Office of Utilities Regulation

Jamaica Public Service Company Limited
Tariff Review for Period 2014-2019

Determination Notice

January 7, 2015

OFFICE OF UTILITIES REGULATION

3rd Floor, PCJ Resource Centre
36 Trafalgar Road, Kingston 10

DOCUMENT TITLE AND APPROVAL PAGE

DOCUMENT NUMBER: 2014/ELE/008/DET.004

1. DOCUMENT TITLE: Jamaica Public Service Company Limited Tariff Review for Period 2014 – 2019: Determination Notice

2. PURPOSE OF DOCUMENT

This document sets out the Office's decisions regarding the rates and the mechanism for price control for electricity services provided by Jamaica Public Service Company Limited (JPS), as well as performance and quality of service standards.

3. ANTECEDENT DOCUMENTS

Document Number	Description	Date

4. APPROVAL

This document is approved by the Office of Utilities Regulation and the decisions therein become effective on **January 7, 2015**.

On behalf of the Office:

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Albert Gordon
Director General

Date: January 7, 2015

Foreword

This document is in two parts. Part ONE (SUMMARY OF DECISIONS) presents the legal authority for the Office of Utilities Regulation's (Office's) decision and sets out the specific determinations made by the Office in respect of its review of the Jamaica Public Service Company Limited's ("JPS") April 2014 Tariff Application. Part TWO (REASONS FOR OFFICE DECISION & TECHNICAL ANALYSIS) summarizes the proposals made by JPS and outlines the Office's responses and the underlying rationale.

In arriving at its decision the Office has had extensive public consultation, engaged in ongoing discussions with JPS and, where necessary and relevant, has drawn heavily on best practices. The approach adopted reflects the objective of ensuring that the regime determined for the next five years provides incentives for JPS to deliver real benefits to its customers through improved efficiency, better quality of service and expanded coverage.

The Office, in its economic regulatory activities, is committed to national development by creating an environment for the efficient delivery of reliable utility services to consumers, while ensuring that service providers have the opportunity to make a reasonable return on investment.

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Acronyms and Abbreviations

ABNF	–	Adjusted Non-Fuel Base Rate
ADC	–	Average Dependable Capacity
ADO	–	Automotive Diesel Oil
AFUDC	–	Allowance for Funds Used During Construction
AMI	–	Advanced Metering Infrastructure
AR	–	Auto-Regressive
BAO	–	Best Alternative Option
BIS	–	Business Intelligence System
BL&P	–	Barbados Light and Power Company Ltd
BPRF	–	Bogue Plant Reconfiguration Fund
CACU	–	Consumer Advisory Committee on Utilities
CAMI	–	Commercial Automated Metering Infrastructure
CAAMI	–	Commercial Anti-Theft Automated Metering Infrastructure
CAIDI	–	Customer Average Interruption Duration Index
CAPEX	–	Capital Expenditure
CAPM	–	Capital Asset Pricing Model
CCGT	–	Combined Cycle Gas Turbine
CDU	–	Customer Display Unit
CI	–	Combustion Inspection
CIDA	–	Canadian International Development Agency
CIS	–	Customer Information System
CPLTD	–	Current Portion of Long Term Debt
COB	–	Close of Business
COD	–	Commercial Operations Date
COUE	–	Cost of Unserved Energy
CML	–	Customer Minutes Lost
CPI	–	Consumer Price Index
CRP	–	Country Risk Premium
CS	–	Consumer Surplus
CSR	–	Customer Service Representatives
CT	–	Current Transformer
CWIP	–	Construction work in progress
DCF	–	Discounted Cash Flow
DFID	–	Department for International Development
EA	–	Equivalent Availability
ECPR	–	Efficient Component Pricing Rule
DEA	–	Data Envelope Analysis
EDF	–	Electricity Disaster Fund
EFA	–	Efficiency Frontier Analysis
EFLP	–	Equivalent Full Load Provision
EGS	–	Electricity Guaranteed Standard
EMS	–	Environmental Management System

EEIF	–	Electricity Efficiency Improvement Fund
EPMU	–	Equi-Proportional Mark-Up method
EU	–	European Union
EWI	–	Energy World International Limited
FCAM	–	Fuel Cost Adjustment Mechanism
FCRA	–	Fuel Cost Recovery Adjustment
FTL	–	Fixed Technical Losses
FSA	–	Fuel Supply Agreement
FX	–	Foreign Exchange
GDP	–	Gross Domestic Product
GEI	–	Government Electrical Inspectorate
GOJ	–	Government of Jamaica
GSU	–	Generator Step-up Transformer
GT	–	Gas Turbine
GWh	–	Gigawatt-hour
HAJ	–	Housing Authority of Jamaica
HGPI	–	Hot Gas Path Inspection
HFO	–	Heavy Fuel Oil
IADB	–	Inter-American Development Bank
ICT	–	Information and Communication Technology
IEEE	–	Institute of Electrical and Electronics Engineers
IPP	–	Independent Power Producer
IQR	–	Inter Quartile Range
IVR	–	Interactive Voice Response
IDT	–	Industrial Dispute Tribunal
JCC	–	Jamaica Chamber of Commerce
JEP	–	Jamaica Energy Partners
JIE	–	Jamaica Institute of Engineers
JPPC	–	Jamaica Private Power Company
JPS	–	Jamaica Public Service Company Limited
J$	–	Jamaican Dollar
KPI	–	Key Performance Indicator
KVA	–	Kilo volt ampere
kWh	–	Kilowatt-hour
LCEP	–	Least Cost Expansion Plan
LED	–	Light Emitting Diode
LNG	–	Liquefied Natural Gas
LPG	–	Liquid Petroleum Gas
LRMC	–	Long Run Marginal Cost
LTD	–	Long Term Debt
Licence	–	The Amended and Restated All-Island Electric Licence, 2011
Licensee	–	Jamaica Public Service Company Limited
MAIFI	–	Momentary average interruption frequency index
MED	–	Major Event Day

MFP	–	Multifactor Productivity
MLGCD	–	Ministry of Local Government and Community Development
MMRP	–	Mature Market Risk Premium
MSD	–	Medium Speed Diesel
MTBF	–	Mean Time between Failures
MVA	–	Mega volt ampere
MW	–	Megawatts
MWh	–	Megawatt-hours
NAC	–	Network Access Charge
NEO	–	Net Energy Output
NRW	–	Non-Revenue Water
NTL	–	Non-Technical Losses
NWC	–	National Water Commission
NWU	–	National Workers Union
O&M	–	Operation and maintenance
OMS	–	Outage Management System
OCB	–	Oil Circuit Breakers
OEM	–	Original Equipment Manufacturer
OPEX	–	Operating Expenditure
OUR	–	Office of Utilities Regulation
PCI	–	Non-Fuel Electricity Pricing Index
PEG	–	Pacific Economics Group, LLC
PPA	–	Power Purchase Agreement
PBRM	–	Performance Based Rate–Making Mechanism
PRBO	–	Post Retirement Benefit obligation
PT	–	Potential Transformer
RAMI	–	Residential Advanced Metering Infrastructure
RDC	–	Required Dependable Capacity
RE	–	Renewable Energy
RELI	–	Recloser Energy Limiting Initiative
REP	–	Rural Electrification Programme Limited
ROE	–	Return on Equity
ROI	–	Return on Investment
RPD	–	Revenue Protection Department
SAC	–	Short-run Avoided Cost
SAIDI	–	System Average Interruption Duration Index
SAIFI	–	System Average Interruption Frequency Index
SCADA	–	Supervisory Control and Data Acquisition
SCED	–	Security Constrained Economic Dispatch
SCGT	–	Simple Cycle Gas Turbine
SFA	–	Stochastic Frontier Analysis
SDC	–	Social Development Commission
SIF	–	Self-Insurance Fund/ Electricity Disaster Fund
SLA	–	Service Level Agreement

SOC	–	Standard Offer Contract
SSD	–	Slow Speed Diesel
STATIN	–	Statistical Institute of Jamaica
STS	–	Standard Transfer Specification
SWOT	–	Strength Weakness Opportunity Threat
TCBFTED	–	The Conference Board For Total Economic Data
TFP	–	Total Factor Productivity
TL	–	Technical Losses
TOU	–	Time Of Use
TPDDL	–	Tata Power Delhi Distribution Limited
UAL	–	Useful Asset Lives
USA	–	United States of America
US$	–	United States Dollar
VAM	–	Volumetric Adjustment Mechanism
VOM	–	Variable Operation & Maintenance
VTL	–	Variable Technical Losses
WACC	–	Weighted Average Cost of Capital
WKPP	–	West Kingston Power Partners

SUMMARY OF DECISIONS

Preamble

Jamaica Public Service Company Limited ("JPS"), consistent with the conditions of the Amended and Restated All-Island Electric Licence, 2011 (the "Licence"), submitted an application for a tariff review in April 2014 (the "JPS' Tariff Submission"), after which ensued a period of public consultation (oral and written), correspondences with JPS to secure additional data and clarification and intensive analytical work by the Office of Utilities Regulation's (Office/OUR) technical staff. JPS was also provided with a preview of the draft Determination Notice on which it provided extensive comments and further engaged the Office's technical staff ("JPS' Comments"). The OUR has now concluded its review of the application, considered JPS' Comments and sets out herein its decisions and the reasoning.

For this particular application, JPS requested a departure from the usual five-year rate review to three years, arguing that the anticipation of significant additions to the grid in the next three (3) years by way of intermittent renewables and base-load generation capacity would require major changes. The company also proposed a change from price cap to revenue cap asserting, inter alia, that this mechanism would provide better incentive for it to encourage demand-side management and energy efficiency.

JPS requested the following rate changes:

- An average increase of 21% on total residential tariff;
- An average increase of 15% on the tariff for Rate 20 customers with consumption below 7,500 kWh; and
- An average reduction of 2.80% of the tariff for commercial and industrial customers (Rate 40 and Rate 50).

Other notable requests were:

- A change in the relative share of foreign currency related cost to local cost;
- An increase in the component of fixed payment in the rates;
- The inclusion of a mechanism to allow JPS to recover foreign exchange (FX) losses attributed to settlements with Petrojam;

- A significant increase in the deemed percentage of losses allowed to be passed to paying customers;

- The charging of interest to commercial customers in arrears;

- The proposed launch of a prepayment system and associated rates; and

- The approval of spending on a proposed Community Renewal Programme.

The Office has evaluated JPS' Tariff Submission in the context of Sections 11 and 12 of the Office of Utilities Regulation Act ("OUR Act") and Condition 15 and Schedule 3 of the Licence.

The Office's decisions are set out in this Determination Notice some of which are highlighted below.

Financial, Economic and Technical Analysis

Non-Fuel Rates

Effective January 07, 2015 the Average Base Non-Fuel Rate to be charged to customers by JPS shall be US$0.1288/kWh (J$14.42/kWh at a base exchange rate of J$112.00:US$) compared with US$0.1295/kWh (J$12.76/kWh at a base exchange rate of J$98.50:US$) which was approved by the Office in the "Jamaica Public Service Company Limited Annual Tariff Adjustment for 2013 – Determination Notice, Document No. 2013/ELE/007/Det.001" ("2013 Annual Tariff Adjustment Determination Notice").

The average non-fuel tariff is derived using:

a. The two-part tariff design which uses the long-run marginal cost approach. Tables 01 and 02 below indicate the composition of this rate and the comparison between what currently obtains and that determined by the Office.

Table 01: OUR's Approved Non-Fuel Rates (J$/kWh) by Customer Class

Class		Block/ Rate Option	Customer Charge	Energy- J$/kWh	Demand-J$/KVA Std.	Off-Peak	Part Peak	On-Peak
New Rates								
Rate 10	LV	--100	390	7.00				
Rate 10	LV	> 100	390	18.07				
Rate 20	LV		820	13.61				
Rate 40	LV - Std		6,200	4.38	1,587.07			
Rate 40	LV - TOU		6,200	4.38		66.92	698.32	894.12
Rate 50	MV - Std		6,200	4.05	1,421.81			
Rate 50	MV - TOU		6,200	4.05		63.40	618.68	793.78
Rate 60	LV		2,500	21.50				

Table 02: Change in Non-Fuel Rate (2014 over 2013)

Year	Approved Revenue J$'000	Approved Revenue US$'000	Sales (MWh)	Price J$/kWh	Price US$/kWh	J$: US$
2013	38,483,434	390,695	3,015,791	12.76	0.1295	98.50
2014	42,969,198	383,654	2,979,803	14.42	0.1288	112.00
	Change in Base Rate 2014 over 2013			13.00%	-0.6%	
	2014 Annual Inflation and F/X Adjustment to Date			13.96%		
	Effective Change in Non-Fuel Rate			-0.96%		

b. The audited accounts for 2013 as the 'test year'.

c. Non-Fuel Revenue Requirement of US$383.65M (J$42.97B) determined by the Office is shown in Table 08 below.

d. Test year billing demand determinant of 2,979,803MWh determined by the Office as shown in Table 03.

Table 03: Test Year - Billing Demand Determinant

OUR' Approved Billing Demand Determinant	
Test Year (2013) Sales (MWh)	**3,069,689**
Less Caribbean Cement Company (MWh)	89,886
Test Year Billing Demand (MWh)	**2,979,803**

e. The allowed level of fixed cost recovery remaining unchanged at 23%.
f. A Base Exchange Rate of: US$1.00 = J$112.00.

As shown in Table 04 below, JPS requested a 37.35% increase in the average non-fuel rate expressed in J$ per kilowatt hour (a 20.8% increase expressed in US$ per kilowatt hour terms as presented in its submission). The Office's Determination will result in a 13.0% change in the average non-fuel rate in J$ per kilowatt hour, (a -0.6% change expressed in US$ per kilowatt hour terms) compared to the 2013 rates. When the 2014 Annual Inflation and FX Adjustment to date, are taken into account, the effective change in J$ terms will be -0.96% as shown in Table 02 above.

Table 04: JPS' Proposed Change in Non-Fuel Rate (2014 over 2013)

Year	JPS Revenue Requirement		Sales	Price		J$:US$
	J$'000	US$'000	(MWh)	J$/kWh	US$/kWh	
2013	38,483,434	390,695	3,015,791	12.76	0.1295	98.5
2014	52,009,226	464,368	2,967,417	17.53	0.1565	112.0
	Change in Base Rate 2014 over 2013			37.35%	20.8%	
	2014 Annual Inflation and FX Adjustment to Date			13.96%		
	Effective Increase in Non-Fuel Rate			**23.39%**		

Tables 05 and 06 below show the impact of the Office's determined rates and the JPS' proposed rates respectively on total bill for the typical customer in each rate class utilizing data as at February 2014 for comparison with JPS' Tariff Submission.

Table 05: Bill Impact of the Office's Approved Rates

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	-5.3%	-3.5%
RT 10 LV Res. Service 100-500 kWh	200	n/a	-3.2%	
RT 10 LV Res. Service > 500 kWh	600	n/a	-1.9%	
RT 20 LV Gen. Service < 100 kWh	90	n/a	-7.0%	-5.9%
RT 20 LV Gen. Service 100-1000 kWh	1,000	n/a	-5.9%	
RT 20 LV Gen. Service 1000-7500 kWh	5,000	n/a	-5.7%	
RT 20 LV Gen. Service > 7500 kWh	8,000	n/a	-5.7%	
RT 40 LV Power Service (Std)	35,000	100	-2.8%	-5.0%
RT 50 MV Power Service (Std)	500,000	1,500	-3.2%	
RT 50 MV Power Service (TOU(on- peak))	500,000	1,500	-9.1%	
Efficiency Targets:	System Losses Target		JPS Thermal Heat Rate Target	
	19.20%		12,010 kJ/kWh	

Table 06: Bill Impact of JPS' Proposed Rates

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	11.0%	16.2%
RT 10 LV Res. Service 100-500 kWh	200	n/a	17.4%	
RT 10 LV Res. Service > 500 kWh	600	n/a	20.1%	
RT 20 LV Gen. Service < 100 kWh	90	n/a	13.8%	9.2%
RT 20 LV Gen. Service 100-1000 kWh	1,000	n/a	15.1%	
RT 20 LV Gen. Service 1000-7500 kWh	5,000	n/a	13.0%	
RT 20 LV Gen. Service > 7500 kWh	8,000	n/a	-5.1%	
RT 40 LV Power Service (Std)	35,000	100	-1.3%	-5.2%
RT 50 MV Power Service (Std)	500,000	1,500	-1.9%	
RT 50 MV Power Service (TOU(on- peak))	500,000	1,500	-12.6%	
Efficiency Targets:	System Losses Target		System Heat Rate Target	
	21.50%		10,200 kJ/kWh	

Table 07 below shows the estimated bill impact of the Office's determined rates and targets on customers' November 2014 bills.

