Office of Utilities Regulation

Jamaica Public Service Company Limited
Annual Tariff Adjustment 2016

Determination Notice

OFFICE OF UTILITIES REGULATION

2016 July 04

DOCUMENT TITLE AND APPROVAL PAGE

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DOCUMENT TITLE: Jamaica Public Service Company Limited Annual Tariff Adjustment 2016 - Determination Notice

PURPOSE OF DOCUMENT:

This document sets out the Office's decisions on issues related to the second annual price adjustment for the Tariff Review Period 2014 – 2019, the first such under the Revenue Cap regime which came into being pursuant to the Electricity Licence, 2016.

ANTECEDENT DOCUMENTS:

2014/ELE/008/DET.004	Jamaica Public Service Company Limited Tariff Review for Period 2014 - 2019: Determination Notice	2015 January 07
2015/ELE/003/ADM.001	Jamaica Public Service Company Limited Tariff Review for Period 2014 - 2019: Determination Notice – Addendum 1	2015 February 27

APPROVAL:

This document is approved by the Office of Utilities Regulation and this Determination becomes effective as of **2016 July 05**

On behalf of the Office:

Joseph M. Matalon
Chairman

2016 July 04

TABLE OF CONTENTS

Acronyms and Abbreviations

ABNF	-	Adjusted Base-rate Non-Fuel
CAIDI	-	Customer Average Interruption Duration Index
CIS	-	Customer Information System
CPI	-	Consumer Price Index
CT	-	Current Transformer
dI	-	The annual growth rate in an inflation and devaluation measure
EGS	-	Electricity Guaranteed Standard
EOS	-	Electricity Overall Standard
FCAM	-	Fuel Cost Adjustment Mechanism
GCT	-	General Consumption Tax
GDP	-	Gross Domestic Product
GNTL	-	Portion of NTL not completely with JPS' control
GOJ	-	Government of Jamaica
GIS	-	Geographic Information System
IPP	-	Independent Power Producer
JEP	-	Jamaica Energy Partners Limited
JNTL	-	Portion of NTL completely within JPS' control
JPS/JPS Co	-	Jamaica Public Service Company Limited
KVA	-	Kilo Volt Amperes
KWh	-	Kilowatt-hours
MAIFI	-	Momentary Average Interruption Frequency Index
MSET	-	Ministry of Science Energy and Technology
MVA	-	Mega Volt Amperes
MW	-	Megawatt

MWh	-	Megawatt-hours
New Licence	-	The Electricity Licence, 2016
NLT	-	Non-technical losses
OCC	-	Opportunity Cost of Capital
Old Licence	-	The Amended and Restated All-Island Electric Licence, 2011
O&M	-	Operating and Maintenance
Office/OUR	-	Office of Utilities Regulation
PPA	-	Power Purchase Agreement
PBRM	-	Performance Based Rate-Making Mechanism
PCI	-	Non-fuel Electricity Pricing Index
RE	-	Renewable Energy
RF	-	Responsibility Factor
SAIDI	-	System Average Interruption Duration Index
SAIFI	-	System Average Interruption Frequency Index
T&D	-	Transmission & Distribution
TFP	-	Total Factor Productivity
TL	-	Technical losses
TOU	-	Time of Use
WKPP	-	West Kingston Power Plant
WT	-	Wholesale Tariff

Introduction

The Office of Utilities Regulation's ("Office's/OUR's") Jamaica Public Service Company Limited Tariff Review for Period 2014 – 2019 Determination Notice (Document No. 2014/ELE/008/DET.004), which came into effect on 2015 January 07 ("2014 – 2019 Determination Notice") sets out determinations regarding the tariff levels and structure for the sale of electricity by JPS for the period 2014 – 2019. Consistent with the then prevailing terms and conditions of the Amended and Restated All-Island Electric Licence, 2011 ("the Old Licence"), the tariff determined was predicated on a price cap mechanism. On 2016 January 27, a new licence was issued, entitled the Electricity Licence, 2016 ("the New Licence"), which made fundamental changes in the regulatory framework and the methodology for the calculation of tariffs and annual adjustments. The most notable change is the provisions for the use of a revenue cap approach instead of the price cap mechanism.

The New Licence also stipulates a 2016 July implementation date for annually adjusted rates determined under revenue cap. However, the New Licence does not explicitly address how the transition from price cap based tariff regime to a revenue capped adjustment is to be effected.

Such a transition must, however, of necessity be accomplished in undertaking this annual review. In this regard, the Office has been guided in its deliberations by the following as fundamental considerations:

1. The 2014 -2019 Determination Notice remains valid in so far as its requirements are not explicitly altered by either the Electricity Act, 2016 (the Electricity Act) or the New Licence;
2. The new revenue cap mechanism becomes applicable on 2016 July 1, in keeping with the New Licence; and
3. To the extent that it is prudent and reasonable so to do, this annual rate adjustment should take account of future adjustments that will be required in the next review and make provisions where possible to smooth out their impacts.

In this context, the Office takes the view that based on a proper construction of the New Licence and the principles of consistency and fairness, the components of the revenue cap mechanisms should be applied going forward and ought not to be applied looking backward where they were not previously specified under the price-cap formula, since the revenue cap regime became effective on 2016, January 27 and its implementation to be effective 2016 July 1. Otherwise, the components would be applicable retroactively which would be anathema to the principles governing the introduction of a new tariff regime and for which there was no explicit provision stated in the New Licence as is usually required by law.

The decisions set out in the Office's determination have therefore been guided by the principle of a forward looking approach and in this way provide for an apt transitioning to the full revenue-cap regime.

Pursuant to the Old Licence, the 2014 - 2019 Determination Notice along with the Jamaica Public Service Company Limited Tariff Review for Period 2014 – 2019 Determination Notice – Addendum 1 (Document No. 2015/ELE/003/ADM.001) which came into effect on March 01, 2015 ("Addendum 1"), established the average base non-fuel rate at J$14.42/kWh under the price cap regime. This base rate was adjusted in 2015 pursuant to the annual review exercise and to date, there has been monthly rate adjustment to account for movements in the monetary exchange rate between the United States dollar and the Jamaican dollar.

Further, pursuant to the Old Licence, the annual review merely involved changes in the inflation offset index including efficiency gains and also, potentially provides for the application of penalty/rewards for changes in quality of service to the base year revenue requirement. The Jamaica Public Service Company Limited ("JPS") is allowed to adjust the tariffs for each rate class on such a basis that the resulting percentage change does not result in an increase of the annual rate of change in non-fuel electricity revenues (dPCI).

The Office is of the view that the adjusted tariffs for this annual adjustment should also accord with the 2014 - 2019 Determination Notice and Addendum 1 whereby until informed by a new cost of service study, JPS is allowed to recover its revenue requirement by 23% fixed charges and 77% variable charges. Given that JPS has been making interim monthly adjustments (as allowed by both licences) reflecting movements in the foreign exchange rate, the effective change in rate for this annual adjustment for the average customer should reflect the value of the annual adjustment of the base year revenue less the accumulated value of the foreign exchange adjustments over the preceding time period.

1. Legislative and Regulatory Framework

The Office/OUR is a multi-sector regulator established pursuant to the Office of Utilities Regulation Act, 1995 (the "OUR Act"), to regulate the provision of utility services in Jamaica. Under Section 4(1) (a) of the OUR Act, the Office has regulatory authority over the provision for the generation, transmission, distribution and supply of electricity.

JPS, which has exclusive rights for the transmission, distribution and supply of electricity in Jamaica, is regulated by the Office through the provisions of the Electricity Act, the New Licence published in the Jamaica Gazette Vol. CXXXIX No. 6A[1] dated 2016 January 27 and the OUR Act.

Section 4(d) of the Electricity Act states that "the Office shall regulate the electricity sector generally."

This Determination Notice is being issued pursuant to Sections 11 and 12 of the OUR Act and Condition 15, Schedule 3 and Exhibit 1 of the New Licence.

Sections 11 and 12 of the OUR Act provide as follows:

> ***"11.Power to fix rates***
>
> *11. (1) Subject to subsection (3), the Office may, either of its own motion or upon application made by a licensee or specified organization (whether pursuant to subsection (1) of section 12 or not) or by any person, by order published in the Gazette prescribe the rates or fares to be charged by a licensee or specified organization in respect of its prescribed utility services.*
>
> *(2) For the purposes of this section, the Office may conduct such negotiations as it considers desirable with a licensee or specified organization, industrial, commercial or consumer interests, representatives of the Government and such other persons or organizations as the Office thinks fit.*
>
> *(3) The provisions of subsections (1) and (2) shall not apply in any case where an enabling instrument specifies the manner in which rates may be fixed by a licensee or specified organization.*
>
> ***12. Application by approved organization to fix rates.***
>
> *12. (1) Subject to subsection (2), an application may be made to the Office by a licensee or specified organization by way of a proposed tariff specifying the rates or fares which the licensee or specified organization proposes should be charged in respect of its prescribed utility services and the date (not being earlier than the expiration of thirty days after the making of the application) on which it is proposed that such rates should come into force (hereinafter referred to as the specified date).*
>
> *(2)…*

(3) Where an application by way of a proposed tariff is made under subsection (1) notice of such application and, if so required by the Office, a copy of such tariff, shall be published in the Gazette and in such other manner as the Office may require.

(4) A notice under subsection (3) shall specify the time (not being less than fourteen days after the publication of the notice in the Gazette) within which objections may be made to the Office in respect of the proposed tariff to which the notice relates.

(5) Subject to the provisions of this Act, the Office may, after the expiration of the time specified in the notice under subsection (3), make an order either -

> *(a) confirming the proposed tariff without modifications or with such modifications as may be specified in the order; or*
>
> *(b) rejecting the proposed tariff.*

(6) If, after publication of notice of an application in accordance with subsection (3), no order under subsection (5) has been made prior to the specified date, the proposed tariff shall come into force on the specified date.

(6) An order confirming a proposed tariff shall not bring into operation any rates or fares on a date prior to the date of such order."

Condition 2, paragraph 3 of the New Licence, provides,

"Subject to the provisions of this Licence the Licensee shall provide an adequate, safe and efficient service based on modern standards, to all parts of the island of Jamaica at reasonable rates so as to meet the demands of the Island and to contribute to economic development."

Condition 15, paragraphs 1 and 2 of the New Licence, provide,

"***Condition 15: Price Controls***

(1) The Licensee is subject to the conditions in Schedule 3.
(2) The rates to be charged by the Licensee in respect of the Supply of electricity shall be subject to such limitation as may be imposed from time to time by the Office."

Schedule 3 of the New Licence outlines the Revenue Cap Principle as follows:

"*The basis of the rate setting shall be the revenue cap principle which looks forward at five (5) year intervals and involves the decoupling of kilowatt hour sales and the approved revenue requirement…*"

Schedule 3, paragraphs 1– 5 of the New Licence entitled "Rates" provide as follows:

1. *"The rates shall be charged to customers in accordance with the rate classes approved by the Office.*
2. *The rates are comprised of the following:*
   a. *Non-fuel rate; and*
   b. *Fuel rate.*
3. *The fuel rate shall be adjusted by the Office monthly in accordance the Fuel Cost Adjustment Mechanism.*
4. *The non-fuel rate shall be reviewed by the Office:*
   a. *In rate reviews that are customarily done every five years;*
   b. *In extra-ordinary rate reviews which may be conducted in between rate reviews; and*
   c. *Annually under the Performance Based Rate-making Mechanism ("PBRM") adjustment."*
5. *All rates shall be determined by the Office."*

Schedule, 3, paragraphs 42 to 46 of the New Licence entitled "Annual Review", provide as follows:

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

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

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

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

46. The Office shall apply the following adjustment factors to the non-fuel rate at each PBRM:

   a. *The **Q-Factor**, which is the annual allowed price adjustment to reflect changes in the quality of service provided by the Licensee to its customers. The Office shall measure the quality of service versus the annual target set in the 5 year rate review determination.*
   b. *The **H-Factor**, if applicable, will reflect the heat rate as defined by the Office of the power generated in Jamaica versus a pre-established yearly target in the 5 year rate setting determination by the Office.*
   c. *The **Y-Factor** reflects the achieved results versus the long-term overall system losses target.*

d. *The **Z-Factor** reflects the adjustment to the non-fuel rate due to special circumstances. The Z factor is the allowed percentage increase in the Revenue Cap due to any of the following special circumstances:*

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

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

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

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

(iv) Government Imposed Actions;

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

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

Schedule 3, paragraphs 49 – 54 of the New Licence, inter alia, gives the Licensee the right to charge late payment interest to GOJ and customers, other than residential customers, who do not pay their bills in full by the due date and the amount to be charged. With respect to residential customers, it prohibits the charging of interest on overdue balances, but maintains the Licensee's right to charge a late payment fee and offer an early payment incentive fee for payments made on time in full by the due date.

Schedule 3, Exhibit 1 of the New Licence entitled "Performance Based Rate-making Mechanism", provides as follows:

"Annual Adjustment of the Annual Revenue Target

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

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

where:

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

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

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

and

$\mathrm{ART_y}$ = *Annual Revenue Target for Year "y"*

RCy = *Revenue Cap for the current tariff adjustment year "y" as established in the last Rate Review Process*

$\mathrm{RS_{y-1}}$ = *Revenue surcharge for Year "y-1"*

$$\mathrm{TUVol_{y-1}} = \left\{\frac{\mathrm{kWh\ Target_{y-1}} - \mathrm{kWh\ Sold_{y-1}}}{\mathrm{kWh\ Target_{y-1}}}\right\} \times \textit{Non Fuel Rev Target for Energy } REV_{y-1}$$

$$+ \left\{\frac{\mathrm{kVA\ Target_{y-1}} - \mathrm{kVA\ Sold_{y-1}}}{\mathrm{kVA\ Target_{y-1}}}\right\} \times \textit{Non Fuel Rev Target for Demand } REV_{y-1}$$

$$+ \left\{\frac{\mathrm{\#Customer\ Charges\ Billed\ Target_{y-1}} - \mathrm{\#Customer\ Charges\ Billed_{y-1}}}{\mathrm{\#\ Customer\ Charges\ Billed\ Target_{y-1}}}\right\} \times$$

Non Fuel Rev Target for Customer Charges REV_{y-1}

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

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

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

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

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

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

where:

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

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

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

RF = *The responsibility factor determined by the Office, which is a percentage from 0% to 100%. This responsibility factor shall be determined by the Office, in consultation with the Licensee, having regard to the (i) nature and root cause of losses; (ii) roles of the Licensee and Government to reduce losses; (iii) actions that were supposed to be taken and resources that were allocated in the Business Plan; (iv) actual actions undertaken and resources spent by the Licensee; (v) actual cooperation by the Government; and (vi) change in external environment that affected losses.*

SFX_{y-1} = *Annual foreign exchange result loss/(gain) surcharge for year "y-1".*

This represents the annual true-up adjustment for variations between the foreign exchange result loss/(gain) included in the Base Year revenue requirement and the foreign exchange result loss/(gain) incurred in a subsequent year during the rate review period.

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

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

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

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

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

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

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

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

The annual Performance-Based Rate-Making (PBRM) filing will follow the general framework where the rate of change in the Revenue Cap will be determined through the following formula:

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

where:

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

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

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

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

The Growth Rate (dI)

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

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

Specifically, dI is set as:

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

where

EX_b = *Base US exchange rate at the start of the Rate Review period.*

EX_n = *Applicable US exchange rate at Adjustment Date.*

INF_{US} = *Change in the agreed US inflation index as at 60 days prior to the Adjustment Date and the US inflation index at the start of the Rate Review period.*

INF_J = *Change in the agreed Jamaican inflation index as at 60 days prior to the Adjustment Date and the Jamaican inflation index at the start of the Rate Review period.*

USP_b = *US portion of the total non-fuel expenses as determined from the Base Year.*

$USDS_b$ = *US debt service portion of the non-fuel expenses as determined from financials in the Base Year of the rate setting period.*

<u>The Z-Factor</u>

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

In accordance with Sections 11 and 12 of the OUR Act as well as Condition 15 and Schedule 3 of the New Licence, the Office has made the **DETERMINATIONS** set out in the Executive Summary below.

2. Executive Summary

JPS submitted its application for the annual review for the recalculation of the Non-Fuel Base Rates to the OUR on 2016 May 04. A replacement version was received by the OUR on 2016, May 05 (“JPS Tariff Adjustment Filing” or “the Submission”) and the New Licence stipulates a sixty (60) day completion period. This marks the first annual adjustment that is being sought under the New Licence.

The following constitutes a summary of JPS application and the determinations made by the Office. The content of the application and the reasoning applied by the Office in arriving at its determinations are set out in greater details in subsequent sections.

2.1. Annual Inflation and Devaluation Growth Rate (dI).

In making the annual filings to the Office, JPS requested and provided support for adjustments to the following consumer price indices:

- The Jamaican point-to-point inflation rate March 2014 to March 2016 - **7.05%**, derived from the most recent CPI data[1] (i_j)
- The U.S. point-to-point inflation rate March 2014 to March 2016 - **0.78%,** derived from the US Department of Labour statistical data[2] (i_{us})

The OUR has verified the above movement in the indices and in addition has determined that the base rates for the foreign exchange movement should be increased from US$1: J$112.00 to **US$1: J$122.50**

dI is determined to be 9.53%.

2.2. Allowed Price Changes to Reflect Service Quality *(Q-Factor)*

In accordance with the 2014 -2019 Determination Notice and the New Licence:

Q is determined to be 0%.

The Q-factor is the allowed price adjustment to reflect changes in quality of service provided by JPS to its customers.

2.3. Allowed Adjustment due to Special Circumstances (*Z-Factor*)

In accordance with the 2014 - 2019 Determination Notice and the New Licence:

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[1] Obtained from the Statistical Institute of Jamaica, CPI Statistical Bulletin
[2] Obtained from US Bureau of Labour Statistics website, http://data.bls.gov/cgi-bin/surveymost

Z is determined to be 0%.

JPS did not propose any adjustments in this review period.

2.4. Total Non - Fuel Adjustment to Revenue Target

The annual adjustment to the Base $Year_{2014}$ Non-Fuel Revenue Requirement approved by the Office to become effective **2016 July 03 is 9.53%.** The Actual Non-Fuel Revenue that was collected by JPS for 2015 (J$42.47 Billion) was adjusted to establish the Annual Non-Fuel Revenue Target for 2016 (J$44.47 Billion). The effective change to the Non-Fuel Revenue Requirement is **6.03%**.

The details of the current annual adjustment are set out in Tables 2.1 and 2.2 below.

Table 2.1: Details of Revenue Adjustments (2015-2016)

Annual Non-Fuel Revenue Adjustment 2016 (J$)	
Base $Year_{2014}$ Non-Fuel Revenue Adjusted with X-Factor of 1.10% (RC_{2016})	40,604,648,523
Foreign Exchange, Interest and Non-Fuel Revenue Surcharges (SFX_{2015} - SIC_{2015} + RS_{2015})	489,170,865
Annual Non-Fuel Revenue Target for 2016 (ART_{2016})	45,028,110,780
Actual Non-Fuel Revenue for 2015	42,466,096,275
Effective Non-Fuel Revenue Change for 2016	**2,562,014,506**

Table 2.2: Details of Annual Inflation Adjustments (2015-2016)

Annual Non-Fuel Revenue Adjustment 2016	
Growth Rate in Inflation and Exchange Rate (dI) for 2016	9.53%
Q-Factor	0.00%
dI adjusted for Q factor	**9.53%**
Change attributed to Surcharges	1.36%
Change attributed to Actual Non Fuel Revenue for 2015 (Already accounted for in customers' bills)	4.58%
Effective Non-Fuel Revenue Change for 2016	**6.03%**

The effective adjustment of 6.03% to the revenue requirement is to be applied to individual items in the tariff basket so that the overall change in the tariff basket does not exceed 6.03%.

2.5.1. Non-Fuel Tariff Table

Table 2.3 below shows the adjusted base non-fuel tariffs to be applied in the current 2016 - 2017 period.

Table 2.3: Inflation Adjusted Base Non-Fuel Tariffs (dI ± Q + Z)

Class	Block Rate Option	Customer Charge J$/Mth	Energy Charge J$/kWh	Demand-J$/KVA Std.	Demand-J$/KVA Off-Peak	Demand-J$/KVA Part Peak	Demand-J$/KVA On-Peak
Rate 10 LV	--100	429.31	9.13				
Rate 10 LV	> 100	429.31	21.26				
Rate 20 LV		956.42	17.61				
Rate 40A LV							
Rate 40 LV - Std		6,738.40	5.49	1,720.68			
Rate 40 LV - TOU		6,738.40	5.49		72.56	757.11	969.40
Rate 50 MV - Std		6,738.40	5.29	1,541.51			
Rate 50 MV - TOU		6,738.40	5.29		68.74	670.77	860.61
Rate 60 LV		2,717.10	23.32				

2.5.2. The Electricity Efficiency Improvement Fund (EEIF)

The EEIF funding contribution will be reduced by fifty percent (50%) as of the effective date of this Determination Notice. The revenues which are collected through a separate line item on customers' bills shall be billed at the rate of **J$0.2499/kWh**.

2.5.3. Residential Customers Prepaid Rates (Rate 10)

The approved non-fuel pre-paid rate is as follows:

- **J$195.49/kWh** for the first 2 kWh within a thirty (30) day consumption cycle
- **J$10.08/kWh** for the next 99 kWh within a thirty (30) day consumption cycle
- **J$21.51/kWh** for each additional kWh thereafter within that thirty (30) day consumption cycle

The prepaid rates shall be subject to review at the next Annual Tariff Adjustment.

2.5.4. Small Commercial Customers Prepaid Rates (Rate 20)

The approved non-fuel tariff to be charged for Rate 20 prepaid service shall be revenue neutral when compared to the existing postpaid rates for Rate 20 customers and shall be applied as follows:

- **First 10kWh J$113.50/kWh**
- **Additional kWhs J$17.86/kWh**

The prepaid rates shall be subject to review at the next Annual Review.

2.5.5. Community Renewal Rate (Rate 10) (CRR)

The approved Community Renewal Rate to be charged for Rate 10 service is a flat rate of **J$9.13/kWh** for consumption up to 150kWh. Customers consuming more than 150kWh per month, will pay the regular prepaid or post-paid rate, whichever is applicable, for the incremental consumption above 150kWh per month. The Community Renewal Rate and conditions related to it shall be subject to review at the next Annual Review.

2.5. Fuel Cost Adjustment Factor – System Losses

Technical Losses (TL)
The technical losses target to be applicable for the 2016/2017 rate adjustment period shall be **8.2%** of net generation.

Non-Technical Losses (NTL)
The non-technical losses target within JPS' control shall be **3.5%**
The non-technical losses target not totally within JPS' control shall be **9.8%** with a responsibility factor **(RF) of 20%**.

2.6. Fuel Cost Adjustment Factor – Heat Rate

The Office determined that:

- The Heat Rate (actual) to be used by JPS in the approved Fuel Cost Adjustment Mechanism (FCAM) each month shall be based on JPS' thermal generating plants.
- The approved Heat Rate target is applicable to JPS' thermal generating plants.
- JPS' proposal for the use of a JPS System Heat Rate (JPS thermal and JPS RE plants) in the FCAM is **not approved**.
- The Heat Rate target for JPS' thermal generating system for the rate adjustment period 2016 July to 2017 June shall be **11,620 kJ/kWh.**

2.7. Bill Impact[3]

It is estimated that with the determinations set out herein, on the average, there will be an overall 2.60% increase in the total on the average customer bill. This results from the combined effects of:

a) the 9.53% increase in the Non-fuel Revenue Cap (effective increase of 6.03% in non-fuel rates);
b) the full pass through of System losses in the fuel rate (effective increase of 8.7% in fuel rates);
c) the reduction of the EEIF contribution (0.2499J$/kWh); and
d) the resetting of JPS heat rate target.

The average bill impact across all rate classes is summarized in Table 2.4 below. The impact is as follows:

- Typical Rate 10 customer = 2.4% Increase
- Typical Rate 20 customer = 2.4% Increase
- Typical Rate 40 customer = 2.9% Increase
- Typical Rate 50 customer = 3.2% Increase

[3] The bill impact was estimated on data received from JPS for May 2016 billing for electricity consumed in April 2016

Table 2.4: Estimated Bill Impact of OUR Determined Annual Tariff Adjustment

Customer Class	Overall Bill Impact of the OUR Approved Rates			
	Typical Usage (kWh)	Demand (kVA)	Total Bill Impact (%)	Average Change (%)
RT 10 LV Res. Service < 100 kWh	90	n/a	2.4%	2.4%
RT 10 LV Res. Service 101-350 kWh	349	n/a	2.4%	
RT 10 LV Res. Service > 350 kWh	350	n/a	2.4%	
RT 20 LV Gen. Service < 100 kWh	90	n/a	2.1%	2.4%
RT 20 LV Gen. Service 100-1000 kWh	1,000	n/a	2.4%	
RT 20 LV Gen. Service 1000-7500 kWh	5,000	n/a	2.5%	
RT 20 LV Gen. Service > 7500 kWh	8,000	n/a	2.5%	
RT 40 LV Power Service (Std)	35,000	100	2.9%	3.1%
RT 50 MV Power Service (Std)	500,000	1,500	3.0%	
RT 50 MV Power Service (TOU-Partial Peak)	500,000	1,500	3.5%	
Efficiency Targets:	System Losses Target		JPS Thermal Heat Rate Target	
	Full Pass Through on Fuel		11,620 kJ/kWh	

Table 2.5 below shows the effect of the JPS proposed adjustments.

Table 2.5: Estimated Bill Impact of JPS Proposed Annual Tariff Adjustment

Customer Class	Overall Bill Impact of the JPS Proposal			
	Typical Usage (kWh)	Demand (kVA)	Total Bill Impact (%)	Average Change (%)
RT 10 LV Res. Service < 100 kWh	90	n/a	2.6%	2.5%
RT 10 LV Res. Service 101- 350 kWh	349	n/a	2.4%	
RT 10 LV Res. Service > 350 kWh	350	n/a	2.4%	
RT 20 LV Gen. Service < 100 kWh	90	n/a	2.1%	2.3%
RT 20 LV Gen. Service 100-1000 kWh	1,000	n/a	2.4%	
RT 20 LV Gen. Service 1000-7500 kWh	5,000	n/a	2.4%	
RT 20 LV Gen. Service > 7500 kWh	8,000	n/a	2.4%	
RT 40 LV Power Service (Std)	35,000	100	2.8%	2.9%
RT 50 MV Power Service (Std)	500,000	1,500	2.5%	
RT 50 MV Power Service (TOU-Partial Peak)	500,000	1,500	3.5%	
Efficiency Targets:	System Losses Target		JPS Thermal Heat Rate Target + Renewables	
	Full Pass Through on Fuel		10,710 kJ/kWh	

Notably in its response to the draft Determination Notice, JPS while maintaining its advocacy for a heat rate that incorporated its renewable plants, proposed in the alternative an overall thermal heat rate of 11,710 kJ/kWh as against the OUR's determined heat rate of 11,620kJ/kWh. This would have resulted in an average increase of 5.3% in the overall bill in comparison to the average 2.6% increase derived with the OUR determined target of 11, 620 kJ/kWh.

3. Synopsis of JPS' Annual Rate Adjustment Proposal

This section captures extracts from JPS' rate adjustment proposals that are relevant to the Office's determination on the company's application for rate adjustment.

3.1. Interpretation of Exhibit 1 Parameters

The New Licence came into effect during the second year of the 2014 - 2019 Five Year Tariff Review period and has introduced several parameters which were not considered in previous rate filings or determinations of the OUR. JPS in its Submission presented its interpretation of aspects of the New Licence which would have implications on the proposed rate adjustment that the company is applying for.

Outlined below is a synopsis of JPS' position on the establishment of these parameters in the context of JPS' interpretation of the New Licence.

3.4.1. The Revenue Cap for 2016 (RC_{2016})

The New Licence states that the basis for rate setting shall be the Revenue Cap regime instead of the Price Cap regime that previously existed. Under the Price Cap regime, 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 regime introduces a cap on real revenues (the aggregate of volumes multiplied by prices) with annual adjustments made for inflation. In the context of the New Licence, the explicit performance based incentive for reliability is retained while the efficiency (X) factor has been removed from the annual adjustment formula. JPS' view is that the removal of the X-Factor from the annual adjustment formula does not remove the incentive for JPS to improve efficiency. The company states that the X-Factor 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 New Licence, 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 2014 - 2019 Determination Notice with allowance made for efficiency improvement over the period, from the last rate review to the current adjustment period.

JPS stated that 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 Determination Notice 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.

JPS' interpretation is that the New 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:

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

Where: X is the efficiency factor that was set at 1.1% in the 2014 - 2019 Determination Notice. 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).

3.4.2. True Up for Volumetric (TUVol) Adjustments

JPS' position is that the TUVol cannot be applied in the 2016/2017 tariff adjustment period. JPS postulates that the revenue requirement as determined in the 2014 - 2019 Determination Notice is US383.65M inclusive of EEIF (US$370.65M excluding EEIF), and that during the 2015/2016 tariff adjustment period when the price cap was applied, the tariff basket determined by the OUR (in the Jamaica Public Service Company Limited Annual Tariff Adjustment 2015 Determination Notice Document No. Ele 2015/ELE/007DET.001 dated 2015 September 03 ("the 2015 Annual Tariff Adjustment Determination Notice")) was US$361.4M. 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.

JPS' position is that the volumetric adjustment cannot be applied in the 2016/2017 period as per the New Licence but rather should be considered for the 2017/2018 period when the determined revenue requirement would have been re-established.

3.4.3. Targets for FX Losses and Interest Charges

The late payment fees and the corresponding early payment incentive were not included in the revenue requirements of the 2014 - 2019 Determination Notice.

The New Licence 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. According to JPS, the New 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. JPS stated that since these charges were not contemplated in the last rate review the target interest income and late payment charges and the target FX losses should be set at zero.

3.4.4. Weighted Average Cost of Capital (WACC)

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

3.4.5. Computation of dI

The format of the inflation adjustment has changed in the New Licence. JPS stated that the formula in effect is similar to the formula in the 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:

EX_b	=	Base US exchange rate.
EX_n	=	Applicable US exchange rate at Adjustment Date.
INF_{US}	=	The US inflation rate
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

JPS mentioned that there are some changes in the way that the formula is actually applied and interpreted.

In the New Licence, JPS stated that the inflation factors, INF_{US} and 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 EX_b is different from what was previously applied. In the context of the New Licence, 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).

JPS stated that this change in interpretation was necessary due to the way the RC_y is established. JPS further stated that the $RC_{y,}$ will be established from the 5 year 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, RC_y will need to be adjusted with respect to the base year.

In the context of the 2014 - 2019 Determination Notice, USAF refers to the fraction of the non-fuel revenue which is subject to US inflation (USAF excluded; debt service, return on equity, depreciation expenses and financing costs). The values for USP and USAF in the 2014 - 2019 Determination Notice were derived based on the test year (2013) financials. JPS mentioned that the computation was done on the basis on JPS' test year expenses rather than on the proposed revenue requirement.

JPS is of the view that the computation of USP and USAF should have been based on the approved revenue requirement rather than the test year financials. However, JPS stated that given that the company is interpreting the New Licence in the context of the 2014 – 2019 Determination Notice they are proceeding with the OUR's approach. JPS further argued that in future rate reviews, the OUR should revisit the methodology used in computing these two parameters.

In the case of the New Licence, $USDS_b$ is defined as the US debt service portion of the non-fuel expenses as determined from financials in the Base year. JPS' interpretation is that this covers a smaller portion of JPS' non-fuel revenue requirement than 1-USAF. JPS stated that $USDS_b$ 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.

JPS stated that 1-USAF covers a broader category than was the intent of the New 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.

Using the redefined definition of USAF, JPS proposed that the following:

$USDS_b = 80\%*8.57\% = 6.88\%$

3.4.6. System Losses Targets

JPS noted that the annual non-fuel adjustment formula proposed in the New Licence incorporates an incentive mechanism for system losses performance. JPS said that this incentive mechanism is included in the revenue surcharge through TULos. TULos is computed by first disaggregating system losses into three components. Namely; TL, JNTL and GNTL.

Where:

TL = Technical Losses;
JNTL = Portion of Non-technical losses which is completely within JPS' control and
GNTL = Portion of Non-technical losses which is not completely within JPS' control.

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

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

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

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

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

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

JPS stated that there was a typographical error in formulae set out in the New Licence and proposed a correction that should be applied.

The formulae:

Ycy-$_1$ = Target System Loss "c" Rate%y-1 – Actual System Loss "c" Rate%y-1 * RF

should actually have been:

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

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

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

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

$TULos_{y-1} = Y_{y-1}*ART_{y-1};$ where: ART_{y-1} = Annual Revenue Target for year "y-1".

JPS' proposal for the disaggregation of system losses into TL, JNTL and GNTL and a proposed losses target for 2016 as shown in Table 3.1 below.

Table 3.1: Proposed Losses Targets for 2016

Description/Category		Target %Loss	Target JNTL	Target GNTL
Billed	Streetlight /Stoplight/ Interchange (R60)	0.00%	0.00%	0.00%
Customers	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%**

3.4.7. JPS Position on the Heat Rate Target

Prior to the New Licence, the recovery of the fuel cost was subject to two efficiency measures, Heat Rate and System Losses. In the 2014 - 2019 Determination Notice the fuel recovery mechanism was amended as follows:

- 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 Cost Adjustment Mechanism was:

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

JPS stated that the company began applying this new fuel rate adjustment mechanism in its 2015 March billing.

According to JPS, Schedule 3, Exhibit 2 of the New 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. JPS is of the opinion that regardless of the heat rate utilized, the fuel rate calculation proceeds as indicated below.

