	**Charges (J$)**	**Usage**	**Rate**	**Charges (J$)**	**Charges (J$)**	**%**
Base/Exchange Rate	115.50	121.8522		122.50	121.8522			
Non-Fuel Charges								
Demand	116	1,622.78	188,242.48	116	1,722.31	199,787.51	11,545	6.1%
Energy	33,135	5.18	171,639.87	33,135	5.50	182,166.65	10,527	6.1%
Customer Charge		6,355.00	6,355.00		6,744.76	6,744.76	390	6.1%
EEIF Charges	33,135	0.4998	16,560.93	33,135	0.4998	16,560.93	-	0.0%
Sub Total			382,798.27			405,259.84	22,462	5.9%
F/E Adjustment			16,842.33			(1,714.46)	(18,557)	
Total Non-Fuel Bill			**399,640.60**			**403,545.37**	**3,904.77**	**1.0%**
Fuel & IPP Charges	33135.10932	9.059	300,163.83	33135.10932	9.431	312,489.77	12,326	4.1%
Bill Total (J$)			699,804.43			716,035.15	16,231	2.3%

Bill Impact Rate 50 STD

Enter your usage here	Energy (kWH)	270,899	Exchange Rate	121.8522	JMD/USD
	Demand kVA	751	EEIF	0.4998	JMD
	Load Factor	49%	EEIF (proposed)	0.4998	JMD

	February 2016 Bill						Change February 2016 Bill	
Description	Usage	Rate	Charges (J$)	Usage	Rate	Charges (J$)	Charges (J$)	%
Base/Exchange Rate	115.50	121.8522		122.50	121.8522			
Non-Fuel Charges								
Demand	751	1,453.80	1,091,214.66	751	1,542.96	1,158,139.53	66,925	6.1%
Energy	270,899	4.99	1,351,784.26	270,899	5.30	1,434,690.03	82,906	6.1%
Customer Charge		6,355.00	6,355.00		6,744.76	6,744.76	390	6.1%
EEIF Charges	270,899	0.4998	135,395.15	270,899	0.4998	135,395.15	-	0.0%
Sub Total			2,584,749.07			2,734,969.46	150,220	5.8%
F/E Adjustment			113,723.59			(11,570.37)	(125,294)	
Total Non-Fuel Bill			2,698,472.66			2,723,399.09	24,926	0.9%
Fuel & IPP Charges	270,899	9.059	2,454,012.62	270,899	9.431	2,554,784.32	100,772	4.1%
Bill Total (J$)			5,152,485.28			5,278,183.41	125,698	2.4%

Bill Impact Rate 60

Enter your usage here	Energy (kWH)	15,000.3		Exchange Rate		121.8522 JMD/USD			
				EEIF		0.4998 JMD			
				EEIF (proposed		0.4998 JMD			
Before				After			Change		
February 2016 Bill				February 2016 Bill			February 2016 Bill		
Description	Usage	Rate	Charges (J$)	Usage	Rate	Charges (J$)	Charges (J$)	%	
Base/Exchange Rate	115.50	121.8522		122.50	121.8522				
Non-Fuel Charges									
Energy	15,000	21.99	329,856	15,000	23.34	350,086	20,230	6.1%	
Customer Charge		2,562.50	2,563		2,719.66	2,720	157	6.1%	
EEIF Charges	15,000	0.4998	7,497	15,000	0.4998	7,497	-	0.0%	
Sub Total			339,915			360,303	20,387	6.0%	
F/E Adjustment			14,956			(1,524)	(16,480)		
Total Non-Fuel Bill			354,871			358,778	3,908	1.1%	
Fuel & IPP Charges	15,000	9.059	135,884	15,000	9.431	141,464	5,580	4.1%	
Bill Total			490,755			500,242	9,488	1.9%	

8 APPENDIX V – Losses Dictionary

Loss Category	Description
Bypass Connection	All or part of the energy being consumed is not registered on the JPS revenue meter due to bridged meter socket and connection between pothead and meter socket used to divert energy from JPS meter.
Defective Meter Socket	The state of the meter socket in which the meter cannot be properly housed, has a poor connection or other situation resulting in improper functioning and registration of energy used by the meter.
Defective Wiring	The condition of the wires leading to and from the meter or meter socket that presents either an unsafe condition or results in under registration of energy used by the meter.
Direct Connection at Pothead	A situation in which there is an illegal connection to the power supply at the pothead that results in energy not being registered on the meter, or there is no meter at all to register this energy consumption.
Direct Connection within the meter	Direct connection is done inside the meter or meter socket.
Idle Service (Supply with no contract)	Such service would have been disconnected by JPS, whether for debt or on a customer's request, and supply is being used illegally without the consent or knowledge of JPS.
Line Tap	Same as Direct Connection at Pothead.
Open Circuit	A situation in which there is a break in the wire or wires supplying the meter and/or customer that results in the meter either not registering or under-registering the energy being consumed.
Single Phasing	Same as open circuit, except that that it includes a break in service to the customer on one phase of the two or three phase supply.
Inverted Meter	A situation where the meter is turned upside down resulting in energy being reversed through the meter.
Meter Burnt	A situation in which the meter and/or meter socket is destroyed or damaged by fire resulting in under or no registration of energy consumed. The likely cause is either an overload on the circuit or slack/loose joints in the meter circuit.