Table 07: Estimated Bill Impact of the Office's Determination on November 2014 Bills

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	-3.9%	-1.9%
RT 10 LV Res. Service 100-500 kWh	200	n/a	-1.5%	
RT 10 LV Res. Service > 500 kWh	600	n/a	-0.2%	
RT 20 LV Gen. Service < 100 kWh	90	n/a	-6.2%	-5.0%
RT 20 LV Gen. Service 100-1000 kWh	1,000	n/a	-4.7%	
RT 20 LV Gen. Service 1000-7500 kWh	5,000	n/a	-4.5%	
RT 20 LV Gen. Service > 7500 kWh	8,000	n/a	-4.5%	
RT 40 LV Power Service (Std)	35,000	100	-0.8%	-1.1%
RT 50 MV Power Service (Std)	500,000	1,500	-1.3%	
RT 50 MV Power Service (TOU(on- peak))	500,000	1,500	-1.3%	
Efficiency Targets:	**System Losses Target**		**JPS Thermal Heat Rate Target**	
	19.20%		12,010 kJ/kWh	

Test Year Rate Base and Weighted Average Cost of Capital

Regarding the Test Year Rate Base and Weighted Average Cost of Capital (WACC), the Office **DETERMINES** that:

- The JPS' Rate Base is **US$519.891M** (J$58.23B)
- The allowed pre-tax WACC is **13.22%** based on:
  - Cost of Debt of 8.07% pre-tax.
  - Cost of Equity of 12.25% post-tax and 18.4% pre-tax.
  - Allowed Gearing Ratio of 50%.
  - Tax rate of 33⅓%

Test Year Revenue Requirement

The Office **DETERMINES** that JPS' Non-Fuel Revenue Requirement is **US$383.65M** (J$42.97B). The basis of the approved Revenue Requirement is detailed in Table 08.

Table 08: Test Year - JPS' Revenue Requirement

Revenue Requirement	JPS Proposed (US$'000)	Office Determined (US$'000)
Purchased Power Costs	104,111	104,111
Operating Expenses	150,844	147,736
Total Operational Expenses	**254,955**	**251,847**
Net finance costs (excl. long-term debt):		
Interest on short-term loans	1,403	1,403
Interest on customer deposits	549	549
Interest – Bank overdraft and other	5,721	1,990
Int. Capitalised during construction (AFUDC)	1,450	1,450
Debt issuance cost and expenses	4,829	3,202
Finance income	(1,615)	(1,615)
	12,338	**6,979**
Depreciation	**57,498**	**47,412**
FX Losses	**14,000**	-
Other Income	**(2,822)**	**(1,785)**
Other Expenses	**3,000**	**3,000**
Self-Insurance Fund (SIF) contribution	2,000	2,000
Gross up for taxes on SIF	1,000	1,000
Return on Equity	**62,552**	**31,837**
Taxation (Gross up)	**31,276**	**15,918**
Long Term Interest Expenses	**23,507**	**20,985**
Revenue Requirement	**456,304**	**376,194**
Less Caribbean Cement Revenue	(4,936)	(4,936)
JPS Managed IPP Expenses		(604)
Loss Reduction Fund (incl. taxes)	**13,000**	**13,000**
Adjusted Revenue Requirement	**464,368**	**383,654**

Foreign Exchange (FX) Risk on Settlement of Business Transactions

The Office **DETERMINES** as follows:

- The inclusion of FX losses incurred on business transactions in the Revenue Requirement is **NOT APPROVED**.
- JPS' proposed "true-up" mechanism to reconcile any incurred FX losses is **NOT APPROVED.**

Price Cap

The price-cap mechanisms remain. Notwithstanding, adjustments shall be made in such a manner that will not compromise the allowed revenue across retail customer classes and will not cause any indiscriminate cross-subsidization among rate classes. In other words, the 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 tariff basket instead of the individual tariffs. JPS is allowed to adjust the tariffs for each rate class on such a basis that the weighted average increase of the tariff basket does not exceed the price adjustment. Concessional rates should not compromise the allowed revenue across retail customer classes.

JPS' request for a revenue cap is **NOT APPROVED**. The tariff structure as proposed by JPS is also **NOT APPROVED** as the Office deemed that the methodology for the allocation of cost is inadequate and does not clearly and sufficiently demonstrate that there would be no cross-subsidization of costs among rate classes.

The Office accepts that, to the extent that there is any major change to the base-load generating capacity during the price cap period, there may be need to conduct a new rate review. In the event of such a development the Office, in consultation with JPS, will decide on an appropriate framework for addressing any possible attendant request for rate adjustment.

No determination has been made on a tariff for LED lights, but JPS is mandated to obtain and provide to the Office the necessary information, in order to ascertain the capital and O&M components and all the relevant systems that are required to put in place a tariff for LED lights, within six (6) months of the effective date of this Determination Notice.

Annual Rate of Change in Non-Fuel Base Prices (dPCI)

The Non-Fuel Base Rate for each customer class shall be adjusted on an annual basis pursuant to the following formula:

$$\mathbf{ABNF_y = ABNF_{y-1}(1 + dPCI)}$$

Where:

$ABNF_y$	=	Adjusted Non-Fuel Base Rate for Year "y"
$ABNF_{y-1}$	=	Non-Fuel Base Rate prior to adjustment
dPCI	=	Annual rate of change in non-fuel electricity prices as defined below
PCI	=	Non-fuel Electricity Pricing Index

The annual rate of change in non-fuel electricity prices (dPCI) shall be determined through the following formula:

$$\mathbf{dPCI = dI \pm X \pm Q \pm Z}$$

X-Factor

The Office **DETERMINES** that the productivity efficiency gain (X-factor) for JPS to be applied at the Annual Tariff Adjustments during the price-cap period shall be 1.10%.

Q-Factor

The Office **DETERMINES** that the Q-Factor for the 2015 Annual Tariff Adjustment shall be zero.

The Office further **DETERMINES** that:

- JPS shall submit a properly calibrated and completed 12-month System outage dataset to the OUR as part of the 2015 Annual Tariff Adjustment for a complete evaluation to determine acceptability, before proceeding to establish the Q-Factor baseline.

- In the event that the 12-month System outage data provided by JPS at the 2015 Annual Tariff Adjustment is found to be unsuitable for setting the Q-Factor baseline, the OUR will explore alternative options in an effort to implement the Q-Factor adjustment mechanism in fulfilment of the requirement of the Licence.

- MAIFI will not be included in the Q-Factor adjustment mechanism at the point when the baseline data is established. Instead, MAIFI will be treated as a technical standard for which an appropriate benchmark will be established by the OUR in consultation with JPS to ensure proper monitoring of momentary interruptions. Notwithstanding, MAIFI will be reviewed annually by the Office for benchmark adjustments and if necessary, to determine its applicability in the Q-Factor adjustment mechanism during the 2014-2019 price-cap period.

- JPS shall separately record all momentary interruptions experienced on the System each month. This outage data along with the MAIFI calculations shall be submitted to the OUR in the monthly Technical Reports. Following the effective date of this Determination Notice, the OUR will indicate the specific format in which the MAIFI data should be reported.

Z-Factor and Deductibles

The Office **DETERMINES** that the materiality threshold for the Z-Factor shall be J$31M, which shall be adjusted annually to account for Jamaican Inflation.

The Office **DETERMINES** that all insurance deductibles are included in the PBRM and therefore do not qualify for compensation under the Z-Factor.

Inflation Adjustment (dI)

The Office **DETERMINES** that the Annual Growth Rate adjustment formula that shall be used by JPS to adjust the Non-Fuel Base Rates at each Annual Tariff Adjustment during the 2015 - 2019 price cap period is as follows:

$$\boldsymbol{dI} = USP \times \left(\frac{EXn - EXb}{EXb}\right)(1 + USAF \times INFus) + (USP \times USAF \times INFus) + (1 - USP) \times INFj$$

Where:

EX_b	=	Base US Exchange Rate
EXn	=	Applicable US Exchange rate at Adjustment Date
$INFus$	=	US Inflation as defined in the Legal and Regulatory Framework.
$INFj$	=	Jamaica Inflation as defined in the Legal and Regulatory Framework.
USP	=	0.80 (US portion of the total non-fuel expenses)
$USAF$	=	0.45 (the US Adjusted Factor which represents that portion of the US component of the total non-fuel expenses that is not subject to US inflation adjustment)

Interest on Accounts Receivables for Commercial Customers

JPS' request to charge interest on commercial customers' accounts is **NOT APPROVED**.

Electricity Efficiency Improvement Fund (EEIF)

The Office sees the urgent need for efficiency improvement measures in the overall electricity system which can ultimately lead to a reduction in the average price of electricity to customers. Accordingly, the Office **APPROVED** the continuation of an EEIF with the following conditions:

- The amount for the EEIF shall be US$13M per annum and will be subject to review by the Office at the Annual Tariff Adjustments during the price cap period.

- The revenues for the EEIF shall be collected through a separate line item on customers' bills and the rate shall be J$0.4886/kWh.

- The EEIF shall only be used for efficiency improvement projects which shall be subject to review and approval by the Office.

- The Office will prescribe rules to govern the operations of the EEIF.

Bogue Plant Reconfiguration Fund (BPRF)

To ensure optimal operation of the electricity System and the minimization of the total variable cost of electricity production by JPS, the Office considers it an imperative that JPS' Bogue Combined Cycle Gas Turbine (CCGT) unit be reconfigured to accommodate the utilization of gas-based fuels such as natural gas (NG) or alternatives, which are cheaper than ADO. In this regard the Office **APPROVED** the establishment of a BPRF with the following conditions:

- The amount for the BPRF shall be US$15M which shall be accumulated over a 12-month period commencing on the effective date of this Determination Notice.

- The revenues for the BPRF shall be collected through a separate line item in the monthly FUEL RATE CALCULATION. This means that JPS shall apply equal amounts of US$1.25M to the fuel rate on a monthly basis over the stated 12-month accumulation period.

- For the avoidance of doubt, the BPRF collection as specified above shall terminate after the designated 12-month period when the fund has accumulated to the amount of U$15M.

- The BPRF shall be used firstly and primarily for the reconfiguration of the Bogue CCGT to accommodate the use of gas-based fuels.

- JPS shall be required to submit to the Office by February 28, 2015 a complete proposal for the implementation of this project, which shall include, inter alia, a credible feasibility study, procurement strategy, project costs and a project implementation schedule.

- Any portion of the BPRF remaining after the execution of the reconfiguration of the Bogue CCGT may be used to support capital projects aimed at improving the efficiency of other JPS-owned generating facilities. However, in pursuance of such projects, JPS shall be required to submit proposal(s) to the Office for review and approval before such funds are committed.

- The Office will prescribe the rules that will govern the administration and utilization of the BPRF after the effective date of this Determination Notice.

Economic Dispatch of Generating Units

JPS shall be required to submit economic dispatch information, as set out in detail in Chapter 9, Section 9.12 of this Determination Notice, which shall include details of deviations from optimal dispatch, along with causation for such deviations.

Pre-paid Metering

The Office **DETERMINES** that:

- The approved maximum transition period is fifteen (15) days for a customer who opts out of pre-paid service in favour of going back to post-paid service.

- A customer switching from pre-paid to post-paid service or vice versa should not be left without electricity supply during the transition period because of the switch.

- The customer deposit, plus any accrued interest less any outstanding balance on the account, shall be returned to a post-paid customer who has switched to pre-paid service.

- The administrative switching fee of $1,500 is **APPROVED** with the proviso that customers should be allowed to switch from post-paid to pre-paid service and back to post-paid within twelve (12) months without being charged the administrative switching fee. There should be no initial cost to switch from post-paid to pre-paid service.

- The incremental transaction fee to be levied by third party vendors of $50 is **APPROVED**.

- The approved pre-paid rate is J$10.90 per kWh for the first 100 kWh within a thirty (30)-day consumption cycle and J$18.34 per kWh for each additional kWh thereafter within that thirty (30)-day consumption cycle. The pre-paid rates shall be subject to review at the Annual Tariff Adjustment.

- The pre-paid metering service shall not be imposed on any existing or new customer unless the customer agrees and the Office approves.

Community Renewal Programme (Rate 10)

The Office may consider the implementation of a specified rate to encourage non-paying customers in high-loss areas who have affordability challenges to become legitimized. However, the initial transitional rate of $4.34/kWh proposed by JPS is **NOT APPROVED**. The Office's position is that the composition, operation and application of the programme have not been sufficiently defined to allow it to prescribe a specific rate.

Notwithstanding, the Office may consider a prescribed rate after a complete proposal has been submitted.

Fuel Cost Adjustment Mechanism

Heat Rate

The Office **DETERMINES** as follows:

- Net generation from non-combustible renewables such as wind, hydro and solar shall not be included in the JPS' generating heat rate calculation.

- The Independent Power Producers' (IPPs') fuel cost shall only be adjusted for efficiency by the System losses factor: (1-System Losses Actual) / (1-System Losses Target).

- The fuel cost pass-through formula that shall be applied by JPS in the Fuel Rate Adjustment Mechanism in accordance with paragraph 3 (D) and EXHIBIT 2 of Schedule 3 of the Licence is:

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

- JPS' generating heat rate target shall be **12,010 kJ/kWh** for the period January 2015 to May 2015.

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

- JPS shall comply with the fuel cost monitoring framework set out under Chapter 9, Section 9.12 and other requirements of this Determination Notice.

System Losses

The Office **DETERMINES** as follows:

- The aggregate System losses target ceiling for the price cap period January 2015 – May 2019 shall be **19.20%**.

- The value of the technical losses and non-technical losses each month shall be reported in the monthly Fuel Rate Calculation submission.

- The System losses target will be reviewed by the Office at each Annual Tariff Adjustment during the price-cap period.

Independent Power Producers' (IPPs') Non-Fuel Costs

The Office **DETERMINES** that the methodology for the recovery of IPPs' non-fuel costs shall remain unchanged for the price-cap period 2015 - 2019.

The actual IPPs' non-fuel costs shall be recovered as a pass-through on customers' bills by using the following methodology:

- Estimated base non-fuel IPP costs shall be embedded in the non-fuel charges.

- Reconciliation shall be done monthly and any surplus or deficit adjusted in the kWh billed.

Depreciation

The Office **DETERMINES** that the asset lives and corresponding depreciation rates set out under Schedule 4 of the Licence shall be applied for the 2015 - 2019 price cap period.

- The proposed depreciation adjustment of US$8.33M which was derived based on the recommended asset lives is NOT APPROVED.

- The annual depreciation amount allowed in the Non-Fuel Revenue Requirement is the Test Year depreciation expenses calculated in accordance with the useful lives of assets specified in Schedule 4 of the Licence and adjusted for known and measurable costs.

The annual depreciation expense allowed for the price-cap period 2015 - 2019 shall be US$47,412,437.

Time-of-Use (TOU)

JPS did not submit a proposal for adjustment to its TOU schedule, however, the Office **DETERMINES** that the existing TOU schedule shall remain unchanged.

Customer Quality-of-Service Standards

The Guaranteed Standards set forth in Table 09 below shall become effective on the date of this Determination Notice.

The Office recognizes that JPS may need to put the necessary systems in place to apply automatic compensation to all breaches. Additionally, the Office has noted that JPS is in the process of implementing an upgrade to its Customer Information System (CIS), which the company has advised will pose challenges in making the necessary system changes to the standards at this time. Accordingly, the mechanism for all standards to attract automatic compensation will be implemented on a phased basis. In the first phase, which takes effect on **June 1, 2015**, the number of standards attracting automatic compensation shall increase to eight (8) with the inclusion of the following four (4) standards:

- EGS 1: Connection to Supply – New and Simple Connections
- EGS 8: Estimation of Consumption
- EGS 10: Billing Adjustments
- EGS 14: Compensation

At the second phase, which shall take effect on **January 1, 2016**, the following four (4) standards will attract automatic compensation thereby bringing the total automatic compensation standards to twelve (12):

- EGS 2a: Connection to supply - within 30 and 100 meters of the existing distribution line
- EGS 2b: Connection to Supply - within 101 and 250 meters of the existing distribution line
- EGS 4: First bill
- EGS 15: Transitioning of existing customers to RAMI System

The final phase shall take effect on **June 1, 2016** at which time all Guaranteed Standards shall attract automatic compensation.

The approved schedule that shall be applied by JPS in implementing automatic compensation for breach of the Guaranteed Standards is given in Table 09.