JPS further stated that 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 = $\{(\text{HR T} - \text{HR Act}_{m-1})/\text{HR T}\} * FAct_{m-1}$

HRT = Heat Rate Target per year as established during the rate setting process

HRAct = Actual Heat-Rate prior month, corrected for items outside the Licensee's control; meaning higher than anticipated forced outages 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).

JPS is of the opinion that 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 stated that the company invested over US$40M during the period 2010 to 2014 in Wind and Hydro Renewables and that the impact of renewables on fuel cost to customers weighed heavily in JPS' decision to invest in the renewable capacity. JPS requested that the OUR gives reconsideration to 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.

3.2. Application of the Annual Revenue Cap Adjustment Formula

According to JPS, the rate of change in the revenue cap is determined by the application of the annual escalation adjustment formula dPCI and this 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 2016 March and 2014 March of 7.05%, derived from the CPI data[4] published by Statin;
- U.S. point-to-point inflation rate (INFUS) between 2016 March and 2014 March of 0.78%, derived from the U.S. Department of Labor statistical data[5] ; and
- The 9.38% increase in the Base Exchange Rate $\left(\frac{\mathbf{EX_n - EX_b}}{\mathbf{EX_b}}\right)$ from J$112: US$1 to J$122.50: US$1.

Table 3.2 below sets out the details of the annual adjustment factor, dPCI that amounts to a 9.53% increase to RC_{2016} as proposed by JPS.

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

Table 3.2: JPS Proposed 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%

3.3. JPS Proposed Computation of the Revenue, FX and Interest Surcharges and RC_{2016}

JPS proposed values for revenue cap 2016 (RC_{2016}) FX and interest surcharges (SFX_{2015} and SIC_{2015}) as shown in Table 3.3 below.

Table 3.3: JPS Computed Value for 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**

<u>Formula</u> - $ARTy = RCy(1 + dPCI) + (RSy-1 + SFXy-1 - SICy-1) \times (1 + WACC)$

JPS stated that the application of the computed values of RC_{2015}, SFX_{2015} and SIC_{2015} to the annual adjustment formula above resulted in a revenue requirement of J$45,070,568,280 representing an increase of 6.13% over the 2015 actual revenue.

Tables 3.4 to Table 3.10 below show the data and values for the JPS proposed 2016 - 2017 tariff.

Table 3.4: JPS 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 3.5: 2015 Approved Non-Fuel Revenue Basket

				Energy Revenue	**Demand (KVA) revenue**					
Block/ Rate Option			**12 Months 2011 Customer Revenue**		**Std.**	**Off-Peak**	**Part Peak**	**On-Peak**	**Total Demand Revenue**	**Total Revenue**
Rate 10 Rate 10	LV LV	<100 >100	1,119,893,221 1,531,243,204	4,218,090,152 9,858,081,966					**0** **0**	5,337,983,373 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 Rate 50 Rate 50 Rate 60	LV - TOU MV - Std MV - TOU LV		8,922,420 9,456,240 1,830,240 9,481,250	610,839,596 2,011,454,983 460,327,450 1,551,905,877	1,623,727,413	23,603,697 21,420,545	235,599,911 198,537,714	239,192,611 195,115,009	498,396,219 1,623,727,413 415,073,269 -	1,118,158,235 3,644,638,636 877,230,959 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 3.6: JPS 2015 Actual Revenues

Class		Block/Rate Option	Customer Charge	Energy- J$/kWh	Demand- J$/KVA Std.	Off-Peak	Part Peak	On-Peak	Total Revenue
Rate 10	LV	< 100	1,022,002,955	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 3.7: JPS 2015 Billing Determinants[6]

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

[6] 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 2015 October and 2016 January. Since the CIS system is an open item system, there were minor variances from the earning sheet total in the order of 0.1%.(Source: JPS Submission)

Table 3.8: 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 Rate 40A Rate 40 Rate 40 Rate 50	LV LV LV - Std LV - TOU MV - Std		694,164,379 - 133,060,548 9,631,512 10,036,197	10,683,840,966 - 3,627,752,643 637,086,375 2,185,947,887	- 3,886,816,021 - 1,785,068,694	- 24,480,842 -	- 246,727,108 -	- 248,613,060 -	11,378,005,345 - 7,647,629,211 1,166,538,897 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 3.9: JPS 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 Rate 10	LV LV	--100 > 100	6.1331% 6.1331%	6.1331% 6.1331%				
Rate 20	LV		6.1331%	6.1331%				
Rate 40A Rate 40 Rate 40 Rate 50 Rate 50	LV LV - Std LV - TOU MV - Std MV - TOU		6.1331% 6.1331% 6.1331% 6.1331%	6.1331% 6.1331% 6.1331% 6.1331%	6.1331% 6.1331%	6.1331% 6.1331%	6.1331% 6.1331%	6.1331% 6.1331%
Rate 60	LV		6.1331%	6.1331%				

Table 3.10: JPS 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 Rate 10 LV	--100 > 100	429.71 429.71	9.14 21.28				
Rate 20 LV		957.32	17.63				
Rate LV 40A LV - Std Rate 40 LV - TOU MV Rate 40 - Std Rate 50 MV - TOU Rate 50		6,744.76 6,744.76 6,744.76 6,744.76	5.50 5.50 5.30 5.30	1,722.31 1,542.96	72.63 68.81	757.82 671.40	970.31 861.42
Rate 60		2,719.66	23.34				

3.4. Pre-paid Rates

3.4.1. Rate 10 Pre-paid Rates

JPS stated that its pre-paid pilot programme ended in 2015 December 31 and as of the end of 2015 December, there were 294 customers on the programme from whom revenues for 2015 of J$4,794,884.00 were obtained. JPS further mentioned that in its 2015 Annual Adjustment Filing, the company 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. JPS argued that 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. JPS stated that 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 would more accurately captures the essence of the equivalent post-paid rates. JPS proposed the three-tiered structure to be implemented for the 2016/2017 period.

JPS proposed non-fuel tariff for the Rate 10 prepaid customers 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

3.4.2. Rate 20 Pre-paid Rates

JPS' proposal for the non-fuel tariff for the Rate 20 prepaid customers using the proposed post-paid tariffs as the basis of the calculation were 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

3.5. Community Renewal Rate (CRR)

In the 2015 Annual Tariff Adjustment Determination Notice, the OUR approved a rate for eligible participants of the community renewal programme. The eligibility criteria that was proposed by JPS is its 2015 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. JPS in its 2016 Tariff Adjustment Filing states that since submitting the 2015/2016 proposal, further field work in the communities indicates that there were only a limited number of people who were enrolled on the PATH programme and thus, the Community Renewal programme will not be as effective if this criteria is not expanded to be more inclusive.

JPS stated that the company has been consulting with the Planning Institute of Jamaica (PIOJ) to finalise a selection criteria and will submit a separate proposal on this to the OUR by 2016 May 31. JPS claimed that the company 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 JPS said, will not attract a customer charge or the EEIF tariff as long as consumption remains below 150kWh in a billing cycle. Customers 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.

3.6. Tariffs for LED Street Lighting

JPS stated that the company had negotiated a licence amendment with the then Ministry of Science, Technology, Energy and Mining (MSTEM) which concluded in 2015 December. The responsibility and ownership for the Street Lighting Replacement project was addressed in Condition 28, paragraph 6 of the New Licence which states as follows:

"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 Licensee to recover the costs of implementing the Smart Streetlight Programme."

JPS stated that given the changes introduced in the New Licence and the intent to establish a Fund for the programme, the company believes it is prudent to delay the implementation of the LED tariff until the 2017/2018 filing where JPS is requesting OUR's consideration for an Extra-ordinary Rate Review. JPS further adds that the company is at an advanced stage of the selection process for the Contractor to implement the Smart LED street lighting replacement project but this has not been finalised and until then, the final cost and economic evaluation of the project cannot be established. JPS stated that the company intends to finalise the selection process by 2016 October 01.

3.7. Factors Impacting the Non-Fuel Tariff

JPS mentioned that system energy losses, especially non-technical losses (NTL), remain a chronic problem for JPS despite the initiatives and investments made to reduce the problem. In 2015, JPS stated that the company incurred a revenue loss of US$37.5M due to system loss impairment. JPS said it spent US$8M capital investments in system loss reduction initiatives over the said period.

JPS estimated existing technical energy loss 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. The two main technical loss reduction initiatives are the primary distribution feeder power factor correction and the primary distribution feeder phase balancing.

JPS mentioned that 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 JPS 2016 – 2020 non-technical energy loss reduction is said to be a 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. JPS stated that the primary objective is to demonstrate through the strategy, prioritized initiatives and solutions the incremental gains to be realized towards reducing energy loss.

3.8. Foreign Exchange (FX) Losses in 2015

JPS is seeking to recover FX losses incurred during 2015 in this annual filling. JPS stated that the total FX loss for the year 2015 was US$4, 924,859.

3.9. Customer Interest Income/Expenses in 2015

JPS stated that the net late payment/fee income remaining after the payment of early payment incentive income was US$625,505.00.

3.10. Request for Extra-ordinary Rate Review for the 2017/2018 Filing

JPS is requesting the OUR's consideration for an Extra-ordinary Rate Review in the 2016/2017 tariff period. The request JPS said, comes against the backdrop of the exceptional circumstances necessitated by the need to operationalization of the New Licence. The New 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 the customers require. The items include:

- The inclusion of the current portion of long term debt (CPLTD) in the rate base which is addressed in Schedule 3, paragraph 29 of the New 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

JPS stated that these items could have been included in an annual tariff filing through the Z-Factor adjustment mechanism which was expanded in the New Licence. However, given the need to address wheeling, net billing and standby rates in a comprehensive, cost reflective and non-discriminatory manner, the company believes that it is prudent to reset the tariffs based on cost of services studies. JPS mentioned that the cost of service studies are currently being conducted and will be used to inform the new tariff design.

3.11. Request for Re-imbursement of Losses Related Fuel Impairment Cost for 2016

JPS stated that between 2016 January and March, the company incurred US$5.4M in fuel cost impairment directly attributable to system losses. The company further stated that this financial impairment is likely to grow until the end of 2016 July 01when 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. JPS argued that this could result in the company being penalised twice for the fuel losses performance from 2016 January to June 30. JPS is requesting OUR's consideration of a mechanism to allow JPS to recover the fuel impairment cost for the first half of the year.

3.12. Fuel Efficiency Mechanism

JPS stated that the New Licence introduced a major change in the fuel cost recovery mechanism that has existed since 2001. Fuel cost recovery which was previously subject to two efficiency measures (heat rate and system losses) is now only dependent on JPS' heat rate performance. 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.

3.12.1.1. Heat Rate Target

JPS reported that the system heat rate has improved during the current tariff period. The heat rate fell by 125 kJ/kWh over the period from 2015 January to present. According to JPS 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.

JPS stated that its proposal on heat rate is based on system modelling of the current and future unit availability and dispatch which suggest a JPS Heat Rate target (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. JPS based its proposal for the heat rate target based on the planned mix of generating units, including IPPs, their projected availability and dispatch, other heat rate influencing variables and possible variation in heat rate performance for reasons JPS stated is beyond JPS' control.

JPS proposed 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.

3.13. Ensuring Quality of Service: The Q-Factor

JPS sought to clarify some of the points raised by the OUR in the 2015 Annual Tariff Adjustment Determination Notice. This JPS stated was important as the points were germane to the OUR's conclusions on the validity and integrity of the submitted dataset.

JPS had requested that the Q-Factor be set at 0% for the 2013 to 2014 period. This request it argued accords with KEMA Inc.'s position, the consultants engaged by the OUR to conduct a review of the measurement and calculation of the reliability indices to inform the target-setting of the baseline and Q-Factor targets.

JPS proposal is that the submitted dataset for the reporting period 2015 January 01–December 31 be utilized to establish the Q-Factor benchmark. JPS stated that the benchmarks outlined in Table 3.11 below be utilized by the OUR in establishing the Q-Factor targets in the PBRM.

Table 3.11: 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. OUR's Analysis of the Proposal

4.1. Interpretation of Exhibit 1 Parameters

As previously indicated, the New Licence introduced a number of changes that has impacted how the electricity sector is regulated. Of these changes, the most significant is the replacement of the price cap regime that has been a feature of the tariff since 2001 with a revenue cap or more correctly a 'revenue target mechanism'. This section sets out the Office's analysis of JPS's proposal beginning with general comments on JPS interpretation and application of the elements of the adjustment formula especially in the context of the transition from Price Cap to Revenue Cap.

4.1.1. General Comments on JPS Interpretation and Application of the Annual Tariff Adjustment Formula

In arriving at the decision on the issues in this adjustment the Office have guided by the following fundamental considerations:

1. The 2014 - 2019 Determination Notice based on price-cap regulation is still valid up July 1;
2. The new revenue cap mechanism becomes applicable on 2016 July 1, in keeping with the New Licence; and
3. To the extent that it is prudent and reasonable so to do, this annual rate adjustment should take account of adjustments that will be required in the next review and make provisions where possible to smooth out their impacts.

Inevitably, transitioning from a price cap to a revenue cap regime in process of an annual adjustment, creates a dilemma since it requires the grafting of the revenue cap mechanism on to a construct which was predicated on a price cap formulation. In the circumstances, it is not surprising that there are apparent conflicting application of principles in JPS' Submission.

It is the Office considered view, however, that to ensure consistency and fairness the components revenue cap mechanisms should correctly be applied going forward and ought not to be applied looking backward where they were not previously specified under the price cap formula. This is so because whereas the New Licence became effective on 2016, January 27 the implementation of a revenue cap regime is to be effective 2016 July 1. Applying the revenue cap retroactively would therefore be anathema to the principles governing the introduction of a new tariff regime and for which there was no explicit provision stated in the New Licence as is usually required by law.

Notably, JPS in its Submission seems to recognize this and consequently in seeking to justify its position on the true-up for volumetric adjustments, asserts that "*volumetric adjustment cannot be applied in the 2016/17 period as per the Licence but rather should be considered for the 2017/18 period when the determined revenue requirement would have* *been re-establish*." The Office is of like mind on this principle. That approach cannot be applied selectively, however, without creating complexity and the added risk of challenge. In the circumstances, the Office's position is that there must be consistency in the treatment of all decisions concerning true-ups. In this regard, all retroactive adjustments, whether they cause the tariff to increase or decrease are correctly disallowed. At the same time, consistent with the spirit of the New Licence the Office has where it deems it prudent allowed for provisions against future adjustment to, *inter alia*, mitigate the risk of rate shock.

<u>New Revenue Cap</u>

JPS in its Submission proposes that the new revenue cap (RC_y) should be "based on the revenue requirement established in the 2014 - 2019 Determination Notice with allowance made for efficiency improvement over the period, from the last rate review to the current adjustment period." On this matter, the Office concurs with JPS since it represents a simple and straight forward approach. The alternative would be the derivation of a 5-year revenue-cap would be complex and time-consuming and therefore it should be reserved for a full rate review.

<u>X-Factor</u>

The position taken by JPS with respect to productivity improvement is plausible. In its Submission it correctly argues that even though X-Factor is not in the new formula, efficiency improvements are to be factored into the tariff. It further proposes that consistent with the 2014 Tariff Review, the X-Factor should be set at 1.1%.

In its conclusion on this issue, JPS takes the view that the current revenue cap should be calculated as follows:

$$\mathrm{RC}_y = \mathrm{RC}_{y-1}(1-x)^2$$

In this regard, JPS' position coincides exactly with the Office's position and the X-Factor will be treated in the precise manner proposed in the Submission.

<u>Volumetric True-up</u>

Applying volumetric true-up poses two challenges in this transitional exercise. First, the use of targets other than kWh sales requires independent validation and more importantly these targets were not established in the 2014 Tariff Review. JPS' position that the volumetric true-up cannot be applied since the decisions in the 2014 - 2019 Determination Notice did not contemplate the revenue cap methodology is a pragmatic stance.

JPS' position is consistent with the OUR's legal interpretation of the New Licence. A retroactive adjustment would be going beyond what may be reasonably deduced from the regulation and it is not consistent with good regulatory practice. Even so, the Office is cognizant that this approach merely defers a determination of how the volumetric true-up is to be applied to the next review. The matter, however will require further engagement with JPS to determine a feasible and agreeable approach. In the circumstances, the Office has signalled to JPS that subsequent to the issuance of this Determination Notice and by 2016 December 31, it will consult on, determine and issue by way of an addendum to this

Determination Notice a decision on the approach and methodology to be adopted in applying the volumentric true-up provision in the 2017 Annual Review.

Foreign Exchange (FX) Losses & Interest Charges True-up

The annual adjustment formula also makes allowance for the recovery of FX losses in the previous year set-off against the interest income generated from charges on late payment of customer bills. However, the formula also includes a FX provision and an interest income targets (TFX and TIC) to be included in the rate base. Hence, the Actual Revenue Target in any given year only passes through to customers the under or over-recovered FX losses net of the under or over-recovered interest income. This may be expressed as:

$$\text{Foreign Exchange Surcharge} = \mathrm{SFX}_{\mathrm{y}-1} - \mathrm{SIC}_{\mathrm{y}-1}$$

Where,

$$\mathrm{SFX}_{\mathrm{y}-1} = \textit{Adjustment for previous year Net Foreign Exchange Losses}$$
$$\mathrm{SIC}_{\mathrm{y}-1} = \textit{Adjustment for the Net Interest Income on unpaid Customer bills}$$

Further:

$$\mathrm{SFX}_{\mathrm{y}-1} = \mathrm{AFX}_{y-1} - \mathrm{TFX} \quad \text{and} \quad \mathrm{SIC}_{\mathrm{y}-1} = \mathrm{AIC}_{y-1} - \mathrm{TIC}$$

Where,

$$\mathrm{AFX}_{\mathrm{y}-1} = \textit{Actual foreign exchange loss}/(\textit{gain})\textit{in previous year}$$
$$\mathrm{TFX} = \textit{Foreign exchange loss}/\ (\textit{gain})\ \textit{included in Rate Base}$$
$$\mathrm{AIC}_{\mathrm{y}-1} = \textit{Actual Interest Income on unpaid Customer bills in previous year}$$
$$\mathrm{TIC} = \textit{Interest Incom on unpaid Cusomer bills in previous year}$$

Given that the revenue-cap becomes effective 2016 July 1 and no previous provision was made for any of the components in the FX Surcharge formula technically the value is zero. Notwithstanding, the Office is of the view that given that the Jamaica dollar is likely to depreciate in the foreseeable future it would be prudent to include in the tariff a provision for FX loss (TFX) and actual interest income (TIC) going forward. Additionally, the Office maintains that the Rate Base established in the 2014 Tariff Review should not be reopened.

In light of the fact that this tariff adjustment seeks to marry price-cap determinants with a revenue cap mechanism, it may be argued that no injustice would be done if the forward looking TFX and TIC are captured exclusively in the revenue-cap mechanism and not in the Rate Base. In any case, customers would have to pay the full FX loss net of interest income next year. This has several advantages:

- It provides JPS with cash upfront to deal with a depreciating currency;
- It minimizes the level of rate increase next year, thus dampening the possible impact of a rate shock; and
- It allows for the avoidance of the payment of a large opportunity cost to the utility on the foreign exchange surplus next year.

Consequently, in keeping with the estimated FX loss and interest income in 2016, the provisions for TFX and TIC have been set respectively at $603,295,228 and $114,124,363 respectively. It should be noted that the values established are transitional and has no impact on the Rate Base.

Notably, JPS has indicated that it will subsequent to the issuance of this Determination Notice, provide the Office with a policy proposal for its approval which will set out how it proposes to apply the provisions for interest charges. In its engagement with JPS, the Office will seek to ensure fairness and equity in the application of the policy to all customer classes, while having full regards to the rights accorded in the Licence. This is especially important, as the Office is concerned to ensure that no customer class is penalised by any lack of diligence in pursuing the rights conferred by this provision in the licence.

Weighted Average Cost of Capital (WACC)

JPS proposes in its Submission that the rate of return on investment should be the pre-tax WACC as determined by the OUR in the 2014 - 2019 Determination Notice (i.e. 13.22%). The Office takes the view that reopening the WACC should be a part of a full tariff review owing to the complexity of the exercise. Therefore the position taken by JPS is plausible. At the same time, the Office would wish to observe that a future determination on WACC will need to reflect the extent to which JPS' risk has been reduced by the terms of the New Licence.

Inflation Factor

In its Submission, JPS has pointed out that the inflation factor is now a cumulative adjuster rather than a one-year factor. This re-interpretation of the formula leads to the same result had the revenue cap been cumulative and the inflation adjuster a one-year factor. On this matter, the Office takes the view that this improvisation works. Notwithstanding, for reasons of transparency and computational convenience, the cumulative revenue cap coupled with a one-year inflation factor is preferable.

Additionally, the company has pointed to a redefinition of the US proportion of non-fuel expenses subject to inflation (USAF) in the New Licence that has resulted in its value changing from 45% to 91.43%. This change in the value of USAF is consistent with the 2014 - 2019 Determination Notice and the definition in the New Licence.

System Losses Target & Energy Efficiency Improvement Fund (EEIF)

In its Submission, JPS took the follow positions:

- The system loss formula contains an error and it should be restated
- In arriving at system losses, the components should be set as follows:
  - Technical losses: 8.6%
  - Non-technical losses completely under JPS' control: 4.38%

- Non-technical losses partially under JPS' control: 14.00%
- Responsibility factor is to be decided in the adjustment exercise

- The EEIF should be retained in the tariff

The Office has had sight of copy letter dated 2016 June 29 from the Ministry of Science Energy & Technology (MSET), the issuer of the New Licence, to JPS which confirms JPS' assertion that there is an error in the formula as correct and that the formula is to be represented as set out in JPS' Submission. MSET in the said letter also indicated that this correction will be effected by publication of a letter agreement between itself and JPS in the Jamaica Gazette. On the basis of this assurance, the Office has treated the formula as represented by JPS in its Submission.

The Office has indicated to JPS that it has concerns regarding the extent to which the EEIF has generated benefits to rate payers in terms of achieving measurable loss reductions. Added to this, the New Licence adopts a different approach in the treatment of system losses and the extent of pass through. Even so, the Office has taken cognizance of JPS' argument that it has planned its budget on the assumption of a full year availability of the collections from the EEIF and that a sudden cessation would be disruptive to its investment programme.

Additionally, the Office continues to be of the view that there is merit in having a fund by which it is able to influence JPS' behaviour in terms of its loss management initiatives. In this regards, the Office has determined that the EEIF will be retained for this adjustment period but at a reduced level. The EEIF funding contribution is therefore to be reduced by fifty percent (50%) as of the effective date of this Determination Notice. The revenues which is collected through a separate line item on customers' bills shall be billed at the rate of **J$0.2499/kWh**.

<u>Heat Rate Target</u>

The heat rate formula established in the 2015 Annual Tariff Adjustment Determination Notice is based entirely on the fleet of JPS' thermal plants. The company however takes the view that it should be set on the basis of all its plant including renewable generation and at 10,710 kJ/kWh. Further in its response to the draft Determination Notice JPS maintained its advocacy for a heat rate that incorporated its renewable plants but in any event proposed an overall thermal heat rate of 11,710 kj/kWh.

The Office mantains however that heat rate is fundamentally about the conversion of fossil fuel to usable energy. The approach currently employed by the OUR is specific and targeted and forces the utility to focus on the efficiency of its thermal plants, in this respect, there is no need for a change. The matter is discussed in greater details elsewhere in this document.

Extra-Ordinary Rate Review

The Submission proposes that there should be an Extra-ordinary Rate Review in 2017/18 to address the following:

- the treatment of long term debt (CPLTD) in the rate base;
- changes to the depreciation schedule;
- Smart Street Lighting investments;
- the inclusion of new IPPs into the non-fuel tariff; and
- review of the ROE.

The OUR takes the view that given the magnitude of the changes done in this transition tariff and the processes required in conducting the changes proposed, an Extra-ordinary Review is unwarranted. Notwithstanding, JPS still has the option to make an application if it is convinced that it has a compelling case. There is, therefore, no need to address that issue as part of this annual adjustment.

4.2. Application of the Annual Revenue Cap Adjustment Formula

Applying the Performance-Based Rate-Making (PBRM) formula to JPS' Submissions pursuant to the provisions of the New Licence, the annual rate of change in non-fuel electricity revenues (dPCI) is derived using the following factors:

- Jamaican point-to-point inflation (INFJ) between 2016 March and 2014 March of 7.05%, derived from the CPI data published by STATIN (see Appendix 6.1.2);
- U.S. point-to-point inflation rate (INFUS) between 2016 March and 2014 March of 0.78%, derived from the U.S. Department of Labor statistical data (see Appendix 6.1.1); and
- The 9.38% increase in the Base Exchange Rate from J$112: US$1 to J$122.50: US$1.
- The Q-Factor and the Z-Factor are both zero.

Table 4.1 below sets out the details of the annual adjustment factor, dPCI that amounts to a 9.53% increase to the revenue cap (RC_{2016}).

Table 4.1 Annual Escalation Adjustment Calculation (dI - Q)

Annual Adjustment Clause Calculation			
Line	Description	Formula	Value
L1	Base Exchange Rate		112.00
L2	Adjusted Billing Exchange Rate		122.50
L3	Jamaican Inflation Index		
L4	CPI @ March 2016		229.3
L5	CPI @ March 2014		214.2
L6	US Inflation Index		
L7	CPI @ March 2016		238.1
L8	CPI @ March 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 Adjustment 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%**

DETERMINATION 1

The 2016- 2017 Annual Inflation and Foreign Exchange Growth Rate (dI) is 9.53%.

4.3. *Q-Factor* Component of PBRM

Background

The electricity transmission and distribution (T&D) system is inherently a communal asset. The system is expected to provide the same level of service to all customers, or to all customers within a defined area. The T&D system does not easily differentiate among different customers' needs, therefore, there must be appropriate requirements for the basic level of service quality and reliability to all customers. This is essentially a regulatory decision made by considering the value of reliability and service quality to the aggregation of all customers versus the cost of providing that level of service. Once the regulator decides on the level of service quality and reliability that is desired, market forces by way of incentive mechanisms may be used to encourage electric utilities to provide that service at the lowest cost.

In principle, the efficient level of service quality is considered to be at the level which results in the maximization of the difference between how much customers value service quality and how much it costs. From an economic perspective, this means that the efficient service quality level is the point where the marginal costs and benefits of changes in service quality are equal.

To manage System reliability effectively, a utility must be able to properly measure and monitor it. Performance metrics become useful in this objective as they provide a mechanism to quantitatively measure System reliability and improvement. The use of metrics such as the frequency and duration of power interruptions have been essential in objectively managing System reliability. Additionally, reliability measurements are necessary to support utility regulators' efforts to monitor performance and to establish performance benchmarks and incentive mechanisms aimed at improving the reliability and quality of electricity service to customers.

The reliability and service quality of an electric utility distribution system is commonly assessed by the use of the following reliability indices[7]:

- SAIFI – System Average Interruption Frequency Index;
- SAIDI - System Average Interruption Duration Index;
- CAIDI - Customer Average Interruption Duration Index; and
- MAIFI - Momentary Average Interruption Frequency Index

Licence Requirements for Q-Factor

The annual Performance-Based Rate Making (PBRM) formula for determining the rate of change in the Revenue Cap - $dPCI = dI \pm Q \ \pm Z$; explicitly provides for the application of a Q-Factor.

The Q-Factor is the allowed price adjustment to reflect changes in the quality of service provided by JPS to its customers. The New Licence stipulates that the Q-Factor should be based on three quality indices until revised by the Office and agreed between the Office and JPS. The three quality indices currently used are SAIFI, SAIDI and CAIDI. Notably, the indices as defined in the New Licence is consistent with the IEEE Standard 1366 – 2012, the Guide for Electric Power Distribution Reliability Indices.

Q-Factor Implementation

For the implementation of the Q-Factor, the OUR and JPS have previously established that it should in principle, satisfy the following criteria:

- provide proper financial incentive to deliver a level of service quality based on customers' view of the value of that service quality;

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[7] See Annex _ for definitions

- measurement and calculation should be accurate and transparent without undue cost of compliance;
- there should be fair treatment for factors affecting performance that are outside of JPS' control, such as IPP forced outages, natural disasters, and other Force Majeure events, as defined under the New Licence; and
- it should be symmetrical in application, as stipulated in the New Licence with appropriate caps or limits of effects on rates

In process of implementing a Q-Factor mechanism, one of the prevailing challenges is the establishment of a reliable and credible baseline from which to measure changes in quality of service. From the perspective of the utility, the baseline is considered crucial to its expected revenues and should therefore be set consistent with the quality of service expectations agreed in the PBRM. Despite the regulatory requirement to implement the Q-Factor mechanism as under the PBRM, this has been hindered on the basis that a credible baseline could not be established due to System outage data integrity concerns. Resulting from a Q-Factor Audit conducted by the OUR in 2012, as a cure to the outage data issues JPS committed to the implementation of an Outage Management System (OMS) to enable it accurately collect and record System outage data. This data is essential deriving the service quality indicators necessary for the establishment of the Q-Factor baseline and the incentive scheme.

In its 2014-2019 tariff review application, JPS reported that a new Outage Management System (OMS) and Service Suite was procured and commissioned into service on 2013 December 5. This was intended to replace a system previously introduced in early 2013 but which experienced major problems. According to JPS, this new OMS was interfaced with their existing GIS system and was broadly meeting their expectations. The resulting delay, caused by the introduction of a functional OMS, meant that the complete set of outage data required to establish the Q-Factor baseline was not available thus delaying a definitive determination on the Q-Factor.

JPS' 2016 Q-Factor Proposal

<u>JPS Reliability Performance Improvement Objectives</u>

In its Submission, JPS posited that, in 2015, its strategy for reliability performance improvement was pivoted around four major initiatives, namely:

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.

JPS Initiatives to Improve Reliability Metrics

JPS, its initiatives for improving reliability and quality of service measurements in 2016 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 customers 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"

With regards to their data accuracy, JPS indicated that based on their research, the accuracy of OMS data is, to a very large extent, reliant on the accuracy of the GIS model incorporated in the collection of outage information. JPS also provided a brief description of how GIS data quality is assessed and how their levels of GIS data quality compare to some US electric utilities. The current status of JPS' GIS data quality, as indicated in their Submission, is shown in Table 4.2 below.

Table 4.2: Current Status of JPS' GIS Data Quality

ITEM	ACCURACY	COMPLETENESS
FEEDER MAPPING	98%	99%
TRANSFORMER MAPPING	98%	99%
TRANSFORMER TO FEEDER MAPPING	98%	99%
CUSTOMER TO TRANSFORMER MAPPING	84%	91%

Source: JPS Annual Adjustment Filing 2016

According to the information included in Table 4.2 above, JPS claims that several aspects of its GIS mapping system data quality is on par with the better performing US electric utilities with which it compared itself. However, its performance with respect to customer to transformer mapping is only regarded as average within the group of utilities with which it compared itself.

JPS also indicated that it has established a 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 company asserted that the initiation of these rules aid in the calibration process as there are maintenance activities which may result in their SCADA registering an outage due to switching activity, when none actually occurred.

<u>JPS Proposal for Q-Factor Baseline</u>

For the establishment of the Q-Factor Baseline, JPS proposed the use of its outage dataset for the period 2015 January 1 to 2015 December 31. The reliability indices calculated by JPS which it proposed for use to set the Q-Factor baseline are shown in Table 4.3 below.

Table 4.3: JPS' Proposed Q-Factor Baseline Data

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

Source: JPS Annual Adjustment Filing 2016

Notably, no units (such as minutes) were referred to in the proposed quality indices. Based on JPS' response to the OUR's Q-Factor determinations as set out in the draft Determination Notice submitted to the company on 2016 June 22, the company accepted that absence of the units of measurement for the quality indices was an omission on its part. Importantly, under Schedule 3 of the New Licence, the specified quality indices, SAIFI, SAIDI and CAIDI are appropriately defined with their designed units of measurement.

Evaluation of the Q-Factor

The OUR evaluated JPS' Q-Factor proposals, including the supporting System outage data in order to make its determination on the Q-Factor. The dataset was thoroughly examined to ascertain whether the data collected by JPS' over the stated two-year period is of sufficient quality and consistency to be used in establishing a credible Q-Factor baseline. The observations and findings related to the submitted Q-Factor data are set out below.

General Information about Dataset

General information about the outage data, as provided in ANNEX A of JPS' Submission, are summarized in Table 4.4.

Table 4.4: General Information on Outage Data Provided by JPS

Date Range for Data Provided	Number of Outage Events			Annual Total Customer Counts Used by JPS	
	2014	2015	Total	2014	2015
01/01/2014 – 31/12/2015	61,838	63,171	125,009	606,127	597,321

Discrepancies in Dataset

In the process of determining the reliability indices from JPS' System Outage dataset, the OUR conducted initial checks to determine if there were any glaring discrepancies, omissions, errors or misrepresentations in the data. These include checks for outages with negative duration (as was found in the dataset submitted in 2015), checks for multiple instances of the same outage event occurring in the dataset and checks for outage events incorrectly classified as a momentary or sustained outage (based on the IEEE 1366-2012 definitions for momentary and sustained interruptions) among other things. These checks were considered to be necessary and prudent given that significant problems were discovered in the 2014 Outage dataset which accompanied the 2015 Annual Tariff Adjustment Application. Based on the mathematical computations required by the IEEE 1366-2012 and the New Licence, these discrepancies or errors can adversely impact the accuracy of the reliability indices which are crucial constituents to the Q-Factor baseline. The findings from the checks are summarized in Table 4.5 below.

Table 4.5: Number of Discrepancies in Dataset

Outage Events with Negative Duration			Repeat Outage Events			Outage Events Incorrectly Classified as Momentary or Sustained		
2014	2015	Total	2014	2015	Total	2014	2015	Total
0	0	0	149	0	149	80	192	272

As represented in Table 4.5 above the data contained 149 repeated outage events and 272 incorrectly classified outage events (momentary and sustained). To ensure that the Outage dataset was representative for the purpose of the OUR's Q-Factor analysis, the repeated outage events were deleted and the incorrectly classified outages correctly classified.

Calculation of Reliability Indices

Subsequent to making the corrections to the dataset, as described above, some level of disaggregation of the outage data had to be done in order to calculate the required quality indices specified by the New Licence. The disaggregation was required as each outage event in the dataset submitted could fall under several classifications, some of which would cause an outage event to be relevant, or irrelevant, when calculating the different reliability indices.

Major classifications to consider were:

1. Whether an outage was classified by JPS as being "Reportable" or "Non-Reportable"; and
2. Whether an outage was classified as "Forced" or "Planned".

According to JPS, an outage event is classified as "Non-Reportable" when clear errors are obtained in the information related to the outage event. It is further indicated that these classifications are made using an "automated rule based dictionary". Only outage events classified as "Reportable" are considered when calculating reliability indices. Also, planned outage events are not considered when calculating reliability indices, therefore, only outage events classified as "Forced" are considered when calculating reliability indices.

The results of disaggregating the outage events are reflected in the outage classification shown in Table 4.6 below.

Table 4.6: Outage Data Classification

Reportable vs. Non-Reportable Outage Events				Forced vs. Planned Reportable Outage Events			
2014		2015		2014		2015	
Reportable	Non-Reportable	Reportable	Non-Reportable	Forced	Planned	Forced	Planned
61,540	149	58,318	4,853	61,287	253	57,976	342

Table 4.6 indicates that 61,287 outage events would be relevant in calculating the reliability indices for the year 2014 and 57,976 outage events are relevant for calculating the reliability

indices for 2015. These outage figures represent about 99.1% and 91.8% respectively, of the total number of outage events submitted in ANNEX A.

Major Event Days

According to Section 3.5 of the IEEE 1366-2012 Standard, events that occur on days identified as Major Event Days are not included when calculating reliability indices. Major Event Days are identified based on calculating the Major Event Day Threshold (T_{MED}) according to the procedure outlined in Section 3.5 of IEEE 1366-2012 Standard. The standard recommends that five years of data be used to calculate T_{MED} but suggests that less data can be used if a full five years data is not available. JPS used two year's data (2014 and 2015) to calculate T_{MED}.

The calculation of T_{MED} involved the calculation of SAIDI figures for each day represented in the outage dataset. The calculation of T_{MED} was done by JPS in its worksheet titled ANNEX C of the workbook containing the submitted outage data. To verify the accuracy of JPS' T_{MED} calculation, daily SAIDI figures were calculated using the outage data given in Annex A and monthly customer count numbers given in "JPS' 2015 Final Data Set". Although the daily SAIDI values calculated by the OUR were slightly different from those calculated by JPS, the T_{MED} calculated by the OUR identified the same Major Event Day as would be identified by JPS' calculations, that is: *July 31, 2014*. However, the estimated T_{MED} differed slightly. There were, however no Major Event Days identified for 2015 which were consistent with JPS' report. The number of reportable forced outage events occurring on the identified Major Event Day totalled 796. Consistent with IEEE 1366-2012 Standard, these forced outages were not included in the computation of the reliability indices for 2014.

Number of Outages by Class

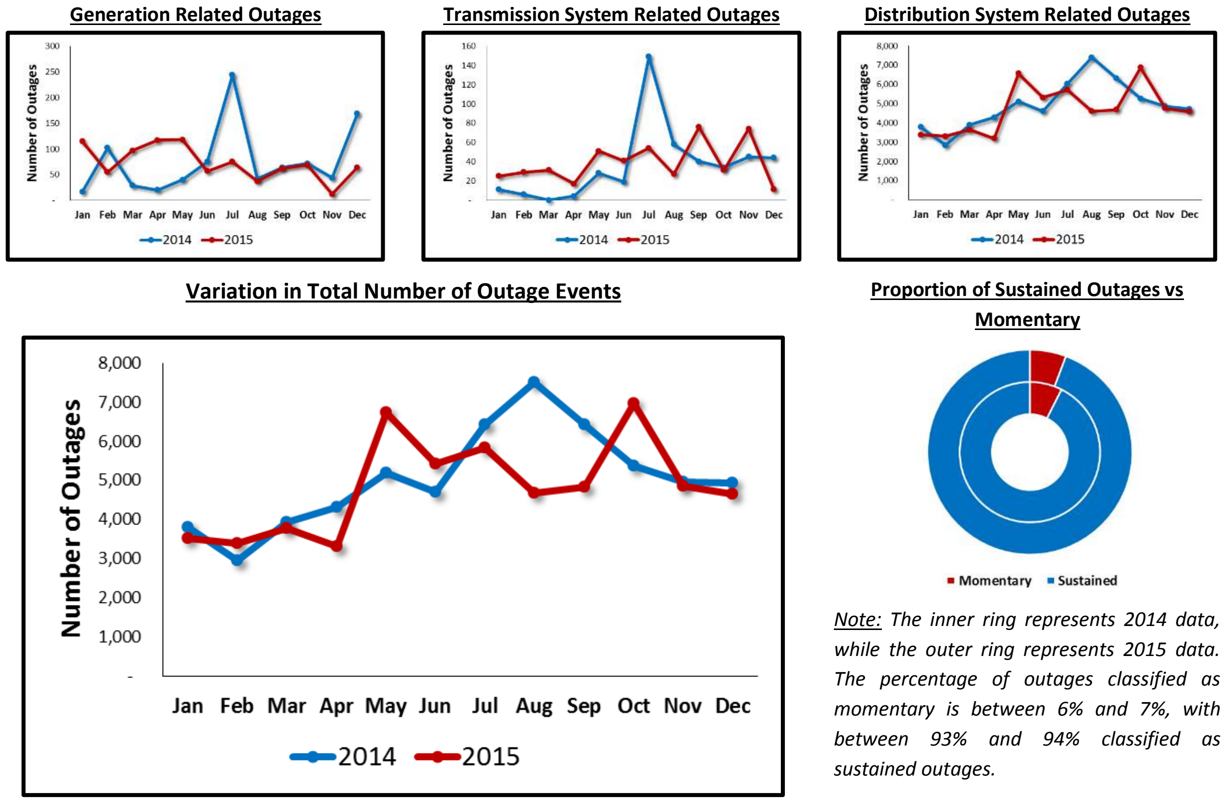
After disaggregating the outage data and accounting for non-reportable outages, planned outages and outages occurring on Major Event Days, the remaining outage events were categorized as shown in the Table 4.7 below.

Table 4.7: Number of Reportable Forced Outage Events per Month

NUMBER OF REPORTABLE FORCED OUTAGE EVENTS PER MONTH SHOWN BY TYPE (GENERATION, TRANSMISSION, DISTRIBUTION)									
	Generation			Transmission			Distribution		
Mth-Yr	*Momentary*	*Sustained*	*Total*	*Momentary*	*Sustained*	*Total*	*Momentary*	*Sustained*	*Total*
Jan-14	10	7	**17**	6	5	**11**	365	3,415	**3,780**
Feb-14	47	55	**102**	6	-	**6**	186	2,658	**2,844**
Mar-14	13	16	**29**	-	-	**-**	195	3,707	**3,902**
Apr-14	3	17	**20**	-	4	**4**	258	4,026	**4,284**
May-14	8	32	**40**	5	23	**28**	299	4,813	**5,112**
Jun-14	6	69	**75**	1	18	**19**	305	4,299	**4,604**
Jul-14	218	26	**244**	100	49	**149**	415	5,622	**6,037**
Aug-14	11	31	**42**	17	41	**58**	558	6,847	**7,405**
Sep-14	18	46	**64**	11	29	**40**	323	5,999	**6,322**
Oct-14	29	43	**72**	11	23	**34**	309	4,953	**5,262**
Nov-14	27	17	**44**	20	25	**45**	356	4,507	**4,863**
Dec-14	74	95	**169**	3	41	**44**	293	4,427	**4,720**
TOTAL	**464**	**454**	**918**	**180**	**258**	**438**	**3,862**	**55,273**	**59,135**
Jan-15	47	68	**115**	4	21	**25**	156	3,231	**3,387**
Feb-15	14	41	**55**	9	20	**29**	136	3,175	**3,311**
Mar-15	33	64	**97**	11	20	**31**	207	3,437	**3,644**
Apr-15	39	78	**117**	4	13	**17**	173	3,016	**3,189**
May-15	47	71	**118**	15	36	**51**	349	6,218	**6,567**
Jun-15	24	33	**57**	19	22	**41**	281	5,040	**5,321**
Jul-15	36	39	**75**	18	36	**54**	313	5,403	**5,716**
Aug-15	24	13	**37**	7	20	**27**	278	4,329	**4,607**
Sep-15	28	34	**62**	10	66	**76**	225	4,457	**4,682**
Oct-15	37	32	**69**	14	17	**31**	322	6,546	**6,868**
Nov-15	4	8	**12**	21	53	**74**	192	4,569	**4,761**
Dec-15	28	36	**64**	4	7	**11**	188	4,390	**4,578**
TOTAL	**361**	**517**	**878**	**136**	**331**	**467**	**2,820**	**53,811**	**56,631**

An illustration of the outage events for the various segments of the System is provided in Figure 4.1 below.

Figure 4.1: Plots showing Variation in the Number of Outage Events during 2014 and 2015



Note: The inner ring represents 2014 data, while the outer ring represents 2015 data. The percentage of outages classified as momentary is between 6% and 7%, with between 93% and 94% classified as sustained outages.

OUR's Derivation of the Reliability Indices

Taking into account the System outage data related issues described above, the quality indices for 2014 and 2015 were computed by the OUR based on the JPS outage data which was adjusted and the monthly customer counts provided in the "JPS 2015 Final Dataset".

The indices computed are presented in Table 4.8 and Table 4.9 below, where SAIDI is given in minutes/customer, SAIFI in interruptions/customer, CAIDI in minutes/customer.

Table 4.8: OUR Computed Monthly Q-Factor Indices

Q-FACTOR INDICES													
		Generation				Transmission				Distribution			
Mth-Yr	Customer Count	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI
Jan-14	608,159	0.462	0.066		0.132	1.191	0.031		0.058	132.143	0.847		3.030
Feb-14	607,763	8.938	0.665		0.849	-	-		0.046	124.635	0.828		1.223
Mar-14	608,470	1.290	0.096		0.251	-	-		-	162.478	1.479		1.194
Apr-14	609,760	1.220	0.046		0.044	0.882	0.006		-	138.431	1.076		1.860
May-14	610,013	9.480	0.196		0.154	9.262	0.133		0.082	255.732	1.353		2.073
Jun-14	611,111	17.097	0.395		0.088	10.988	0.095		0.005	146.429	1.307		2.075
Jul-14	611,674	6.940	0.163		0.869	19.423	0.037		0.336	213.263	1.830		2.198
Aug-14	598,814	3.048	0.160		0.171	0.446	0.013		0.106	298.562	2.257		4.086
Sep-14	602,239	2.981	0.251		0.098	25.060	0.078		0.094	219.848	1.758		2.373
Oct-14	597,994	7.008	0.530		0.402	12.066	0.168		0.093	236.744	2.005		2.784
Nov-14	598,654	1.919	0.240		0.402	7.962	0.168		0.176	189.346	1.746		2.795
Dec-14	594,430	26.408	0.647		1.000	13.612	0.140		0.022	105.372	1.042		1.829
TOTAL		**86.791**	**3.456**	**25.113**	**4.460**	**100.892**	**0.868**	**116.295**	**1.018**	**2,222.982**	**17.527**	**126.832**	**27.520**
Jan-15	584,136	6.704	0.424		0.685	7.110	0.121		0.041	120.474	0.960		1.255
Feb-15	586,657	5.383	0.413		0.232	5.030	0.069		0.027	110.727	0.784		1.074
Mar-15	583,504	8.728	0.676		0.552	10.122	0.092		0.067	124.266	0.968		1.170
Apr-15	584,246	35.104	1.192		0.761	4.993	0.034		0.031	108.629	0.888		0.813
May-15	583,357	21.228	0.720		0.763	18.940	0.188		0.146	252.723	1.377		1.814
Jun-15	584,398	3.312	0.211		0.524	7.815	0.137		0.183	152.263	1.055		2.069
Jul-15	586,806	8.495	0.639		0.808	24.224	0.208		0.087	181.831	1.252		1.697
Aug-15	589,032	1.400	0.188		0.500	24.059	0.125		0.071	128.960	0.937		1.671
Sep-15	588,572	5.077	0.482		0.420	39.482	0.267		0.067	122.066	0.782		1.342
Oct-15	589,902	8.718	0.455		0.638	4.633	0.099		0.180	219.639	1.293		1.983
Nov-15	590,249	1.054	0.141		0.087	10.453	0.202		0.156	113.001	0.716		1.113
Dec-15	593,274	6.849	0.316		0.420	0.409	0.010		0.020	114.978	0.679		1.195
TOTAL		**112.052**	**5.858**	**19.129**	**6.389**	**157.271**	**1.551**	**101.418**	**1.075**	**1,749.557**	**11.692**	**149.632**	**17.194**

Table 4.8 above is summarized and shown below.

Table 4.9 Annual Values for OUR Computed Q-Factor Indices

YEAR	INDICATOR	UNITS	GENERATION	TRANSMISSION	DISTRIBUTION	TOTAL
2014	**SAIDI**	mins/customer	86.791	100.892	2,222.982	**2,410.665**
	SAIFI	interruptions/customer	3.456	0.868	17.527	**21.851**
	CAIDI	mins/customer	25.113	116.295	126.832	**110.325**
	MAIFI	interruptions/customer	4.460	1.018	27.520	**32.998**
2015	**SAIDI**	mins/customer	112.052	157.271	1,749.557	**2,018.880**
	SAIFI	interruptions/customer	5.858	1.551	11.692	**19.101**
	CAIDI	mins/customer	19.129	101.418	149.632	**105.696**
	MAIFI	interruptions/customer	6.389	1.075	17.194	**24.658**

During the evaluation of the Q-Factor data, it was found that the quality indices calculated from the 2014 System outage data included in JPS' Submission exhibited a departure from the values computed by the OUR in the 2015 Annual Tariff Adjustment Determination Notice. This implies that the 2014 outage dataset may have been modified by JPS as the same methodology was used by the OUR to calculate the reliability indices in both cases. This is an issue to be explored further as it raise concerns regarding the plausibility and integrity of the outage data sets being submitted by JPS.

Notably, JPS in its response to the OUR's Q-Factor determinations as set out in the draft Determination Notice submitted to the company on 2016 June 22, asserted that it provided full response to the OUR during the recent post filing consultation meetings regarding the errors in the 2014 data. According to JPS, the recalibration of the outage data to address the errors was the reason for the difference in its 2014 System outage data set as submitted in 2015 Annual Tariff Adjustment Submission and the current Submission. There was, however, no revised calculation of the 2014 quality indices by JPS for purpose of comparison.

A comparison of the 2015 quality indices computed by OUR and those presented by JPS in ANNEX B of the outage dataset is shown in Table 4.10 below.

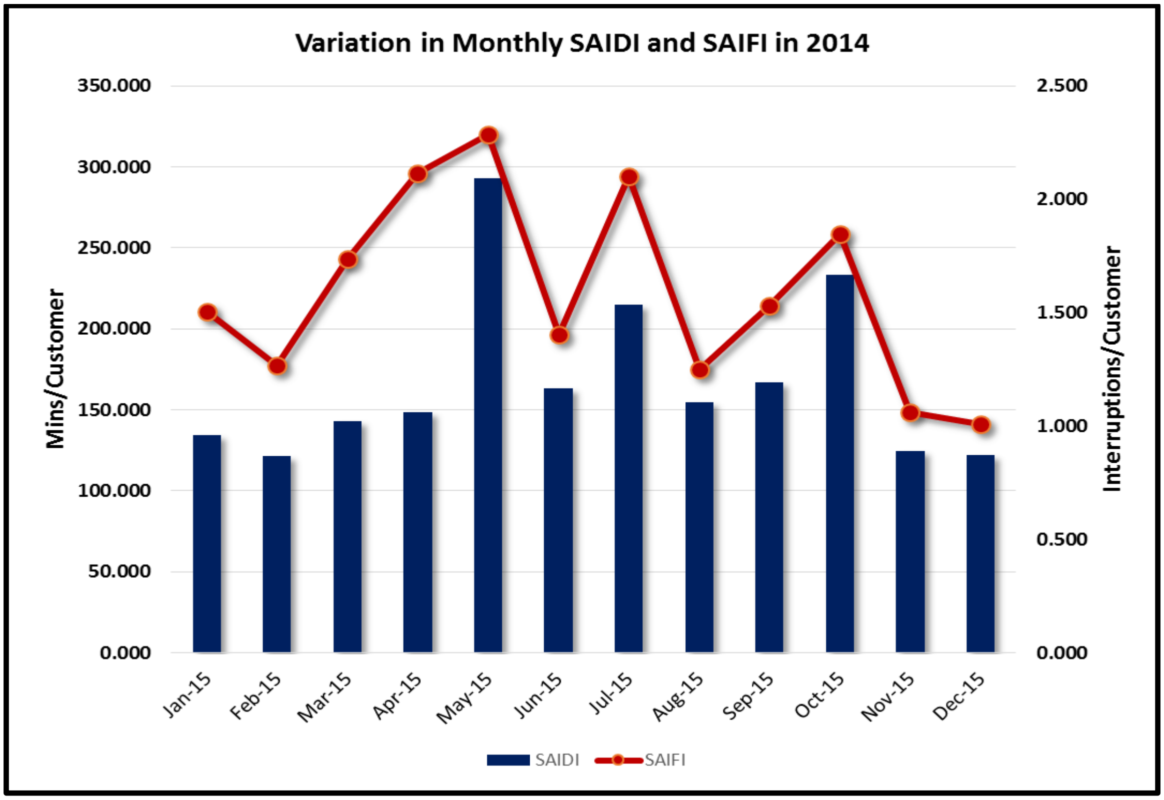
Table 4.10: Comparison of 2015 Reliability Indices Calculated by JPS and OUR

INDICATOR	UNIT	JPS CALCULATED INDICES	OUR CALCULATED INDICES	PERCENTAGE DEVIATION
SAIDI	mins/customer	1,983.724	2,018.880	**1.77%**
SAIFI	interruptions/customer	18.851	19.101	**1.33%**
CAIDI	mins/customer	105.232	105.696	**0.44%**
MAIFI	interruptions/customer	24.130	24.658	**2.19%**

As shown, the reliability indices calculated by OUR were not largely dissimilar to those calculated by JPS. The indicated differences are likely attributable to the identified discrepancies in the dataset, as well as, JPS' use of an annual customer count as opposed to the monthly customer count used by the OUR, which it considers to be more aligned to the outages at the respective times when they occurred.

As shown in Table 4.8 above, SAIDI and SAIFI were calculated for each month of 2015. The variability of these indices is represented in the plot shown in Figure 4.2 below.

Figure 4.2: Variation in Monthly SAIDI and SAIFI in 2015



OUR's Position on the Q-Factor

One of the objectives of the PBRM, is to provide JPS with an incentive to become more cost efficient over the regulatory period. However, there is some potential for this framework to have perverse incentives in that the company may encourage cost reductions at the expense of service quality and reliability. The application of a Q-Factor is an attempt to mitigate this by seeking to ensure through it monitoring that JPS provide acceptable levels of service to customers.

Upon review and evaluation of JPS' Q-Factor Proposal, the OUR's position is as follows:

- OUR's found that JPS' Q-Factor dataset contains embedded errors in data classification, recording and calculation methodology that translates to inaccuracies in the calculation of the specified quality indices. This situation would adversely impact the integrity of an adopted Q-Factor baseline.

- While JPS indicated that an automated rules-based system is used to calibrate outage data, the methodology behind this system, and how it is applied is not completely clear. This presents a condition which introduces doubts about the authenticity and plausibility of the JPS System outage data provided. An attempt was made to address this by requesting additional data from JPS on the rules-based system but this was not submitted in sufficient time to allow for its examination.

- JPS indicated in the Submission and also at post-submission consultations with the OUR that there were outstanding issues impacting the accuracy and completeness of their customer mapping enabled by the integration of its GIS database interface. JPS admitted that this has the potential to induce significant distortion and errors in its customer location and count, which is an integral component to the calculation of the quality indices. Having regard to this issue, there is considerable concern on the part of the OUR as to the efficacy and completeness of the outage data collection system and the impact of such defects on the recorded outage data and ultimately the effect on the calculation of the quality indices.

- JPS also indicated in post-submission consultations with the OUR that its "Customer to Transformer Mapping" as at 2016 February achieved accuracy of 84% with completeness of 91%. While the reported outcome appeared to be within an indicative utility best practice benchmark, the OUR still has concerns about using the 2015 outage dataset, as the indicated improvements in data quality would be subsequent to the collection of this 2015 data. Further, the reported accuracy in customer to transformer mapping would still be impacted by the functionality of the OMS and GIS interface.

- The Q-Factor submission, including its outage dataset revealed that outage data being recorded for sustained interruptions is still not at a satisfactory level to enable consistent, accurate and reliable determination of the Q-Factor indices. Imperatively, these indices are crucial to the establishment of a credible Q-Factor baseline which will provide the reference to measure changes in quality of service.

JPS Comments on the OUR's Position on the Q-Factor

Responding to OUR's comments on the Q-Factor in the draft Determination Notice submitted to JPS on 2016 June 22, JPS comments and the Office's comments thereon are as follows:

- JPS expressed regret that the OUR did not utilize the modified 2015 System outage dataset submitted to the OUR, following the post consultation meeting held on 2016 May 31 as the final resubmitted calibrated dataset does not reflect the inaccuracies identified. The OUR wishes to underscore however that the New Licence, prescribes a tight sixty (60) day time line to complete the Annual Review. One of the implications of this is that all the relevant supporting documentation should have accompanied the initial filing. Even so, it was acknowledged during post submission consultations that there were issues with the 2015 System outage data set initially submitted and that the OUR would consider further submissions if done promptly. Unfortunately the revised data was submitted only two days prior to the timeline for sending the draft Determination Notice for Office review. This did not afford sufficient time to undertake a comprehensive review and evaluation of the resubmitted 2015 System outage data. In any event, due to the issues identified by the OUR in relation to the accuracy and completeness of JPS "Customer to Transformer Mapping" as well as the GIS/OMS interface, the modified 2015 System outage data would still be considered to be unsuitable for establishing the Q-Factor baseline. This is on the basis that the modified 2015 System outage data would have been affected by issues described which according to JPS were largely prevalent up 2016 February.

- Regarding OUR's expressed concerns with its methodology for calibrating the dataset, JPS indicated that the company is receptive to facilitating further consultation with the OUR to clarify rules-based methodology. The OUR is open to facilitating this engagement.

- JPS also stated that it intends to continue to consult with the OUR towards establishing a credible Q-Factor baseline and a Q-Factor data management process and it believes that with the level of investment, improvement and priority given since 2013, the company will be able to bring closure to the Q-Factor situation in short order.

OUR's Determination on JPS Q-Factor

Given all the factors impacting the Q-Factor, as outlined above, the OUR is of the view that JPS' outage data collection and processing systems are still not robust enough to generate sufficiently accurate Q-Factor data to facilitate the establishment of a representative and credible baseline for the Q-Factor implementation for the 2016/2017 tariff period. As part of the regulatory requirements, the OUR intends to continue discussions with JPS in relation to the Q-Factor and to intensify its monitoring of the periodic reported System outage data with the aim of ensuring that the Q-Factor mechanism can be implemented within the remaining period of the Revenue Cap.

On the basis that, the submitted System outage data was not considered suitable by the OUR for the establishment of a reliable baseline to support the application of the Q-Factor mechanism, the Office determined that no adjustment will be allowed in the PBRM to reflect changes in the quality of service provided to customers by JPS for the 2016/2017 tariff adjustment period. Accordingly, the Q-Factor shall remain in the dead band.

DETERMINATION 3

The Q-Factor for the 2016 Annual Tariff Adjustment shall be 0% (zero percent).

4.4. FX, Interest and Revenue Surcharges (SFX_{2015} - SIC_{2015} + RS_{2015})

The adjustment mechanism set out in the New Licence also allows for a revenue surcharge which includes a true-up for the previous year's under/over-recovered revenues, system losses incentive mechanism and a FX surcharge offset by income received for interest paid by customers.

JPS' position is that the true-up for volumetric adjustments (TUVol) cannot be applied in the 2016/2017 tariff adjustment period. JPS stated that the revenue requirement as determined in the 2014 - 2019 Determination Notice is US$383.65M inclusive of EEIF (excluding the EEIF it is US$370.65M). JPS argued that 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 Notice) was US$361.4M. 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.

The New Licence states that the revenue cap is the revenue requirement approved in the 2014 – 2019 rate review as adjusted for the rate of change in non-fuel electricity revenues at each Annual Adjustment date. Furthermore the New Licence stipulates that the Annual Revenue Target shall be adjusted on an annual basis commencing 2016 July 1.

The New Licence also outlines the methodology for the computation for the $TUVol_{2015}$ which is;

y =2016 the current year

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

On the one hand, JPS takes a position 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."* JPS, on the other hand, is claiming that the tariff basket "determined" by the OUR in the 2015 Annual Tariff Adjustment Determination Notice does not represent that which JPS should have obtained under revenue cap regulation and hence applying the TUVol mechanism to the 2015 revenue target would be erroneous.

Consistent with the Office's approach outlined herein, the Office disallowed the 2015 foreign exchange surcharges as part of the rate base. However, since this tariff adjustment exercise involves the grafting of a revenue cap mechanism on a price cap tariff, it is reasonable that JPS is allowed to recovery an amount for foreign exchange losses for the current year 2016 and in addition to offset an amount for the interest income, it will receive from commercial and GOJ customers for 2016.

The OUR finds some favour in the argument that this component of the revenue-cap mechanism was designed to provide cash flow support to JPS throughout the year and not after the fact. In this respect, the Office gives approval for the inclusion of a provisional amount for the 2016 FX surcharge which will be offset during the 2017 Annual Review. The actual 2015 FX surcharge amount was used as the basis to determine the 2016 provision. Additionally, the Office gives approval for the inclusion of a provision for interest income to be collected by JPS in relation to interest to be charged to commercial and GOJ customers for 2016. The provisional amount of J$37.5M is based on an estimate that was provided by the JPS. Actual net late payment fees of J$76.6M for 2015 was included as an adjustment offset to the FX surcharge provision.

For the 2017 Annual Tariff Submission, JPS should apply the actual FX losses recorded for 2016 **less** the provision of J$603.295M as the FX surcharge. Additionally, the interest surcharge to be applied in the 2017 Annual Tariff Submission should be the actual interest earned from commercial and GOJ customers for 2016 **less** the provisional amount of J$37.5M. For the avoidance of doubt the provisional amounts are not to be carried forward (that is, they are not intended to be applied as a true–up).

The details of the adjustments are as indicated in Table 4.11 below.

Table 4.11: OUR Determined FX, Interest and Revenue Surcharges for 2015 (SFX_{2015} - SIC_{2015} + RS_{2015})

FX, Interest and Revenue Surcharges for 2015 (SFX_{2015} - SIC_{2015} + RS_{2015})				
Line	**Description**	**Amount**	**Formula**	**Value**
	FX Surcharge			
L1	TFX			
L2	AFX_{2015} **(2016 Provision)**			**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 **(2016 Provision)**			**37,500,000**
L5	Actual Net Late Payment Fees for 2015			**76,624,363**
L6	AIC_{2015}		**L4+L5**	114,124,363
L7	TIC_{2015}			-
L8	**SIC_{2015}**		**L6-L7**	**114,124,363**
L9	**SFX_{2015} - SIC_{2015}**		**L3-L8**	**489,170,865**
	Revenue Surcharge (RS_{2015})			
L10	kWh $Target_{2015}$	2,912,555,499		
L11	kWh $Sold_{2015}$	2,972,549,058		
L12	Non Fuel Revenue Target for Energy Rev_{2015}	32,035,690,737		
L13			**(L10 - L11)/L10 x L12**	-
L14	kVA $Target_{2015}$	5,208,288		
L15	kVA $Sold_{2015}$	5,194,994		
L16	Non Fuel Revenue Target for Demand Rev_{2015}	6,221,283,986		
L17			**(L14 - L15)/L14 x L16**	-
L18	# of Customer charges billed $Target_{2015}$	609,937		
L19	# of Customer charges billed Act_{2015}	594,284		
L20	Non Fuel Rev Target for Customer Charges Rev_{2015}	3,476,723,331		
L21			**(L18 - L19)/L18 x L20**	-
L22	**$TUVol_{2015}$**		**L13 + L17 + L21**	-
L23	Target System Loss "Technical Losses" $(\%)_{2015}$	0%		
L24	Actual System Loss "Technical Losses" $(\%)_{2015}$	0%		
L25			**L23 - L24**	0.00%
L26	Target System Loss "Portion of Non-technical losses which is completely within JPS' control" $(\%)_{2015}$	0%		
L27	Actual System Loss "Portion of Non-technical losses which is completely within JPS' control" $(\%)_{2015}$	0%		
L28			**L26 - L27**	0.00%
L29	Target System Loss "Portion of Non-technical losses which is not completely within JPS' control" $(\%)_{2015}$	0%		
L30	Actual System Loss "Portion of Non-technical losses which is not completely within JPS' control" $(\%)_{2015}$	0%		
L31	RF-Responsibility Factor determined by the Office (%)	0%		
L32			**(L29 - L30) x L31**	0.00%
L33	Y_{2015} System Losses		**L25 + L28 + L32**	0.00%
L34	ART_{2015}			41,733,698,054
L28	**$TULos_{2015}$**		**L33 x L34**	-
L28	**RS_{2015} = $TUVol_{2015}$ + $TULos_{2015}$**		**L22 + L28**	**0**
L29	**SFX_{2015} - SIC_{2015} + RS_{2015}**		**L9 + L28**	**489,170,865**

4.5. System Losses

Definition

Losses in an electric utility system are measured as the difference between the amount of electrical energy generated and the amount of energy delivered to customers. Losses tend to occur at all levels of the System, from generation, through transmission and distribution, to the supply to customers including meters. These losses can be divided into two categories: technical and non-technical losses.

Technical losses (TL) are naturally occurring losses (caused by actions internal to the power system) and consist mainly of power dissipation in electrical system components such as transmission lines, power transformers, measurement systems, etc. Technical losses are possible to compute and control. They can also be simulated and calculated using computation tools and computer simulation models which have been developed over time. Improvements in information technology and data acquisition have also provided enhanced capability for the calculation and verification of technical losses.

Non-technical Losses (NTL), on the other hand, are due to human manipulation or errors and are considered to emanate from actions external to the power system. NTL are more difficult to measure and are often inaccurately accounted for by the electricity system operator. From an economic perspective, non-technical losses tend to have several perverse effects. A manifestation of this becomes obvious, when legitimate electricity customers who are billed by the utility for accurately measured consumption and regularly paying their bills, are required to subsidize those users who do not pay for all or part of their electricity consumption.

Background on JPS System Losses

In 2001, the energy losses in JPS' System, calculated on a 12-month rolling average basis, stood at 16.58% of net generation. This increased steadily to 19.67% in 2004 and escalated to 23.04% by the end of 2009. Subsequently, losses advanced to 26.65% by 2014 and were reported by JPS to be 26.98% in 2015 December according to its Energy Loss Spectrum.

In JPS' 2004 Rate Submission, the company proposed a schedule for loss reduction over the 2004-2009 price cap period. This entailed a reduction in losses from 18.0% of net generation in 2004 to 17.7% in 2005, followed by 17.4% in 2006, 17.1% in 2007, 16.8% in 2008, and 16.5% in 2009. Correspondingly, the OUR in its 2004 Determination Notice on JPS' 2004 Rate Submission, determined a System losses target of 15.8% of net generation for 2004 with projected targets of 15.3% for 2005, 15.0% for 2006, 14.7% for 2007, 14.2% for 2008. However, the proposed reduction in System losses were not achieved.

In JPS' 2009 - 2014 Tariff Application, the company proposed that the System losses target of 15.8% which was in effect at the time of the Rate Review be increased to 20.5% in 2009 June then reduced to 19.5% in 2010 June, followed by 18.5% in 2011 June, 17.7% in 2012

June, 16.9% in 2013 June 2013 16.3% in 2014 June. Interestingly, the proposed target of 16.3% at the end of the price cap period would be higher than the target of 15.8% existing prior to the effective date of the 2009 - 2014 Determination Notice. This proposed reduction in the System losses target by JPS in 2009 was supported by the company's loss reduction forecast for the same 5 year period in which actual losses would be gradually reduced from 22.9% reported at 2008 December to 18.3% by 2014 June. In the said 2009 - 2014 Tariff Application, JPS also provided in detail, its planned loss reduction initiatives and attendant costs to achieve its proposed reductions in System losses from 22.9% in 2008 December to 18.3% by 2014 June.

In response to JPS' 2009 - 2014 loss reduction proposals, the OUR in its 2009 - 2014 Determination Notice, expressed the view that if the System losses target was increased from the existing value of 15.8% and a portion of the improved revenues accruing from the changes to the fuel efficiency targets is used specifically to address System losses, the reduction rate could be accelerated. As such, the Office approved an increase in the System losses target initially from 15.8% to 19.5% for 2009/2010 and a target of 17.5% to be applied at the 2011 Annual Tariff Adjustment and determined that subsequent targets would be approved at the remaining Annual Tariff Adjustments during the price cap period. The Office also directed JPS to establish a fund to finance System loss reduction projects that OUR endorsed/approved. It was projected at the time that the System losses fund, designated the EEIF would accrue at a rate of approximately US$13 Million annually.