Table 09: Guaranteed Standards

Code	Focus	Description	Performance Measure
EGS 1	Access	Connection to Supply - New & Simple Installations	New service installations within five (5) working days after establishment of contract, including connection to RAMI system. **Automatic Compensation as of June 1, 2015.**
EGS 2(a)	Access	Complex Connection to supply	From 30m to 100m of existing distribution line: (i) estimate within ten (10) working days; (ii) connection within thirty (30) working days after payment. **Automatic Compensation as of January 1, 2016.**
EGS 2(b)	Access	Complex Connection to supply	From 101m to 250m of existing distribution line: (i) estimate within fifteen (15) working days; (ii) connection within forty (40) working days after payment. **Automatic Compensation as of January 1, 2016.**
EGS3	Response to Emergency	Response to Emergency	Response to Emergency calls within five (5) hours – emergencies defined as: broken wires, broken poles, fires. **Automatic Compensation as of June 1, 2016.**
EGS4	First Bill	Issue of First bill	Produce and dispatch first bill within forty (40) working days after service connection. **Automatic Compensation as of January 1, 2016.**
EGS 5(a)	Complaints/ Queries	Acknowledgements	Acknowledge written queries within five (5) working days. **Automatic Compensation as of June 1, 2016.**

Code	Focus	Description	Performance Measure
EGS 5(b)	Complaints/ Queries	Investigations	Complete investigations and respond to customer within thirty (30) working days. Where investigations involve a 3rd party, same is to be completed within sixty (60) working days. **Automatic Compensation as of June 1, 2016.**
EGS 6	Reconnection	Reconnection after Payments of Overdue amounts	Reconnection within twenty-four (24) hours of payment of overdue amount and reconnection fee. **Automatic Compensation**
EGS 7	Estimated Bills	Frequency of Meter reading	Should NOT be more than two (2) consecutive estimated bills (where company has access to meter). **Automatic Compensation as of June 1, 2016.**
EGS 8	Estimation of Consumption	Method of estimating consumption	An estimated bill should be based on the average of the last three (3) actual readings **Automatic Compensation as of June 1, 2015.**
EGS 9	Meter Replacement	Timeliness of Meter Replacement	Maximum of twenty (20) working days to replace meter after detection of fault which is not due to tampering by the customer. **Automatic Compensation**
EGS 10	Billing Adjustments	Timeliness of adjustment to customer's account	Where it becomes necessary, customer must be billed for adjustment within three (3) months of identification of error, or subsequent to replacement of faulty meter. **Automatic Compensation as of June 1, 2015.**
EGS11	Disconnection	Wrongful Disconnection	Where the company disconnects a supply that has no overdue amount or is currently under investigation by the OUR or the company and only the disputed amount is in arrears. **Automatic & Special Compensation**

Code	Focus	Description	Performance Measure
EGS12	Reconnection	Reconnection after Wrongful disconnection	The company must restore a supply it wrongfully disconnects within five (5) hours. **Automatic & Special Compensation**
EGS13	Meter	Meter change	JPS must notify customers of a meter change within one (1) billing period of the change. The notification must include: the date of the change, the meter readings at the time of change, reason for change and serial number of new meter. **Automatic Compensation as of January 1, 2016.**
EGS 14	Compensation	Making compensatory payments	Accounts should be credited within one (1) billing period of verification of breach. **Automatic Compensation as of June 1, 2015.**
ESG 15	Service Disruption	Transitioning Existing Customers to RAMI System	Where all requirements have been satisfied on the part of the company and the customer, service to existing JPS customers must not be disrupted for more than three (3) hours to facilitate transition to the RAMI system. **Automatic Compensation as of January 1, 2016.**

Legislative and Regulatory Framework

Regulatory Authority

1.1 The OUR is a multi-sector regulator established pursuant to the Office of Utilities Regulation Act (the "OUR Act"), to regulate the provision of prescribed utility services by licensees or specified organizations in Jamaica. Under Section 4(1)(a) and the First Schedule of the OUR Act, the OUR has regulatory authority over the generation, transmission, distribution and supply of electricity.

1.2 JPS operates under the Licence, which provides the company with exclusive rights for the commercial transmission, distribution and supply of electricity in Jamaica.

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

Power of the Office to Fix Rates

1.4 Pursuant to Sections 11 and 12 of the OUR Act, the Office has a general power to fix rates in relation to the provision of electricity service. Sections 11 and 12 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.

(7) 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."

Rates must be Cost-reflective Unless Otherwise Directed by the Office

1.5 Pursuant to Condition 2(3) of the Licence, JPS is required to provide an adequate, safe and efficient electricity service at reasonable rates so as to meet the demands and to contribute to economic development. Condition 2(3) of the Licence provides as follows:

"General Conditions"
"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."

1.6 Condition 14(1) of the Licence, *inter alia*, provides that in relation to the sale of electricity, JPS shall charge its customers such published tariffs as approved by the Office. The published tariffs shall be cost-reflective, unless otherwise directed by the Office. Condition 14(1) reads,

*"**Charges and Terms and Conditions for the Supply of Electricity**"*
"The Licensee shall, save where it enters into special contracts with customers for the Supply [sale of electricity] pursuant to Section 14 of the OUR Act, charge its customers for such Supply according to published tariffs, approved by the Office, as updated from time to time. ***Such published tariffs shall be cost-reflective unless otherwise directed by the Office****…"* (Emphasis added).

1.7 Condition 14(2) of the Licence provides that the Licensee may be required to provide a special concessional or lifeline tariff for residential customers, which does not cross-subsidize the allowed revenue across retail customer classes. Condition 14(2) reads,

"In accordance with policy directives issued by the Minister, the Office may require the Licensee to provide concessional or lifeline tariff for residential customers in such a manner that will not compromise the allowed revenue across retail customer classes served by the Licensee."

Price Control Mechanism

1.8 Condition 15 of the Licence indicates that JPS is subject to price controls. Condition 15 inter alia, provides as follows:

"***Condition 15: Price Controls***
(1) The Licensee is subject to the conditions in Schedule 3.
(2) *The prices 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."*

1.9 Therefore the Office, in calculation of the tariff rates, is obliged to observe the relevant provisions of Schedule 3 which specifies how the rates are to be calculated and the considerations therefor. Specifically, Schedule 3, paragraph 2(C) of the Licence provides as follows:

"(C) ***Rates Post May 31, 2004***
Non-Fuel Base Rate. *The Licensee shall submit a filing with the Office no later than March 1, 2004 and thereafter on each succeeding fifth anniversary, with an application for the recalculation of the Non-Fuel Base Rates. The new Non-Fuel Base Rate will become effective ninety (90) days after acceptance of the filing by the Office. This filing shall include an annual non-fuel revenue requirement calculation and specific rate schedules by customer class. The revenue requirement shall be based on a test year in which the new rates will be in effect and shall include efficient non-fuel operating costs, depreciation expenses, taxes, and a fair return on investment. The components of the revenue requirement which are ultimately approved for inclusion will be those which are determined by the Office to be*

prudently incurred and in conformance with the OUR Act, the Electric Lighting Act and subsequent implementing rules and regulations. The revenue requirement shall be calculated using the following formula unless such formula is modified in accordance with the rules and regulations prescribed by the Office.

Non-Fuel Revenue Requirement *= non-fuel operating costs + depreciation + taxes + return on investment, with the components defined as follows:*

Non-fuel operating costs: All prudently incurred costs *which are not directly associated with investment in capital plant, other operating cost shall include, but not limited to: salaries and other costs related to employees; operating costs of generation, transmission and distribution and supply facilities; interest costs on other borrowings not associated with capital investment, if applicable; rents and leases on property associated with the Licensed Business; taxes which the Licensee is required to pay other than income taxes of the Licensee; and other costs which are determined to be* ***reasonably incurred*** *in connection with the Licensed Business.*

Depreciation: The deprecation component will be calculated by applying annual depreciation rates, as provided for at Schedule 4, to the gross value of the individual plant asset accounts.

Taxes: *Taxes which are calculated based on the net income of the Licensee (Income Taxes) and payable to the Government of Jamaica shall be a component of the revenue requirement. Loss carry-forwards and any incentives to encourage capital investments are not included in the calculation of income taxes.*

Return on Investment: *This component is calculated based on the approved Rate Base of the Licensee and the required rate of return which allows the Licensee the opportunity to earn a return sufficient to provide for the requirements of consumers and acquire new investments at competitive costs. The Office shall determine a working capital component of the Rate Base.*

The Licensee shall provide schedules that support these specific operating costs, depreciation expenses, and taxes. The return on investment shall be calculated by multiplying the allowed rate-of-return by the Licensee's total investment base (Rate Base) for the test year. The allowed rate of return is the Licensee's Weighted Average Cost of Capital (WACC). The WACC ("K%") will balance the interests of both consumers and investors and be commensurate with returns in other enterprises having corresponding risks which will assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital. The WACC will be based on the actual capital structure or an appropriately adjusted capital structure which adjustment is required to keep parity of the interests of the consumers and investors and at the time of the filing such capital structure and WACC shall be *adjusted by any known and measurable changes which are expected to occur during the test year:*

*Return on Investment = K% *(Rate Base)"*

1.10 The Test Year is defined in Schedule 3, paragraph 1 of the Licence as comprising:
"… the latest twelve months of operation for which there are audited accounts and the results of the test year adjusted to reflect:

(i) Normal operational conditions, if necessary;

(ii) Such changes in revenues and costs as are known and measurable with reasonable accuracy at the time of filing and which will become effective within twelve months of the time of filing. Costs, as used in this paragraph, shall include depreciation in relation to plant in service during the last month of the test period at the rates of depreciation specified in the Schedule to this Licence. Extraordinary or Exceptional items as defined by The Institute of Chartered Accountants of Jamaica shall be apportioned over a reasonable number of years not exceeding five years; and

(iii) Such changes in accounting principles as may be recommended by the independent auditors of the Licensee."

1.11 Paragraph 4 of Schedule 3 of the Licence provides as follows:

"The process to be used by the Office in the implementation and management of the incentive regulation process is set out in detail in Exhibit 1."

1.12 Exhibit 1 of Schedule 3 of the Licence provides as follows:

"Annual Growth Rate for Non-Fuel Base Rates

The Non-Fuel Base Rate for each customer class shall be adjusted on an annual basis…… pursuant to the following formula:

$$ABNFy = ABNFy_{-1}\,(1 + dPCI)$$

Where:

ABNFy	=	*Adjusted Non-Fuel Base Rate for Year "y"*
ABNFy-1	=	*Non-Fuel Base Rate prior to adjustment*
dPCI	=	*Annual rate of change in non-fuel electricity prices as defined below*
PCI	=	*Non-fuel Electricity Pricing Index*

The annual Performance-Based Rate-Making (PBRM) filing will follow the general framework where the annual rate of change in non-fuel electricity prices (dPCI) will be determined through the following formula:

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

where:

dI	=	*the annual growth rate in an inflation and devaluation measure;*
X	=	*the offset to inflation (annual real price increase or decrease)resulting from productivity changes in the electricity industry;*
Q	=	*the allowed price adjustment to reflect changes in the quality of service provided to the customers; and,*
Z	=	*the allowed rate of price adjustment for special reasons not captured by the other elements of the formula.*

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

Annual Rate of Change of Electricity Prices (dPCI) is the annual rate of change that will be applied to the average non-fuel ($/kWh) price of electricity to all consumers.

Annual Inflation Growth Rate (dI) represents the changes in the value of the Jamaican Dollar against the US Dollar and the inflation in the cost of providing electricity products and services.

Specifically, dI is set as:

$$dI = 0.76((EXn - Exb)/EXb)(1+0.92INFus) + (0.76)(0.92)1 + (0.24INFj)$$

EXb	=	*Base US Exchange Rate*
EXn	=	*Applicable US Exchange rate at Adjustment Date*
INFus	=	*Change in agreed US inflation index as at 60 days prior to the Adjustment Date and an agreed US inflation index one year prior to the said date (i.e 60 days prior to the Adjustment Date.*
INFj	=	*Change in agreed Jamaican inflation index as at 60 days*

prior to the Adjustment Date and an agreed Jamaican inflation index one year prior to the said date (i.e. 60 days prior to the Adjustment Date.)"

Guaranteed and Overall Standards

1.13 In relation to Guaranteed and Overall Standards, the Office at tariff review may review and introduce new Overall and Guaranteed Standards. Condition 17 of the Licence, inter alia, provides:

"5. Guaranteed Standards as well as the level of compensation payments will be reviewed periodically by the Office (normally between tariff reviews) and where appropriate and in consultation with the Licensee, introduce new standards.

7. The Overall Standards will be reviewed periodically by the Office (at tariff reviews) and where appropriate and in consultation with the Licensee, new standards introduced at tariff reviews."

Rate Review Process

1.14 The application for a rate review process by the Licensee is governed by paragraph 3 of Schedule 3 which provides, inter alia, as follows:

"(A) The Licensee shall file with the Office proposed rates schedules and shall demonstrate that the non-fuel rates proposed for the various rate categories will generate the non-fuel revenue requirement for the test year.

The Office shall accept the filing within ten (10) working days following certified delivery of the filing with the Office unless the filing is clearly deficient to the extent that it will not allow the complete evaluation of the Licensee's application including the proposed rate schedules…

Upon acceptance of the rate filing ***the Office shall initiate a rate proceeding to conduct its review of the [L]icensee's proposed rates in which the office shall have full discretion to accept, modify or reject the proposed rates****. The Office shall have the full discretion to determine the format and procedure at such proceedings and in making its decision shall observe reasonable standards of procedural fairness and the rules of natural justice and act in a timely manner.* ***The Office's review shall consist of an evaluation of the non-fuel revenue requirement including***

***prudent operating costs, depreciation expenses, taxes and return on investment**…*" (Emphasis added)

(B) *The Licensee shall submit to the Office no later than September 1, 2003, and every succeeding five (5) years thereafter, a proposal for new baseline values for the performance indicators contained in the Performance Based Rate-making Mechanism…… The Licensee shall also have the option of proposing new performance indicators or mechanisms for the Office's consideration. Upon receipt of any such proposal, the Office shall conduct a review of the Licensee's proposed performance indicators or mechanisms and shall have the full discretion to accept, modify, reject or order the implementation of alternative performance indicators or mechanisms; provided, however, that any Performance Based Rate-making Mechanism shall include (I) an applicable price index (including, if necessary, a factor thereof) which serves as a reasonable proxy index for the measurement of the periodic change in the Licensee's non-fuel costs, and (II) a performance-based discount factor which rewards or penalizes the Licensee as (the case may be)…"*

(C) *The Non-Fuel Base Rate shall be capped under the Performance Based Rate-making Mechanism described in paragraph (B) above.*

(D) *….. The Licensee shall include with its filing schedules giving the distribution of the fuel cost across the rate categories."*

1.15 Pursuant to Schedule 3, Paragraph 3 of the Licence, JPS submitted its application for the recalculation of the Non-Fuel Base Rates to the Office on April 7, 2014. The Office, in accordance with the requirements of rate review process, by letter dated April 10, 2014, indicated its acceptance of JPS' Tariff Submission for its consideration.

REASONS FOR OFFICE DECISION

&

TECHNICAL ANALYSIS

Chapter 1: Introduction

1.1 Background

JPS is a vertically integrated electricity company in operation for over ninety (90) years. Pursuant to the Licence, JPS is the sole distributor of electricity in Jamaica. Over the years, through the expansion of its generation, transmission and distribution capabilities, JPS has grown from a modest network serving fewer than 4,000 customers in the early years, to now serving a customer-base of over 603,000. The company has generation capacity exceeding 620 MW, using steam (oil-fired), gas turbines combined cycle, diesel and hydroelectric technologies. JPS operates twenty four (24) generating units including nine (9) hydro power plants and one (1) wind farm. JPS also purchases electricity from four (4) IPPs under long-term Power Purchase Agreements (PPAs). The company also owns fifty two (52) substations and approximately 16,000 kilometers of distribution and transmission lines.

JPS is owned by four (4) shareholder groupings: Marubeni Caribbean Power Holdings Inc. and Korea East-West Power Co. Ltd., each holding 40%; the GOJ which owns approximately 19.9% and a small group of minority shareholders, owning 0.1% stake. The company was granted a Licence by the GOJ in 2001, the All-Island Electric Licence, 2001 and this licence was amended and restated in 2011. The company reported a staff complement of approximately 1,600 workers delivering service to its customers. JPS is regulated by the OUR.

1.2 JPS' Tariff Submission

On April 7, 2014, JPS submitted its proposal for a tariff review in accordance with the provisions of the Licence. The final set of data which formed a part of the submission was received on April 8, 2014 and this allowed for the commencement of the review process by the OUR. Albeit there was need to revert to JPS on a number of occasions for clarification, additional information and verification which inevitably led to waiting periods.

The tariff review process included a series of formal public consultations which commenced on April 14, 2014 and ended on April 29, 2014. Through the consultation process, the OUR engaged the public and other stakeholders in a broad discussion on the wide range of tariff issues and requests that were presented in the JPS' Tariff Submission.

Public consultation events were held in the parishes indicated below:

- Kingston and St. Andrew – April 14 & 29
- Manchester – April 15
- St. Catherine – April 16
- St. Ann – April 22
- St. James – April 23

- Westmoreland – April 24
- Portland – April 28

The OUR also indicated to all stakeholders that they had until May 16, 2014 to submit their written submissions. A number of written submissions were received from various stakeholders.

After completing the draft of its Determination Notice, the Office, in keeping with established tariff review process, provided JPS with a preview to which the company responded with extensive commentary. There was also intense engagement during the months of July and August between JPS and the Office's staff on issues of clarifications and more complete information and even further consultations in the ensuing months.

In arriving at its determination, the Office has taken into account the views and submissions from all stakeholders including those who participated in the public consultations and/or submitted written comments.

1.3 Purpose of Document

The purpose of this document is to present the results of the OUR's analysis and evaluation of JPS' Tariff Submission and to set out the Office's determinations and the underlying reasons informing these determinations. The review follows the format of the JPS' Tariff Submission which included:

1. An application for the recalculation of the non-fuel base rate;

2. A report on the customer quality of service provided by the company during the last five (5) years; and

3. Proposed revisions to several PBRM components with proposed justification.

1.4 Structure of Document

The document is divided into two major sections, Section 1 and Section 2.

Section 1 sets out in summary JPS' tariff proposals and the OUR's financial, economic and technical analyses of the proposals and the resulting determinations.

Section 2 summarizes the issues and discussions on the Guaranteed and Overall Standards along with the dialogue with and on behalf of the broad consumer base and other interest groups throughout the consultative process. Additionally, Section 2 sets out the Office's decisions on the Guaranteed and Overall Standards and the OUR's evaluation of JPS' demand projections.

The more detailed structural arrangement of the document is as follows:

Section 1

- Chapter 2 provides a summary of JPS' proposal.
- Chapter 3 provides a description of the PBRM tariff setting including the principles and procedures; discusses JPS' submission on the productivity factor (X-Factor), the Technical Quality of Service Standards (Q-Factor) and the Special Circumstances Factor (Z-Factor) Indices, and sets out the OUR's analysis and the Office's decisions.
- Chapter 4 presents the discussions and decision on the proposed Revenue Cap rate adjusting mechanism.
- Chapter 5 presents JPS' calculations and OUR's analysis and determinations on the company's Cost of Debt, Cost of Equity, the WACC and all its components.
- Chapter 6 provides analysis and the determination of JPS' Rate Base, Return on Investment and Revenue Requirement using the Test Year financial data appropriately adjusted for known and measurable changes, with justification.
- Chapter 7 provides the description and discusses the details of the tariff design and the Office's decisions.
- Chapter 8 discusses the proposed Foreign Exchange (FX) adjustment mechanism and sets out the Office's decisions.
- Chapter 9 discusses the Fuel Cost Recovery – Heat Rate Target and other fuel efficiency measures and sets out the Office's decisions.
- Chapter 10 discusses the Fuel Cost Recovery – System Losses Target, JPS' proposed System loss reduction initiatives such as the Community Renewal Program and sets out the Office's decisions.
- Chapter 11 discusses and presents the other proposed fees – Interest on Accounts Receivables for Commercial Customers and the Office's decisions.
- Chapter 12 discusses the decommissioning of JPS' aged oil-fired steam generating plants located at Old Harbour and Hunt's Bay and indicates the Office's position.

Section 2

- Chapter 13 provides the analysis and discussions on consumer issues and customer quality-of-service standards and indicates the Office's decisions.
- Chapter 14 presents the discussions and the Office's decisions on the Guaranteed and Overall Standards.
- Chapter 15 discusses the sales demand projection which is developed to determine the billing determinant for the tariff review period and indicates the Office's position.

SECTION I: - Financial, Economic and Technical Analysis

Chapter 2: Summary of JPS' Proposal

2.1 Proposed Rate Changes

2.1.1 Residential (Rate 10)

JPS proposed **increasing** the residential tariff for Rate 10 customers, on average, by **21%** as shown in Tables 2.11 and 2.12 below.

In this proposal, the **first tier** (customers with monthly consumption < 100 kWh) which includes mainly low-income families would receive an average tariff increase of **17%**. The number of residential customers affected by this increase was said to be 222,531 customers, representing 41% of the residential class.[1]

Table 2.11: Proposed Bill Impact - Residential Customer

Class	Current Rate Billing (JMD/month)	Proposed Rate Billing (JMD/month)	Variation (%)
RT 10 LV Res. Service < 100 kWh	2,041	2,381	17%
RT 10 LV Res. Service 100-500 kWh	7,891	9,567	21%
RT 10 LV Res. Service > 500 kWh	40,385	49,874	23%

Table 2.12: Proposed Bill Impact - Residential Customer

	Customers by tier		Typical Customer's Billing Determinants and Billing				
Class	Quantity	%	Customer	Energy (kWh/month)	Current Rate Billing (USD/month)	Proposed Rate Billing (USD/month)	Variation (%)
RT 10 LV Res. Service < 100 kWh	222,531	41%	1	54	18	21	17%
RT 10 LV Res. Service 100-500 kWh	301,954	56%	1	196	70	85	21%
RT 10 LV Res. Service > 500 kWh	14,116	3%	1	927	361	445	23%

2.1.2 General Service (Rate 20)

JPS proposed an **increase** of **15%** for Rate 20 customers with consumption below 7,500 kWh per month as shown in Table 2.13 below. This would impact approximately 98% of the Rate 20 customers who accounted for 70% of the total energy sales for that rate class.

[1] Given the interest in showing the total average tariff variation, a fuel charge needs to be considered in the analysis. For JPS' purposes, a fuel charge is added to current non-fuel rates (0.239 USD/kWh). This fuel charge is based on the same data used to determine the February 2014 fuel charge, but relies on the proposed losses target of 21.5%, and excludes the FCRA component that was scheduled to end in June 2014. The resulting fuel charge is 0.232 USD/kWh.

JPS represented that, in line with the results of their cost-of-service study, and taking into consideration the Best Alternative Option (BAO) for customers with monthly consumption > 7,500, it has recommended an amendment to the tariffs that would result in a **6% decrease** on average. This would impact 2% of the Rate 20 customers who accounted for 30% of the total energy sales for that rate class.

Table 2.13: Proposed Bill Impact - General Service Customers (Rate 20)

Class	Current Rate Billing (JMD/month)	Proposed Rate Billing (JMD/month)	Variation (%)
RT 20 LV Gen. Service < 100 kWh	3,103	3,514	13%
RT 20 LV Gen. Service 100-1000 kW	17,712	20,838	18%
RT 20 LV Gen. Service 1000-7500 k\	124,458	141,963	14%
RT 20 LV Gen. Service > 7500 kWh	710,091	667,063	-6%

2.1.3 Commercial and Industrial (Rate 40 and Rate 50)

As shown in Table 2.14 below, JPS proposed to **reduce** the overall cost to some Rate 40 and all Rate 50 customers by an average of just **1%**.

Table 2.14: Proposed Bill Impact - Commercial & Industrial Customers

Class	Current Rate Billing (JMD/month)	Proposed Rate Billing (JMD/month)	Variation (%)
RT 40 LV Power Service (Std)	1,205,440	1,220,296	1%
RT 40 LV Power Service (TOU)	2,780,941	2,716,646	-2%
RT 50 MV Power Service (Std)	4,157,327	4,075,079	-2%
RT 50 MV Power Service (TOU)	3,717,202	3,684,224	-1%

2.2 Proposed Non-fuel Rate Schedule

JPS' proposed new rate schedule is shown in Table 2.21.

Table 2.21: JPS' Proposed Rate Schedule

			Demand Charge USD/kVA			Standby Rate (USD/kVA)				
	Network Access Charge USD/Month	Energy Charge USD/kWh	STD and On-Peak	Partial-Peak	Off-Peak	STD and On-Peak	Partial-Peak	Off-Peak	Network Access Charge USD/Month	Energy Charge JMD/kWh
RT 10 Prepaid Rate		0.22								24.92
RT 10 Community Renewal Program	0.00	0.07							0.00	7.75
RT 10 LV Res. Service < 100 kWh	6.00	0.09							672.00	10.30
RT 10 LV Res. Service 100-500 kWh	12.00	0.22							1,344.00	24.53
RT 10 LV Res. Service > 500 kWh	18.00	0.28							2,016.00	30.84
RT 10 LV Res. Service - Net Billing	18.00	0.00	70.00						2,016.00	0.00
RT 20 LV Gen. Service < 100 kWh	9.00	0.20							1,008.00	22.51
RT 20 LV Gen. Service 100-1000 kWh	15.00	0.19							1,680.00	21.84
RT 20 LV Gen. Service 1000-7500 kWh	25.00	0.19							2,800.00	21.18
RT 20 LV Gen. Service > 7500 kWh	40.00	0.12							4,480.00	13.13
RT 20 LV Gen. Service - Net Billing	25.00	0.00	80.00						2,800.00	0.00
RT 60 LV Street Lighting	40.00	0.21							4,480.00	23.52
RT 40 (Std)< 1 MVA	80.00	0.00	28.50						8,960.00	0.00
RT 40 (Std)- From 1 MVA to 2 MVA	80.00	0.00	27.65						8,960.00	0.00
RT 40 (Std)- From 2 MVA to 3 MVA	80.00	0.00	26.79						8,960.00	0.00
RT 40 (Std)- From 3 MVA to 4 MVA	80.00	0.00	25.94						8,960.00	0.00
RT 40 (Std)> 4 MVA	80.00	0.00	25.08						8,960.00	0.00
RT 40 (Std) - Net Billing	80.00	0.00	28.00						8,960.00	0.00
RT 40 (Std) - Wheeling	80.00	0.00	14.54			13.10			8,960.00	0.00
RT 40 (TOU)< 1 MVA	80.00	0.00	16.05	12.54	1.21				8,960.00	0.00
RT 40 (TOU)- From 1 MVA to 2 MVA	80.00	0.00	15.56	12.16	1.17				8,960.00	0.00
RT 40 (TOU)- From 2 MVA to 3 MVA	80.00	0.00	15.08	11.79	1.14				8,960.00	0.00
RT 40 (TOU)- From 3 MVA to 4 MVA	80.00	0.00	14.60	11.41	1.10				8,960.00	0.00
RT 40 (TOU)> 4 MVA	80.00	0.00	14.12	11.04	1.06				8,960.00	0.00
RT 40 (TOU) - Wheeling	80.00	0.00	8.19	6.40	0.62	7.86	6.14	0.59	8,960.00	0.00
RT 50 (Std)< 1 MVA	80.00	0.00	26.16						8,960.00	0.00
RT 50 (Std)- From 1 MVA to 2 MVA	80.00	0.00	25.38						8,960.00	0.00
RT 50 (Std)- From 2 MVA to 3 MVA	80.00	0.00	24.59						8,960.00	0.00
RT 50 (Std)- From 3 MVA to 4 MVA	80.00	0.00	23.81						8,960.00	0.00
RT 50 (Std)> 4 MVA	80.00	0.00	23.02						8,960.00	0.00
RT 50 (Std) - Net Billing	80.00	0.00	27.00						8,960.00	0.00
RT 50 (Std) - Wheeling	80.00	0.00	13.35			12.03			8,960.00	0.00
RT 50 (TOU)< 1 MVA	80.00	0.00	14.54	11.34	1.16				8,960.00	0.00
RT 50 (TOU)- From 1 MVA to 2 MVA	80.00	0.00	14.10	11.00	1.13				8,960.00	0.00
RT 50 (TOU)- From 2 MVA to 3 MVA	80.00	0.00	13.66	10.66	1.09				8,960.00	0.00
RT 50 (TOU)- From 3 MVA to 4 MVA	80.00	0.00	13.23	10.32	1.06				8,960.00	0.00
RT 50 (TOU)> 4 MVA	80.00	0.00	12.79	9.98	1.02				8,960.00	0.00
RT 50 (TOU) - Wheeling	80.00	0.00	7.42	5.78	0.59	7.12	5.55	0.57	8,960.00	0.00

2.3 Proposed Revenue Cap

JPS proposed a revenue cap approach to replace the price cap which is now in place. The company stated that this would allow for the flexibility to rebalance the tariff baskets at the annual adjustment for variations in sales mix and sales growth. JPS further stated that the revenue cap approach would minimise their demand risk, avoid a tariff restructuring in relation to the mismatch between fixed costs and fixed charges, and enable JPS to become a full partner in Jamaica's energy policy goals for generation choice and energy efficiency.

JPS stated that under the existing price cap, its real tariff basket is fixed for the duration of a five-year regulatory period. It gave as the reasoning behind this, that the arrangement would protect consumers from imprudent costs, and provides incentives for JPS to operate efficiently. By contrast, JPS argued that the price cap regime has exposed the utility to demand risk that is damaging and unnecessary.

The company posited that where a revenue cap differs from a price cap is particularly evident when actual demand varies from expected demand. Under a price cap, if demand is higher than expected, the utility earns more revenue than expected, and so makes higher profits than expected (because it over-recovers fixed costs). If demand is lower than expected, the utility makes less revenue than it expects, and so its profits fall below a reasonable rate of return.

By contrast, under a revenue cap, revenue does not vary with changes in demand. If demand rises above expected level so that revenue is over-recovered in one year, the extra revenue is put into an account and rebated to customers in lower charges the following year. Conversely, if demand drops, leading to under-recovery of fixed costs, the shortfall in revenue is tracked and recovered through higher per unit charges the following year.

2.4 Proposed Tariff Design

JPS proposed a new **three-tiered rate class** structure for residential (Rate10) and **four-tiered structure** for small commercial (Rate 20) customers. Different service/customer charges and energy charges would apply to the tiers. The redesign, JPS claimed was a more cost-reflective tariff structure that would apply a minimal increase to customers consuming at the lowest levels in Rate 10 and Rate 20 classes. JPS stated that with this structure the company was attempting to keep electricity prices affordable to marginal and vulnerable customers. The customer charge would be replaced with a network access charge (NAC) which it argued would ensure a more appropriate allocation of capacity charges for Rate 10 and Rate 20 customers.

2.5 Proposed Wholesale Tariff

JPS proposed the introduction of a wholesale rate shown in Table 2.51 below for its largest customers to encourage such customers with demand in excess of 1 MVA to remain on the grid as full service customers. The company claimed that this would be in the interest of all customers on the grid as large customers leaving the grid would apply upward pressure on electricity rates.

JPS also proposed to introduce power wheeling rates as shown in Table 2.52 below for customers who wish to self-generate. These rates would include standby rates to ensure there is service available for the wheeling customers if the wheeling customers' operating units are not operational due to scheduled maintenance or forced outages.

The proposed new Wholesale Tariff would have four declining blocks in recognition of the lower BAO for larger generation equipment.