Following the OUR's 2009 - 2014 Determination Notice, the first reset of JPS' System losses target was done at the 2011 Annual Tariff Adjustment when it was reduced from 19.5% to 17.5%, which was in accordance with OUR's determinations on JPS' System losses as set out in the 2009 - 2014 Determination Notice. Since the 2011 Annual Tariff Adjustment the System losses target was kept at 17.5% until it was determined by the OUR to be 19.2% in the 2014 - 2019 Determination Notice, which became applicable as of the effective date of the said Determination Notice.

During the 2009 - 2014 Rate Review, JPS committed to providing funding to support its loss reduction programmes and initiatives. However, by the 2011 Annual Tariff Adjustment, the company's proposal on the System losses target indicated that it had deviated from its loss reduction proposals it committed to in the 2009 - 2014 Tariff Review Application. Despite the OUR's Determination for the System losses target to be 17.5% at the 2011 Annual Tariff Adjustment, JPS in its 2011 Annual Tariff Adjustment submission proposed a System losses target of 19.5%, which was at variance with its proposed System losses target of 18.5% for 2011 in the 2009 - 2014 Tariff Application.

At the 2013 Annual Tariff Adjustment, JPS completely shifted from its 2009 - 2014 loss reduction commitments and instead requested a full pass-through of its total fuel costs (without efficiency adjustment) to its customers.

In its 2009 - 2014 Tariff Application and subsequent Annual Tariff Adjustment submissions during the price cap period, JPS proffered various reasons for the continued upward movement in System losses. However, given the level of regulatory support and loss reduction funding provided to JPS as well as the company's reported loss reduction efforts and initiatives over the 2009-2014 price cap, the continued and progressive increase in System losses generated considerable cause for concern. The expectation was that by the 2014 Rate Review, there would be evidence of tangible decrease in the energy losses.

As previously indicated, the regulatory treatment of the System losses, involved the OUR's approval of a funding facility of approximately US$13 Million per annum, designated the EEIF to enhance JPS' proposed loss reduction programmes. While this translated to increased costs to customers in the short to medium term, the OUR was of the view that the utilization of these funds would provide impetus to JPS to effectively reduce System losses, which would ultimately result in lower average electricity rates to its customers in the long-run. To complement this regulatory intervention, in 2013 July, the OUR provided additional support to JPS by way of a Fuel Cost Recovery Adjustment (FCRA), which allowed JPS to recover US$20 Million (US$1.67 Million per month) through the monthly fuel rates for twelve months. This facility was approved to be in effect from 2013 July to 2014 June but was extended to the effective date of the 2014 - 2019 Determination Notice, being 2015 January 7. The extension resulted in an aggregate amount of US$30.33 Million recovered by JPS through this facility during the stated period. The FCRA was contingent on specific conditions, including certain loss reduction initiatives set out under section 4.7 of the 2013 Annual Tariff Adjustment Determination Notice. It should be noted that some of these loss reduction initiatives included some of the loss reduction projects that were already proposed by JPS in its 2009 - 2014 Tariff Application.

Despite the regulatory interventions and allowances regarding JPS' System losses, the System loss performance since 2009, indicated that JPS' proposals for energy loss reduction were not achieved. Consequently, System losses remained stubbornly high. During previous rate reviews, JPS contended that certain elements of non-technical losses are not within its control. However, based on available data on JPS' System losses, the OUR has maintained the view that NTL is largely within the company's management and control, although some components of these losses may be more difficult to control. This has been demonstrated repeatedly by JPS' own efforts in addressing the issue of non-technical losses caused by illegal users (non-customers) in various areas across the island. It was reported by JPS in 2013 that illegal users (150,000 un-authorised consumers) contributed to approximately 45% of non-technical energy losses. According to JPS, the primary solution used to address the problem was Residential Automated Metering Infrastructure (RAMI). As a result of the deployment of this metering technology in 19 communities by JPS, approximately 20,000 households were regularized and remained active up to 2012 December.

At the 2014 - 2019 Rate Review, the OUR after evaluating JPS' System losses proposals, determined that the aggregate System losses target ceiling for JPS over the price cap period 2015 January – 2019 May shall be 19.20% of total net generation. The System losses target was comprised of a technical losses target and a non-technical losses target ceiling of 8.4% and 10.8% respectively. The OUR's determinations on JPS's 2014 - 2019 System losses proposals are set out under Chapter 10 of the 2014 - 2019 Determination Notice.

To complement the approved System losses target of 19.2% and to support JPS' loss reduction initiatives over the 2014-2019 price cap period, the OUR in the 2014 - 2019 Determination Notice, approved the continuation of the EEIF which would continue to accumulate to US$13 Million per annum. The total collection from the EEIF was expected to partially fund JPS' loss reduction initiatives over the price cap period which were estimated by JPS to cost a total of US$92.39 Million with projected overall impact of 7.17% reduction in System losses.

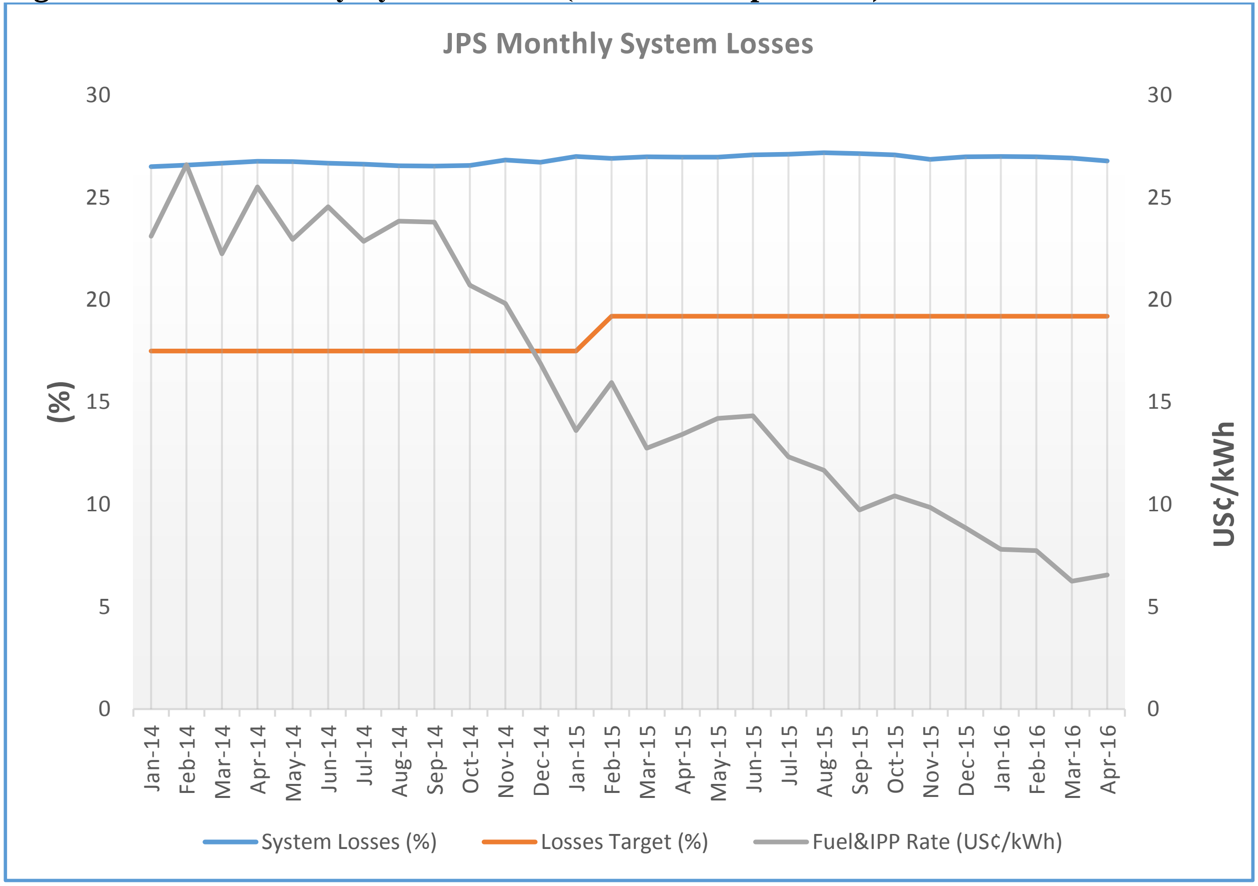
In the 2015 Annual Tariff Adjustment Determination Notice, the OUR determined that the System losses target should remain at 19.2% for the adjustment period, given that the 2014 - 2019 Determination Notice only became effective in 2015 January.

Since the issue of the JPS Licence in 2001, in accordance with the the Fuel Cost Adjustment Mechanism (FCAM) set out in the Price Control regime, the actual System losses and targets were directly applicable to the recovery of the total (JPS and IPPs) fuel cost and fuel rates. Subject to such regulatory requirement, the System losses targets were consistently determined on the basis of fairness and reasonableness and in accordance with good regulatory practice. That approach was considered to be crucial in ensuring that the determined System losses targets provided sufficient incentive to JPS to reduce its System losses and improve revenues, while at the same time, ensuring that the rates to customers are reasonable and that customers are not unduly exposed to imprudent costs or burdened by excessive costs due to JPS' non-performance or inefficiencies.

JPS System Losses Performance

Since 2014 January, JPS monthly System losses moved from 26.51% of net generation to 27.01% coinciding with the issue of the 2014 - 2019 Determination Notice in 2015 January. Thereafter, the losses peaked at 27.19% in 2015 August and then fluctuated slightly with losses reported at 27% at the end of 2015. Since the start of 2016, the losses have exhibited marginal but sustained reduction up to 2016 April. According to JPS, losses moved from 27.01% in 2016 January to 26.79% in 2016 April reflecting a change of 0.22%. The movement in monthly System losses relative to the target and monthly fuel rate over the stated period is illustrated in Figure 4.3.

Figure 4.3: JPS' Monthly System Losses (Jan 2014 – April 2016)



Based on System losses data in JPS' "Final Data Set for OUR 2015", the rolling average System losses for 2015 was reported at 27.03% of net generation. This represents an increase of 0.38% in the level of System losses when compared to the 26.65% at 2014 December.

Over the 28 month period under observation, the monthly fuel rate decreased steadily from 26.609 US¢/kWh in 2014 February to a value of 6.249 US¢/kWh in 2016 March, reflecting a change of approximately 76%. This reduction in the monthly fuel rate was occasioned by the relatively low prices of fuel oil resulting from the demand/supply dynamics in international oil markets. Concomitantly, these reduced monthly fuel rates progressively reduced the average price of electricity to levels significantly below those prior to 2014.

Notwithstanding the favourable economic benefits which accrued from the low fuel price environment, that is, the lower average electricity rates rendered the product more affordable to consumers, there was no observed material reduction in System losses due to the massive reduction in fuel rates over the period. This indication, in some ways, would have served to negate the position that high fuel costs was one of the main drivers of System losses.

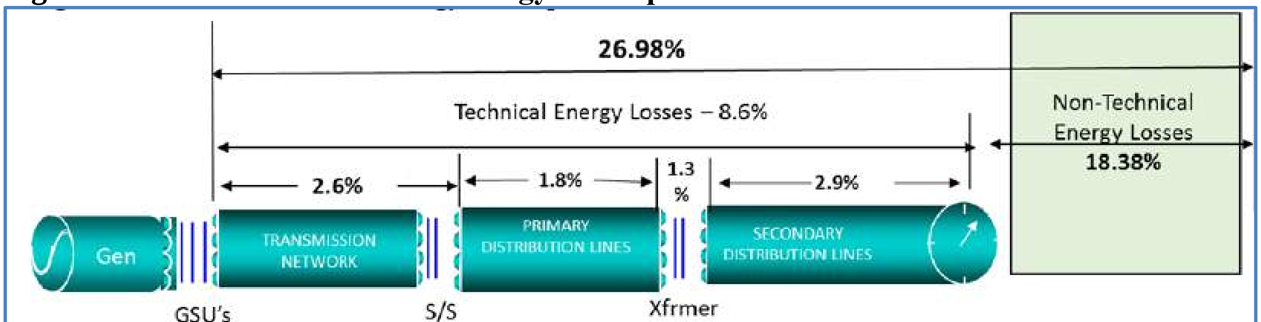
Categorization of JPS' System Losses

In JPS' 2015 Annual Report, the company reported that System losses as a percentage of net generation was 27% at 2015 December 31. As previously indicated, this was corroborated with the rolling average System losses for 2015 of 27.03% of net generation reported by the company in its "Final Data Set for OUR 2015".

While the losses are often reported as a composite figure, they are composed of various categories distributed in varying proportions and which tend to have different and distinct influences on the overall System losses percentage. According to JPS, the overall System losses including the losses in the various categories were estimated at 2015 December and represented in its December 2015 Energy Loss Spectrum shown in Figure 4.4 below.

As illustrated, the losses are primarily related to JPS' transmission and distribution (T&D) operations with the larger portion of the losses confined to the Distribution System. As reflected in the loss spectrum, technical losses were estimated at 8.60% of net generation while non-technical losses for 18.38% of net generation or 68% of total System losses.

Figure 4.4: JPS' 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%

Source: JPS 2016 Annual Tariff Adjustment Filing

A comparison of the energy loss components in JPS' Energy Loss Spectrum for 2014 January, 2014 December and 2015 December is provided in Table 4.12 below.

Table 4.12: Comparison of JPS' 2014 January to 2015 December Energy Loss Spectrum

Loss Category	Components	January 2014	December 2014	December 2015
Technical Losses	Transmission Network	2.60%	2.6%	2.6%
	Primary Distribution Lines	1.80%	1.8%	1.8%
	Distribution Transformers	1.30%	1.3%	1.3%
	Secondary Distribution Lines	2.90%	2.9%	2.9%
	Total Technical Losses	**8.60%**	**8.60%**	**8.60%**
Non-Technical Losses	Streetlight/Stoplight (Rate 60)	0.20%	0.20%	0.09%
	Large C&I (Rate 40&50)	1.19%	0.75%	0.45%
	Medium C&I (Rate 20)	0.45%	0.29%	0.31%
	Small C&I (Rate 20)	0.31%	0.33%	0.32%
	Residential (Rate 10)	4.36%	6.10%	7.08%
	Sub-Total	**6.51%**	**7.67%**	**8.25%**
	Internal Bleeds/Unquantified	1.56%	0.27%	0.53%
	Illegal Users (non-customers)	9.85%	10.11%	9.60%
	Total Non-Technical Losses	**17.92%**	**18.05%**	**18.38%**
TOTAL		**26.52%**	**26.65%**	**26.98%**

The System losses data in Table 4.12 above shows that:

- Technical losses have remained constant at 8.6% of net generation from 2014 January to 2015 December. This suggests that there may not have been any tangible efforts geared at reducing technical losses over the stated period.
- NTL have increased by a margin of approximately 3% from 17.92% in 2014 January to 18.38% in 2015 December.
- NTL attributable to Residential Customers (Rate 10) have increased by approximately 62% from 4.36% in 2014 January to 7.08% in 2015 December.
- NTL attributable to Illegal Users (non-customers increased from 9.85% in 2014 January to 10.11% in 2014 December but declined to 9.60% in 2015 December with the estimated number of users remained fixed at 180,000 as reported by JPS.

Licence Requirement for System Losses

According to Schedule 3, paragraph 37 of the New Licence, the Office shall have the power to set targets for JPS' losses which should be reasonable and achievable taking into consideration the Base Year, historical performance and agreed resources included in the five (5) Year Business Plan, corrected for extraordinary events.

As set out in the New Licence, the rolling nature assures a clear long term focus for loss mitigation, incentivizing JPS to go beyond what might have been agreed in the five year

Business Plan, because the benefit will be accrued over a longer period. Schedule 3 of the New Licence also states that the breakdown of the elements of the loss target will assure a linkage to the reductions targeted and the actions taken and/or funded in the 5 year Business Plan. It also supports a potential "Z-Factor" adjustment in case the non-technical losses that are not totally within JPS' control are strongly influenced by matters unforeseen during the rate review process.

Specifically, with respect to the setting of targets for JPS' Systems losses by the Office, Schedule 3, paragraph 38 of the New Licence, provides as follows:

> *"The target set by the Office for losses shall normally be done at the Rate Review and be for a "rolling"[1] ten (10) year period broken out year by year over the following three (3) categories:*
>
> *a. Technical Losses;*
>
> *b. The aspect of non-technical losses that are within the control of the Licensee; and*
>
> *c. The aspect of the non-technical losses that are not totally within the control of the Licensee."*

Technical Losses (TL)

In the operation of an electric utility system, technical losses will always arise due to the physics of electricity transport. In that regard, there is an optimal technical losses level at which a particular electric utility should operate. However, there is no absolute optimal level of technical losses, as this is essentially a trade between the costs of the capacity and energy to supply the technical losses, versus the capital costs of the network infrastructure to reduce them.

Essentially, the level of technical losses incurred tend to depend on the configuration and characteristics of the System, such as geography, customer density, electrical plant and equipment, T&D voltage levels, System utilization and load factor, and importantly the way the System is managed.

To induce greater efficiency in the operation of the T&D network and supply to customers, one of the main objectives should be the drive to achieve the optimal level of technical losses that is economically justified for the System. This can be accomplished by the implementation of a credible and feasible technical loss reduction programme with a glide path for reduction over a designated period.

JPS' Proposed Technical losses Target

In its' Submission, JPS proposed a technical losses target of 8.4% of net generation.

JPS argued that its 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. However, it was indicated by JPS in its 2014 - 2019 Tariff Application that this level of technical losses was based on a revision in 2014 January consistent with recommendations from KEMA presented to it in 2013 June.

JPS further argued that it 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.

JPS also posited that its two main technical loss reduction initiatives are:

- primary distribution feeder power factor correction
- primary distribution feeder phase balancing

In the Submission, JPS presented its Annual Loss Reduction Plan for 2016, which projected an overall annual reduction in technical losses of 0.08% with 0.06% due to power factor correction and 0.02% from phase balancing activities. The specific initiatives directed at reduction technical losses is shown in Figure 4.5 below.

Figure 4.5: JPS' Technical Losses Reduction 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)
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

Source: JPS 2016 Annual Tariff Adjustment Filing

OUR's Evaluation of JPS' Technical Losses Proposal

Based on the legal and regulatory provisions, the New Licence requires the Office to set the targets for JPS' losses in accordance with the provisions of Schedule 3 of the said New Licence. The Rate Review regime as defined by the New Licence with the required inputs and components as a matter of practicality is however in transition. In the circumstances, the OUR considers reasonable and prudent to address the technical losses target at each Annual Tariff Adjustments within a transitional framework up to the next Rate Review having full regard to the 2014 - 2019 Tariff Determination Notice.

According to JPS' 2015 December Energy Loss Spectrum, technical losses accounted for 8.6% of net generation. The constituents of these losses and their respective proportions are represented as follows:

- JPS Transmission Network TL – 2.6%

- JPS Primary Distribution Lines TL – 1.8%
- JPS Distribution Transformers TL – 1.3%
- JPS Secondary Distribution Lines TL – 2.9%

For technical losses on JPS' transmission network, the OUR is of the view that based on the configuration of the network, the estimated losses of 2.6% may not be representative. JPS is encouraged to employ feasible approaches to investigate the optimality of the power flows in the transmission network to ascertain the true level of technical losses resulting from this segment of the System.

In JPS' 2014 - 2019 Tariff Application, the company presented its 5 Year Loss Reduction Plan for both technical and non-technical losses from 2014 to 2018. The details of the referenced plan is shown in Figure 4.6.

Figure 4.6: Summary of JPS' 5 Year Loss Reduction Program in its 2014-2019 Rate Case Application

Category	Initiatives	2014	2015	2016	2017	2018	Total
Illegal (Users) Non-customers	Strike Force, RAMI, CAAMI, Community Renewal Program	0.14%	0.25%	0.43%	0.43%	0.43%	**1.68%**
Residential	Field Audit	0.13%	0.15%	0.10%	0.10%	0.10%	**0.58%**
Small Commercial	Field Audit	0.07%	0.07%	0.10%	0.10%	0.10%	**0.44%**
Large Commercial & Industrial	Field Audit	0.24%	0.10%	0.10%	0.10%	0.10%	**0.64%**
Technical Energy Loss	Feeder PF & PB, S/s Capacitor Banks, Secondary Rehabilitation.	0.18%	0.23%	0.24%	0.15%	0.10%	**0.90%**
Targeted Feeder Energy Balance Sol.	RAMI, CAAMI, Field Audit & Aggregate meters	0.33%	0.50%	0.60%	0.70%	0.80%	**2.93%**
Impact on Losses		**1.09%**	**1.30%**	**1.57%**	**1.58%**	**1.63%**	**7.17%**

Source: JPS 2014-2019 Rate Case Application

Based on JPS' proposed loss reduction initiatives, it was expected that technical losses would be reduced by 0.18% at the end of 2014 and by 0.23% at the end of 2015. In its Submission, JPS also estimated that US$0.85 Million of Capex would be required to finance the proposed technical losses reduction initiatives in 2014 while US$3.1 Million would be required for 2015. Notably, these loss reduction programmes were expected to be supported by the EEIF which was extended by the Office in the 2014 - 2019 Determination Notice. The breakdown of JPS' 5 year loss reduction programme submitted in 2014 is shown in Figure 4.7.

Figure 4.7: Breakdown of JPS' 5 Year Loss Reduction Programme - 2014-2019 Rate Case Application

		2014		2015		2016		2017		2018		TOTAL	
	Program	Impact	Capex	Impact	Capex	Impact	Capex	Impact	Capex	Impact	Capex	Impact	Capex
		%	US$M	%	US$M	%	US$M	%	US$M	%	US$M	%	US$M
Illegal (Users) Non-Customers	Theft Resistant CAMI (CAAMI)	0.04%	0.5	0.10%	1	0.10%	1	0.10%	1	0.10%	1	0.44%	4.5
	Residential Anti-Theft AMI System	0.10%	0.5	0.10%	0.3	0.15%	0.3	0.15%	0.4	0.15%	0.6	0.65%	2.1
	Community Renewal Program	0.00%	1	0.05%	1	0.18%	1	0.18%	1	0.18%	1	0.59%	5
Residential	Auditing of Rate 10 Customers	0.13%	0.24	0.15%	0.24	0.10%	0.26	0.10%	0.29	0.10%	0.32	0.58%	1.35
Small Commercial	Auditing of Small Commercial Customers	0.07%	0.12	0.07%	0.12	0.10%	0.12	0.10%	0.12	0.10%	0.12	0.44%	0.6
Large C&I	Large Account Audit	0.24%	0.05	0.10%	0.1	0.10%	0.11	0.10%	0.11	0.10%	0.12	0.64%	0.49
Technical Energy Loss	Feeder Phase Balancing	0.03%	0	0.03%	0	0.04%	1	0.05%	1	0.00%	0	0.15%	2
	Distribution Feeder P F Correction	0.10%	0.25	0.10%	0.3	0.10%	0.05	0.00%	0.05	0.00%	0.1	0.30%	0.75
	Secondary Rehabilitation	0.00%	0	0.05%	2.5	0.05%	2.5	0.05%	2.5	0.05%	2.5	0.20%	10
	Substation VAR Management	0.05%	0.6	0.05%	0.3	0.05%	0.3	0.05%	0.3	0.05%	0.3	0.25%	1.8
Targeted Feeder Energy Balance Solution	Sub-feeder & aggregate transformer Energy Balance Metering	0.00%	1.8	0.00%	2.5	0.00%	3	0.00%	3	0.00%	3	0.00%	13.3
	New CAAMI Installation	0.06%	3.5	0.15%	3	0.20%	3	0.20%	3	0.20%	3	0.81%	15.5
	New RAMI Installation	0.27%	7	0.35%	7	0.40%	7	0.50%	7	0.60%	7	2.12%	35
Total impact on Losses		1.09%	15.56	1.30%	18.36	1.57%	19.64	1.58%	19.77	1.63%	19.06	7.17%	92.39

Since the effective date of the 2014 - 2019 Determination Notice, January 2015, it would be logical to expect that the loss reduction proposals for each year in the plan would be pushed forward to the following year. Therefore, on that basis, the expectation was that by the end of 2015, the implementation of the proposed loss reduction programmes would result in a reduction of technical losses by approximately 0.18%. Nevertheless, no reduction in JPS' technical losses was reported for 2015 and up to the first quarter of 2016.

This was confirmed from the Quarterly EEIF reports for 2015 and the first Quarter of 2016 which indicated that there was limited intervention by JPS in addressing technical losses over the stated period. Evidence of JPS' EEIF loss reduction expenditure for 2015 and first Quarter 2016 is provided in Table 4.13 and Figure 4.8 below.

Table 4.13: JPS' EEIF Loss Reduction Expenditure for 2015

BUDGET VS. ACTUAL EXPENDITURE – LOSS REDUCTION			
	TOTAL (US$'000)		
	Budget	Actual	Variance
QUARTER ENDING MARCH 2015			
CAPITAL EXPENDITURE			
AMI Systems	770	102	668
Community Renewal Program	160	-	160
RAMI & CAAMI Development	160	-	160
RAMI & CAAMI Maintenance	50	-	50
Technical Loss Reduction Projects	140	-	140
Theft Resistant Distribution Network/ Meter Centres	662	896	(234)
TOTAL CAPITAL EXPENDITURE	**1,942**	**997**	**945**
QUARTER ENDING JUNE 2015			
CAPITAL EXPENDITURE			
AMI Systems	1,642	540	1,102
Community Renewal Program	240	90	150
RAMI & CAAMI Development	160	2	158
RAMI & CAAMI Maintenance	50	12	38
Technical Loss Reduction Projects	210	27	183
Theft Resistant Distribution Network/ Meter Centres	706	546	160
TOTAL CAPITAL EXPENDITURE	**3,008**	**1,218**	**1,791**
QUARTER ENDING SEPTEMBER 2015			
CAPITAL EXPENDITURE			
AMI Systems	1,646	1,503	144
Community Renewal Program	240	50	190
RAMI & CAAMI Development	-	14	(14)
RAMI & CAAMI Maintenance	50	19	31
Technical Loss Reduction Projects	210	12	198
Theft Resistant Distribution Network/ Meter Centres	277	188	89
TOTAL CAPITAL EXPENDITURE	**2,423**	**1,785**	**638**
QUARTER ENDING DECEMBER 2015			
CAPITAL EXPENDITURE			
AMI Systems	841	1,332	(490)
Community Renewal Program	160	168	(8)
RAMI & CAAMI Development	-	10	(10)
RAMI & CAAMI Maintenance	50	42	8
Technical Loss Reduction Projects	-	36	(36)
Theft Resistant Distribution Network/ Meter Centres	135	467	(332)
TOTAL CAPITAL EXPENDITURE	**1,186**	**2,053**	**(867)**

Source: JPS 2015 EEIF Quarterly Reports

As shown, in Table 4.13 above, in 2015, a total of US$560,000 from the EEIF was allocated by JPS for expenditure on technical loss reduction projects. However, as indicated, only US$75,000 was utilized during the year. This suggests that in 2015, there were limited efforts expended by JPS in addressing technical losses.

Figure 4.8: JPS' EEIF Loss Reduction Expenditure for January – March 2016

Budget vs. Actual Expenditure - Loss Reduction Quarter Ending March 2016 US$'000	Total		
	Budget	Actual	Variance
CAPITAL EXPENDITURE			
AMI Systems	650	69	581
Community Renewal Program	300	-	300
RAMI & CAAMI Development	40	-	40
RAMI & CAAMI Maintenance	113	103	10
Technical Loss Reduction Projects	10	-	10
Theft Resistant Distribution Network/Meter Centres	40	-	40
TOTAL CAPITAL EXPENDITURE	**1,153**	**171**	**982**

Source: JPS 2016 EEIF First Quarter Report

As shown, in Figure 4.8 above, US$10,000 from the EEIF was allocated by JPS for expenditure on technical loss reduction projects during the first quarter of 2016. However, similar to the situation in 2015, it was reported that none of the funds was utilized for the designated purpose. This implies that little or no technical loss reduction activities were undertaken during the stated period. This brings into question JPS' approach to addressing its technical losses.

OUR's Determination on JPS' Technical Losses Target

Based on the expected reduction in JPS' technical energy losses of 0.23% for 2015 and the company's proposed technical loss reduction initiatives and commensurate impact of 0.08% for 2016, the OUR determined that the technical losses target to be applicable for the 2016/2017 rate adjustment period shall be reduced from the existing target of 8.4% to 8.2% of net generation.

Table 4.14: Determination on JPS' Technical Losses Target

ASPECT OF SYSTEM LOSSES	OUR TARGET
JPS Technical Losses	8.2%

JPS Non-Technical Losses

In JPS' Submission, the company indicated that the portion of non-technical losses that are within its control and those that are not totally within its control were estimated to be 4.38% and 14.0% respectively. Refer to Figure 4.9 below.

Figure 4.9: JPS Apportionment of Non-Technical Losses

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%

According to JPS, JNTL represented NTL that are within its control while GNTL represented NTL that are not totally within its control.

JPS' proposed targets for JNTL and GNTL are shown in Figure 4.10 below.

Figure 4.10: JPS Proposed NTL Targets

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%

OUR's Evaluation of JPS' Non-Technical Losses Proposals

For JPS' non-technical losses, the OUR's evaluation focused on the categories of energy losses represented in JPS' 2015 December Energy Loss Spectrum.

<u>Losses Associated with Streetlight/Stoplight/Interchange (Rate 60)</u>

According to JPS' December 2015 Energy Loss Spectrum, in 2015, the Streetlight/Stoplight/Interchange Rate Category (Rate 60) contributed 0.09% to System losses. This represented a reduction of 55% from the reported 2014 December loss level of 0.20%.

In its Submission, JPS stated that the Ministry of Local Government (MLG) in conjunction with JPS executed a joint streetlight audit, in 2013, which showed that there were 9,150 streetlights that at the time were not being billed by JPS. JPS further stated that subsequent to the audit, the MLG without any empirical evidence suggested that up to 25% of the street lights being billed by JPS were not working and as such, paying additional funds would be unfair.

JPS indicated that it was also concerned about the growing arrears for streetlight service which peaked with the GOJ having approximately twenty (20) months usage outstanding. According to JPS, those concerns have resulted in numerous meetings between JPS and the GOJ in an attempt to resolve the issues. JPS expressed that it has continued to work with the MLG to resolve the matter, and is confident that it will come to an agreement with the MLG on the billing of all operational street lights by 2016 July. In that regard, JPS stated that it will take full responsibility for Rate 60 related losses.

Consequently, this category of NTL will not be factored into the respective targets for NTL.

Losses Associated with Large C&I (Rate 40 & 50) Customers

According to JPS' 2015 December Energy Loss Spectrum, in 2015, there were 1,913 large C&I (Rate 40 & 50) customers in its total customer base which contributed 0.45% to System losses in 2015. The company indicated that the sources of losses in this rate category and the contribution of each source was obtained from information gathered from the annual audits that it conducted on these meters.

JPS posited that the losses incurred by this group of customers are not totally within its control given the clear evidence of meter tampering in some cases. JPS also noted that although these customers are equipped with AMI meters, they continue to display great ingenuity in finding new methods of tampering.

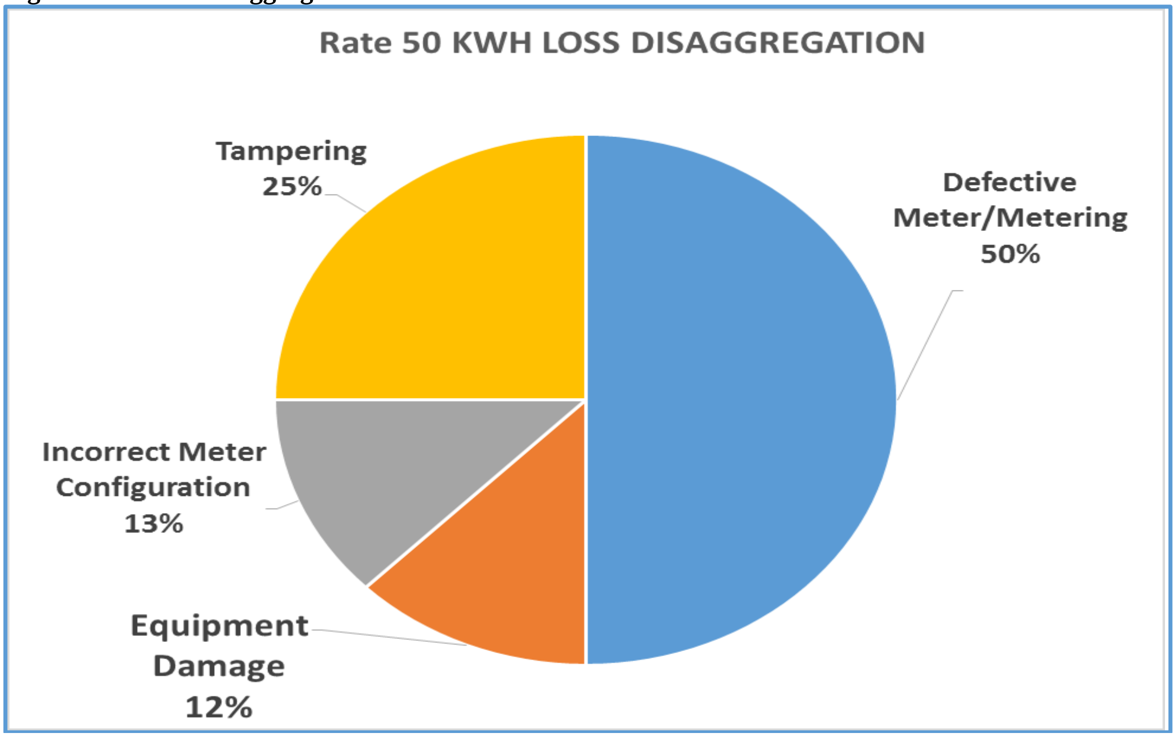
Based on JPS' energy loss disaggregation for this category, the reported losses appeared to have been incurred from the following causes:

- Defective Meter/Metering
- Equipment Damage
- Incorrect Meter Configuration/Inefficiencies
- Meter Tampering
- Electronic Tampering

Based on System losses information submitted to the OUR by JPS, the nature of electronic tampering involves entry into the meter program and changing parameters or values to misrepresent and mislead the utility about the actual energy consumed in the billing period.

The disaggregation of NTL attributed to JPS' Rate 40 and Rate 50 customers are shown in Figures 4.11 and 4.12 below respectively.

Figure 4.11: JPS Disaggregation of Rate 50 Losses

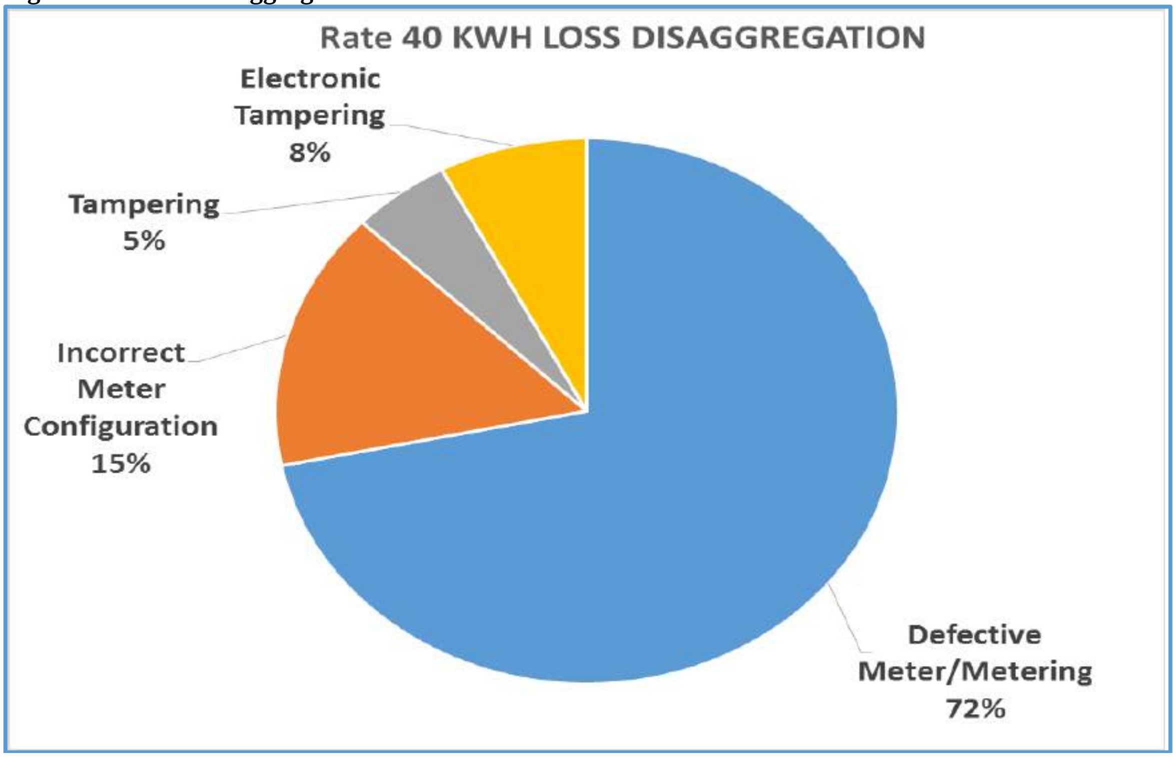


As illustrated in Figures 4.11 and 4.12 a significant portion of the losses the Rate 40 & 50 category is due to JPS' metering infrastructure related issues. This evidence suggest that these sources and causes of NTL are within the total control of JPS. This position was corroborated by JPS at page 21 of its Submission regarding a description of Rates 40 and 50 meters as distinct from Rates 10 and 20 meters, which states as follows:

"…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…"

This represents a clear indication from JPS that it recognizes its responsibility regarding metering facilities of its Rate 40 & 50 customers.

Figure 4.12: JPS Disaggregation of Rate 40 Losses



According to JPS, Large C&I (Rate 40 & 50) customers represent 0.3% of its total customer base and contribute to 45% of annual electricity sales. In that regard, JPS indicated that priority is given to these Rate categories, which is evident through investments in the application of Advanced Metering Infrastructure (AMI) for the automation of meter reading and theft detection. AMI technology provides JPS with immense capability and functionalities to monitor in real time the supplied energy and power parameters of its large C&I customers. JPS in its Submission has also underscored the significance of its Rate 40 & 50 customers to its operation.

While the deployment of AMI gives JPS tremendous reach, visibility and flexibility in the monitoring and control of its large C&I customers' accounts, the importance of these accounts to the company's annual sales and revenue would dictate that this remote monitoring functionality must be complemented with periodic audits, inspection and testing to ensure that energy loss or leakage in this customer category is minimized or kept at zero.

On the matter of account/meter audits, while JPS under the New Licence is required to test 50% of Rate 40 and 50 meters annually (Refer to Figure 4.13 below), the company has reported that as part of its routine operation, 100% of Rate 40 and 50 customers' metering facilities are being investigated annually.

Figure 4.13: Licence Requirement for JPS to Test its Rate 40 & 50 Meters

SCHEDULE 2
OVERALL STANDARDS

CODE	STANDARD	UNITS	TARGETS JULY 2014 – MAY 2019
EOS7 (a)	Frequency of meter testing	Percentage of rates 40 and 50 meters tested for accuracy annually	50%
EOS7 (b)	Frequency of meter testing	Percentage of other rate categories of customer meters tested for accuracy annually	7.5%

Based on System losses information submitted to the OUR by JPS, the company conducted audits on Rate 50 and Rate 40 services in 2015 totalling 1913 audits. According to JPS, from the 1913 audits, eight (8) Rate 50 services and thrity-nine (39) rate 40 services were found with loss impacting irregularities ranging from defective metering, incorrect meter configuration, tampering and electronic tampering as illustrated in Figures 4.11 and 4.12 above.

As shown in Figure 4.12, losses due to large C&I customers (Rate 40&50) as at 2014 January was reported at 1.19% of net generation and by 2014 December it was reported at 0.75%. Subsequently, in 2015 December these losses were reported to be 0.45%.

In the Submission, JPS proffer to assign two thirds of the losses related to its Rate 40 & 50 customer class to the category of losses it has control over, arguing that this is reasonable given the prevalence of tampering. The OUR does not accept this proposal and rationale on the basis that:

- All the energy loss impacting irregularities associated with Large C&I customers (Rates 40 & 50) identified by JPS in Figures 4.11 and 4.12 are considered to be totally within the control of the company;

- The number of customers/meters are relatively small compared to the total customer base and therefore should not impose insurmountable challenges for ongoing monitoring;

- The meters are read monthly, therefore it should be easier to detect some irregularities and apply the necessary adjustments on timely basis;

- All of the Rates 40 & 50 accounts are equipped with AMI with real-time monitoring and theft detection functionalities, which provide the company sufficient reach and capability to monitor these accounts;

- The disaggregation of NTL due to these Rate classes indicates that JPS is fully aware of all the elements of the losses and has the capability to detect the irregularities at the instant they occur which is provides an advantage to address these losses; and

- The sources of the losses in these Rate classes suggest that the cost of the energy losses can be recovered by way of adjustments in accordance with the "Back Billing Policy" or through other means outside of the price control mechanism.

Having regard to these factors and given the importance of these accounts to JPS' annual revenue, the company should be focused on bringing these losses to zero. As such, the OUR determined that JPS shall be responsible for 100% of these losses.

Losses Associated with Medium C&I (Rate 20) Customers

According to JPS' December 2015 Energy Loss Spectrum, in 2015, there were 4,061 Medium C&I (Rate 20) customers in its total customer base which contributed 0.31% to System losses.

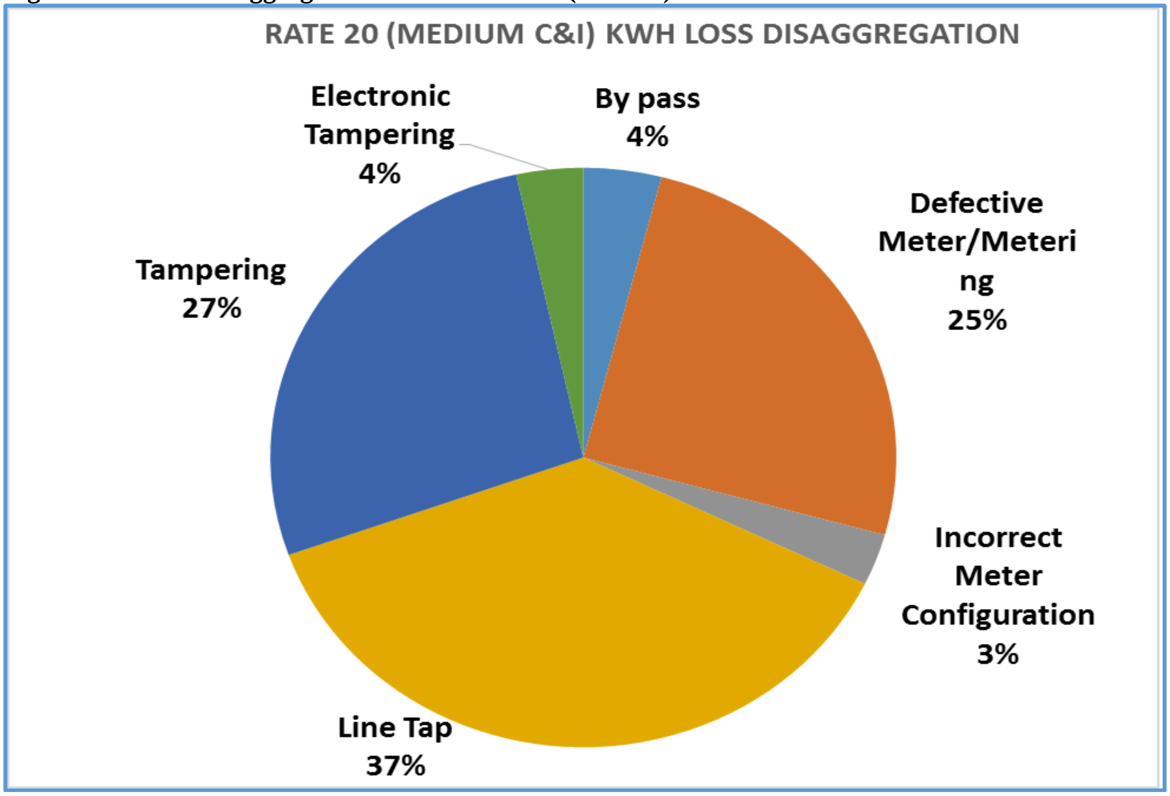
JPS also indicated that, similar to the Rate 40 & Rate 50 customers, the large Rate 20 customers are equipped with smart meters which are audited annually. The results from the audit show that 37% of the irregularities found were "Line Tap". JPS further indicated that the line taps are due to the pervasive 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 posited that customers' are cunningly devising ways to abstract electricity using methods and means that are uncommon and difficult to detect.

Based on JPS' disaggregation of this category of losses into sources and proportions, the reported losses are incurred from the following causes:

- Defective Meter/Metering
- Incorrect Meter Configuration
- Line Tap
- Tampering
- Electronic Tampering
- By-Pass

The disaggregation of NTL by JPS for the Medium C&I (Rate 20) customer category is shown in Figure 4.14 below.

Figure 4.14: JPS Disaggregation of Medium C&I (Rate 20) Losses



According to JPS, in addition to the Rate 40 & Rate 50 AMIs, a further 4,000 Rate 20 customers utilizing greater than 3MWh per month are now equipped with AMI smart meters. JPS also indicated that it 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 3 MWh annually.

In its Submission, JPS indicated that it believed that the responsibility factor related to this customer class should be the product of consultation with the OUR given the various factors that the New Licence require to be taken into consideration in deriving the factor.

In conformance with the New Licence, consultations were held between JPS and the OUR which sought to address the situation influencing these losses. The OUR considers that as it relates to the responsibility factor for this NTL category, JPS' loss disaggregation shown in Figure 4.14 above, provides a basis for the allocation of responsibility.

As illustrated in Figure 4.14 above, 37% of the losses due to medium C&I customers was caused by Line Tap. Within the generality of electrical connections, a Line Tap could be referred to as a situation in which there is an illegal connection to an electric utility's power supply to a customer's electrical installation in the vicinity of the pothead; or connection point that results in energy not being registered on the meter; or there is no meter at all to register this energy consumption. Additionally, the orientation of a Line Tap bear some common features to an illegal throw-up to the utility's secondary distribution network.

Based on the sources and distribution of the losses in medium C&I (Rate 20) category, it was considered that with the exception of the NTL due to Line Tap, all the other identified sources and causes are directly within the control of JPS. The OUR is also of the view that these losses are not impossible to control due to the following reasons:

- The number of customers/meters are relatively small compared to the total customer base and therefore should not impose insurmountable challenges for ongoing monitoring;

- Most, if not all of the Medium C&I (Rate 20) accounts are equipped with AMI with real-time monitoring and theft detection functionalities, which provide the company sufficient reach and capability to monitor these accounts;

- The meters are read monthly, therefore it should be easier to detect some irregularities and apply the necessary adjustments on timely basis;

- The disaggregation of the losses in the Rate class indicates that the company is fully aware of all the elements of the losses or has the capability to detect the irregularities when they occur, which provides an advantage to address these losses; and

- The sources of the losses in these Rate classes suggest that the cost of the energy losses can be recovered by of adjustments in accordance with the "Back Billing Policy" or through other means outside the price control mechanism.

Accordingly, the OUR determined that 63% of NTL in the Rate 20 customer class are directly within the control of JPS while 37% are considered to be not totally within its control.

Losses Associated with Small C&I (Rate 20) Customers

According to JPS' December 2015 Energy Loss Spectrum, in 2015, there were 56,530 Small C&I (Rate 20) customers in its total customer base which contributed 0.32% to System losses.

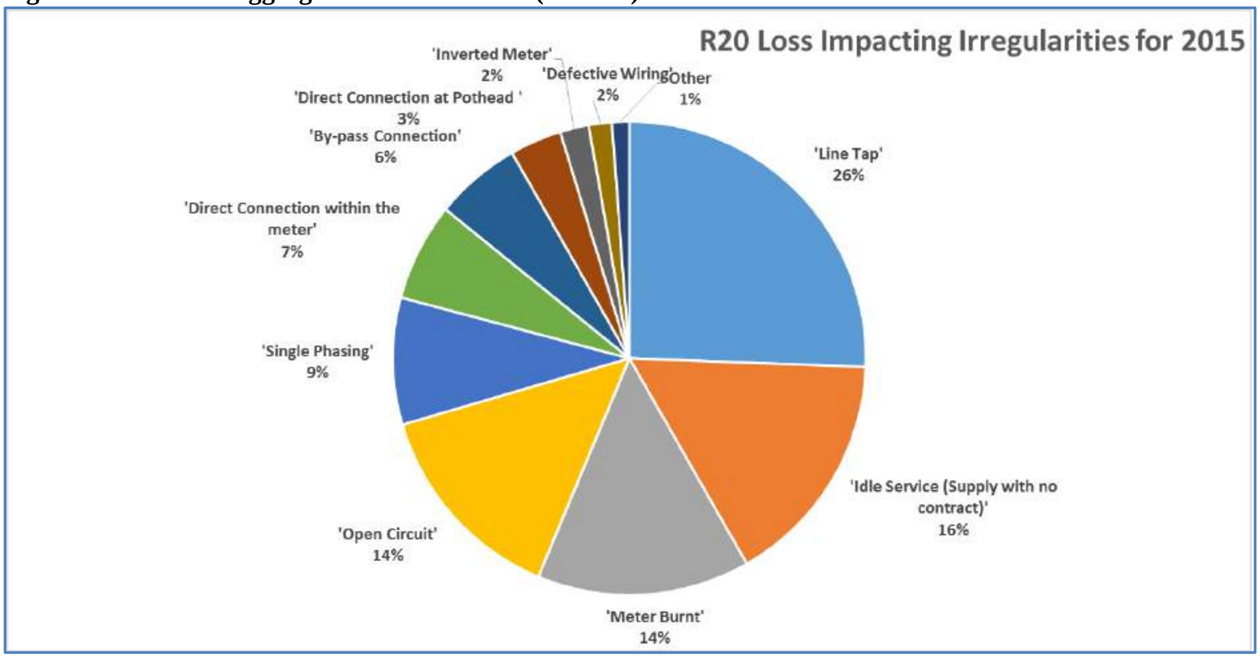
Based on JPS' disaggregation of this category of losses into sources and proportions, the reported losses are incurred from the following causes:

- Idle Service (Supply with no contract)
- Burnt Meter
- Open Circuit
- Single Phasing
- Direct Connection within the meter
- By-Pass Connection
- Direct connection at Pothead

- Inverted Meter
- Defective Wiring
- Other

The disaggregation of NTL by JPS for the Small C&I (Rate 20) customer category is shown in Figure 4.15 below.

Figure 4.15: JPS Disaggregation of Small C&I (Rate 20) Losses



In its Submission and in consultation meeting with the OUR, JPS contends that only 30% of the losses attributed to Small C&I (Rate 20) customers are totally within the control of JPS. The OUR disagrees with that position on the basis that most of the sources of losses identified by JPS for this category involve issues related to JPS metering facilities and electricity supply/connection to the customers.

As shown in Figure 4.15 above, with the exception of the losses due to Line Tap and Direct Connection at Pothead, all the other sources and causes are directly within the control of JPS.

JPS also emphasized that the meter socket used for 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 these sockets are maintained and kept in good working order. JPS also expressed that its responsibility in the case of this customer class stops at the pothead. JPS further stated that all other infrastructural work to be done on the customer's premises is the responsibility of the customer.

Additionally, JPS indicated that where its audits and investigations reveal loss impacting defects with customer owned infrastructure, the losses are attributed to the customers.

Regarding the positions proffered by JPS, it is important to underscore that JPS under its New Licence has an obligation to serve customers. This responsibility obligates JPS to install the appropriate connection facilities to ensure that electricity supply to the customers is safe and reliable. It is acknowledged that the customers' electrical installation (certified by GEI) required to accommodate electricity service from JPS is the responsibility of the customer. However, once electricity supply is provided to the customer and a JPS meter is place, the customer is not authorized to have any access to the electrical connection at the connection point or the meter/meter socket at the metering point.

Under such conditions, losses emanating from defects associated with a customer's owned electrical infrastructure, should be administered within the established framework to address the correction of meter socket related defects, wiring issues, etc., and billing adjustments as applicable. In such cases, reference should be made directly to specific customer(s) affected and not to the entire customer base, as JPS appeared to have suggested in its Submission.

Notably as well, a significant portion of the causal conditions of the NTL due to this Rate category are recognized in the "Back Billing Policy" with the appropriate regulatory treatment.

Having regard to these considerations pertaining to losses attributed to Small C&I (Rate 20) customers, the OUR determined that that 70% of NTL in this category are directly within the control of JPS while 30% are considered to be not totally within its control.

Losses Associated with Residential (Rate 10) Customers

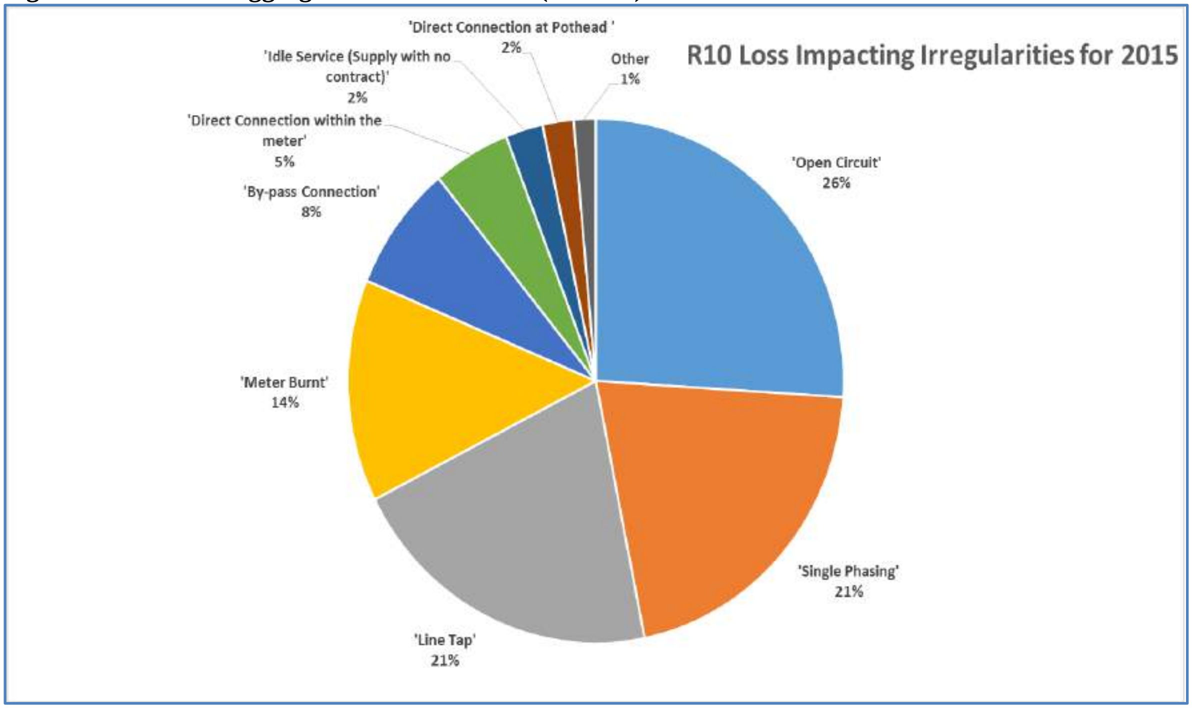
According to JPS' December 2015 Energy Loss Spectrum, in 2015, there were 533,705 Residential (Rate 10) customers in its total customer base which contributed 7.08% to System losses in 2015.

Based on JPS' disaggregation of this category of losses into sources and proportions, the reported losses are incurred from the following causes:

- Open Circuit
- Single Phasing
- Line Tap
- Meter Burnt
- By-Pass Connection
- Direct Connection Within the Meter
- Idle Service (Supply with no Contract)
- Direct connection at Pothead
- Other

The disaggregation of NTL by JPS for the Residential (Rate 10) customer category is shown in Figure 4.16 below.

Figure 4.16: JPS Disaggregation of Residential (Rate 10) Losses



According to JPS, only 39% of the NTL attributed to Residential (Rate 10) customers are totally within the control of JPS. However, the OUR disagrees with that position on the basis that most of the sources of losses identified by JPS for this category involve issues related to JPS metering facilities and electricity supply/connection to the customers.

As shown in Figure 4.16 above, with the exception of the losses due to Line Tap, Direct connection, all the other sources and causes are directly within the control of JPS.

JPS also emphasized that the meter socket used for Residential (Rate 10) customers utilizing under 100 and 200 amperes respectively, are not owned by JPS, and it is the responsibility of the customer to ensure that these sockets are maintained and kept in good working order. JPS also expressed that its responsibility in the case of these customer classes stops at the pothead. JPS further stated that all other infrastructural work to be done on the customer's premises is the responsibility of the customer.

Regarding the positions proffered by JPS, the OUR reiterate that under its New Licence, JPS has an obligation serve customers. This responsibility obligates JPS to install the appropriate connection facilities to ensure that electricity supply to the customers is safe and reliable. This is notwithstanding the fact that the customers' electrical installation (certified by GEI) required to accommodate electricity service from JPS is the responsibility of the customer. As previously noted, once electricity supply is provided to the customer and a JPS meter is place, the customer is not authorized to have any access to the electrical connection at the connection point or the meter/meter socket at the metering point.

Therefore, under such conditions, losses emanating from defects associated with a customer's owned electrical infrastructure, should be administered within the established framework to address the correction of meter socket related defects, wiring issues, etc., and billing adjustments as applicable. In such cases, reference should be made directly to specific customer(s) affected and not to the entire customer base as JPS appeared to argue in its Submission.

It is also relevant that a significant portion of the causal conditions of the NTL due to this Rate category are recognized in the "Back Billing Policy" with the appropriate regulatory treatment.

The OUR also notes however, that the large number of residential customers in JPS' total customers base, the limited used of Automated Metering systems, and limited capability to monitor these accounts, present a greater challenge to control these losses. As such, greater consideration was given to this category in the determination of the target for NTL that are considered to be within JPS' control. Having regard to these considerations pertaining to losses attributed to Small C&I (Rate 20) customers, the OUR determined that 76% of NTL in this category are directly within the control of JPS while 26% are considered to be not totally within its control.

Internal Bleeds/Unquantified Losses

In its Submission, JPS indicated that in 2015, Internal Bleeds/Unquantified losses accounted for 0.53% percent of net generation.

According to JPS, this category of NTL represents any losses incurred due to the company's own internal operations as well as any margin of error within its System losses estimates.

JPS posited that it will 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.

Consequently, the reported 0.53% of NTL due to "Internal Bleeds/Unquantified" will not be factored into the targets for JPS non-technical losses.

Non-Technical Losses due to Illegal Users

In its Submission, JPS indicated that in 2015, there were an estimated 180,000 Illegal Users connected to its electricity network who contributed 9.60% to System losses in 2015.

JPS asserted that system losses associated with illegal users is mainly due to socioeconomic conditions which are largely outside of the purview of the electric utility. The company contends that Data from the 2011 Census conducted by STATIN 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. JPS also indicated that it recognized that a segment of the population resides in tenement housing facilities and therefore it cannot say definitively, without further information, that all 200,000 households are illegally connected. JPS claims its conservative assessment indicates that there are approximately 180,000 illegal consumers.

JPS also posited 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 outside of JPS control.

Notwithstanding, the OUR maintains the view that all aspects of the System losses are largely within the control of JPS, although some elements may be more difficult to control. Nonetheless, based on the provisions of the New Licence, the OUR is required to give consideration to NTL that are deemed to be not totally within the control of JPS. Therefore, based on the OUR's evaluation and analysis, the indication is that approximately 80% may be due to the conditions that JPS have highlighted.

OUR's Determination on JPS' Non-Technical Losses (NTL) Proposal

Based on the evaluation of JPS' non-technical losses, the OUR estimated that:

- Non-technical losses of 6.87% of net generation are within the control of JPS
- Non-technical losses of 11.51% of net generation are not totally within the control of JPS

Table 4.15: JPS Computed NTL

Loss Category	Components	December 2015 Losses	JNTL	GNTL
Non-Technical Losses	Streetlight/Stoplight (Rate 60)	0.09%	0.09%	0.00%
	Large C&I (Rate 40&50)	0.45%	0.37%	0.08%
	Medium C&I (Rate 20)	0.31%	0.21%	0.10%
	Small C&I (Rate 20)	0.32%	0.10%	0.21%
	Residential (Rate 10)	7.08%	3.08%	4.00%
	Internal Bleeds/Unquantified	0.53%	0.53%	0.00%
	Un-metered Households	9.60%	0.00%	9.60%
	Total Non-Technical Losses	**18.38%**	**4.38%**	**14.00%**

Based on the sources and distribution of JPS NTL in each category, the OUR's estimation of JPS' NTL which are considered to be within its control and those which are not totally within its control is provided in Table 4.16 below.

Table 4.16: OUR's Estimation of JPS' NTL

Loss Category	Components	JPS NTL at December 2015	OUR Estimated: NTL Totally within JPS Control	OUR Estimated: NTL Not Totally Within JPS Control
Non-Technical Losses	Streetlight/Stoplight (Rate 60)	0.09%	0.09%	-
	Large C&I (Rate 40&50)	0.45%	0.45%	-
	Medium C&I (Rate 20)	0.31%	0.20%	0.11%
	Small C&I (Rate 20)	0.32%	0.22%	0.10%
	Residential (Rate 10)	7.08%	5.38%	1.70%
	Internal Bleeds/Unquantified	0.53%	0.53%	-
	Un-metered Households	9.60%	0.00%	9.60%
	Total Non-Technical Losses	**18.38%**	**6.87%**	**11.51%**

Non-Technical Losses (NTL) TargetNon-Technical Losses Target

Based on the evaluation of JPS' System losses, the NTL targets determined by the OUR are given in Table 4.17 below.

Responsibility Factor (RF)

According to Schedule 3 of the New Licence, one of the components of the System losses factor to be included in the revenue surcharge for each year, will be dependent on a responsibility factor, denoted as RF.
As defined in Schedule 3 of the New Licence, RF is the responsibility factor determined by the Office, which is a percentage from 0% to 100%. The RF shall be determined by the Office, in consultation with JPS, having regard to (i) nature and root cause of losses; (ii) roles of JPS and the Government to reduce losses; (iii) actions that were supposed to be undertaken and resources to be allocated in the Business Plan; (iv) actual actions undertaken by the resources spent by JPS; (v) actual cooperation by the Government; and (vi) change in external environment that affected losses.

Based on: the OUR's review and evaluation JPS' System losses situation including causes, distribution and allocation (as discussed under losses above); the proposed Loss Reduction programmes and initiatives indicated by JPS; and the allowance of 50% of the existing amount of the EEIF; the OUR has determined as a starting point, a responsibility factor (RF) for JPS for non-technical losses not totally within its control of **20%.**

Summary of the OUR's Determination of JPS' Non-Technical Losses Targets

Table 4.17: Determination on JPS Non-Technical Loss Target

ASPECT OF SYSTEM LOSSES	OUR Target	RF for JPS
Non-Technical Losses within JPS Control	**3.5%**	
Non-Technical Losses not totally within JPS Control	**9.8%**	**20%**

The OUR's Determination on JPS' System Losses Proposals is summarised as follows:

DETERMINATION

Technical Losses

- The Technical Losses Target to be applied at the 2017 Annual Tariff Adjustment shall be **8.2%.**

Non-Technical Losses

- The Target for Non-Technical Losses that are within the control of JPS to be applied at the 2017 Annual Tariff Adjustment shall be **3.5%**.

- The Target for Non-Technical Losses that are not totally within the control of JPS to be applied at the 2017 Annual Tariff Adjustment shall be **9.8%.**

Responsibility Factor (RF) for Non-Technical Losses

- The RF applicable to JPS for Non-Technical Losses that are not totally within its control to be applied at the 2017 Annual Tariff Adjustment shall be **20%**.

4.6. The Electricity Efficiency Improvement Fund (EEIF)

The Office in the 2009 - 2014 Determination Notice directed JPS to establish the EEIF to finance OUR endorsed system losses projects and to the company's efforts to reduce system losses. In the 2014 -2019 Determination Notice, the Office saw the even more urgent need for efficiency improvement measures in the overall electricity system, which it stated could ultimately lead to a reduction in the average price of electricity to customers. Accordingly, the Office approved the continuation of the EEIF. It was also stated that the fund is subject to review by the Office at each Annual Tariff Adjustments during the price cap period.

Under the price cap regime, the OUR was required to set a target for system losses in the fuel adjustment incentive mechanism which was designed to force the reduction of system losses. However, the New Licence has removed system losses from the Fuel Cost Adjustment Mechanism (FCAM) which is to be implemented as of 2016 July 1.

In its Submission, JPS recognised the effect of the removal of system losses from the FCAM and stated that the impact would be a 4.1% increase in fuel tariffs. In respect of the EEIF, JPS proposed that it should remain at J$0.4998/kWh for all rate classes so as to ameliorate the effect of the 4.1% increase in fuel tariffs. The EEIF normally would be subjected to the annual adjustments.

The OUR, as previously discussed, has expressed reservations regarding the effect of the EEIF on losses over the period of its existence and has indicated to JPS that it is minded to discontinue the programme. JPS has in turn emphasized the investments it has undertaken and proposes to undertake under the EEIF. In post-submission discussions and written correspondence, JPS has also argued that what it envisaged would be a gradual reduction of the EEIF with some minimum retained to fund specific loss management projects. The company also asserted that the EEIF is represented in its budget and therefore any sudden cessation would be potentially disruptive.

The Office's position however is that given the provisions of the New Licence, JPS is no longer exposed to the kind of financial risk on fuel that would result from the company not achieving a system losses target. The risks are now fully transferred to the customers who are now asked to bear the full fuel impact of both the TL and NTL. The significant impact of system losses is translated in the fuel cost that is passed through to customers.

Notwithstanding, the Office has taken account of JPS' arguments regarding the effect of a sudden cessation of the EEIF and also of the usefulness of having a facility that that affords it to retain some influence on loss adjustment initiatives. Given the expressed concerns regarding performance however, and the changes reflected in the New Licence, the Office has determined that as a first step, it will reduce the amount of the contribution into the EEIF by fifty percent (50%).

Additionally, with reference to the discussion on losses, the OUR is in the process of conducting an audit of the EEIF to examine the use of the EEIF by JPS and to determine the extent of its impact on loss reduction. The outcome of the audit will inform the OUR as to the way forward in relation to the EEIF. Further, as regards the inclusion of the EEIF as an item in JPS' annual budget, the OUR wishes to underscore that it has always been a condition of the EEIF that annual reviews would be undertaken to determine its continuance.