Table 2.51: Proposed Wholesale Tariff Rate Schedule (RT40 and Rate50)

		Proposed Regular Customers' Rates - Power Demands > 1 MVA				
Class	Power Demand Block	Network Access Charge (USD/Cust./ month)	Energy Charge (USD/kWh)	Demand Charge STD and On-Peak (USD/kVA)	Demand Charge STD and Partial-Peak (USD/kVA)	Demand Charge STD and Off-Peak (USD/kVA)
RT 40 LV Power Service (Std)	1 MVA to 2 MVA	80.000	0.000	27.645		
	2 MVA to 3 MVA	80.000	0.000	26.790		
	3 MVA to 4 MVA	80.000	0.000	25.935		
	Above 4 MVA	80.000	0.000	25.080		
RT 40 LV Power Service (TOU)	1 MVA to 2 MVA	80.000	0.000	15.565	12.164	1.173
	2 MVA to 3 MVA	80.000	0.000	15.083	11.788	1.137
	3 MVA to 4 MVA	80.000	0.000	14.602	11.412	1.101
	Above 4 MVA	80.000	0.000	14.120	11.035	1.065
RT 50 MV Power Service (Std)	1 MVA to 2 MVA	80.000	0.000	25.378		
	2 MVA to 3 MVA	80.000	0.000	24.593		
	3 MVA to 4 MVA	80.000	0.000	23.809		
	Above 4 MVA	80.000	0.000	23.024		
RT 50 MV Power Service (TOU)	1 MVA to 2 MVA	80.000	0.000	14.099	10.997	1.128
	2 MVA to 3 MVA	80.000	0.000	13.663	10.657	1.093
	3 MVA to 4 MVA	80.000	0.000	13.227	10.317	1.058
	Above 4 MVA	80.000	0.000	12.791	9.977	1.023

Table 2.52: Proposed Wheeling Rate Schedule (Rate 40 and Rate 50)

	Proposed Wheeling Customers' Rates				
Class	Network Access Charge (USD/Cust./ month)	Energy Charge (USD/kWh)	Demand Charge STD and On-Peak (USD/kVA)	Demand Charge STD and Partial-Peak (USD/kVA)	Demand Charge STD and Off-Peak (USD/kVA)
RT 40 LV Power Service (Std)	80.000	0.000	14.541		
RT 40 LV Power Service (TOU)	80.000	0.000	8.187	6.398	0.617
RT 50 MV Power Service (Std)	80.000	0.000	13.348		
RT 50 MV Power Service (TOU)	80.000	0.000	7.416	5.784	0.593

	Proposed Regular Customers' Rates				
Class	Network Access Charge (USD/Cust./ month)	Energy Charge (USD/kWh)	Demand Charge STD and On-Peak (USD/kVA)	Demand Charge STD and Partial-Peak (USD/kVA)	Demand Charge STD and Off-Peak (USD/kVA)
RT 40 LV Power Service (Std)	80.000	0.000	28.500		
RT 40 LV Power Service (TOU)	80.000	0.000	16.046	12.540	1.210
RT 50 MV Power Service (Std)	80.000	0.000	26.163		
RT 50 MV Power Service (TOU)	80.000	0.000	14.535	11.337	1.163

	Variation %				
Class	Network Access Charge	Energy Charge	Demand Charge STD and On-Peak	Demand Charge Partial-Peak	Demand Charge Off-Peak
RT 40 LV Power Service (Std)	0%		-49%		
RT 40 LV Power Service (TOU)	0%		-49%	-49%	-49%
RT 50 MV Power Service (Std)	0%		-49%		
RT 50 MV Power Service (TOU)	0%		-49%	-49%	-49%

2.6 Proposed FX Adjustment Factor

JPS recovers revenues through tariffs set on an assumed Base Exchange rate. JPS contended that the company is exposed to high currency risk and settlement risk as a large proportion of its expenses are incurred in US dollars. It asserted that the Licence permitted the company to adjust billing rates to account for movements in the exchange rate between the US dollar and Jamaican dollar for that portion of its expenses that is US Dollar denominated.

Since 2004, JPS' foreign exchange adjustment factor has been predicated on the assumption that 76% of its costs are foreign-related and 24% are of local origin. In its submission, JPS requested that the US component of costs included in the foreign adjustment factor in the formula be moved upwards from 76% to 80% based on its assessment of the composition of costs in the 2013 Revenue Requirement.

2.7 Foreign Exchange Losses

JPS, among other things, requested the following with respect to the treatment of foreign exchange:

- Allowance for an annual review of the non-fuel foreign exchange adjustment factor to reflect changes in JPS' currency composition of non-fuel costs.
- Allowance for foreign exchange losses as a recoverable expense in the revenue requirement.
- The implementation of an annual "true-up" mechanism between rate reviews to reconcile the amount incurred for FX losses for the previous calendar year with the amount allowed in the revenue requirement.

2.8 Interest on Accounts Receivables for Commercial Customers

JPS stated that currently its accounts receivable are collected on average over a fifty-two (52)-day period. JPS claimed that, as a result of this, it was suffering significant interest costs on the additional working capital requirement to fund the business, and FX losses on the outstanding balances due from those customers especially during periods of rapid devaluation of the Jamaican dollar.

JPS' proposed solution for this is to charge a rate of interest on outstanding debt, to be set at 15% for commercial customers. JPS claimed that by setting the rate at this level, 7% increment over and above the 8% debt financing rate, it would act as a FX recovery proxy. This would be used at the end of each financial year as a contribution to the FX recovery proposed.

JPS further proposed that commercial customers be given five (5) days grace period during which no interest would apply to the outstanding balance on their accounts. The grace period would commence the day following the due date on the customer's bill. Interest accrual would therefore commence on the sixth day following the due date on the customer's bill.

2.9 Community Renewal Programme

JPS proposed a Community Renewal Programme in which JPS, NWC, and GOJ agencies would come together to improve services to low-income communities island-wide, in an integrated way that would emphasize community responsibility and payment as the quid pro quo for service upliftment.

JPS argued that the proposed programme was geared towards low income communities that can reasonably be grouped into the following three types:

- Rural villages
- Squatter settlements
- Inner-city areas

JPS contended that these communities have key features in common such as:

- Almost everyone receives electricity from JPS' network
- Almost no one is paying for electricity in such communities
- JPS' traditional approaches to controlling unauthorized connections have not been working.

JPS proposed the following:

1. Lower Tariffs

   Rates would be less than the full cost of providing service. JPS expressed the view that charging lower tariffs can increase collection rates and overall revenues from these communities. This, the company further claimed, would allow communities to establish a habit of paying utility bills, which they would continue to pay even as tariffs rise.

2. Payment Options

   JPS claimed that the programme would offer improved payment options. First, it would offer transitional "community upliftment tariffs." These tariffs would be discounted and gradually increased as service levels increase and customers' ability to pay increased. Additionally, there would not be any initial connection charge. Instead, customers would be able to pay for the cost of connection in instalments, added on to their monthly bills. Customers that cannot make payments would not be disconnected automatically. Instead, they would be offered credit arrangements with interest. Secondly, pre-paid meters would be provided as a means of helping persons to manage their budget more effectively and to "pay as they go", avoiding large monthly bills at the end of each month.

2.10 Pre-paid Metering

JPS proposed to fully introduce pre-paid meters in order to make it easier for customers to pay for a small amount of electricity at a time and avoid a large bill at the end of the month.

JPS cited the following as expected benefits to be derived by consumers:

- Control over their energy usage and budget - customers could determine the maximum amount of electricity they wish to purchase monthly and the frequency of purchases;
- Point-of-Payment Flexibility to purchase top-up supplies;
- Potential for Energy Savings – JPS submitted that studies have shown that pre-paid customers consume less energy and have lower monthly bills than their post-paid counterparts;
- Avoid the payment of a security deposit;
- Avoid the payment of certain fees - pre-paid customers would not be charged for disconnection or reconnection fees, and they would never have to pay a late payment fee.

2.11 Proposed System Losses & Heat Rate Targets

The current System losses target is set at 17.50%. JPS requested an increase in the target to 22.95% in 2014. The proposed target for 2014 and the remaining years up to 2018 as requested by JPS, are outlined in Table 2.111 below.

JPS further requested that the heat rate target of 10,200kJ/kWh that is now in effect remain in force and new target set on the commissioning of new base load generation facility.

Table 2.111: JPS' Proposed System Losses Target 2014 – 2018

	Actual (%)	Forecast (%)				
	2013	2014	2015	2016	2017	2018
System Losses - 3 Yr Rolling Average	23.34	24.95	25.98	26.22	25.63	24.88
Stretch Target		2	2	2	2	2
Proposed System Losses Target		22.95	23.98	24.22	23.63	22.88

2.12 Customer Quality-of-Service Standards

2.12.1 Proposed Modifications to Guaranteed Standards

JPS requested that the company should not be obliged to make Guaranteed Standard payments in the circumstances set out below. It contended that these are normal exemptions in other jurisdictions with established Guaranteed Standard regimes:

- The customer informs JPS before the Standards contravention period that he/she does not want JPS to take any action or further action in regard to the matter.
- Where the customer agrees with JPS that the action already taken by JPS meets the requirement of the Standard. In the event, however, that JPS promises to take further action, the action must be completed without delay, or in the agreed timeline, for this exemption to be invoked.
- Where information is required from the customer and it is not given to the appropriate telephone number, address or email account as indicated by JPS or is done at a time outside the reasonable hours established by JPS.
- Where it was not reasonably practicable for JPS to perform the necessary Standard due to:

    - Severe weather, as agreed by the OUR;
    - Industrial action by JPS' employees;
    - The act or default of a person not working directly for, or as an agent of JPS to the premises;
    - The existence of circumstances, which would cause JPS to break the law by following the Standards;
    - Circumstances of an exceptional nature beyond the control of JPS, and JPS had in each case taken all reasonable steps to both prevent the circumstances from occurring and from having an adverse effect.

- Belief on the part of JPS that the information provided is of a frivolous or vexatious nature.
- The breach occurs during a period when the customer has failed to pay charges due after receiving a disconnection notice.

2.13 Three-Year Rate Review Request

JPS proposed a three-year rate review for current application, with the assumption that the successful commissioning of the proposed 381 MW LNG-fired facility that was being negotiated with EWI at the time the tariff application was submitted, would be the trigger for the next review. JPS noted that upon completion of the proposed facility, over half of its generation would be replaced and more than 70% of generation capacity would be owned by IPPs. Furthermore, JPS also stated that in the interim, there would be a substantial amount of renewables added to JPS' system. These variable resources, JPS submitted, may require system improvements to accommodate their operational dynamics. JPS stated that it would also need to retire and decommission the Old Harbour and Hunt's Bay plants, and such costs would be material and would require compensation. JPS expressed the view that the most prudent approach would be to file a Notice with the OUR, at the commercial operations date of the EWI plant, for a rate review to address all of the above issues. JPS made the assumption in its application that the three-year rate review would be filed in March of 2017, contingent upon a successful start-up of the proposed EWI plant.

Chapter 3: Performance Based Rate-Making Mechanism (PBRM)

3.1 Introduction

Consistent with the Licence, JPS' rates are to be reset once every five (5) years and its revenues are to be adjusted based on the company's performance. Incentive targets are set for JPS to meet or exceed them. If JPS does not meet these targets then the company must absorb the extra costs. If JPS meets or exceeds the targets, the company keeps the profits. Consistent with the provisions of the Licence, tariffs are set on the basis of two components – fuel and non-fuel. Under the existing price control mechanism, total reasonable and prudent fuel costs incurred by JPS each month is recovered through calculated monthly fuel rates which are adjusted for efficiency by the System losses target and heat rate target determined by the Office in accordance with Schedule 3, EXHIBIT 2 of the Licence. In contrast, adjustments to the non-fuel rates incorporate a PBRM which is implemented by the Office in accordance with the relevant provisions of Schedule 3 of the Licence.

3.2 Three-Year Rate Request

JPS' three-year rate review request was premised on the successful commissioning of the planned 381 MW LNG-fired facility to be developed by EWI. This project was aborted prior to the conclusion of the rate review but there is still an imperative for new base-load capacity to be installed. The OUR is therefore of the view that the commissioning of any such major generation capacity, within the price-cap period, may require an interim review of the rates to take into account the cost impact of the new generation capacity. In the event that such generation capacity development is initiated, the Office, in consultation with JPS, will decide on an appropriate framework for addressing any possible request for rate adjustment.

3.3 Annual Adjustment in Tariffs

In accordance with Schedule 3, EXHIBIT 1 of the Licence, the Non-Fuel Base Rate for each customer class shall be adjusted on an annual basis pursuant to the following formula:

ABNFy = ABNFy-1(1 + dPCI)

Where:

ABNFy	=	Adjusted Non-Fuel Base Rate for Year "y"
ABNFy-1	=	Non-Fuel Base Rate prior to adjustment
dPCI	=	Annual rate of change in non-fuel electricity prices as defined below.
PCI	=	Non-fuel Electricity Pricing Index

The annual rate of change in non-fuel electricity prices (dPCI) shall be determined through the following formula:

dPCI = dI ± X ± Q ± Z

JPS will be required to develop tariff schedules annually, during the 2015 - 2019 price-cap period. Each year during the stated period, the Office will consider approving the annual schedule of rates submitted by JPS provided that the weighted average of the individual rates included in the schedule complies with the constraints in the above equation.

At the Annual Tariff Adjustment review, JPS may request changes to the tariff structure of its existing tariff basket provided that:

- It also provides the Office with a statement of reasons for any proposed modifications.
- The resultant impact on individual customer bills, for the same level and type of consumption as applied in the previous year, will not produce, as determined by the Office, any rate shock.

Any such change shall be consistent with the pricing principles outlined in Condition 14 and Schedule 3 of the Licence and subject to the approval of the Office.

Accordingly, the Office DETERMINES that the Annual Growth Rate adjustment formula that shall be used by JPS to adjust the Non-Fuel Base Rates at each Annual Tariff Adjustment during the 2015 - 2019 price-cap period is as follows:

$$dI = USP \times \left(\frac{EXn - EXb}{EXb}\right)(1 + USAF \times INFus) + (USP \times USAF \times INFus) + (1 - USP) \times INFj$$

Where:

EXb	=	Base US Exchange Rate
EXn	=	Applicable US Exchange rate at Adjustment Date
$INFus$	=	US Inflation as defined in the Legal and Regulatory Framework.
$INFj$	=	Jamaica Inflation as defined in the Legal and Regulatory Framework.
USP	=	0.80 (US portion of the total non-fuel expenses)
$USAF$	=	0.45 (the US Adjusted Factor which represents that portion of the US component of the total non-fuel expenses that is not subject to US inflation adjustment)

3.4 Productivity Efficiency Factor (X-Factor)

3.4.1 The X-Factor Framework

The price cap framework that governs JPS' tariff is predicated on a PBRM which establishes the annual maximum allowed change in the non-fuel electricity prices. The maximum allowed change (*dPCI*) is defined by the formula:

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

In the formula, *dI* captures the inflation and exchange rate depreciation movements in the general economy; *X* is the offset to inflation (annual real price increase or decrease) resulting from productivity changes in the electricity industry; *Q* is the allowed price adjustment to capture changes in the quality of service provided to customers; and *Z* is the allowed rate of price adjustment for exogenous factors that are independent of other elements of the PBRM.

Under price cap regulation, the average price of electricity is set in real terms for a pre-determined period (5 years in JPS' case, which is consistent with international best practice). This type of regulation is expected to incentivize the utility to improve its efficiency over the duration of the tariff period. The X-Factor is the component in the PBRM formulation through which the utility can share the efficiency gains with customers.

3.4.2 JPS' Proposed X-Factor

JPS proposed that the X-Factor over the 2014 - 2019 tariff period be set between 0.0% and 0.35%. This proposal was based on work done by its consultant, Castalia Strategic Advisors (Castalia), and was centered on an analysis of the difference between the expected change in the total factor productivity of JPS (ΔTFP_{JPS}) and that of the general economy (ΔTFP_{Gen}), which may be expressed as follows:

$$X = \Delta TFP_{JPS} - \Delta TFP_{Gen}$$

3.4.2.1 Selection of the 2006-2011 Calculation Period

Castalia employed data spanning the period 2006 – 2011 for the X-Factor calculation. Apparently, 2011 was selected as the end point for the calculation because the World Penn Tables version 8, from which the Jamaican productivity data was taken, had 2011 as the terminal point for its dataset. On the other hand, Castalia indicated that 2006 was selected as the starting point of the calculation for the following reasons:

1. 2006-2011 represents a 5-year period which matches the tariff period; and
2. the most recent data available was more likely to give a better indication of what might occur in the future.

3.4.2.2 JPS' Productivity

According to Castalia's analysis, with the advent of privatization in 2001, JPS' non-fuel TFP had grown at an average annual rate of:

- 2.00% from 2001-2006
- 0.53% from 2006-2011
- 1.27% from 2002-2011

This suggests that since 2001, the company has experienced significant improvements in the productivity of the non-fuel component of its business.

3.4.2.3 Productivity in the General Economy

Consistent with the methodology employed by the OUR in the 2009-2014 Tariff Review, JPS assumed that the TFP for the general economy was derived from the combined effects of productivity growth in the US and Jamaican economy, weighted in the ratio of 76% and 24% respectively. In this regard, the change in general productivity (ΔTFP_{Gen}) maybe expressed as:

$$\Delta TFP_{Gen} = \left(0.76 \times \Delta TFP_{US} + 0.24 \times \Delta TFP_{Ja}\right)$$

In arriving at the growth in productivity for the US economy, Castalia relied on the Nonfarm, Private Multifactor Productivity from the US Bureau of Labor Statistics. The average annual rate of growth in productivity in the US economy (ΔTFP_{US}) over the period 2006-2011 was 0.421%.

For the period 2006-2011, data from the Penn World Tables (Version 8) indicates indicated that the Jamaican economy registered an average annual decline change in productivity of -0.583 %.

Consequently, by taking into account the combined impact of the growth in TFP in the US and Jamaican economy, as derived by Castalia, the expected growth in productivity for the general economy is 0.180% (see Box 1 below).