Having regard to all of the reasons set out above, the Office has determined that the EEIF funding contribution will be reduced by fifty percent (50%) as of the effective date of this Determination Notice.

DETERMINATION 4

The EEIF funding contribution is reduced by 50%.

4.7. *Z-Factor* Component of PBRM

According to Schedule 3, paragraph 46(d) of the New Licence, the Z-Factor is the allowed percentage increase in the Revenue Cap and reflects the adjustment to the non-fuel rate due to special circumstances. As seen in Schedule 3, Exhibit 1 of the New Licence, the *Z-Factor* is redefined as follows:

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

The OUR is not aware of any qualifying event and JPS did not include any adjustment for the Z-Factor in its Submission.

DETERMINATION 5

The Z-Factor applicable for this review period is 0%.

4.8. Pre-Paid Rates

4.8.1. Residential Customers Prepaid Rates (Rate 10)

Tables 4.2 and 4.3 below sets out JPS' position on Prepaid Rates. Using JPS' proposed tariffs and assuming that all residential customers migrate from post-paid to pre-paid (PAYG) metering, JPS would be revenue neutral for customers with consumption levels above 100kWh for both the two-tiered and the three-tiered structures. However, for consumption levels below 100kWh pre-paid customers would benefit in the amount on J$2.8 million/month using the two-tiered structure in comparison to J$23.9 million/month with the existing two-tiered structure. JPS stated that it stands to lose far less revenue with the three-tiered structure.

Table 4.2 Comparison of prepaid and postpaid non-fuel bills for average consumption in intervals (JPS) – Three-Tiered

Customer Bands	Customer Count	Test Year Demand	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 4.3 Comparison of prepaid and postpaid non-fuel bills for average consumption in intervals (JPS) – Two-Tiered

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)**

The OUR has no objection to JPS using the three-tiered structure for the purposes of billing its pre-paid customers providing the benefits of the life-line rates are maintained for consumption levels up to 100 kWh/month for all residential customers. In this regard, the OUR computed the pre-paid rates based on the JPS proposed three-tiered structure. Table 4.4 below shows the revenue comparisons of the prepaid and post-paid rates using the assumption that all post-paid customers migrate to pre-paid metering.

Table 4.4 Comparison of prepaid and postpaid non-fuel bills for average consumption in intervals (OUR) – Three-Tiered

Customer Bands	Customer Count	Test Year Demand (MWh)	Average Consumptio n (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	27.52	25.75	51,508,677.08	48,195,800.69	(3,312,876.39)	(39,754,516.68)
50-100 kWh	105,616	97,278	76.75	14.97	14.91	121,347,239.16	120,860,877.48	(486,361.68)	(5,836,340.16)
100-200 kWh	192,771	335,134	144.88	16.10	16.10	449,651,465.93	449,651,465.93	-	-
200-300 kWh	76,070	220,429	241.48	18.26	18.26	335,424,944.54	335,424,944.54	-	-
300-400 kWh	26,291	108,015	342.37	19.22	19.22	173,004,018.66	173,004,018.66	-	-
400-500 kWh	10,639	56,673	443.91	19.74	19.74	93,227,252.59	93,227,252.59	-	-
500- 1000 kWh	11,961	94,617	659.20	20.32	20.32	160,216,925.18	160,216,925.18	-	-
>1000 kWh	3,471	89,133	2,139.95	21.14	21.14	157,022,982.75	157,022,982.75	-	-
Total						**1,489,894,829**	**1,489,408,467**	**(3,799,238)**	**(45,590,857)**

The benefit of the lifeline rate is maintained with the prepaid metering service. A typical customer consuming 46kWh would pay approximately J$860.79 (non-fuel) using the postpaid service and J$834.50 (non-fuel) using the prepaid service.

DETERMINATION 6

The approved non-fuel pre-paid rate is as follows:

> **J$195.49/kWh for the first 2 kWh within a thirty (30) day consumption cycle**
> **J$10.08/kWh for the next 99 kWh within a thirty (30) day consumption cycle**
> **J$21.51/kWh for each additional kWh thereafter within that thirty (30)-day consumption cycle.**
>
> **The prepaid rates shall be reviewed at the next Annual Tariff Adjustment.**

4.8.2. Small Commercial Customers Prepaid Rates (Rate 20)

The pre-paid tariff for small commercial customers (Rate 20) was approved in the 2015 Annual Tariff Adjustment Determination Notice. JPS has not requested any change to the design of this tariff.

The non-fuel tariff to be charged for this service shall remain revenue neutral when compared to existing post-paid rates for Rate 20 customers. The approved non-fuel rate for Rate 20 post-paid customers were used to compute the pre-paid rates.

The rates to be charged are as follows:

First	10kWh	J$113.50/kWh
Additional	kWhs	J$17.86/kWh

The analysis of the approved rates showing revenue neutrality is illustrated in Table 4.5 below.

Table 4.5 Comparison of prepaid and postpaid non-fuel bills for average consumption in intervals – 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	61.95	61.95	13,754,067.14	13,754,067.14	-	-
(50-100] kWh	7,405	6,643	74.76	30.65	30.65	16,967,772.57	16,967,772.57	-	-
(100-1000] kWh	26,680	119,640	373.69	20.42	20.42	203,588,404.66	203,588,404.66	-	-
(1000-7500] kWh	9,279	278,824	2,504.08	18.24	18.24	423,812,935.76	423,812,935.76	-	-
>7500 kWh	1,013	203,568	16,746.30	17.92	17.92	303,994,914.05	303,994,914.05	-	-
Total						**948,364,027.04**	**948,364,027.04**	**-**	**-**

DETERMINATION 7

The approved non-fuel tariff to be charged for Rate 20 prepaid service in comparison to the existing postpaid rates shall be revenue neutral and shall be applied as follows:

First	**10kWh**	**J$113.50/kWh**
Additional	**kWhs**	**J$17.86/kWh**

The prepaid rates shall be reviewed at the next Annual Tariff Adjustment.

4.9. Community Renewal Rate (CRR)

A Community Renewal Rate (CRR) was approved by the Office in the 2015 Annual Tariff Adjustment Determination Notice in which the Office gave JPS its no objection to the methodology and design of the rate. The community renewal rate is an incentive rate for the on-boarding of participants who should be beneficiaries of the PATH programme and they should be new customers signing up onto the Community Renewal Programme and who otherwise are consuming electricity without paying.

JPS stated that since submitting its 2015 proposal, further field work in the communities indicated that there were only a limited number of people who were enrolled on the PATH programme. Thus, the Community Renewal Programme will not be as effective if this criteria is not expanded to be more inclusive. JPS had initially advised the Office that it was consulting with the Planning Institute of Jamaica (PIOJ) to finalise a selection criteria and would submit a separate proposal to the OUR by 2016 May 31. In a subsequent advisory however (email dated 2016 June 29), JPS advised that it had concluded that it needed to engage a consultant to further assist with this objective and that its new time table to conclude on this is now 2016 September.

Notably, the CRR is not part of the JPS tariff basket of rates and ultimately the expected revenue gains from these consumers were not factored into the JPS revenue requirement which was approved in the 2014 – 2019 Determination Notice.

Condition 14, paragraph 1 of the New Licence under "Charges and Terms and Conditions for the Supply of Electricity" states as follows:

"The Licensee shall, save where it enters into special contracts with customers for the Supply of electricity pursuant to Section 14 of the OUR Act, charge its customers for such a Supply according to published rates, approved by the Office, as updated from time to time. Such published rates shall be cost-reflective, unless otherwise directed by the Office. Each rate category will apply uniformly across the Island and there will be no discrimination to customers on the rate charged based on location."

Consistent with the 2015 Annual Tariff Adjustment Determination Notice, the OUR reiterates that there should be no discrimination in the tariff charged in each rate category. Further, at the next rate reset, JPS will be required to apply the same rate, which is the rate charged to Rate 10 customers, to consumers who will be regularized during the 2014 – 2019 tariff period.

The approved CRR to be charged for Rate 10 service is a flat rate of J$9.13/kWh for consumption up to 150kWh. Customers consuming more than 150kWh per month, will pay the regular prepaid or post-paid rate, whichever is applicable, for the incremental consumption above 150kWh per month. The CRR and conditions related to it shall be subject to review at the next Annual Tariff Adjustment.

DETERMINATION 8

The approved Community Renewal Rate to be charged for Rate 10 service is a flat rate of J$9.13/kWh for consumption up to 150kWh.

Customers consuming more than 150kWh per month will pay the regular prepaid or post-paid rate, whichever is applicable, for the incremental consumption above 150kWh per month. The Community Renewal Rate and conditions shall be subject to review at the next Annual Tariff Adjustment.

4.10. Tariffs for LED Street Lighting

The OUR over many years has facilitated the negotiations between the Ministry of Local Government and Community Development (MLGCD) and JPS aimed at replacing street lighting with LED. In the 2014 – 2019 Determination Notice, the OUR requested that JPS submit a proposal for tariffs for LED Street Lighting within six (6) months of the effective date of the said Determination Notice. In the 2015 Annual Tariff Adjustment Determination Notice, JPS was given sixty (60) additional days to allow for further negotiations between the MLGCD 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.

Following the publication of the 2015 Annual Tariff Adjustment Determination Notice, JPS indicated that the company was experiencing difficulties in finalizing the terms and conditions within the stipulated time period and asked for a further extension. At the same time the New Licence was being negotiated. The responsibility and ownership for the Street Lighting Replacement project is addressed in Condition 28, paragraph 6 of the New Licence which provides as follows:

> *"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 Licensee to recover the costs of implementing the Smart Streetlight Programme."*

In its Submission, JPS stated that given the changes introduced in the New Licence and the intent to establish a Fund for the Smart Streetlight Programme, the company believes that it is prudent to delay the implementation of the LED tariff until the 2017/2018 filing when JPS will be requesting OUR's consideration for an Extra-ordinary Rate Review. JPS further stated that the company is at an advanced stage in the selection process for a contractor to implement the Smart LED Street lighting replacement project and that this should be finalized by 2016 October 1.

The OUR is of the view that the implementation of this scheme needs not await an Extra-ordinary Rate Review, the occurrence of which has not been determined. In the circumstances and given what JPS has indicated regarding the selection process for a contractor to implement the Smart LED Street lighting replacement project, pursuant to Condition 28, paragraph 6 of the New Licence, the OUR directs JPS to commence the implementation of the Smart Streetlight Programme. In this regard, the JPS within sixty (60) days from the date of this Determination Notice, is required to submit the full implementation plan to the OUR for review and approval.

4.11. Request for Extra-ordinary Rate Review for the 2017/2019 Filing

JPS Request

JPS has requested the OUR's consideration for an Extra-ordinary Rate Review in the 2016/2017 tariff period. JPS has posited that the request comes against the backdrop of the exceptional circumstances necessitated by the need to operationalization of the New Licence. JPS is contending that the New 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 the customers require. JPS proposed that these include:

- The inclusion of the current portion of long term debt (CPLTD) in the rate base which is addressed in Schedule 3, paragraph 29 of the New Licence.
- Changes to the depreciation schedule
- Allowance for Smart Street Lighting investments.
- The incorporation of the new IPPs into the non-fuel tariff.
- Review of the ROE

JPS argued that these items could have been included in an annual tariff filing through the Z-Factor adjustment mechanism which was expanded in the New Licence. JPS is also asserting that, given the need to address wheeling, net billing and standby rates in a comprehensive, cost reflective and non-discriminatory manner, it is prudent to reset the tariffs based on cost of services studies. JPS asserted that these studies are currently being conducted and will be used to inform the new tariff design which will necessitate the need for an Extra-ordinary Rate Review.

OUR's Response

The Office considers that the terms and conditions for an Extra-ordinary Rate Review are clearly defined at Schedule 3, paragraphs 59 – 61 of the New Licence which allows for such an application to be made. In the event that JPS proposes to make such an application, it would need to demonstrate that those terms and conditions are met. This represents a separate and distinct process with its own requirements and peculiarities. The occasion of an annual adjustment is therefore neither the appropriate time nor process to address this matter. The Office therefore declines JPS invitation to commit to an Extra-ordinary Rate Review for 2017/18.

4.12. Request for Re-imbursement of Losses Related Fuel impairment Cost for 2016

In its Submission, JPS requested approval for re-imbursement of losses related to impairment costs for 2016.

The company asserted that between 2016 January and 2016 March, it incurred US$5.4M in fuel cost impairment directly attributable to System losses. According to JPS, the financial impairment is likely to grow until 2016 July 1, when the System losses efficiency mechanism is removed from the fuel rate calculation. JPS indicated that 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. The company argued that the situation would result in JPS being penalised twice for the fuel losses performance from 2016

January to June 30 and that it is therefore requesting the OUR's consideration of a mechanism to allow JPS to recover the fuel impairment cost for the first half of the year.

According to the provisions of Schedule 3, Exhibit 2 of the New Licence, there is no mechanism for the consideration or allowance of any form of re-imbursement of cost to JPS due to System losses induced impairment.

In principle, the FCAM defined in Schedule 3, Exhibit 2 of the New Licence, which is also consistent with the OUR's determinations on JPS' fuel cost recovery set out in the 2014 - 2019 Determination Notice, allows for the total fuel cost to be adjusted for efficiency by actual System losses, against the OUR determined System losses target as well as the actual Heat Rate against the OUR determined Heat Rate target for the applicable month.

This defined adjustment mechanism does not implicitly or directly provide any avenue for awarding re-imbursement to JPS due to a differential resulting from its actual System losses being above the target. In that regard, JPS' request for re-imbursement of System losses related fuel impairment cost of US$5.4 Million it claimed it incurred between 2016 January and 2016 March, is **NOT APPROVED**.

In its comments on the OUR draft Determination Notice submitted for its review, JPS argued that its request for the reimbursement of the fuel cost impairment due to system losses between 2016 January and June was in recognition of the fact that the application of the true-up for system losses in the 2017/2018 annual tariff adjustment could see JPS being penalised for one year of system losses performance thus, there would be a double counting of the impact of system losses. JPS pointed out that the "OUR had indicated in its draft determination notice, however, that the request would not be approved as based on the formula "there would be no basis for JPS' losses related fuel impairment cost referred to the period 2016 January to 2016 June to be incorporated in the 2017/2018 Non-Fuel Revenue and therefore should not impact the true-up mechanism."

JPS further indicated that it is seeking a commitment from the OUR that in applying the true up for system losses in 2017, the following formula be used instead to calculate $TULos_{2017}$.

$$TULos_{2017} = \frac{1}{2}Y_{2016} \times ART_{2016}$$

JPS claimed this would result in the application of the system loss target for half of the year as it relates to non-fuel rates, consistent with the fact that a system loss target was applied to the fuel rates for the first six month of 2016. This, JPS argued, is necessary to assure that there would be no double penalty on JPS in relation to system losses for 2016.

Generally, the Office is not disposed towards giving commitment on a matter that would pertain to a future determination notice but in any event, and with respect to the issue of the impact of the indicated losses related fuel impairment cost on the true-up mechanism for System losses in the 2017/2018 Annual Tariff Adjustment filing, the OUR would wish to point out that according to Schedule 3, paragraph 38 of the New Licence, the respective targets for System losses are required to be set for each year of a rolling ten (10) period.

This implies that the System losses target for the specified losses categories determined by the OUR in this Determination Notice will form the basis for the losses component of the Revenue surcharge and applicable adjustment to the Non-Fuel Revenue Target at the 2017/2018 Annual Tariff Adjustment. Accordingly, there would be no basis for JPS' losses related fuel impairment cost referred to the period 2016 January to 2016 June to be incorporated in the 2017/2018 Non-Fuel Revenue and therefore should not impact the true-up mechanism. Therefore, contrary to JPS' position, this would not result in a scenario in which JPS would be penalised twice for the fuel losses performance from 2016 January to June 30.

DETERMINATION 9

JPS' request for re-imbursement of System losses related fuel impairment cost of US$5.4 Million it claimed it incurred between 2016 January and 2016 March, is NOT APPROVED .

4.13. Fuel Cost Recovery – Heat Rate

4.13.1. Heat Rate

Introduction

A significant portion of JPS' monthly operating expenses is the cost of fuel consumed by JPS and IPPs generating plants for the production of electricity which it supplies to electricity consumers.

The total monthly fuel cost depends on, among other things, the following factors:

1) The price of fuel consumed by JPS and IPPs generating plants;
2) The fuel conversion efficiencies (Heat Rates) of JPS and IPPs' generating plants;
3) The quantity of electrical energy generated for the month; and
4) The proportion of electricity generation provided by different generating plants.

The monthly fuel cost is likely to change whenever one or more of the above factors are altered.

Based on the fuel cost recovery process, the total monthly fuel cost is translated to monthly fuel rates in accordance with the FCAM. The approved fuel rates are then used by JPS to bill customers in order to recover the cost of fuel incurred in the production of electricity.

Since the effective date of the 2014 - 2019 Determination Notice, approximately 69% of the monthly average fuel consumption was attributable to JPS' plants while 31% was due to IPP plants with commensurate aggregate fuel costs of US$284.3 Million and US$129.5 Million respectively. The relative proportions of these costs are illustrated in Figure 4.17 below.

Presently, all the fuel used for electricity generation are petroleum based and are supplied by Petrojam Limited to JPS and IPPs under long-term fuel supply agreements (FSA). The fuels used are heavy fuel oil (HFO) and automotive diesel oil (ADO). HFO is predominantly used in JPS' steam generating units and IPPs' MSD and SSD generating units while ADO is mainly used in the operation of JPS' simple cycle gas turbines (SCGT) and combined cycle gas turbine (CCGT) units.

The prices of these fuels are hugely influenced by international fuel markets and as such, are subject to high volatility and unpredictability. According to Petrojam's Fuel Oil weekly "Price List" to JPS, since 2014 January, the average HFO price (US Gulf Average Mean) declined from US$100 per barrel to a low of US$28 per barrel in 2016 January but recovered to US$35 per barrel by 2016 April. Similarly, for ADO, the average price declined from US$136 per barrel in 2014 January to US$48 per barrel in 2016 January but subsequently recovered to US$57 per barrel in 2016 April. These prices changes represented a reduction in fuel oil prices of over 65% from 2014 to present.

This reduction in international fuel oil prices translated into a significant reduction in JPS' monthly fuel charge over the stated period. Notably, the current fuel charge to JPS' residential customers represents approximately 39% of their electricity bills.

Figure 4.17: JPS and IPPs Fuel Cost and Net Generation (2014 February – 2016 April)

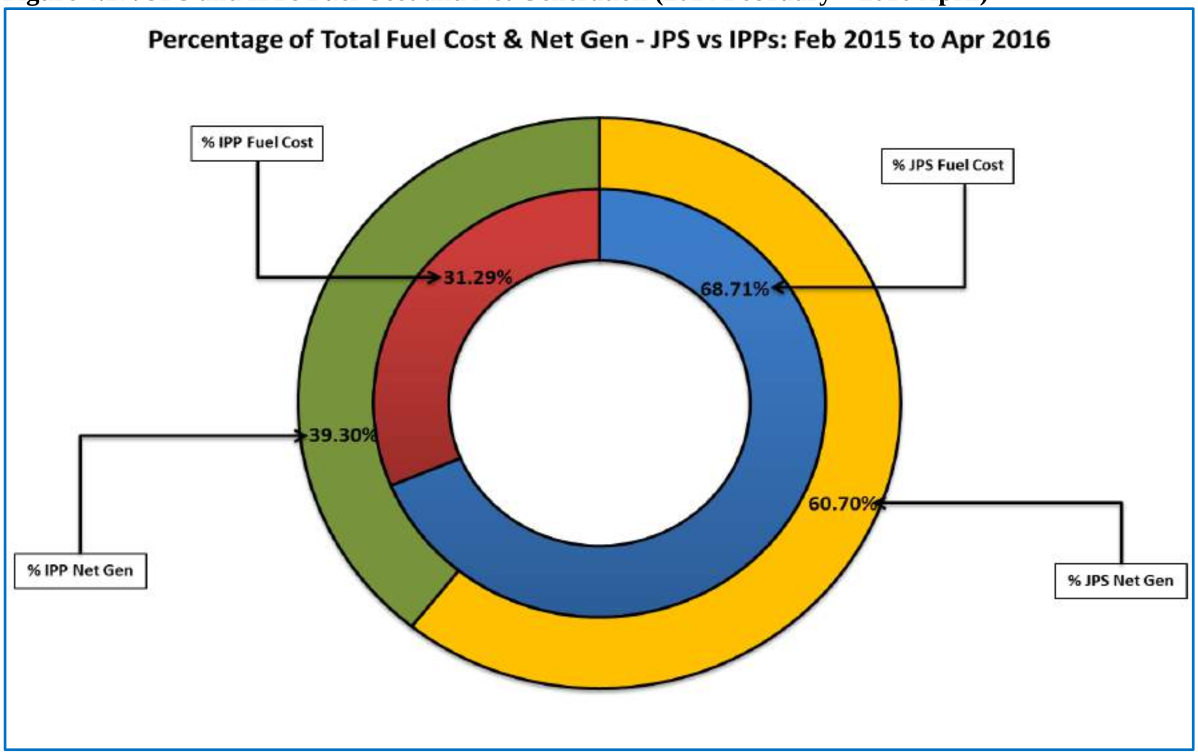


Figure 4.17 above also shows the monthly average net generation corresponding to the respective proportions of JPS' and IPPs' aggregate fuel costs. As shown, IPPs account for approximately 39.3% of the monthly average net generation but approximately 31% of the aggregate fuel cost over the period. The proportion of electricity production attributable to the IPPs and commensurate cost of fuel consumed implies that higher utilization of the IPPs generation facilities could result in lower fuel rates to customers.

Heat Rate

Definition- Generating Plant Heat Rate

A generating plant Heat Rate is normally represented as its fuel conversion efficiency at rated capacity (full-load heat rate). However, a plant's average Heat Rate is based on its operation along its Input - Output Curve (fuel energy input – electrical energy output). The average Heat Rate at a level of generation is equal to the corresponding input energy in the fuel divided by the energy generated. A lower Heat Rate means that less fuel is used per kWh of electricity and this corresponds to greater efficiency and to reduced fuel expenses. Heat Rates are not the same for all generating plants. Generating units used for peaking purposes, such as gas turbines, generally have higher heat rates than base-load units, which are more efficient. The existence of these differences in heat rates underscores the importance of the generation technology mix. Based on the variations in plant output during the System's load curve, the fuel conversion efficiency indicator of a generating plant is usually represented as the average heat rate over a given period.

Heat Rate Target

In the 2014 - 2019 Determination Notice, the OUR determined that a System Heat Rate factor, defined as the ratio of the actual System Heat Rate for a given month and the System Heat Rate (System Heat Rate Target ÷ System Heat Rate Actual) should no longer be applied in the FCAM on the basis that it was not in accordance with the requirements of the Old Licence, which was applicable at the time. Nonetheless, the OUR determined that the System Heat Rate should continue to be calculated by JPS and reported as a key performance indicator to facilitate the monitoring of System efficiency.

Alternatively, based on the provisions of the Old Licence, the OUR determined that the Heat Rate Factor that shall be used in the FCAM should be the ratio of JPS Heat Rate target (thermal) to JPS heat rate actual (thermal). That is:

$$\boldsymbol{Heat\ Rate\ Factor} = \frac{\boldsymbol{JPS\ Heat\ Rate\ Target\_Thermal}}{\boldsymbol{JPS\ Heat\ Rate\ Actual\_Thermal}}$$

In accordance with the requirements of the Old Licence, the OUR evaluated JPS' 2014 Heat Rate proposals and determined a heat rate target for the company's thermal generating system of 12,010 kJ/kWh. This Heat Rate target was to be applied to the FCAM to effect efficiency adjustment to the total cost of fuel consumed in JPS' generating units each month over the period 2014 September to 2015 June. It is important to note that at the time, the monthly fuel cost was also subject to efficiency adjustment by the System losses parameters.

The OUR was of the view that the determined Heat Rate target was fair, reasonable and consistent with the technical capability and configuration of JPS' thermal generating system. The Heat Rate target also provided the incentive for JPS to improve the fuel conversion efficiency of its thermal generating plants and realize the associated rewards.

According to the 2014 - 2019 Determination Notice, the OUR also determined that the Heat Rate target would be reviewed and reset at each Annual Tariff Adjustment during the 2014 - 2019 price cap period to reflect, among other things, the impact of:

1) Changes in the efficiency of JPS' existing generating units;
2) Major reconfiguration of any existing generating unit impacting the entire generation System;
3) The addition of renewable and/or conventional generation capacity to the System; and
4) The retirement of existing generation facilities.

In its Submission, JPS' argued that notwithstanding the foregoing continuing objection to the use of the JPS' Thermal Heat Rate, based on the planned mix of generating units (including IPPs); their projected availability and dispatch; the heat rate affecting variables; and the possible variation in heat rate performance for reasons beyond JPS' control, the company was not proposing a revised Heat Rate target for the 2015/2016 tariff period.

In the Submission, JPS also asserted that its decision not to make a Heat Rate proposal at the 2015 Annual Tariff Adjustment Date was based on two pertinent factors:

- The late implementation of the 2014 rate schedule and fuel recovery mechanism subsequent to the 2014 - 2019 Determination Notice and Addendum 1.

- The known disagreements between the OUR and JPS as adumbrated by JPS' appeal against aspects of the 2014 - 2019 Determination Notice.

Despite JPS' position on the 2015/2016 Heat Rate target, consistent with the Heat Rate determinations in the 2014 - 2019 Determination Notice, the OUR reviewed the company's Heat Rate performance since 2015 January 07 (the effective date of the 2014 - 2019 Determination Notice) and evaluated the heat projections for 2015/2016 provided in its 2014 - 2019 Application Submission to substantiate its determination of JPS Heat Rate target for the 2015/2016 tariff period.

Contrary to JPS' arguments, based on the OUR's Heat Rate analysis, it was expected that JPS' projected monthly generating Heat Rate and annual average Heat Rate for the 2015/2016 tariff period would perform well below the Heat Rate target of 12,010 kJ/kWh proposed by JPS.

Nevertheless, the OUR determined that:

- Consistent with the 2014 - 2019 Tariff Determination Notice, a Thermal Heat Rate target shall continue to be in effect.

- JPS' generating Heat Rate for the 2015/2016 tariff period should remain at 12,010 kJ/kWh.

Given, the composite of Heat Rate and System losses parameters in the FCAM, the OUR considered its determined Heat Rate targets fair and reasonable and consistent with good regulatory practice.

JPS' Heat Rate Performance

The Heat Rate performance reported by JPS for its thermal generating system from the effective date of the 2014 - 2019 Determination Notice, that is 2015 January 07, to April 2016 is provided in Table 4.22 and Figure 4.18 below.

Table 4.22: JPS' Thermal Generating Plants Heat Rate (2015 January - 2016 April)

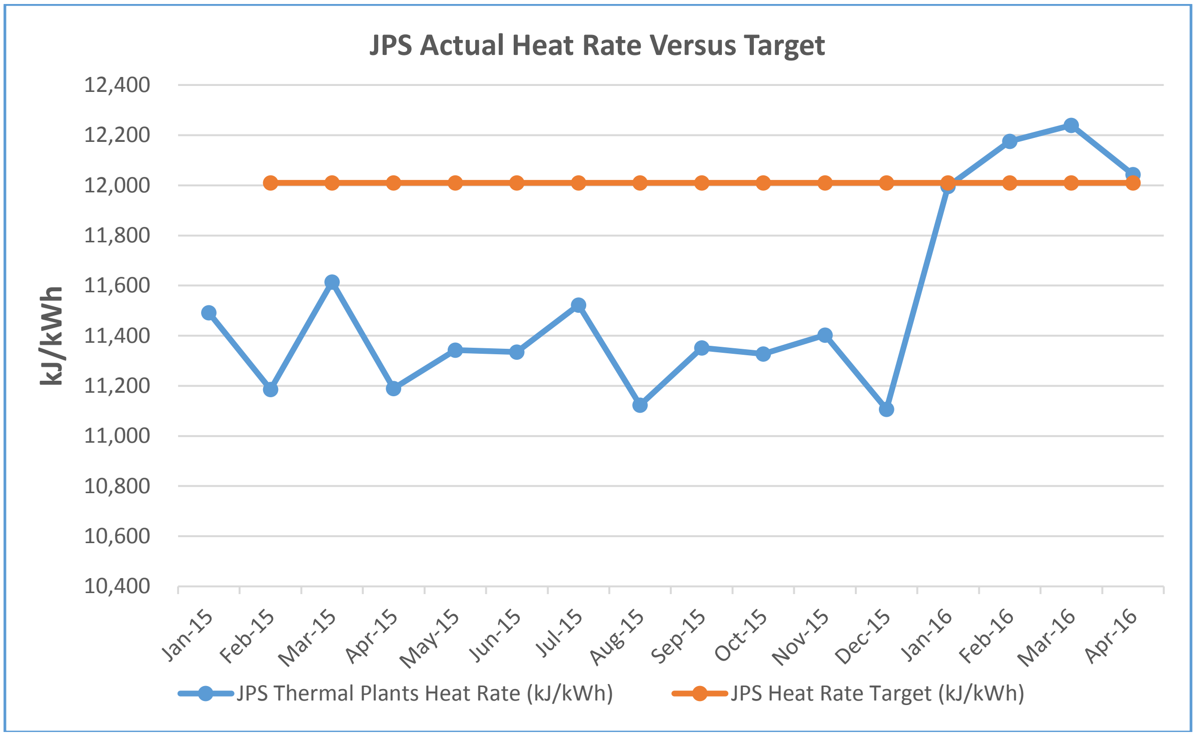
JPS' Thermal Generating Plants Heat Rate Performance			
Date	**JPS Thermal Plants Heat Rate (kJ/kWh)**	**JPS Heat Rate Target (kJ/kWh)**	**Change (kJ/kWh)**
2015 January	11,492		
2015 February	11,186	**12,010**	-824
2015 March	11,615	**12,010**	-395
2015 April	11,190	**12,010**	-820
2015 May	11,343	**12,010**	-667
2015 June	11,335	**12,010**	-675
2015 July	11,523	**12,010**	-487
2015 August	11,124	**12,010**	-886
2015 September	11,351	**12,010**	-659
2015 October	11,327	**12,010**	-683
2015 November	11,403	**12,010**	-607
2015 December	11,107	**12,010**	-903
2016 January	11,996	**12,010**	-14
2016 February	12,175	**12,010**	165
2016 March	12,240	**12,010**	230
2016 April	12,044	**12,010**	34

As shown in Table 4.22, in 2015, the reported monthly Heat Rate ranged between 11,107 kJ/kWh to 11,615 kJ/kWh resulting in an average annual Heat Rate value of 11,333 kJ/kWh for the year. This performance reflected an average Heat Rate differential of 677 kJ/kWh in favour of JPS.

In contrast to 2015, the monthly Heat Rates reported for 2016 January to April have increased markedly relative those for the same period in 2015. Notably, the Heat Rate from 2016 February to April were greater than the target of 12,010 kJ/kWh, which means a worst performance relative to the Heat Rate target.

Based on JPS generation data submitted to the OUR, the relatively poor Heat Rate performance for the stated period was apparently due to the constrained operation of the Bogue CCGT unit since 2016 January to facilitate the reconfiguration activities to accommodate the use of Natural Gas (NG) scheduled to be completed in 2016 August. As shown, while the monthly Heat Rate has been adversely affected, the overall impact was however, considered to be marginal.

Figure 4.18: Illustration of JPS' Thermal Generating Plants Heat Rate Performance (2015 January - 2016 April)



Licence Requirements for Fuel Rate Adjustment

Applicable Fuel Cost Adjustment Mechanism (FCAM)

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

*"A. **Alternative 1** Fuel Cost Adjustment Mechanism*

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

As required by the New Licence, the cost of fuel per kilo-watt-hour shall be computed on a monthly basis under the appropriate rate schedule having regard to the applicable efficiency adjustments and effective dates as specified in the New Licence.

Accordingly, the fuel cost portion of the monthly bill be computed under the appropriate rate schedule should be calculated in the following manner:

"$F = F_m/S_m$

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].*

The total applicable energy cost for the Billing Period is:

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

(b) the fuel portion of the cost of purchased power (including IPPs), adjusted for the contract heat rate, for the said preceding calendar month; and

(c) an amount to correct for the over-recovery or under-recovery of total applicable energy cost for a billing period, such amount shall be determined as the difference between the actual total applicable energy cost for a given month adjusted for the determined heat rate and system losses, if applicable and the fuel costs billed for such month, using fuel costs and fuel weights.

(d) an amount to correct for the over-recovery or under-recovery of the non-fuel portion of the purchased power. This amount shall be determined as the difference between the actual IPP non-fuel cost for a given month and the

estimated base non-fuel IPP charge billed to customers for such calendar month.

S_m = *the kWh sales in the Billing Period.*

The kWh sales in the billing period is the actual kWh sales occurring in the previous calendar month.

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

Requirement for Heat Rate Target

With respect to the determination of the Heat Rate target, Schedule 3, paragraph 40 of the New Licence provides as follows:

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

JPS Heat Rate Proposal

Outline of proposal

JPS' Heat Rate proposals presented in its Submission are outlined as follows:

JPS proposed that the Heat Rate target be set with respect to the JPS system (including JPS controlled renewable energy [RE] plants) for the 2016/2017 tariff period rather than the JPS thermal Heat Rate that is currently applicable.

With respect the Heat Rate proposal, the JPS argued that:

- The proposed use of the JPS system Heat Rate rather than the JPS thermal was 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 it generating 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, and therefore it is 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 steadier Heat Rate curve.

- 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$40 Million 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.

JPS posited that 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).