Box 1

$$\begin{aligned}\Delta TFP_{Gen} &= (0.76 \text{ x } \Delta TFP_{US} + 0.24 \text{ x } \Delta TFP_{ja}) \\ &= 0.76 \text{ x } 0.421\% + 0.24 \text{ x} - 0.583\% \\ &= 0.180\%\end{aligned}$$

Given that the growth in JPS' productivity (ΔTFP_{JPS}) over the period 2006-2011 was calculated to be 0.53%, then the proposed X-Factor being the difference between JPS' expected productivity growth and the growth in the general economy would be 0.35% (see Box 2 below).

Box 2

$$X = \Delta TFP_{JPS} - \Delta TFP_{Gen}$$
$$= 0.53\% - 0.18\%$$
$$= 0.35\%$$

3.4.2.4 Stretch Factor

JPS noted that in previous rate setting exercises, the OUR invoked a stretch factor in arriving at the final determination of the X-Factor. The stretch factor is a parameter that is added so as to capture some degree of the incremental gains attained by the utility operating under incentive regulation.

Stretch factors are set to reflect the regulator's perception of the distance the utility is from the efficiency boundary. JPS argued that in the immediate period after the privatization of a government-owned utility, the performance gap between the privatized entity and the most efficient utilities in its class is often great. Over time, however, with effective incentive regulation, the gap should be narrowed and accordingly the stretch factor reduced.

While Castalia's TFP analyses proposed that the upper limit of JPS' productivity factor be set at 0.35%, it has made the case that consideration should be given to setting JPS' X-Factor, which includes the stretch factor, at zero. Castalia, drawing from a sample of forty nine (49) utilities, applied three analytical techniques to assess JPS' proximity from the efficiency boundary, viz:

1. Productivity benchmarking;
2. Efficiency frontier analysis; and
3. Data envelope analysis.

In the end, Castalia concluded that:

> *"The results of each technique suggest that JPS is operating on, or near, the efficiency frontier for electric utilities. Therefore, there should be no stretch factor applied in order to arrive at JPS' expected TFP growth rate in the tariff period 2009-2014.[2] "*

[2] JPS Tariff Application 2014-2019 Annex, p.29

Applying the above advice, JPS urged that an X-Factor at 0.0% – 0.35% be established and applied over the next tariff period.

3.4.3 OUR's Response and Analysis

The OUR accepts that a plausible approach to the setting of an expected productivity factor is to make projections based on past behaviour. In this regard, the approach based on the computation of changes in the total productivity factor of the non-fuel component of JPS' operation has been deemed acceptable.

Citing research done by Makholm et al on the TFP of 72 electric utilities in the US over the period 1972-2009, Castalia observed that over the 37-year period, US electric utilities grew at an average annual rate of 0.85% while the US economy grew at a slightly higher rate of 0.91%. Castalia also referenced the rapid rate of productivity growth experienced by utilities in the 1980s after public-owned utilities were privatized. Castalia argued that:

1. *"there is no a priori reason to think that electricity utilities should be able to increase productivity faster than the economy as a whole"*
2. *"there is no reason to take a condition that existed in Great Britain in the 1980's, and assume that it is equally applicable in the Jamaican context"*

It is submitted that in using research cited above to support the setting of the X-Factor at 0.0% - 0.35% Castalia failed to give consideration to at least three factors.

First, in the Makholm study the TFP data was based exclusively on the distribution component of the utilities' operation[3]. As such, generation and transmission costs were not a part of the Makholm study. On the other hand, JPS' TFP analysis included non-fuel generation and transmission costs. It is therefore clear that the variables being compared in JPS' analysis and the Makholm study are not the same. In this respect, the conclusion drawn by Castalia on the basis of this study is questionable.

Second, the productivity results of the US electricity industry are not readily comparable to the Jamaican situation because the industry is largely based on private ownership and at no time over the duration of this study (1973 -2009) did it experience the extent of privatization of the electricity sector that occurred in Jamaica.

Third, the expectation that heightened productivity at JPS, mirroring the experience in the UK after the privatization of public utilities, was not unreasonable, at least for the non-fuel operation of JPS. In fact, the data showed that over the period 2001-2012, productivity in the Jamaican economy changed annually at an average rate of -0.82% while JPS' Non-fuel TFP registered an annual

[3] See p.3 - Makholm, Jeff., Augustin J. Ros, and Meredith A. Case, "Total Factor Productivity and Performance-Based Ratemaking for Electricity and Gas Distribution"(2010)

increase of 1.26% (see Table 3.41 below). This suggests that the expectation is also supported by empirical observations.

Castalia's suggestion that the X-Factor may be set at zero percent similarly to what was done in New Zealand in 2012 was without a sound foundation.

3.4.3.1 Expected TFP Growth

In an attempt to bolster its position concerning the imperative of setting the stretch factor, and the X-Factor at zero, Castalia employed three empirical approaches to gauge the company's position relative to the efficiency frontier.

First, it used Productivity Benchmarking in which data spanning 2005-2011 on utilities from the Caribbean, USA and New Zealand were included in the dataset. In the analysis, inputs included variables such as staff cost, depreciation, non-fuel operating expense and number of employees. Output variables, on the other hand, encompassed customer numbers, MWh, MW peak load and network length.

Benchmarking presents serious challenges even when done in a single country. Therefore, it becomes even more problematic when multiple countries spanning different regions are involved. In this type of benchmarking, consideration must be given to factors such as the nature of the area and population being served, network design and topology, approach to outsourcing, to mention a few.

A close examination of Castalia's dataset indicates that no such care was exercised in the benchmarking analysis. This is perhaps one explanation for the fact that the analysis indicates that for all the benchmarks accessed, JPS was in an elite group of efficiency frontrunners.

The result of a Productivity Benchmarking study can easily become skewed by incomparable utilities. For instance, Florida Power and Light (FPL), which was included in the dataset, employed 14,000 workers against JPS' 1,600; supplies 4.7 million customers against JPS' 0.6 million; operates across 27,650 sq. miles against JPS' 4,111 sq. miles and possesses an installed capacity of 25GW versus Jamaica's 0.9GW. Similarly, disparities were found with Georgia Power which was also included in the data.

The OUR is of the view that the evidence presented in JPS' Tariff Submission was insufficient and provided no confidence in arriving at the conclusion that the company 'is operating at the efficiency frontier'.

The second approach Castalia used in its assessment was the Efficiency Frontier Analysis (EFA). This technique is based on multiple-regression modelling which derived the relationship between multiple independent variables.

Apart from stating that the dataset was comprised of 49 utilities drawn from the Caribbean, USA and New Zealand over the period 2005-2011, JPS' Tariff Submission is deficient in shedding light on the nature of the data used. Additionally, while a number of models were short-listed in the EFA from which 'Model 1.9' was selected, JPS' Tariff Submission failed to reveal explicitly why that model was selected rather than any of the other models.

In justifying this technique, Castalia cited that the Office of Gas and Electricity Markets (Ofgem), the UK regulator, used the methodology. Notwithstanding, it should be noted that Ofgem applied this approach to '14 relatively homogenous companies active within the same market structure' and not a group of heterogeneous electric utilities operating under widely varying circumstances.

On the basis of the EFA, JPS concluded that the company was the 4th most efficient in the dataset of forty-nine (49) utilities. The OUR has expressed reservations as to whether 'sufficient normalization' was carried out on the data and questioned whether the analysis included 'appropriate explanatory variables' that would yield meaningful results.

The third approach used to assess JPS' efficiency was based on the Data Envelope Analysis (DEA). JPS' Tariff Submission correctly noted that, unlike the other two techniques discussed above, the DEA was a non-parametric approach that avoided the problem of:

- Matching specific costs with particular outputs (like the Productivity Benchmarking)
- Constructing an appropriate cost model (like the EFA)

However, while this technique presented clear advantages over the other two approaches, in conducting the analysis, little or no information was provided to facilitate the analysis of the results.

JPS used DEA-*Solver* software package[4] which was chosen, it claims, partly on the basis of documentation by Ofgem and the Australian Energy Regulator. Notwithstanding, the model as presented in JPS' Tariff Submission, was a black box and the acceptance of the conclusion that JPS was an efficient cost performer was not something that can be rationally deduced based on the evidence presented.

Furthermore, this purported convergence of these three methodologies was intuitively unappealing since it ran counter to what may be deduced without the aid of high science.

For instance, in the 2004 Tariff Submission, JPS in its X-Factor assessment described itself as an *'average performer relative to US electric utilities*[5]*'*. In its 2009 Tariff Submission it proposed a stretch factor of 0.5% in keeping with the notion of an average performer. In addition, in the 2009 Submission JPS estimated that its TFP for the company would grow at an annual rate of 1.94% over the 5-year period, 2009-2014. However, the actual annual rate of TFP growth that the company registered over the period 2008-2012 was 1.16% or 0.78 percentage points below the expectation.

It therefore seemed odd that a company considered an average performer five (5) years ago, one that continued to operate with an aging fleet of generating plant, and had underperformed against its own

[4] From a text book from Cooper, William W., Lawrence M. Seiford, Kaoru Tone
[5] JPS 2004-2009 Tariff Review Application, p. 82

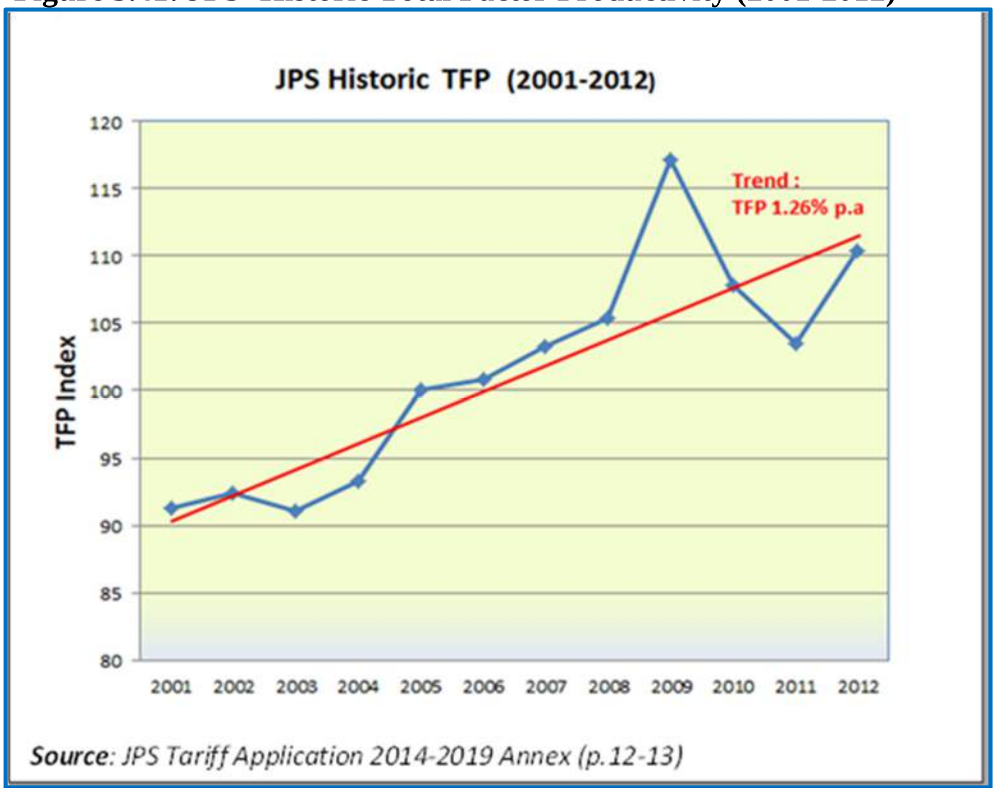
TFP expectation had now dramatically assumed the position of an efficiency frontier leader. The OUR has therefore rejected the conclusion of JPS' X-Factor study that the company was at or near the efficiency frontier.

3.4.3.2 Setting the X-Factor

In setting the X-Factor, JPS used the period 2006-2011 for its calculations. The OUR is of the view that the period 2001-2012 was more suitable for the setting of the X-Factor for the following reasons:

1. Given that the privatization of JPS occurred in 2001, it was an appropriate reference point for the observation of the productivity trend.
2. From a statistical perspective, a longer time series should provide a more reliable indicator of productivity trends. In this regard, it was perhaps no coincidence that the Makholm study employed a 37-year time series to assess productivity in the US electricity industry and not a 5-year series. In any event, the TFP data for the 2006-2011 period exhibits extreme volatility. Indeed, since 2001, the 2006-2011 period had registered both the highest increase in non-fuel productivity and the greatest decline in a single year. In 2009, JPS' TFP grew by 11.2% and in the following year it declined by 7.9% (see Figure 3.41). The longer period therefore offered the advantage of capturing both trends and likely outliers.

Figure 3.41: JPS' Historic Total Factor Productivity (2001-2012)



Given that the *Penn World Table* used by JPS in its calculation of the TFP for the Jamaican economy had a terminal point of 2011, the OUR used the TFP data produced by *The Conference Board for Total Economic Data* (TCBFTED) which had a 2012 terminal point. Interestingly, both data sources gave, more or less, the same annual rate of growth for the period 2001-2011[6](see Table 3.41).

Table 3.41: TFP Jamaican and US Economy 1991-2012

	TFP –Jamaican Economy		TFP-US Economy	TFP-JPS
	PENN	*TCBFTED*	*BLS*	*JPS*
1991	108.94	111.25	82.46	91.24
1992	117.25	110.90	84.54	85.04
1993	116.99	111.50	84.44	75.55
1994	114.60	109.52	84.94	82.12
1995	111.44	108.82	85.13	69.71
1996	110.50	107.50	86.42	76.09
1997	108.18	105.69	86.92	76.09
1998	105.92	102.74	88.40	76.00
1999	107.11	104.45	89.99	82.76
2000	106.69	104.97	91.28	82.94
2001	106.45	104.87	91.67	91.33
2002	101.05	100.37	93.56	92.43
2003	101.89	101.49	95.84	91.06
2004	101.94	101.70	98.61	93.25
2005	**100.00**	**100.00**	**100.00**	**100.00**
2006	99.89	99.99	100.30	100.82
2007	98.56	98.41	100.69	103.28
2008	97.42	96.71	99.41	105.37
2009	96.30	94.60	99.11	117.19
2010	96.44	94.54	101.78	107.87
2011	97.01	95.74	102.48	103.54
2012	97.01*	95.74	104.06	110.35
Avg. Growth per Annum (2001-2012)	**-0.84***	**-0.82%**	**1.12%**	**1.26%**

Note: All data converted to a 2005 Base Year
*: Estimated value
PENN: Penn World Table,
TCBFTED: The Conference Board for Total Economic Data
BLS: Bureau of Labor Statistics (USA)

Employing the 2001-2012 period yielded the following inputs for the X-Factor calculation:

[6] For the 2001-2011 period the annual rate of TFP growth based on the *Penn World Table* and *The Conference Board for Total Economic Data were -0.91 and -0.92 respectively*.

- TFP for JPS: 1.26%
- TFP for the US economy: 1.12%
- TFP for the Jamaican economy: -0.82

While JPS' X-Factor formula assumed that 76% of the company cost was foreign-related and 24% was of local origin, the OUR has conceded that the foreign to local cost ratio is now 80%: 20%. In this regard, this change must be captured in the equation for the change in TFP for the general economy (ΔTFP_{Gen}). Consequently, the appropriate formula for computing the change in general productivity (ΔTFP_{Gen}) is:

$$\Delta TFP_{Gen} = \left(0.8 \times \Delta TFP_{US} + 0.2 \times \Delta TFP_{Ja}\right)$$

Applying the equation above and replicating the calculation done in Box 2 above, resulted in a productivity growth in the general economy of 0.73% and an X-Factor of 0.53% (see Box 3 below).

Box 3

$$\begin{aligned}\Delta TFP_{Gen} &= (0.8 \text{ x } \Delta TFP_{US} + 0.2 \text{ x } \Delta TFP_{Ja})\\ &= 0.8 \text{ x } 1.12\% + 0.2 \text{ x} - 0.82\%\\ &= \mathbf{0.73\%}\end{aligned}$$

$$\begin{aligned}X &= \Delta TFP_{JPS} - \Delta TFP_{Gen}\\ &= 1.26\% - 0.73\%\\ &= \mathbf{0.53\%}\end{aligned}$$

3.4.3.3 Setting of the Stretch Factor

As discussed above, the setting of the stretch factor was a discretionary exercise determined by the regulator's perception of the productivity gap to be closed between the utility and the industry efficiency frontier. JPS has contended that the stretch factor should be set close to zero because: (i) it is operating in a low/negative growth environment; (ii) the structure of its tariff under-emphasizes fixed cost recovery; (iii) it will require relatively high levels of expenditure to keep its old inefficient plants operating; and (iv) the X-Factor offset in the price cap adjustment formula was deficient in its treatment of US$ costs.

Regarding JPS' comment that the X-Factor offset is deficient, the OUR takes the position that the formulation captures the intended objective fairly well. Moreover, if there is an issue with the formulation it should be addressed by way of a reformulation rather than attempting to tweak the stretch factor that is a discretionary measure. The JPS' Tariff Submission did not include a revision of the X-Factor formula for consideration.

Additionally, the OUR is of the view that since privatization JPS has made progress under successive price cap regimes in improving its non-fuel productivity. However, there is still scope for significant improvements in the company's operation. For instance, while admittedly there are differences in fuel source, generation plants, network configuration, to name a few, between US utilities and JPS', the average all-in price for US utilities is 11.01 US c/kWh[7] while JPS' non-fuel electricity price is currently 13.56 US c/kWh. Furthermore, since 2004 JPS' non-fuel cost had increased by almost 59.2%. It was in this regard that the argument proffered by JPS that low sales growth, a skewed recovery structure and the operation of a fleet of aging plants justified a stretch factor next to zero was unacceptable. Consequently, it is imperative that JPS reduces its non-fuel cost more aggressively over time.

It is important to note that production possibility boundaries are not static enclosures. On the contrary, they are continually impacted by technological development and improved management practices and therefore stretch factors should place some pressure on utilities, even those very close to the boundary, to remain alert and agile in a dynamic environment.

The Pacific Economic Group (PEG) Research, a well-respected research company in utility productivity, has indicated that regulators in North America, on the basis of judgment, have "*approved stretch factors in a relatively narrow range, between 0.25% and 1% with an average value of approximately 0.5%*"[8]. In this respect the OUR takes the view that, under normal circumstances, it would be fair to apply a stretch factor of 0.5% to an average efficiency performer. Notwithstanding, in setting the X-Factor the regulator must take into account the specific circumstances which are expected to affect the utility's efficiency in order to balance the final X-Factor. Given, the need for JPS to contain its expanding non-fuel rate and the scope for heightened productivity, having regard to all the circumstances, the OUR has decided to set the stretch factor at 0.57%.

After making its assessment of the historic productivity exhibited by JPS and the general economy, while giving due recognition for the scope for internal incremental improvements within the company, the OUR has determined that the X-Factor applicable to JPS over the 2014-2019 tariff period is 1.10% per annum (i.e. productivity of 0.53% plus a stretch factor of 0.57%).

DETERMINATION 1

The Office DETERMINES that the X-Factor for the price-cap period 2015 – 2019 is 1.10%.

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[7] See EIA: US Energy Information Administration Report (July 2014) @ http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=ep

[8] See PEG, *Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario: Final Report to the Ontario Energy Board* (Nov 2013), p.14

3.5 The Q-Factor (Quality of Service)

3.5.1 Introduction

Repeated large-scale blackouts and frequent total shutdown of the Jamaican power system since 2006 have directed attention to the importance of a reliable and secure electricity service. During most, if not all of the System shutdown incidents, electricity customers experienced outage durations of more than twelve (12) hours. Resulting from these major outage events, recommendations have been made, with some already implemented, in an effort to improve System reliability and prevent future occurrences, both large and small.

To manage System reliability effectively, a utility must be able to properly measure and monitor it. In this regard, performance metrics become useful as they provide a mechanism to quantitatively measure System reliability and improvements in it. The use of metrics such as the frequency and duration of power interruptions have been essential in managing System reliability. This is because reliability measurements provide a quantitative and objective basis for assessing the effectiveness of the utility's efforts to maintain or improve reliability. Additionally, reliability measurements are necessary to support utility regulators' efforts to monitor performance and to establish performance benchmarks and incentive mechanisms that will encourage the utility to improve the reliability of electricity service to customers.

System reliability can be understood simply by considering a basic distribution feeder. There are many protective devices (fuses, reclosers, sectionalizers, breakers, etc.), overhead and/or underground line segments, three-phase and single-phase line elements, several different distribution voltage levels and in general many places for failure of components.

In electrical power networks, most of the connected loads are usually concentrated in the distribution systems which generally consist of radial feeders. A consequence of using radial feeders is that many customers can be affected by the failure of any single component. Modified radial system designs with normally open tie-points have become popular to minimize the reliability impact of the radial feeder design.

Due to its predominant aerial orientation, the distribution system is greatly affected by weather and vegetation and, in some regions, snow and salt accumulation are major problems. In other areas, lightning is a major cause of interruption in service. However, utilities' outage data have shown that tree branches are among the most common causes of distribution system interruptions.

In dealing with System reliability, utilities typically track weather factors such as wind, rain, lightning and salt accumulation in order to predict the performance of the distribution network and for planning purposes.

Worldwide data on distribution system reliability have indicated that better reliability performance can be achieved with better vegetation control, tree-trimming schedules, regular maintenance schedules and effective crew placement. Improved reliability performance can also be achieved by the utilization of advanced distribution design schemes which include automation and the use of advanced equipment such as reclosers, sensors, monitors and advanced technologies for condition monitoring. Utilities can also achieve high reliability performance in dense urban centres by serving their customers via looped underground networks rather than overhead radial feeders. Hence designing and maintaining a system which is as resistant as possible to failure can markedly improve reliability.

The performance of an electric utility distribution system can be assessed by the use of reliability indices such as:

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

Currently, these indices are adopted by JPS for measuring the reliability performance of the electricity System and quality of service provided to customers. These indices are also crucial to the OUR for establishing an appropriate benchmark level to facilitate the implementation of the Q-Factor incentive mechanism as required under Exhibit 1, Schedule 3 of the Licence.

3.5.2 Definition of Reliability Indices

Under Schedule 2 of the Licence, the reliability indices SAIFI, SAIDI and CAIDI are defined as Overall Standards (OS). The targets for these indices are to be set annually and in accordance with Condition 17, paragraph 1 of the Licence. JPS shall use all reasonable endeavours to achieve them.

These indices are referred to as sustained interruption indices and are defined below in accordance with the IEEE Guide for Electric Power Distribution Reliability Indices (IEEE 1366-2012). In line with prudent industry standards and international best practice, this IEEE Guide from its earlier 2003 version had been adopted by the OUR to provide guidance on the application of reliability performance indices in the Jamaican electricity System.

In JPS' Tariff Submission, the company also stated that it has formally adopted the IEEE 1366-2012 Guide.

The definitions of the relevant indices are provided as follows:

3.5.2.1 Sustained Interruption Indices

SAIFI: System Average Interruption Frequency Index

SAIFI indicates how often the average customer experiences a sustained interruption over a predefined period of time. Mathematically, this is given in the equation below:

$$SAIFI = \frac{\sum Total\ Number\ of\ Customer\ Interrupted}{Total\ Number\ of\ Customers\ Served}$$

SAIDI: System Average Interruption Duration Index

SAIDI indicates the total duration of interruption for the average customer during a predefined period of time. It is commonly measured in minutes or hours of interruption. Mathematically, this is given in the equation below:

$$SAIDI = \frac{\sum Customer\ Minutes\ of\ Interruption}{Total\ Number\ of\ Customers\ Served}$$

CAIDI: Customer Average Interruption Duration Index

CAIDI represents the average time required to restore service. Mathematically, this is given in the equation below:

$$CAIDI = \frac{\sum Customer\ Minutes\ of\ Interruption}{Total\ Number\ of\ Customer\ Interrupted}$$

Mathematically, CAIDI can also be derived by the quotient: SAIDI/SAIFI.

The definitions imply that these indices provide information about average reliability performance across the entire customer base. Averages tend to provide general performance trends for the utility; however, using averages can lead to loss of detail that could be critical to decision making. For example, using System average alone will not provide information about the interruption duration experienced by any specific customer. While it is recognized that it is difficult for the utility to provide information on a customer basis, the OUR is of the view that tracking of specific details surrounding specific interruptions rather than averages can be accomplished by advanced data capture mechanisms. In addition, the utility could also consider for reporting purposes, indices that examine performance at the customer level.

Average System reliability performance also does not consider the load demand of the various Rate categories relative to System load. Technical analysis of JPS’ System outage data and computation of the referenced indices indicate that residential customers tend to dominate SAIFI and SAIDI since these indices treat each customer the same. According to JPS’ 2013 performance dataset, legitimate residential customers accounted for just below 90% of the company’s customer base but contributed to less than 30% of System load. For a more proportional weighting of larger customers in service reliability performance measurements, load-based indices such as Average System Interruption Frequency Index (ASIFI) and Average System Interruption Duration Index (ASIDI) can be considered. Essentially, these indices are scaled by load and represent the equivalent of SAIFI and SAIDI.

The load-based indices are defined in accordance with the IEEE Guide for Electric Power Distribution Reliability Indices (IEEE 1366-2012) as follows:

ASIFI: Average System Interruption Frequency Index

The calculation of ASIFI is based on load rather than customers affected. ASIFI is sometimes used to measure distribution performance in areas that serve relatively few customers that have relatively large concentrations of load, predominantly industrial/commercial customers. Theoretically, in a System with homogeneous load distribution, ASIFI would be the same as SAIFI. Mathematically, this ASIFI is given in the equation below:

$$ASIFI = \frac{\sum \ Total\ Connected\ kVA\ Load\ Interrupted}{Total\ Connected\ kVA\ Served}$$

ASIDI: Average System Interruption Duration Index

ASIDI is based on load rather than customers affected. Its use, limitations, and philosophy are stated in the ASIFI definition. Mathematically, ASIDI is given in the equation below:

$$ASIDI = \frac{\sum \ Connected\ kVA\ Duration\ of\ Load\ Interrupted}{Total\ Connected\ kVA\ Served}$$

Despite the proportionate effect of customer category on System load recognized by load-based indices in reliability performance metrics, many utilities do not measure ASIFI and ASIDI, mainly because they can be difficult to track. Knowing quantity of load interrupted could be more challenging than knowing number of customers interrupted. Irrespective of such limitations, these indices can provide a better representation of the effect of System interruptions and loss of load for the various customer categories.

3.5.2.2 Momentary Interruptions

According to the IEEE Guide for Electric Distribution Reliability Indices, momentary interruption is defined as a brief loss of power delivery to one or more customers caused by the opening and closing operation of an interrupting device. Such switching operations must be completed within a specified time of five minutes or less. In the event that two circuit breaker or recloser operations (each operation being an open followed by a close) briefly interrupt service to one or more customers this is characterized as two momentary interruptions.

MAIFI: Momentary Average Interruption Frequency Index

MAIFI indicates the average frequency of momentary interruptions. Mathematically, this is given in the equation below:

$$MAIFI = \frac{\sum \ Total\ Number\ of\ Customer\ Momentary\ Interruptions}{Total\ Number\ of\ Customers\ Served}$$

Momentary interruptions are those that result from each single operation of an interrupting device such as a recloser. MAIFI measures data on momentary interruptions that result in a zero voltage. For example, two circuit-breakers open operations are equivalent to two momentary interruptions.

The issue of momentary interruptions is widely discussed in the present electricity supply environment. One of the major areas of concern is the duration of the interruptions. Some utilities count them in terms of a variety of durations: 1 minute, 2 minutes, 3 minutes and 5 minutes. Regardless of their length, whether 1 minute or 5 minutes, the number of momentary interruptions may not affect the overall reliability numbers significantly. However, these interruptions can have a significant impact on sensitive and critical loads. The other fundamental issue is the nature of the customers' operation at the time of the momentary interruption and the resulting impact. For example, a commercial production process in which unfinished products experience irreversible damage due to a five-minute momentary interruption or a series of momentary interruptions within 5 minutes.

Due to the potential adverse effects of momentary interruptions on customers' operations, MAIFI will be considered as an important metric in the monitoring of System reliability and the quality of service provided to electricity customers.

3.5.3 Calculation of Reliability Indices

Research carried out on distribution system reliability indicates that many utilities calculate a subset of the indices listed above and use them for planning and reporting to the utility regulator. Some utilities calculate one set of indices and include every type of interruption. Others calculate the same set of indices but for different subsets of interruption types. For example, some calculate a set with hurricane or storm data excluded, a set with planned interruptions excluded, and a set with nothing excluded.

Utilities tend to calculate reliability indices differently because of the method used to count planned outages, momentary outages, the number of customers in the service area and the duration of the events, major events and importantly, the regulatory requirements.
Factors that can cause wide variation in indices reported by utilities include:

- Weather;
- Geography;
- System design;

- Physical environment (mainly the amount of tree coverage);
- Load density;
- Age of equipment;
- Methods of recording interruptions (level of automated data collection).
- Data classification (whether major event and planned interruptions are included in the dataset)

In the operation of the electricity distribution system, the performance of circuits varies widely for many of the same reasons causing the spread in utility indices. Circuits have different lengths necessary to feed different areas of load density, some are older than others, and some areas may have less tree coverage. As such, the level of service reliability experienced by customers is not normally distributed. From a statistical point of view, a skewed distribution such as the log-normal distribution would be representative and has been used in several reliability applications. Despite its favourability, the skewed distribution has several ramifications, including the following:

- The average performance is usually higher than the median. However, the median is a better representation of the typical customer.
- Poor performing circuits and reliability performance to customers can dominate the indices.
- Storms and other outliers easily skew the indices.

Notwithstanding, under the current regulatory regime, the Licence requires a symmetrical approach in establishing the Q-Factor mechanism which infers that the quality of service provided to customers and the rewards and penalty scheme should be governed by a balanced distribution.

3.5.4 Current Q-Factor Mechanism

According to Exhibit 1, Schedule 3 of the Licence, the Q-Factor is the allowed price adjustment to reflect changes in the quality of service provided to customers.

> *"Allowed (Q-Factor) Price Escalation Reflecting Changes in Quality of Service*
>
> *The Q-Factor adjusts the annual escalation rate to reflect changes in the quality of service provided to customers by the Licensee. The Q-Factor will be a symmetrical adjustment to the PCI. A benchmark level will be determined for each specified service component"*

In the 2004 Determination Notice, the Office made the determination that until the next price review, the verified set of SAIFI, SAIDI and CAIDI indices for 2005 and subsequent years will be used as the baseline quality level. Furthermore, the Office determined that SAIFI, SAIDI and CAIDI should be improving by 2% in 2005 relative to the 2004 performance level and by 3%, relative to the 2005 performance level and in each subsequent year until 2009. Accordingly, the targets set by the Office for the period 2006 to 2009 are shown in Table 3.51.

Table 3.51: OUR's 2006 – 2009 Q-Factor Targets

Year	Target SAIDI	Target SAIFI	Target CAIDI
2006	$SAIDI_{2005}$	$SAIFI_{2005}$	$CAIDI_{2005}$
2007	$SAIDI_{2005}$*(1-0.02)	$SAIFI_{2005}$*(1-0.02)	$CAIDI_{2005}$*(1-0.02)
2008	$SAIDI_{2005}$*(1-0.05)	$SAIFI_{2005}$*(1-0.05)	$CAIDI_{2005}$*(1-0.05)
2009	$SAIDI_{2005}$*(1-0.08)	$SAIFI_{2005}$*(1-0.08)	$CAIDI_{2005}$*(1-0.08)

Since then, the Q-Factor has existed in the dead-band (zero). This has occurred because over the years there have been issues with the outage data from which the reliability indices are calculated. This situation has impeded the full implementation of the Q-Factor adjustment mechanism resulting in a value of zero over the two previous price-cap periods.

With respect to the application of the Q-Factor in the price adjustment mechanism, the OUR is of view that it should meet the following criteria:

- It should provide proper financial incentive to provide a level of service quality based on customers' view of the value of that service quality;
- The measurement and calculation should be accurate and transparent without undue cost of compliance;
- It should provide fair treatment for factors affecting performance that are outside of JPS' control, such as IPP forced outages, natural disasters, and other Force Majeure events, as defined under the Licence; and
- It should be symmetrical in application, as stipulated in the Licence with appropriate caps or limits of effects on rates.

3.5.5 Applicability of Indices to the Q-Factor

In JPS' 2009 Tariff Submission, Pacific Economics Group, LLC (PEG), a consultant engaged by JPS, recommended that the Q-Factor eliminate CAIDI as a quality indicator. PEG stated that including CAIDI when SAIFI and SAIDI are part of the same service quality incentive can only lead to perverse penalties or rewards. PEG also indicated that there are significant uncertainties regarding an appropriate benchmark for MAIFI and recommended that MAIFI simply be monitored, rather than implementing an adjustment mechanism that involves explicit penalties or rewards.

PEG further indicated that more attention should be devoted to understanding customers' willingness to pay for quality improvements, including the willingness to pay for reductions in MAIFI. According to the consultant, more knowledge of customer preferences can help JPS make appropriate investments and ensure that any quality improvements actually improve customer welfare.