Further, JPS proposed that the target for the 2016/2017 adjustment period should be 10,710 kJ/kWh (JPS thermal and JPS renewables).

As part of the consultation between the JPS and the OUR on its Submission, JPS by way of email dated 2016 June 17, submitted a Heat Rate dataset which it defined as Revised Dispatch Input 2016/17 (Excel File - "2016-2017 Maintenance Fuel Budget" dated 2016 June 17), which it indicated was based on the latest demand trend that JPS committed to provide to the OUR at a meeting held 2016 June 14. Further, JPS confirmed that the revised despatch projections constituted a replacement of the initial Heat Rate data set submitted in support of its proposed Heat Rate target.

JPS' Heat Rate Projections for 2016/2017 Tariff Period

JPS' Heat Rate projection for each month in the 2016/2017 tariff period as provided in its updated "2016-2017 Maintenance Fuel Budget" dated 2016 June 17, are presented in Table 4.23 below.

Table 4.23: JPS' Projected Thermal Generating Plants Heat Rate for the 2016/2017 Tariff Period.

JPS Projected Thermal Heat Rate for 2016 July to 2017 June													
DATE	2016 Jul	2016 Aug	2016 Sep	2016 Oct	2016 Nov	2016 Dec	2017 Jan	2017 Feb	2017 Mar	2017 Apr	2017 May	2017 Jun	AVERAGE
HEAT RATE (kJ/kWh)	11,537	11,437	11,385	11,498	11,114	11,149	11,145	11,405	11,346	11,246	11,445	11,650	**11,363**
Net Gen (MWh)	393,633	387,535	376,085	373,143	356,495	357,604	355,216	317,881	364,360	354,267	373,336	381,627	
SYS Peak (MW)	642.3	629.5	637.1	642.5	626.4	621.1	621.0	625.0	628.0	635.0	641.0	650.0	

As shown in Table 4.23 above, the projected monthly Heat Rate for JPS' thermal generating plants ranged between 11,114 kJ/kWh to 11,650 kJ/kWh with an average value of 11,363 kJ/kWh over the period. According to JPS' updated "2016-2017 Maintenance Fuel Budget" (dated 2016 June 17), the monthly Heat Rate projections were based on among other things, the corresponding System net generation and peak demand presented in Table 4.23. Based on the demand data, JPS has forecasted that in June 2017, the System peak demand is expected to increase to 650 MW.

For the evaluation of JPS' Heat Rate and determination of the Heat Rate Target for the 2016/2017 tariff period, these Heat Rate projections, forecasted net generation and forecasted peak demand, among other generation assumptions and parameters were taken into consideration. For the evaluation of JPS' Heat Rate and determination of the Heat Rate Target for the 2016/2017 tariff period, these Heat Rate projections, forecasted net generation and forecasted peak demand, among other generation assumptions and parameters were taken into consideration.

OUR's Review of JPS' Heat Rate Proposals

Rationale

Since Heat Rate is a measure of the fuel conversion efficiency of an electricity generating plant or system, from a regulatory perspective, the consideration of a Heat Rate target or a Heat Rate factor in a FCAM which is utilized to determine fuel rates (net of efficiencies) on a periodic basis, should be predicated on among other things, the following principles:

- The Heat Rate target should provide the Generating Plant Operator with the incentive to minimize its total fuel cost incurred in the production of electricity by improving the fuel conversion efficiency of its generating plants; and

- The Heat Rate target should encourage optimal generation dispatch of the generating system to minimize the total cost of electricity generation which includes fuel cost.

Heat Rate Evaluation

During the review process, the OUR evaluated JPS' Heat Rate proposal and took into consideration, among other things, the following:

- Projected System net generation and peak demand for the period (2016 July to 2017 June);
- JPS and IPPs existing thermal generating plants – technical specifications and maintenance data;
- JPS and IPPs existing RE generation facilities;
- RE generation facilities scheduled to be commissioned within the tariff period including the 80.3 MW of RE generation to be fully commissioned by 2016 July;
- JPS historical Heat Rate data;
- JPS generating units Heat Rate test data;
- The Heat Rate assumptions provided by JPS in its Submission entitled *"2016-2017 Maintenance Fuel Budget June 17 2016"* ;
- Constraints on generating units; and
- Network constraints.

The Heat Rate evaluation also encompassed statistical analysis to assess the effect of variations or uncertainties on the Heat Rate performance.

OUR's Response to JPS Heat Proposal

With respect to JPS' arguments favouring a JPS system Heat Rate (JPS thermal and RE plants), the OUR responses are as follows:

1) Consistent with the positions set out in Chapter 9 of the 2014 - 2019 Tariff Determination Notice, regarding the inclusion of RE generation in the Heat Rate Equation, the OUR's maintains that a JPS System Heat Rate with JPS RE generation is not considered to be reasonable and prudent on the basis that it distorts the Heat Rate calculation and can potentially diminish the incentive for JPS to improve the efficiency of its thermal generating units. Further, with increased participation of RE generation, it could significantly skew the Heat Rate values rendering the JPS System Heat Rate non-representative of the generating system to which it refers.

2) The nature of JPS System load curve and load blocks, necessitate a generation technology mix to supply the System load with the type of variation in Heat Rate as represented by JPS. This orientation is typical in electricity Systems of similar configuration to that of JPS'. However, with respect to generation outages either due to forced or planned events, it should be noted that the projected forced outage rates (FORs) and scheduled maintenance outages provided by JPS for all the generating units operating in the System were factored into its Heat Rate projections for the tariff period. The outage data was also used in the OUR's Heat Rate evaluation to determine the Heat Rate target. Therefore, the argument concerning the potential impact of these outages on JPS' Heat Rate performance does not hold up.

3) The OUR disagrees with JPS' position that 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. Based on its orientation, the construct of a System Heat Rate with RE generation tends to indicate a lower Heat Rate value. However, realistically, this is not the case, due to the fact that the electrical power and energy output from non-combustible renewables such as hydro, wind and solar are produced without fuel combustion, that is, there is no fuel energy (BTU or kJ) input requirements to be converted to electrical energy, hence no Heat Rate. Therefore, the adoption of a JPS System Heat Rate with RE generation would effectively distort the Input-Output mathematical dimensions of the Heat Rate equation. Based on analyses carried out on available generation and fuel data, it has been found that due to the indicated distortions in the Heat Rate calculation caused by the inclusion of RE generation, the adoption of a

Heat Rate target that includes renewables as proposed by JPS would not result in lower fuel cost to its customers.

4) JPS asserted that it invested over US$40 Million between 2010 to 2014 in Wind and Hydro Renewables and that the impact of renewables on fuel cost to customers is weighed heavily in its decision to invest in the renewable capacity. In addressing this issue, the OUR wish to make it clear that the increased participation of renewable energy in Jamaica's energy supply mix is primarily driven by the National Energy Policy goals and objectives, which embrace the dimensions of energy security, environmental sustainability and economics. Importantly, according to the legal and regulatory framework, the procurement and integration of RE generation into the System is not restricted to JPS options but rather through the medium of competitive generation tendering processes. Therefore, investment decisions in RE generation should be rationalized within that context. Additionally, under the existing regulatory framework, RE projects integrated into the System have been allowed to recover their costs through appropriate mechanisms. However, there are no regulatory policy or legal instruments in place that support or promote any expectation or incentive that investment in RE generation will convey Heat Rate benefits to the Generating Entity. Indeed it could also be argued that to confer this exclusively on the System operator, would distort the competitive process for such tenders.

5) Pursuant to Schedule 3, paragraph 39 of the New Licence, the Heat Rate target set for JPS by the OUR represents an annual target. Therefore, while there will be monthly adjustments to JPS' fuel cost by the relevant Heat Rate parameters in the FCAM, the effect of the Heat Rate performance must rationally be based on the aggregate outcome over the tariff period (2016 July – 2017 June).

From a technical and regulatory perspective, the inclusion of JPS' RE generation in the Heat Rate equation and target is not considered to be appropriate.

OUR's Determination on JPS' Heat Rate Proposals

Pursuant to Schedule 3, paragraph 40 of the New Licence, the Office determined that:

- The Heat Rate (actual) to be used by JPS in the approved FCAM each month shall be based on JPS' thermal generating Plants.

- The approved Heat Rate target is applicable to JPS' thermal generating plants.

- JPS' proposal for the use of a JPS system Heat Rate (JPS thermal and JPS RE plants) in the FCAM is not **approved**.

OUR Determined Heat Rate Target

Based on OUR's evaluation and analysis of the Heat Rate target proposal, the Office determined that the Heat Rate target for JPS' thermal generating system for the tariff period 2016 July to 2017 June shall be: **<u>11,620 kJ/kWh</u>**.

This determined Heat Rate target in conjunction with JPS thermal generating plants Heat Rate (actual) for the applicable month shall be used for efficiency adjustment in the approved FCAM.

Given the major modifications to the FCAM stipulated in the New Licence and the relevant factors that were taken into consideration, the Office believes that the Heat Rate target is reasonable and achievable and consistent with the technical capability of JPS' thermal generating system. Additionally, the determined Heat Rate target should incentivize JPS to improve the fuel conversion efficiency of its thermal generating plants and obtain rewards. This incentive is implicitly reflected in the approved fuel cost pass-through formula.

OUR's Determination on the Fuel Cost Adjustment Mechanism (FCAM)

<u>FCAM prior to 2016 July 1</u>

Subject to the provisions of the Old Licence applicable at the time, the OUR in the 2014 - 2019 Determination Notice, determined that the FCAM that should be applied by JPS to the monthly fuel costs in order to derive the monthly fuel rates is as defined by the formula represented below:

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

Where:

- *JPS Heat Rate Actual* = JPS average generating heat rate based on the utilization of its thermal generating plants in the production of electricity each month.

- *JPS Heat Rate Target* = the OUR determined Heat Rate target for JPS' thermal generating plants.

According to Schedule 3, Exhibit 2 of the New Licence, this FCAM shall continue to be applied up to 2016 June 30.

<u>FCAM effective 2016 July 1</u>

Pursuant to the requirements of Schedule 3, Exhibit 2 of the New Licence, effective 2016 July 1, the System losses parameters (actual System losses for the applicable month and System losses target) will no longer be included in the FCAM. This means that the total cost of fuel consumed in the production of electricity will only be adjusted for efficiency by Heat Rate parameters.

Having regard the provisions of the New Licence, the OUR determined that the FCAM that shall be applied by JPS effective 2016 July 1, is defined by the formula represented below:

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

Where:

- *JPS Heat Rate Actual_Thermal* = the average generating Heat Rate of JPS' thermal generating plants utilized in the production of electricity each month.

- *JPS Heat Rate Target_Thermal* = the OUR determined Heat Rate target for JPS' thermal generating plants for the 2016/2017 Tariff Period.

Expected Heat Rate Performance for the 2016/2017 Tariff Period

Technical Capability to Achieve Heat Rate Target

Based on the technical characteristics and configuration of JPS' thermal generating plants, which include inter alia:

- Output capability – minimum and maximum operating levels (MW);
- Heat Rate curves;
- Ramp rates within the operating range;
- Minimum sustained production level;
- Equivalent Availability;
- Planned Maintenance schedule;
- Equivalent Forced Outage Rates (EFOR); and

- Spinning Reserve requirements,

It is expected that the determined Heat Rate target will be achieved by JPS each month over the period 2016 July to 2017 June.

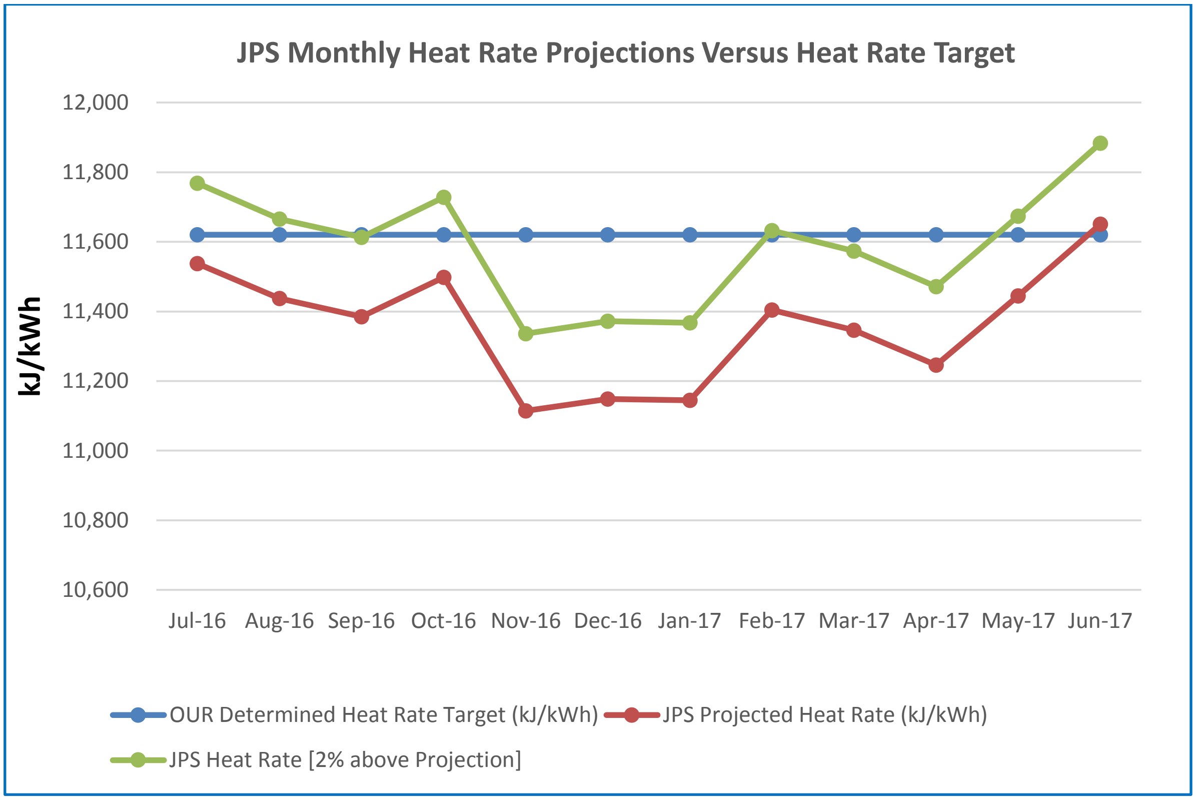
Other factors that were considered to be favourable in enhancing JPS' Heat Rate performance over the stated tariff period include:

- The projected efficiency improvements that will result from the reconfiguration of the Bogue CCGT unit, including Major Overhaul of major components, to accommodate the use of NG;
- Recent efficiency improvements on other existing JPS generating units (such as Rockforth 1 (RF1) and Old Habour # 3 (OH #3));
- The expected efficiency improvements from scheduled major maintenance and major overhaul of other JPS generating units during the period; and
- Expected benefits from other existing and planned efficiency improvement programmes.

JPS' Heat Rate Projections versus Heat Rate Target

A comparison of JPS' thermal generating Heat Rate projections for each month over the tariff period 2016 July to 2017 June against the OUR's determined Heat Rate target is illustrated in Figure 4.19 and Table 4.24 below.

Figure 4.19: JPS' Thermal Heat Rate versus Target – (2016 July to 2017 June)



To assess the robustness of the target, the projected monthly Heat Rates were adjusted upward by a factor of 2% on the basis that JPS' generation dispatch was found to have dispatch deviation in the 2% range. The resulting Heat Rate values were also compared against the Heat Rate target and illustrated in Figure 4.19 above and Table 4.24 below.

Table 4.24: Heat Rate Target versus Projected Monthly Thermal Heat Rate – (2016 July to 2017 June)

Heat Rate Target Versus Heat Rate Projections							
DATE	OUR Determined Heat Rate Target (kJ/kWh)	JPS Projected Heat Rate (kJ/kWh)	Variance w.r.t Target	JPS Heat Rate [2% above Projection]	Variance w.r.t Target	JPS Heat Rate [3% above Projection]	Variance w.r.t Target
2016 Jul	11,620	11,537	- 83	11,768	148	11,883	263
2016 Aug	11,620	11,437	- 183	11,666	46	11,780	160
2016 Sep	11,620	11,385	-235	11,613	- 7	11,727	107
2016 Oct	11,620	11,498	-122	11,728	108	11,843	223
2016 Nov	11,620	11,114	- 506	11,337	- 283	11,448	- 172
2016 Dec	11,620	11,149	- 471	11,372	- 248	11,483	-137
2017 Jan	11,620	11,145	- 475	11,368	- 252	11,479	-141
2017 Feb	11,620	11,405	- 215	11,633	- 13	11,747	127
2017 Mar	11,620	11,346	- 274	11,573	- 47	11,687	67
2017 Apr	11,620	11,246	- 374	11,471	- 149	11,584	-36
2017 May	11,620	11,445	- 175	11,674	- 54	11,788	168
2017 Jun	11,620	11,650	30	11,883	263	12,000	380
AVERAGE	**11,620**	**11,363**	**- 257**	**11,590**	**- 30**	**11,704**	**84**

Based on JPS' monthly Heat Rate projections, the Heat Rate target for the tariff period 2016 July to 2017 June offers the company a reasonable degree of flexibility by allowing an average monthly Heat Hate buffer of 257 kJ/kWh. This buffer will allow JPS sufficient latitude to insulate it from adverse effects attributable to variations in generation dispatch.

As shown in Table 4.24 above, even with an adverse deviation of 3% JPS' Heat Rate projections, on average, the average Heat Rate impact would be marginal.

JPS Comments on OUR' Position on Heat Rate

In its comments on OUR's draft Determination Notice, JPS stated that a reduction in the thermal Heat Rate target from the existing 12,010 kJ/kWh to 11,620 kJ/kWh represents a 3.2% reduction. JPS conceded that relative to its 2015 thermal Heat Rate performance of 11,365 kJ/kWh, the OUR determined Heat Rate target of 11,620 kJ/kWh appeared to be a favourable target. However, JPS argued that the results for 2016 is a starkly different picture with JPS' thermal Heat Rate for the first five months averaging 11,978 kJ/kWh.

Further, in response to OUR's suggestion that the deterioration in Heat Rate performance during the first five months of 2016 was "apparently due to the constrained operation of the

Bogue CCGT unit since 2016 January to facilitate the reconfiguration activities to accommodate the use of Natural Gas", JPS posited that while the situation with the Bogue CCGT is a contributing factor, it is clear that the increased demand placed on the System by the 15 MW increase in peak demand which has resulted in the 5.1% increase in sales for the period from 2016 January to May has played a role.

Based on reports submitted by JPS to the OUR on its electricity generation operations, however, it is confirmed that the reconfiguration activities associated with Bogue CCGT was a causative factor in the deterioration of the JPS' thermal Heat Rate performance in which target was exceeded in 2016 February, March and April. The reported Heat Rate data for 2016 May, also contradicts JPS' argument that the reported 15 MW increase in System peak demand was clearly an influential factor.

As shown in Table 4.25 below, for 2016 May, JPS' System peak was reported as 655.6 MW (the highest peak demand recorded for the electricity System). However, while the System peak for 2016 May represented a 15 MW increase relative to the reported 2015 peak demand of 640.0 MW (Heat Rate – 11,327 kJ/kWh) and the peak demand for 2016 April of 639.1 MW (Heat Rate – 12,044 kJ/kWh), the corresponding Heat Rate was reported as 11,436 kJ/kWh which implies normal generation system operation with Bogue CCGT back to normal generation dispatch levels.

Table 4.25: JPS' Thermal Heat Rate (Actual) – 2016 January to May 2016

JPS Thermal Heat Rate (Actual) from 2016 January to 2016 May					
DATE	**2016 January**	**2016 February**	**2016 March**	**2016 April**	**2016 May**
SYSTEM PEAK (MW) Reported by JPS	623.4	617.5	637.4	639.1	655.6
HEAT RATE (kJ/kWh)	11,996	12,175	12,240	12,044	11,436

JPS also contended that there would be some uncertainty as to how the increased requirement for spinning reserve to accommodate the additional 80 MW of renewable energy will impact JPS thermal Heat Rate. With respect to the integration of the 80.3 MW into the System, it is expected that there will be need for some level of flexibility in JPS' commitment and scheduling of existing thermal generating units to address the intermittency and variability inherent in the operation the respective RE projects comprising the additional 80.3 MW RE generation capacity. However, the forecasted net generation for these RE projects were factored into JPS' generation dispatch and Heat Rate projections for the tariff period 2016 July to 2017 June. The forecasted net generation for these RE projects was also taken into account in the OUR's Heat Rate evaluation.

Regarding the OUR determined Heat Rate target, JPS commented that while it does not have a challenge with some level of reduction in the Heat Rate target, the company is of the view that a 3.2% reduction may be too aggressive at this time. On that basis, JPS indicated it is proposing a 2.5% reduction in the existing target resulting in a target of 11,710 kJ/kWh. JPS argued that the proposed target of 11,710 kJ/kWh is not significantly different from the OUR's determined Heat Rate target of 11,620 kJ/kWh but it affords the company the latitude to see how the dynamics of the rapidly changing sector will affect the Heat Rate results and affords the OUR the opportunity to make meaningful changes in subsequent review periods.

Having considered JPS' comments, arguments and proposals pertaining to the Heat Rate target and given the factors taken into consideration by the OUR in arriving at the target as well as the average monthly Heat Rate buffer of 257 kJ/kWh available to JPS, the Office maintains that the determined Heat Rate target for JPS' thermal generating system shall be **11,620 kJ/kWh** for the tariff period 2016 July to 2017 June on the basis that it is reasonable and achievable.

Summary of the Office's determinations on JPS' Heat Rate Proposals

DETERMINATION 8

1) **JPS' proposal for the use of a JPS System Heat Rate (JPS thermal and JPS RE plants) in the FCAM is not approved.**

2) **The Heat Rate (actual) to be used by JPS in the approved FCAM each month shall be based on JPS' thermal generating Plants.**

3) **The approved Heat Rate target is applicable to JPS' thermal generating plants.**

4) **Heat Rate target for JPS thermal generating system for the 2016/2017 tariff period shall be: 11,620 kJ/kWh.**

5. Revenue Basket Compliance

The requested annual adjustment resulting from changes in the inflation offset index including efficiency gains and changes in quality of service is to be applied to the base year revenue requirement. JPS is allowed to adjust the tariffs for each rate class on the basis that the percentage change does not result in an increase of the annual rate of change in non-fuel electricity revenues (dPCI). The adjusted tariffs should also accord with the 2014 - 2019 Determination Notice and Addendum 1 whereby JPS is allowed to recover its revenue requirement by 23% fixed charges and 77% variable charges. The effective change in the non-fuel revenue is the dPCI offset by surcharges less the cumulative movements due to FX rate changes.

The annual adjustment factor for the non-fuel base revenue of 9.53% [derived from dPCI = (dI = 9.53%) ± (Q = 0%))] is adjusted to take account of revenue surcharge (RS_{2015}), annual FX result loss/gain surcharge SFX_{2015} and annual net interest expense/(income) surcharge (SIC_{2015}). The cumulative change of 4.58% due to FX rate movements (Base Exchange $Rate_{2014}$ – US$1: J$112; Adjusted Billing Exchange $Rate_{2016}$ – US$1: J$122.50) is already accounted for in customers' bills. This results in an effective increase of 6.03% in the annual revenue target. See Tables 5.1 and 5.2 below.

Table 5.1 Details of Annual Inflation Adjustments: 2016-2017

Annual Non-Fuel Revenue Adjustment 2016	
Growth Rate in Inflation and Exchange Rate (dI) for 2016	9.53%
Q-Factor	0.00%
dI adjusted for Q factor	**9.53%**
Change attributed to Surcharges	1.36%
Change attributed to Actual Non Fuel Revenue for 2015 (Already accounted for in customers' bills)	4.58%
Effective Non-Fuel Revenue Change for 2016	**6.03%**

Table 5.2: Details of Revenue Adjustments: 2016-2017

Annual Non-Fuel Revenue Adjustment 2016 (J$)	
Base Year$_{2014}$ Non-Fuel Revenue Adjusted with X-Factor of 1.10% (RC$_{2016}$)	40,604,648,523
Foreign Exchange, Interest and Non-Fuel Revenue Surcharges (SFX$_{2015}$ - SIC$_{2015}$ + RS$_{2015}$)	489,170,865
Annual Non-Fuel Revenue Target for 2016 (ART$_{2016}$)	45,028,110,780
Actual Non-Fuel Revenue for 2015	42,466,096,275
Effective Non-Fuel Revenue Change for 2016	**2,562,014,506**

Table 5.3 below shows the OUR approved annual adjustment factor of 6.03% that is applied to each revenue component in the revenue basket for the 2016 - 2017 period.

Table 5.3 Annual Non-Fuel Adjustment per Revenue Component: 2016 - 2017

Class		Block Rate Option	Customer Charge J$/Mth	Energy Charge J$/kWh	Demand-J$/KVA Std.	Off-Peak	Part Peak	On-Peak
Rate 10	LV	--100	6.03%	6.03%				
Rate 10	LV	> 100	6.03%	6.03%				
Rate 20	LV		6.03%	6.03%				
Rate 40	LV - Std		6.03%	6.03%	6.03%			
Rate 40	LV - TOU		6.03%	6.03%		6.03%	6.03%	6.03%
Rate 50	MV - Std		6.03%	6.03%	6.03%			
Rate 50	MV - TOU		6.03%	6.03%		6.03%	6.03%	6.03%
Rate 60	LV		6.03%	6.03%				

The adjustment to each revenue item in the revenue basket is weighted such that the sum of the weights does not exceed the total effective change of 6.03% as shown in the revenue basket of weights in Table 5.4 below.

Table 5.4 Total Non-Fuel Revenue Basket of Weights

Class		Block/Rate Option	Customer Charge	Energy-Charge	Demand Charge Std.	Off-Peak	Part Peak	On-Peak	TOTAL
Weighted Increase									
Rate 10	LV	--100	0.15%	0.60%	0.00%	0.00%	0.00%	0.00%	0.75%
Rate 10	LV	> 100	0.22%	1.48%	0.00%	0.00%	0.00%	0.00%	1.70%
Rate 20	LV		0.09%	1.43%	0.00%	0.00%	0.00%	0.00%	1.52%
Rate 40	LV - Std		0.02%	0.49%	0.52%	0.00%	0.00%	0.00%	1.02%
Rate 40	LV - TOU		0.00%	0.09%	0.00%	0.00%	0.03%	0.03%	0.16%
Rate 50	MV - Std		0.00%	0.29%	0.24%	0.00%	0.00%	0.00%	0.53%
Rate 50	MV - TOU		0.00%	0.07%	0.00%	0.00%	0.03%	0.03%	0.13%
Rate 60	LV		0.00%	0.22%	0.00%	0.00%	0.00%	0.00%	0.22%
TOTAL			0.48%	4.66%	0.76%	0.01%	0.06%	0.06%	6.03%

Table 5.5 below shows the base year non-fuel basket of revenues that was approved by the Office in the 2014 - 2019 Determination Notice. The New Licence stipulates that for each year of the rate review period, the revenue cap parameter (RC_y) will be established without factoring inflation. During the annual adjustments, the inflation between the base year and the current adjustment period would be factored in through the dI parameter. The approved revenue cap for 2016 (RC_{2016}) is derived as follows:

$$RC_{2016} = (\text{Revenue Requirement approved in } 2014{-}2019 \text{ Tariff Determination Notice}) \times (1 - X)^2$$

In the 2014 - 2019 Determination Notice the productivity efficiency factor (X-Factor) was set at 1.10%. The factor (1-X) is squared to account for the two adjustment periods from the establishment of the revenue requirement (that is, for the periods 2015/2016 and 2016/2017 adjustment years).

Therefore:

$$RC_{2016} = \$41{,}512{,}909{,}469 \text{ x } 0.9781 = \$40{,}604{,}648{,}522.73$$

Table 5.5 Non-Fuel Base Year$_{2014}$ Revenue Basket

		Block/ Rate Option (kWh)	12 Months Test Year Customer Revenue (J$)	Energy Revenue (J$)	Demand (KVA) revenue (J$) Std.	Off-Peak	Part Peak	On-Peak	Total Demand Revenue (J$)	Total Revenue (J$)
Rate 10	LV	≤ 100	1,054,796,940	4,191,406,198	-	-	-	-		5,246,203,138
Rate 10	LV	>100	1,498,171,800	9,561,808,060	-	-	-	-		11,059,979,860
Rate 20	LV		661,657,920	10,600,519,280	-	-	-	-		11,262,177,200
Rate 40	LV - Std		119,114,400	3,267,765,943	3,624,517,296	-	-	-	3,624,517,296	7,011,397,639
Rate 40	LV - TOU		9,002,400	613,795,614	-	24,907,919	248,664,055	255,306,166	528,878,140	1,151,676,154
Rate 50	MV - Std		7,737,600	2,007,252,136	1,215,921,562	-	-	-	1,215,921,562	3,230,911,298
Rate 50	MV - TOU		2,008,800	516,756,352	-	38,607,274	366,976,668	391,469,455	797,053,397	1,315,818,549
Rate 60	LV		7,080,000	1,227,665,631	-	-	-	-		1,234,745,631
TOTAL			**3,359,569,860**	**31,986,969,214**	**4,840,438,858**	**63,515,193**	**615,640,723**	**646,775,621**	**6,166,370,395**	**41,512,909,469**

Table 5.6 below shows the actual basket of revenues that was collected by JPS for 2015 on which the annual adjustment rate of 6.03% is applied.

Table 5.6 Actual Revenues Collected: 2015

Class	Block/Rate Option	Customer Charge	Energy-J$/kWh	Demand-J$/KVA Std.	Off-Peak	Part Peak	On-Peak	Total Revenue
Rate 10 LV	--100	1,022,002,955	4,257,465,344	0	0	0	0	5,279,468,298
Rate 10 LV	> 100	1,560,584,048	10,397,087,158	0	0	0	0	11,957,671,206
Rate 20 LV		654,051,024	10,066,458,808	-	-	-	-	10,720,509,832
		-	-	-	-	-	-	-
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 5.7 below shows the approved annual revenue target for 2016 – 2017 after applying the effective increase of 6.03% on actual revenues collected for 2015.

Table 5.7 Approved Annual Revenue Target: 2016-2017

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

Table 5.8 below shows the actual 2015 billing determinants (obtained from JPS Customer Information System) as presented by JPS. These billing determinants were accepted as the target billing determinants and were applied to the approved revenue requirement to derive the tariffs for 2016 - 2017 period.

Table 5.8 Actual Billing Determinants: 2015

Class	Block/ Rate Option	Average 2015 # of Customers	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 5.9 below shows the approved non-fuel tariffs 2016 - 2017 for each rate category. These rates were derived by applying the billing determinants in Table 5.8 above to the approved revenue target in Table 5.7 above.

Table 5.9 Approved Non-Fuel Tariffs: 2016-2017

Class	Block Rate Option	Customer Charge J$/Mth	Energy Charge J$/kWh	Demand-J$/KVA Std.	Demand-J$/KVA Off-Peak	Demand-J$/KVA Part Peak	Demand-J$/KVA On-Peak
Rate 10 LV	--100	429.31	9.13				
Rate 10 LV	> 100	429.31	21.26				
Rate 20 LV		956.42	17.61				
Rate 40A LV							
Rate 40 LV - Std		6,738.40	5.49	1,720.68			
Rate 40 LV - TOU		6,738.40	5.49		72.56	757.11	969.40
Rate 50 MV - Std		6,738.40	5.29	1,541.51			
Rate 50 MV - TOU		6,738.40	5.29		68.74	670.77	860.61
Rate 60 LV		2,717.10	23.32				

Tables 5.10 and 5.11 below show the overall estimated bill impact[8] of the combination of the non-fuel tariff adjustment and the revised fuel rate (adjusted for full pass through of system losses and revised heat rate target). The impact was estimated with the use of billing information for 2016 May.

With the OUR determined rates the typical residential and small commercial customers (Rate 10 and Rate 20) would have seen an increase of 2.40% in the total balance on their bills while the typical large commercial customers (Rate 40 and Rate 50) would have seen an increase of 3.10%. However, with the JPS proposed rates residential and small commercial customers would have seen on the average a 2.4% increase while the typical larger commercial customer would have seen a 2.9 % increase in the total balance on their bills. The lower bill impact of the JPS rates is however, due to the underestimation of the JPS proposed heat rate target. JPS proposed a heat rate target of 10, 710 kJ/kWh inclusive of JPS renewable energy production (11,160 kJ/kWh Thermal Heat Rate equivalent).

Table 5.10 Estimated Bill Impact of OUR Determined Annual Tariff Adjustment

Customer Class	Overall Bill Impact of the OUR Approved Rates: Typical Usage (kWh)	Demand (kVA)	Total Bill Impact (%)	Average Change (%)
RT 10 LV Res. Service < 100 kWh	90	n/a	2.4%	**2.4%**
RT 10 LV Res. Service 101-350 kWh	349	n/a	2.4%	
RT 10 LV Res. Service > 350 kWh	350	n/a	2.4%	
RT 20 LV Gen. Service < 100 kWh	90	n/a	2.1%	**2.4%**
RT 20 LV Gen. Service 100-1000 kWh	1,000	n/a	2.4%	
RT 20 LV Gen. Service 1000-7500 kWh	5,000	n/a	2.5%	
RT 20 LV Gen. Service > 7500 kWh	8,000	n/a	2.5%	
RT 40 LV Power Service (Std)	35,000	100	2.9%	**3.1%**
RT 50 MV Power Service (Std)	500,000	1,500	3.0%	
RT 50 MV Power Service (TOU-Partial Peak)	500,000	1,500	3.5%	
Efficiency Targets:	**System Losses Target**		**JPS Thermal Heat Rate Target**	
	Full Pass Through on Fuel		11,620 kJ/kWh	

[8] The bill impact was estimated on data received from JPS for May 2016 billing for electricity consumed in April 2016.

Table 5.11 Estimated Bill Impact of JPS Proposed Annual Tariff Adjustment

Customer Class	Overall Bill Impact of the JPS Proposal			
	Typical Usage (kWh)	Demand (kVA)	Total Bill Impact (%)	Average Change (%)
RT 10 LV Res. Service < 100 kWh	90	n/a	2.6%	**2.5%**
RT 10 LV Res. Service 101- 350 kWh	349	n/a	2.4%	
RT 10 LV Res. Service > 350 kWh	350	n/a	2.4%	
RT 20 LV Gen. Service < 100 kWh	90	n/a	2.1%	**2.3%**
RT 20 LV Gen. Service 100-1000 kWh	1,000	n/a	2.4%	
RT 20 LV Gen. Service 1000-7500 kWh	5,000	n/a	2.4%	
RT 20 LV Gen. Service > 7500 kWh	8,000	n/a	2.4%	
RT 40 LV Power Service (Std)	35,000	100	2.8%	**2.9%**
RT 50 MV Power Service (Std)	500,000	1,500	2.5%	
RT 50 MV Power Service (TOU-Partial Peak)	500,000	1,500	3.5%	
Efficiency Targets:	**System Losses Target**		**JPS Thermal Heat Rate Target + Renewables**	
	Full Pass Through on Fuel		10,710 kJ/kWh	

6. Appendix

6.1 Appendix 1: U.S. and Jamaican Consumer Price Indices

6.1.1 U.S. Consumer Price Index

U.S. Consumer Price Index - All Urban Consumers

Series Id: CUUR0000SA0
Not Seasonally Adjusted
Area: U.S. city average
Item: All items
Base Period: 1982-84=100

The Consumer Price Index (CPI-U) is compiled by the Bureau of Labor Statistics and is based upon a 1982 Base of 100. A Consumer Price Index of 168 indicates 68% inflation since 1982. The commonly quoted inflation rate of say 3% is actually the change in the Consumer Price Index from a year earlier.

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual	HALF1	HALF2
2000	168.8	169.8	171.2	171.3	171.5	172.4	172.8	172.8	173.7	174.0	174.1	174.0	172.2	170.8	173.6
2001	175.1	175.8	176.2	176.9	177.7	178.0	177.5	177.5	178.3	177.7	177.4	176.7	177.1	176.6	177.5
2002	177.1	177.8	178.8	179.8	179.8	179.9	180.1	180.7	181.0	181.3	181.3	180.9	179.9	178.9	180.9
2003	181.7	183.1	184.2	183.8	183.5	183.7	183.9	184.6	185.2	185.0	184.5	184.3	184.0	183.3	184.6
2004	185.2	186.2	187.4	188.0	189.1	189.7	189.4	189.5	189.9	190.9	191.0	190.3	188.9	187.6	190.2
2005	190.7	191.8	193.3	194.6	194.4	194.5	195.4	196.4	198.8	199.2	197.6	196.8	195.3	193.2	197.4
2006	198.3	198.7	199.8	201.5	202.5	202.9	203.5	203.9	202.9	201.8	201.5	201.8	201.6	200.6	202.6
2007	202.4	203.5	205.4	206.7	207.9	208.4	208.3	207.9	208.5	208.9	210.2	210.0	207.3	205.7	209.0
2008	211.1	211.7	213.5	214.8	216.6	218.8	220.0	219.1	218.8	216.6	212.4	210.2	215.3	214.4	216.2
2009	211.1	212.2	212.7	213.2	213.9	215.7	215.4	215.8	216.0	216.2	216.3	215.9	214.5	213.1	215.9
2010	216.7	216.7	217.6	218.0	218.2	218.0	218.0	218.3	218.4	218.7	218.8	219.2	218.1	217.5	218.6
2011	220.2	221.3	223.5	224.9	226.0	225.7	225.9	226.5	226.9	226.4	226.2	225.7	224.9	223.6	226.3
2012	226.7	227.7	229.4	230.1	229.8	229.5	229.1	230.4	231.4	231.3	230.2	229.6	229.6	228.8	230.3
2013	230.3	232.2	232.8	232.5	232.9	233.5	233.6	233.9	234.1	233.5	233.1	233.0	233.0	232.4	233.5
2014	233.9	234.8	**236.3**	237.1	237.9	238.3	238.3	237.9	238.0	237.4	236.2	234.8	236.7	236.4	237.1
2015	233.7	234.7	236.1	236.6	237.8	238.6	238.7	238.3	237.9	237.8	237.3	236.5	237.0	236.3	237.8
2016	236.9	237.1	**238.1**												

Source: United States Department of Labour Bureau of Labor Statistics   Bureau of Labor Statistics Data

6.1.2 Jamaican Consumer Price Index

Ja. Consumer Price Index

The Index numbers listed in the table: Consumer Price Index for 2007-2015, are based on the revised calculations using the new series that have been derived by using data from the HES conducted between June 2004 and March 2005. For the years prior to 2007 the data is linked to the 1988 series of the CPI using a link factor.

These index numbers provide an historical series of the CPI on a monthly basis. The monthly indexes are given for the 12 months of the calendar year while the arithmetic mean of the data for the 12 months is used to arrive at an annual average index. The Percentage Changes calculated

Consumer Price Index for 2003-2015

Month	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
January	64.80	74.60	84.10	94.70	101.00	119.40	136.00	152.60	167.80	178.90	193.80	211.80	223.00	231.30
February	64.40	75.00	84.50	94.80	101.30	121.50	137.10	155.90	167.10	180.30	195.00	211.90	221.50	229.60
March	64.70	75.40	85.30	94.90	102.50	122.90	138.20	156.60	168.90	181.20	197.70	**214.20**	222.70	**229.30**
April	65.70	75.70	86.90	96.00	102.90	124.80	138.80	158.70	169.70	181.90	198.50	213.60	223.10	
May	66.80	76.20	88.70	96.30	104.30	127.80	140.00	159.70	171.00	182.80	199.60	215.70	224.20	
June	68.50	76.80	90.00	97.60	105.10	130.30	142.00	160.70	172.30	183.80	199.90	215.90	225.30	
July	69.50	77.60	91.40	98.90	106.10	134.00	143.30	161.30	173.60	183.20	200.90	218.90	227.20	
August	70.40	78.60	91.50	99.20	107.20	135.60	143.90	162.00	174.60	184.10	201.60	221.30	229.00	
September	71.50	79.00	93.80	99.90	108.90	136.50	146.30	162.80	175.91	187.60	207.20	225.90	230.00	
October	72.70	81.60	94.30	99.80	110.40	136.90	147.50	164.00	176.70	189.40	209.00	226.10	230.70	
November	73.40	83.60	94.60	99.60	114.00	136.40	148.70	165.70	177.50	190.60	209.50	224.90	231.80	
December	73.90	84.10	94.60	100.00	116.80	136.50	150.40	168.10	178.20	192.50	210.70	224.10	232.30	
Annual Average	**68.90**	**78.20**	**90.00**	**97.60**	**106.70**	**130.20**	**142.70**	**160.68**	**172.78**	**184.69**	**201.95**	**218.69**	**226.73**	**230.07**
Annual Inflation Rate	**13.80**	**13.70**	**12.60**	**5.70**	**16.80**	**16.80**	**10.20**	**11.80**	**6.00**	**8.00**	**9.45**	**6.36**	**3.66**	**-100.00**

The Consumer Price Index (CPI) is one in a series of economic indicators produced by the Statistical Institute of Jamaica as part of its objective to provide an integrated set of statistical information on the social and economic conditions of the people of Jamaica.

Source: Statistical Institute of Jamaica

6.2 Appendix 2: Estimated Bill Impact of OUR Approved Annual Tariff Adjustment

6.2.1 Bill Comparison for a Typical Rate 10 Consumer with consumption < 100 kWh

Usage 90 kWh

Rate 10	April 2016 Bill - Before			April 2016 Bill - After				
Below 100kWh	2015 - 2016 Rates J$			2016 - 2017 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	115.50	123.15		122.50	123.15			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy 1st	46	8.61	396.06	46	9.13	419.95	23.89	6.03%
Energy 2nd	0	20.05	-	0	21.26	-	-	
Customer Charge			404.88			429.31	24.43	6.03%
Sub Total			**800.94**			**849.26**	**48.32**	**6.03%**
EEIF	46	0.4998	**22.99**	46	0.2499	**11.50**		
F/E Adjust		0.053	42.44		0.004	3.61		
Fuel & IPP	46	8.078	371.57	46	8.780	403.86	**32.29**	**8.69%**
Bill Total			**J$ 1,237.94**			**J$ 1,268.23**	**30.28**	**2.45%**

6.2.2 Bill Comparison for a Typical Rate 10 Consumer with consumption 101kWh < 350kWh

Usage 349 kWh

Rate 10	April 2016 Bill - Before			April 2016 Bill - After				
101 < 350kWh	2015 - 2016 Rates J$			2016 - 2017 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	115.50	123.15		122.50	123.15			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy 1st	100	8.61	861.00	100	9.13	912.94	51.94	6.03%
Energy 2nd	249	20.05	4,992.45	249	21.26	5,293.65	301.20	6.03%
Customer Charge			404.88			429.31	24.43	6.03%
Sub Total			**6,258.33**			**6,635.90**	**377.57**	**6.03%**
EEIF	349	0.4998	**174.43**	349	0.2499	**87.22**		
F/E Adjust		0.053	331.61		0.004	28.17		
Fuel & IPP	349	8.078	2,819.11	349	8.780	3,064.10	**244.99**	**8.69%**
Bill Total			**J$ 9,583.48**			**J$ 9,815.38**	**231.90**	**2.42%**

6.2.3 Bill Comparison for a Typical Rate 10 Consumer with consumption 350kWh and above

Usage 350 kWh

Rate 10	April 2016 Bill - Before			April 2016 Bill - After				
Above 350kWh	2015 - 2016 Rates J$			2016 - 2017 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	115.50	123.15		122.50	123.15			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy 1st	100	8.61	861.00	100	9.13	912.94	51.94	6.03%
Energy 2nd	250	20.05	5,012.50	250	21.26	5,314.91	302.41	6.03%
Customer Charge			404.88			429.31	24.43	6.03%
Sub Total			**6,278.38**			**6,657.16**	**378.78**	**6.03%**
EEIF	350	0.4998	**174.93**	350	0.2499	**87.47**		
F/E Adjust		0.053	332.67		0.004	28.26		
Fuel & IPP	350	8.078	2,827.19	350	8.780	3,072.88		
Bill Sub-Total			**9,613.17**	**Bill Sub-Total**		**9,845.76**		
GCT @16.5%		0.165	1,586.17	GCT @16.5%	0.165	1,624.55	**38.38**	**2.42%**
Bill Total			**J$ 11,199.34**			**J$ 11,470.31**	**270.97**	**2.42%**

6.2.4 Bill Comparison for a Typical Rate 20 Consumer with consumption ≤ 100 kWh

Usage 90 kWh

Rate 20	April 2016 Bill - Before			April 2016 Bill - After				
Below 100kWh	2015 - 2016 Rates J$			2016 - 2017 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	115.50	123.15		122.50	123.15			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	90	16.61	1,494.90	90	17.61	1,585.09	90.19	6.03%
Customer Charge			902.00			956.42	54.42	6.03%
Sub Total			**2,396.90**			**2,541.51**	**144.61**	**6.03%**
EEIF		0.4998	**44.98**	90	0.2499	**22.49**		
F/E Adjust		0.053	127.00		0.004	10.79		
Fuel & IPP	90	8.078	726.99	90	8.780	790.17	**63.18**	**8.69%**
Bill Sub-Total			**3,295.88**			**3,364.96**	**69.08**	**2.10%**
GCT @16.5%		0.165	543.82		0.165	555.22		
Bill Total			**J$ 3,839.70**			**J$ 3,920.17**	**80.48**	**2.10%**

6.2.5 Bill Comparison for a Typical Rate 20 Consumer with consumption 101kWh - 1000kWh

Usage 1000 kWh

Rate 20	April 2016 Bill - Before			April 2016 Bill - After				
101 - 1000kWh	2015 - 2016 Rates J$			2016 - 2017 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	115.50	123.15		122.50	123.15			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	1000	16.61	16,610.00	1000	17.61	17,612.09	1,002.09	6.03%
Customer Charge			902.00			956.42	54.42	6.03%
Sub Total			**17,512.00**			**18,568.51**	**1,056.51**	**6.03%**
EEIF		0.4998	**499.80**	1000	0.2499	**249.90**		
F/E Adjust		0.053	927.91		0.004	78.82	- 849.09	
Fuel & IPP	1000	8.078	8,077.68	1000	8.780	8,779.66	701.98	8.69%
Bill Sub-Total			**27,017.39**			**27,676.89**	**659.50**	**2.44%**
GCT @16.5%		0.165	4,457.87		0.165	4,566.69	108.82	2.44%
Bill Total			**J$ 31,475.25**			**J$ 32,243.58**	**768.32**	**2.44%**

6.2.6 Bill Comparison for a Typical Rate 20 Consumer with consumption 1001kWh - 7500kWh

Usage 5000 kWh

Rate 20	April 2016 Bill - Before			April 2016 Bill - After				
Above 7500kWh	2015 - 2016 Rates J$			2016 - 2017 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	115.50	123.15		122.50	123.15			
		.						
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	8000	16.61	132,880.00	8000	17.61	140,896.76	8,016.76	6.03%
Customer Charge			902.00			956.42	54.42	6.03%
Sub Total			**133,782.00**			**141,853.18**	**8,071.18**	**6.03%**
EEIF		0.4998	**3,998.40**	8000	0.2499	**1,999.20**		
F/E Adjust		0.053	7,088.71		0.004	602.15	- 6,486.56	
Fuel & IPP	8000	8.078	64,621.42	8000	8.780	70,237.25	5,615.83	8.69%
Bill Sub-Total			**209,490.53**			**214,691.78**	**5,201.25**	**2.48%**
GCT @16.5%		0.165	34,565.94		0.165	35,424.14	858.21	2.48%
Bill Total			**J$ 244,056.47**			**J$ 250,115.92**	**6,059.45**	**2.48%**

6.2.7 Bill Comparison for a Typical Rate 20 Consumer with consumption above 7500kWh

Usage above 7500 kWh

Rate 20	April 2016 Bill - Before			April 2016 Bill - After				
Above 7500kWh	2015 - 2016 Rates J$			2016 - 2017 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	115.50	123.15		122.50	123.15			
		.						
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	8000	16.61	132,880.00	8000	17.40	139,163.75	6,283.75	4.73%
Customer Charge			902.00			944.65	42.65	4.73%
Sub Total			**133,782.00**			**140,108.40**	**6,326.40**	**4.73%**
EEIF		0.4998	**3,998.40**	8000	0	-		
F/E Adjust		0.053	7,088.71		0.004	594.75	- 6,493.96	
Fuel & IPP	8000	8.078	64,621.42	8000	8.780	70,237.25	5,615.83	8.69%
Bill Sub-Total			**209,490.53**			**210,940.40**	**1,449.87**	**0.69%**
GCT @16.5%		0.165	34,565.94		0.165	34,805.17	239.23	0.69%
Bill Total			**J$ 244,056.47**			**J$ 245,745.56**	**1,689.10**	**0.69%**

6.2.8 Bill Comparison for a Typical Rate 40 Consumer

Usage 35,000 kWh

Demand 100 kVA

Rate 40	April 2016 Bill - Before			April 2016 Bill - After				
Standard	2015 - 2016 Rates J$			2016 - 2017 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	115.50	123.15		122.50	123.15			
	Usage	Rate (J$)		Usage	Rate (J$)			
Energy kWh	35000	5.18	181,300.00	35000	5.49	192,237.98	10,937.98	6.03%
Demand kVA	100	1622.78	162,278.00	100	1720.68	172,068.37	9,790.37	
Customer Charge			6,355.00			6,738.40	383.40	6.03%
Sub Total			**349,933.00**			**371,044.75**	**21,111.75**	**6.03%**
EEIF		0.4998	**17,493.00**	35000	0.2499	**8,746.50**		
F/E Adjust		0.053	18,541.90		0.004	1,575.05	- 16,966.86	
Fuel & IPP	35000	7.755	271,409.96	35000	8.428	294,996.43	23,586.47	8.69%
Bill Sub-Total			**657,377.87**			**676,362.73**	**18,984.86**	**2.89%**
GCT @16.5%		0.165	108,467.35		0.165	111,599.85	3,132.50	2.89%
Bill Total			**J$ 765,845.21**			**J$ 787,962.58**	**22,117.36**	**2.89%**

6.2.9 Bill Comparison for a Typical Rate 50 Customer

Usage 500,000 kWh

Demand 1,500 kVA

Rate 50	April 2016 Bill - Before			April 2016 Bill - After				
Standard	2015 - 2016 Rates J$			2016 - 2017 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	115.50	123.15		**122.50**	123.15			
	Usage	Rate (J$)		Usage	Rate (J$)			
Energy kWh	500000	4.99	2,495,000.00	500000	**5.29**	2,645,525.40	150,525.40	6.03%
Demand kVA	1500	1453.80	2,180,700.00	1500	**1541.51**	2,312,263.42	131,563.42	6.03%
Customer Charge			6,355.00			**6,738.40**	383.40	6.03%
Sub Total			**4,682,055.00**			**4,964,527.23**	**282,472.23**	**6.03%**
EEIF		0.4998	**249,900.00**	500000	0.2499	**124,950.00**		
F/E Adjust		0.053	248,088.11		0.004	21,073.91	- 227,014.20	
Fuel & IPP	500000	7.755	3,877,285.16	500000	8.428	4,214,234.78	336,949.62	8.69%
Bill Sub-Total			**9,057,328.27**			**9,324,785.92**	**267,457.65**	**2.95%**
GCT @16.5%		0.165	1,494,459.16		0.165	1,538,589.68	44,130.51	2.95%
Bill Total			**J$ 10,551,787.43**			**J$ 10,863,375.59**	**311,588.16**	**2.95%**

6.2.10 Bill Comparison for a Typical Rate 50 TOU Customer (Partial Peak)

Usage 500,000 kWh

Demand 1,500 kVA

Rate 50	April 2016 Bill - Before			April 2016 Bill - After				
TOU (Partial Peak)	2015 - 2016 Rates J$			2016 - 2017 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	115.50	123.15		**122.50**	123.15			
	Usage	Rate (J$)		Usage	Rate (J$)			
Energy kWh	500000	4.99	2,495,000.00	500000	**5.29**	2,645,525.40	150,525.40	6.03%
Demand kVA	1500	618.68	928,020.00	1500	**670.77**	1,006,147.92	78,127.92	8.42%
Customer Charge			6,355.00			**6,738.40**	383.40	6.03%
Sub Total			**3,429,375.00**			**3,658,411.72**	**229,036.72**	**6.68%**
EEIF		0.4998	**249,900.00**	500000	0.2499	**124,950.00**		
F/E Adjust		0.053	181,712.34		0.004	21,073.91	- 160,638.43	
Fuel & IPP	500000	7.449	3,724,627.10	500000	8.097	4,048,310.20	323,683.10	8.69%
Bill Sub-Total			**7,585,614.44**			**7,852,745.83**	**267,131.39**	**3.52%**
GCT @16.5%		0.165	1,251,626.38		0.165	1,295,703.06	44,076.68	3.52%
Bill Total			**J$ 8,837,240.82**			**J$ 9,148,448.90**	**311,208.07**	**3.52%**

6.3 Appendix 3: Estimated Bill Impact of JPS Proposed Annual Tariff Adjustment

6.3.1 Bill Comparison for a Typical Rate 10 Consumer with consumption < 100 kWh

Usage 90 kWh

Rate 10	April 2016 Bill - Before			April 2016 Bill - After				
Below 100kWh	2015 - 2016 Rates J$			2016 - 2017 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	115.50	123.15		**122.50**	123.15			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy 1st	90	8.61	774.90	90	**9.14**	822.43	47.53	6.13%
Energy 2nd	0	20.05	-	0	**21.28**	-	-	
Customer Charge			404.88			**429.71**	24.83	6.13%
Sub Total			**1,179.78**			**1,252.14**	**72.36**	**6.13%**
EEIF	90	0.4998	**44.98**	90	0.4998	**44.98**		
F/E Adjust		0.053	62.51		0.004	5.32		
Fuel & IPP	90	8.078	726.99	90	8.059	725.33		
Bill Total			**J$ 2,014.27**			**J$ 2,027.76**	**13.50**	**0.67%**

6.3.2 Bill Comparison for a Typical Rate 10 Consumer with consumption 101kWh < 350kWh

Usage 349 kWh

Rate 10	April 2016 Bill - Before			April 2016 Bill - After				
101 < 350kWh	2015 - 2016 Rates J$			2016 - 2017 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	115.50	123.15		**122.50**	123.15			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy 1st	100	8.61	861.00	100	**9.14**	913.81	52.81	6.13%
Energy 2nd	249	20.05	4,992.45	249	**21.28**	5,298.64	306.19	6.13%
Customer Charge			404.88			**429.71**	24.83	6.13%
Sub Total			**6,258.33**			**6,642.16**	**383.83**	**6.13%**
EEIF	349	0.4998	**174.43**	349	0.4998	**174.43**		
F/E Adjust		0.053	331.61		0.004	28.20		
Fuel & IPP	349	8.078	2,819.11	349	8.059	2,812.59		
Bill Total			**J$ 9,583.48**			**J$ 9,657.37**	**73.89**	**0.77%**

6.3.3 Bill Comparison for a Typical Rate 10 Consumer with consumption 350kWh and above

Usage 350 kWh

Rate 10	April 2016 Bill - Before			April 2016 Bill - After				
Above 350kWh	2015 - 2016 Rates J$			2016 - 2017 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	115.50	123.15		122.50	123.15			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy 1st	100	8.61	861.00	100	9.14	913.81	52.81	6.13%
Energy 2nd	250	20.05	5,012.50	250	21.28	5,319.92	307.42	6.13%
Customer Charge			404.88			429.71	24.83	6.13%
Sub Total			**6,278.38**			**6,663.44**	**385.06**	**6.13%**
EEIF	350	0.4998	**174.93**	350	0.4998	**174.93**		
F/E Adjust		0.053	332.67		0.004	28.29		
Fuel & IPP	350	8.078	2,827.19	350	8.059	2,820.72		
Bill Sub-Total			**9,613.17**	**Bill Sub-Total**		**9,687.37**		
GCT @16.5%		0.165	1,586.17	GCT @16.5%	0.165	1,598.42		
Bill Total			**J$ 11,199.34**			**J$ 11,285.79**	**86.45**	**0.77%**

6.3.4 Bill Comparison for a Typical Rate 20 Consumer with consumption ≤ 100 kWh

Usage 90 kWh

Rate 20	April 2016 Bill - Before			April 2016 Bill - After				
Below 100kWh	2015 - 2016 Rates J$			2016 - 2017 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	115.50	123.15		122.50	123.15			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	90	16.61	1,494.90	90	17.63	1,586.58	91.68	6.13%
Customer Charge			902.00			957.32	55.32	6.13%
Sub Total			**2,396.90**			**2,543.90**	**147.00**	**6.13%**
EEIF		0.4998	**44.98**	90	0.4998	**44.98**		
F/E Adjust		0.053	127.00		0.004	10.80		
Fuel & IPP	90	8.078	726.99	90	8.059	725.33		
Bill Sub-Total			**3,295.88**			**3,325.01**	**29.13**	**0.88%**
GCT @16.5%		0.165	543.82		0.165	548.63		
Bill Total			**J$ 3,839.70**			**J$ 3,873.64**	**33.94**	**0.88%**

6.3.5 Bill Comparison for a Typical Rate 20 Consumer with consumption 101kWh - 1000kWh

Usage 1000 kWh

Rate 20	April 2016 Bill - Before			April 2016 Bill - After				
101 - 1000kWh	2015 - 2016 Rates J$			2016 - 2017 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	115.50	123.15		122.50	123.15			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	1000	16.61	16,610.00	1000	17.63	17,628.70	1,018.70	6.13%
Customer Charge			902.00			957.32	55.32	6.13%
Sub Total			**17,512.00**			**18,586.02**	**1,074.02**	**6.13%**
EEIF		0.4998	**499.80**	1000	0.4998	**499.80**		
F/E Adjust		0.053	927.91		0.004	78.90	- 849.01	
Fuel & IPP	1000	8.078	8,077.68	1000	8.059	8,059.20	- 18.47	-0.23%
Bill Sub-Total			**27,017.39**			**27,223.92**	**206.54**	**0.76%**
GCT @16.5%		0.165	4,457.87		0.165	4,491.95	34.08	0.76%
Bill Total			**J$ 31,475.25**			**J$ 31,715.87**	**240.61**	**0.76%**

6.3.6 Bill Comparison for a Typical Rate 20 Consumer with consumption 1001kWh - 7500kWh

Usage 5000 kWh

Rate 20	April 2016 Bill - Before			April 2016 Bill - After				
1001 - 7500kWh	2015 - 2016 Rates J$			2016 - 2017 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	115.50	123.15		122.50	123.15			
		.						
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	5000	16.61	83,050.00	5000	17.63	88,143.51	5,093.51	6.13%
Customer Charge			902.00			957.32	55.32	6.13%
Sub Total			**83,952.00**			**89,100.83**	**5,148.83**	**6.13%**
EEIF		0.4998	**2,499.00**	5000	0.4998	**2,499.00**		
F/E Adjust		0.053	4,448.37		0.004	378.22	- 4,070.14	
Fuel & IPP	5000	8.078	40,388.39	5000	8.059	40,296.02	- 92.37	-0.23%
Bill Sub-Total			**131,287.75**			**132,274.07**	**986.32**	**0.75%**
GCT @16.5%		0.165	21,662.48		0.165	21,825.22	162.74	0.75%
Bill Total			**J$ 152,950.23**			**J$ 154,099.30**	**1,149.06**	**0.75%**

6.3.7 Bill Comparison for a Typical Rate 20 Consumer with consumption above 7500kWh

Usage above 7500 kWh

Rate 20	April 2016 Bill - Before			April 2016 Bill - After				
Above 7500kWh	2015 - 2016 Rates J$			2016 - 2017 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	115.50	123.15		122.50	123.15			
		.						
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	8000	16.61	132,880.00	8000	17.63	141,029.61	8,149.61	6.13%
Customer Charge			902.00			957.32	55.32	6.13%
Sub Total			**133,782.00**			**141,986.93**	**8,204.93**	**6.13%**
EEIF		0.4998	**3,998.40**	8000	0.4998	**3,998.40**		
F/E Adjust		0.053	7,088.71		0.004	602.72	- 6,485.99	
Fuel & IPP	8000	8.078	64,621.42	8000	8.059	64,473.63	- 147.78	-0.23%
Bill Sub-Total			**209,490.53**			**211,061.69**	**1,571.16**	**0.75%**
GCT @16.5%		0.165	34,565.94		0.165	34,825.18	259.24	0.75%
Bill Total			**J$ 244,056.47**			**J$ 245,886.87**	**1,830.40**	**0.75%**

6.3.8 Bill Comparison for a Typical Rate 40 Consumer

Usage 35,000 kWh

Demand 100 kVA

Rate 40	April 2016 Bill - Before			April 2016 Bill - After				
Standard	2015 - 2016 Rates J$			2016 - 2017 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	115.50	123.15		122.50	123.15			
	Usage	Rate (J$)		Usage	Rate (J$)			
Energy kWh	35000	5.18	181,300.00	35000	5.50	192,419.24	11,119.24	6.13%
Demand kVA	100	1622.78	162,278.00	100	1722.31	172,230.61	9,952.61	
Customer Charge			6,355.00			6,744.76	389.76	6.13%
Sub Total			**349,933.00**			**371,394.61**	**21,461.61**	**6.13%**
EEIF		0.4998	**17,493.00**	35000	0.4998	**17,493.00**		
F/E Adjust		0.053	18,541.90		0.004	1,576.53	- 16,965.37	
Fuel & IPP	35000	7.755	271,409.96	35000	7.737	270,789.26	- 620.70	-0.23%
Bill Sub-Total			**657,377.87**			**661,253.40**	**3,875.54**	**0.59%**
GCT @16.5%		0.165	108,467.35		0.165	109,106.81	639.46	0.59%
Bill Total			**J$ 765,845.21**			**J$ 770,360.22**	**4,515.00**	**0.59%**

6.3.9 Bill Comparison for a Typical Rate 50 Customer

Usage 500,000 kWh

Demand 1,500 kVA

Rate 50	April 2016 Bill - Before			April 2016 Bill - After				
Standard	2015 - 2016 Rates J$			2016 - 2017 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	115.50	123.15		122.50	123.15			
	Usage	Rate (J$)		Usage	Rate (J$)			
Energy kWh	500000	4.99	2,495,000.00	500000	5.30	2,648,019.90	153,019.90	6.13%
Demand kVA	1500	1453.80	2,180,700.00	1500	1521.93	2,282,901.11	102,201.11	4.69%
Customer Charge			6,355.00			1,542.96	- 4,812.04	-75.72%
Sub Total			**4,682,055.00**			**4,932,463.97**	**250,408.97**	**5.35%**
EEIF		0.4998	**249,900.00**	500000	0.4998	**249,900.00**		
F/E Adjust		0.053	248,088.11		0.004	20,937.81	- 227,150.30	
Fuel & IPP	500000	7.755	3,877,285.16	500000	7.737	3,868,418.07	- 8,867.10	-0.23%
Bill Sub-Total			**9,057,328.27**			**9,071,719.84**	**14,391.57**	**0.16%**
GCT @16.5%		0.165	1,494,459.16		0.165	1,496,833.77	2,374.61	0.16%
Bill Total			**J$ 10,551,787.43**			**J$ 10,568,553.62**	**16,766.18**	**0.16%**

6.3.10 Bill Comparison for a Typical Rate 50 TOU Customer (Partial Peak)

Usage 500,000 kWh

Demand 1,500 kVA

Rate 50	April 2016 Bill - Before			April 2016 Bill - After				
TOU (Partial Peak)	2015 - 2016 Rates J$			2016 - 2017 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	115.50	123.15		122.50	123.15			
	Usage	Rate (J$)		Usage	Rate (J$)			
Energy kWh	500000	4.99	2,495,000.00	500000	5.30	2,648,019.90	153,019.90	6.13%
Demand kVA	1500	618.68	928,020.00	1500	671.40	1,007,096.63	79,076.63	8.52%
Customer Charge			6,355.00			1,542.96	- 4,812.04	-75.72%
Sub Total			**3,429,375.00**			**3,656,659.48**	**227,284.48**	**6.63%**
EEIF		0.4998	**249,900.00**	500000	0.4998	**249,900.00**		
F/E Adjust		0.053	181,712.34		0.004	20,937.81	- 160,774.53	
Fuel & IPP	500000	7.449	3,724,627.10	500000	7.432	3,716,109.12	- 8,517.98	-0.23%
Bill Sub-Total			**7,585,614.44**			**7,643,606.42**	**57,991.98**	**0.76%**
GCT @16.5%		0.165	1,251,626.38		0.165	1,261,195.06	9,568.68	0.76%
Bill Total			**J$ 8,837,240.82**			**J$ 8,904,801.47**	**67,560.65**	**0.76%**

6.4 Appendix 4: Fuel Weights

1.4.1 Existing Weights

FUEL & IPP RATE SUMMARY - April 2016				
Implemented in May 2016				
BILLING EXCHANGE RATE J$123.1541 = US$1.00				
Fuel Weights Applicable				
Class	Std.	Off Peak	Partial Peak	On Peak
Rate 10				
1st. 100 kWh	1.000			
Over 100 kWh	1.000			
Rate 20	1.000			
Rate 40 LV	0.960	0.800	1.044	1.302
Rate 40A LV	0.960			
Rate 50 MV	0.960	0.800	1.044	1.302
Rate 60	0.960			
Traffic Signal	0.960			
Actual Fuel & IPP Rate for April 2016 [USc/kWh]				7.129
Billing Exchange Rate for April 2016				123.15
Fuel & IPP Rates for April 2016				
Class	Std.	Off Peak	Partial Peak	On Peak
Rate 10				
1st. 100 kWh	8.780			
Over 100 kWh	8.780			
Rate 20	8.780			
Rate 40 LV	8.428	7.024	9.170	11.428
Rate 40A LV	8.428			
Rate 50 MV	8.428	7.024	9.170	11.428
Rate 60	8.428			
Traffic Signal	8.428			

6.4.2 Approved Weights

FUEL & IPP RATE SUMMARY - April 2016				
Implemented in May 2016				
BILLING EXCHANGE RATE J$123.1541 = US$1.00				
Fuel Weights Applicable				
Class	Std.	Off Peak	Partial Peak	On Peak
Rate 10				
1st. 100 kWh	1.000			
Over 100 kWh	1.000			
Rate 20	1.000			
Rate 40 LV	0.960	0.800	1.044	1.302
Rate 40A LV	0.960			
Rate 50 MV	0.960	0.800	1.044	1.302
Rate 60	0.960			
Traffic Signal	0.960			
Actual Fuel & IPP Rate for April 2016 [USc/kWh]				6.903
Billing Exchange Rate for April 2016				123.15
Fuel & IPP Rates for April 2016				
Class	Std.	Off Peak	Partial Peak	On Peak
Rate 10				
1st. 100 kWh	8.501			
Over 100 kWh	8.501			
Rate 20	8.501			
Rate 40 LV	8.161	6.801	8.879	11.065
Rate 40A LV	8.161			
Rate 50 MV	8.161	6.801	8.879	11.065
Rate 60	8.161			
Traffic Signal	8.161			