Accordingly, in that application, JPS requested that CAIDI be excluded from the Q-Factor measurement as of 2010 and that MAIFI be included in the Overall Standards and be monitored on an annual basis. This, according to JPS, would have facilitated a continuous dialogue with the OUR on the matter while the company improves its monitoring capabilities, attempts to better understand

and categorize the data with respect to the causative factors and further analyze the relative performance of some feeders vs. others.

At the time, JPS indicated that while it did not believe it prudent to include MAIFI as part of the Q-Factor adjustment mechanism going forward as of 2010, given the significant challenges and concerns noted previously, if the OUR were to include this measure going forward, the weighting of MAIFI in the point score system and its resultant tariff impact should be appropriately adjusted (diminished).

3.5.6 System Reliability Performance (2009-2013)

As reported by JPS, System reliability improved overall between 2009 and 2013. According to the company, SAIFI declined from 26.22 in 2009 to 10.53 in 2013 and SAIDI also trended downwards moving from 38 hours (2280 minutes) per customer to 22 hours (1320 minutes) per customer.

JPS also indicated that there was a similar trend for the customers minutes lost (CML) with CML for 2011 and 2012 being considerably less than for 2009 and 2010 indicating that generally there was a declining number of customers affected by interruptions.

With respect to CAIDI, JPS indicated that it was relatively consistent over the period although it moved to over 2 hours per interruption in 2013.

JPS also noted that the total system shutdown in August 2012 contributed to increases in SAIDI and CAIDI in 2012 and a major outage in March 2013 influenced an increase in CAIDI in 2013.

3.5.7 The Current Q-Factor

In PBRMs that include price adjustment for quality of service, penalties are increased as reliability performance worsens and are capped when a maximum penalty is reached. The reverse is also true, in that, rewards increase with improvements in System reliability but capped when a maximum penalty is reached. The OUR is of the view that this arrangement would provide an incentive for JPS to pursue reliability improvement measures even after they have surpassed the poor reliability threshold for a year, before the year comes to an end, provided the data used to calculate the indices are properly captured, verified and audited.

In establishing the benchmark, the relevant criteria for data capture and reliability performance measurement must be satisfied. This includes verification and audit of outage data and evaluation of the calculated indices.

In the 2009 Determination Notice, the OUR determined that once it was satisfied that JPS' calculation of the reliability indices meet all the relevant quality-of-service criteria, performance will be classified into three categories reflecting the following point system:

- Above average performance (greater than 10% above benchmark) – would be worth 3 Quality Points on either SAIFI, SAIDI, or CAIDI;
- Dead band Performance (+ or -10%) – would be worth 0 quality points on either SAIFI, SAIDI, or CAIDI; and
- Below Average Performance (more than 10% below target) – would be worth -3 Quality Points on SAIFI, SAIDI, or CAIDI.

Subject to the following conditions:

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

Table 3.52: Possible Q-Factor Scores

SAIDI	SAIFI	CAIDI	TOTAL	ADJUSTMENT FACTOR
3	3	3	9	**0.50%**
3	3	0	6	**0.40%**
3	0	3	6	**0.40%**
0	3	3	6	**0.40%**
3	0	0	3	**0.25%**
0	0	3	3	**0.25%**
0	3	0	3	**0.25%**
3	3	-3	3	**0.25%**
-3	3	3	3	**0.25%**
3	-3	3	3	**0.25%**
0	0	0	0	**0.00%**
3	0	-3	0	**0.00%**
3	-3	0	0	**0.00%**
-3	3	0	0	**0.00%**
0	-3	3	0	**0.00%**
0	3	-3	0	**0.00%**
-3	0	3	0	**0.00%**
0	0	-3	-3	**-0.25%**
0	-3	0	-3	**-0.25%**
-3	0	0	-3	**-0.25%**
3	-3	-3	-3	**-0.25%**
-3	-3	3	-3	**-0.25%**
-3	3	-3	-3	**-0.25%**
-3	0	-3	-6	**-0.40%**
0	-3	-3	-6	**-0.40%**
-3	-3	0	-6	**-0.40%**
-3	-3	-3	-9	**-0.50%**

As indicated, the performance in each of the three performance measures can either be above target, below target or on target (dead band). The Adjustment Factor may vary between a minimum of

-0.5% and a maximum of +0.5% and there are twenty-seven (27) possible outcomes as shown in Table 3.52.

This design of the Q-Factor adjustment as a component of the PBRM is symmetrical as stipulated in the Licence. The system is structured to equitably apply rewards and penalties and all possible outcomes appropriately delineated.

At the 2009 rate review, the OUR was not convinced that the available reliability performance data satisfied all the relevant criteria for use in the Q-Factor adjustment mechanism. There was a number of countervailing factors militating against adequate reliability and consequently there was high variability in the monthly calculated reliability indices. The countervailing factors included bad weather in 2004 and 2005, total System shutdowns in 2006, 2007 and 2008 as well as outage data collection issues and measurement inaccuracies that impacted the calculation of the indices.

Given the various challenges, the OUR was of the view that the data presented by JPS was not suitable and for that matter not representative enough to ensure the optimum baseline for a robust Q-Factor. Notwithstanding, the OUR believed that in order to minimize the risk of a lower than optimum baseline for the measurement of subsequent Q-Factors, the dead-band performance target should be sufficiently large to ensure that the utility will have to improve quality of service to score quality points exceeding zero.

The OUR also indicated that until a reasonable trend and consistent quality in the reliability performance dataset can be observed, it would be constrained in establishing a fair and reasonable baseline.

With due consideration to the various issues associated with the 2009 quality-of-service data, the OUR in the 2009 Determination Notice, indicated that before a determination can be made on the implementation of the Q-Factor, an independent audit of the outage data collection procedure and processes along with further analysis on the variability of the performance of the indices was required.

3.5.8 OUR's Audit of JPS' Q-Factor Data

In 2012, the OUR engaged the services of the consulting firm, KEMA Inc., ("KEMA") to carry out an audit of JPS' Q-Factor performance indicators and data collection procedures and methods. The objective of the audit was to inform regulatory decisions with respect to appropriate baseline and quality-of-service measurements.

The audit commenced on April 11, 2012 and a final report dated August 27, 2012 was submitted to the OUR.

Regarding the application of the outage data to the Q-Factor, KEMA came to the following conclusions:

"

- *The error rate in the sample lies between 9% and 16%, which can be classified as high;*
- *Double counts result in a 0.2% overestimation while the absence of recording staged restorations gives an estimated 8% overestimation of true reliability performance;*
- *The current level of accuracy in the reported data by JPS does not allow it to be used for the purpose of setting a baseline or computing financial penalties/rewards."*

With respect to the Q-Factor itself, the following conclusions were drawn by the consultant:

"

- *The application of symmetric incentives (penalties and rewards) is good regulatory practice and should be continued;*

- *CAIDI should be included in the Q-factor as it features an important dimension of reliability;*
- *For making the Q-factor operational it would be advisable to not set the baseline on the basis of reported data but rather to use an external benchmark;*

- *For limiting the risks of stochastic variation in performance the current dead-band could be replaced by another mechanism under which financial incentives are accumulated over time."*

Overall Audit Conclusions are, inter alia, as follows:

"

- *No accurate data is currently available, partly because of JPS' inability to accurately record customer numbers and customer interruption minutes in cases of staged restoration, partly because of double counts which should have been identified and corrected and partly by manual transfer of interruption start and end times from SCADA to the Control Center Outage Log.*

- *Accuracy declined from a good level in 2009 to a low level in 2011, while still in all three years the issue of double counts and staged restoration has led to inaccuracy that cannot be exactly calculated or determined from outage logs, but based on the analysis is expected to be significant.*

- *JPS is moving to best practice interruption data collection with an accurate OMS system, interfacing with GIS and SCADA. Further improvement in the reporting process can be achieved by following up the recommendations from the process review and adhering to the Reliability Manual (which is a separate deliverable of this project). At the same time the OUR should consider changes in the Q-factor to better match the issues identified during the audit."*

Recommendations from the Audit are, inter alia, as follows:

"

- *The OUR should not make use of the existing reported data by JPS for application to the Q-factor;*

- *The OUR should consider the following changes in the existing Q-factor specification:*

    - *Setting the baseline on an external reference or benchmark rather than reported data. In setting the targets the OUR should take into account the impact of generation interruptions on reliability indicators and assure that appropriate benchmarks are used. The OUR could consider to set a separate benchmark for generation and for T&D, respectively;*

    - *Abandoning the dead-band and replacing this by a system where financial incentives are accumulated over time."*

3.5.9 JPS' Response to the Q-Factor Audit Recommendations

In the JPS' Tariff Submission, JPS indicated that following the receipt of the final audit report, the company established a Q-Factor working group comprised of several key stakeholders involved in the Q-Factor process across the company. As stated by JPS, the working group's purpose was to identify initiatives and projects to be implemented in keeping with recommendations made by KEMA in the audit report.

JPS stated that the working group identified and embarked on the following major initiatives:

- The adoption of standardized definitions for reliability performance indices;
- Implementation of OMS and the finalization of GIS customer mappings;
- Development of business process charts and policy documents for the Q-Factor process;
- Implementation/modification/review of data collection and recording systems for the Q-Factor process in OMS/GIS/SCADA;
- Implementation of a data collection and reporting validation system in compliance with the "Reliability Data Collection and Reporting Manual" provided by KEMA.

3.5.10 Data Collection Strategy

In its 2009 Tariff Submission, JPS indicated that it intended to start utilizing improved data capture mechanisms such as GIS with actual customer count to compute System reliability indices. The company revealed that in estimating customer counts it observed that on average the customer counts using the information from the GIS database was 70% higher than that using the fuse approximation method of calculation.

In addition to the GIS, JPS noted that it had undertaken the task of procuring/building an Outage Management System (OMS). According to the company, it had several different software that captured outage data for reporting purposes which will be replaced with a single solution that will log and record outage start and end times, interrupting devices, fuse sizes, customer information on all feeder and sub-feeder outages.

JPS also noted that it was embarking on the implementation of AMI meters in residential communities. These meters, it said, are outfitted with communication capabilities and report kWh readings, tamper flags as well as outages to a central database. According to JPS, it intends to use the data from the AMI meters to accurately define the outage start and end times.

With almost real-time graphical monitoring of System outages and modifications, the company indicated that it intends to shift from a static feeder count system to a dynamic count in order to facilitate system reconfigurations including partial load transfers between feeders.

In addition to the systems mentioned, JPS stated that it had acquired additional SCADA and communication system upgrades to ensure proper monitoring of all its substations.

3.5.11 JPS' Outage Management System

Initiated by JPS in 2009, KEMA in the Q-Factor audit report recognized the implementation of the OMS as an important development to enable the company to achieve substantial improvement in its outage data collection and recording processes, as well as substantial improvement of customer counts at the feeder and sub-feeder level of the distribution system.

Subsequent to the completion of the audit, an update on the status of the OMS from JPS on December 28, 2012 indicated that:

"

1. *The application has failed some of the critical tests and could not be implemented as developed as it could not provide the long term dependable and sustainable solution we all seek.*
2. *Subsequently, we have reviewed our complete IT needs for an Outage Management System and have decided to acquire an "off the shelf" solution from the widely available and mature product offerings available. Recognizing that time is of the essence, we have adopted an aggressive, "fast track" approach and have issued a Request for Proposal to the market on December 5, 2012 with responses due from vendors by January 15, 2013. We estimate that by the late Q1 2013 to early Q2 2013, we will commence phased regional implementation with full implementation by late Q3 2013. We are confident that the approach will yield the results and will be consistent with industry best practices."*

JPS projected then that a full roll-out of the new OMS package would have taken place in December 2013. JPS also projected that if the roll-out of the OMS was completed as planned, the company could possibly collect about three (3) months of reliable outage data prior to its 2014 Tariff Review Application.

According to JPS, the OMS and Service Suite (Mobile Work Dispatch System) were commissioned on December 5, 2013 and has worked to quickly bring the associated Q-Factor elements on track.

JPS also indicated that the OMS was interfaced with its existing GIS at the launch of the system. As reported by the company, all but 9,000 customers were correctly mapped to their service transformers with full location data and phase of power serving them. The company also noted that the OMS operating in conjunction with GIS and SCADA, would provide broad functionality and flexibility to the outage data collection and performance measurement processes as well as enhancements to System restoration activities and emergency orders.

Since commissioning, JPS claimed that the OMS has been broadly meeting expectations but was undergoing post cut-over monitoring, adjustments and data integrity verification that had delayed the immediate production and reporting of reliability indices. This evaluation period it reported should have been concluded in March 2014.

JPS noted that the global experience with utilities and regulators is for reported reliability to worsen after the implementation of OMS. This, the company argued, was because the information was considered more accurate due to the automation of the data capture and reporting process over the manual process that it generally replaces. Accordingly, JPS has recommended that the system be allowed to collect at least twelve (12) months of data for the establishment of a baseline for Q-Factor computations. JPS also gave indications that it intends to install a business intelligence system (BIS) in September 2014. The BIS will integrate with OMS to facilitate reporting of reliability indices directly from the OMS.

3.5.12 JPS' Q-Factor Proposal

JPS asserted that the company had made substantial strides towards the implementation of initiatives which directly address the recommendations made by KEMA in its audit report. All identified activities including validation of sample data reports from OMS were scheduled to be completed by September 30, 2014. JPS argued that this timeline would also allow the implementation of a business intelligence system that would facilitate reporting directly from the OMS and thus eliminate any errors that may arise because of manual gathering of the data for reporting.

The company claimed it was also working to finalize outstanding issues with the OMS and to validate the data from the system. JPS reported that it had estimated that an additional twelve (12) months from March 31, 2014 was required to complete the gathering of accurate reliability indices data for the establishment of a baseline to be used in the computation of the Q-Factor in the tariff at the 2015 Annual Tariff Adjustment.

JPS' Q-Factor proposal is outlined as follows:

- JPS will submit further quarterly reports to the OUR, beginning June 2014 to report on the completion of all outstanding items from the KEMA recommendations with all items scheduled to be completed by September 30, 2014.

- JPS will submit on a monthly basis, beginning April 2014, the reliability indices generated from the OMS and this data, after evaluation by the OUR, should become the baseline data for the setting of the Q-Factor as at the 2015 Annual Tariff Adjustment.

- In keeping with KEMA's recommendation to move to international best practice, JPS and OUR should develop the framework around the IEEE 1366-2012 Standard by December 30, 2014 to support the development of the baseline. The Reliability Data Collection and Reporting Manual adopted by JPS as the compliance standard will be reviewed for conformity with IEEE 1366-2012 in the framework development.

- The OUR should not proceed with the recommendation of KEMA that the baseline be set by way of benchmark rather than the actual data. This would require the OUR to conduct a benchmarking study to establish an appropriate set of comparators. JPS argued that, as it had previously pointed out, this would be most prudently and accurately done subsequent to JPS reporting its reliability using the now-established standard of IEEE 1366-2012. JPS therefore does not believe there is any advantage to be gained by proceeding with that recommendation.

- MAIFI, according to JPS, is an unnecessary overlay on the quality-of-service indices that are rarely used in far more mature electricity markets than Jamaica and will only put upward pressure on already burdened tariffs to fund the investments to comply. Nevertheless, it argued that should the OUR not moderate its policy position, it would propose by December 2014, a method of incorporation of MAIFI in the Q-Factor with a non-financial impact, as recommended by KEMA.

3.5.13 Treatment of Momentary Interruptions

Generally, electricity distribution networks are comprised mainly of overhead lines, which emanate radially from substations. Common causes of momentary interruptions on overhead distribution networks include lightning strikes or other weather related effects, lines making contact, tree interaction with lines as well as animals (birds) and other object contact with lines.

In these networks, feeder protection systems are usually managed through substation reclosers working in tandem with fuses at the feeder laterals. The general philosophy of operation is to have one fast and two slow operations of a substation feeder recloser upon the event of a fault along the feeder.

The first fast operation (instantaneous) of the recloser prevents unnecessary fuse blowing (fuse saver scheme) and strives to minimize sustained interruptions by opening and reclosing immediately to give an opportunity for a temporary fault to clear. On the first slow operation of the breaker, if the fault still persists, this will allow enough time for the fuse required to isolate the fault to blow. Should the fault still persist after the second closing of the breaker, then a third breaker opening will cause a lockout (remain open) of the breaker and no supply to the feeder.

In the case of JPS' distribution system, in the event of a breaker lockout, distribution field personnel may have to be dispatched to identify the source of the fault and carry out the effect isolation and repairs. The unaffected parts of the feeder will be returned to service when isolation is effected by the reclosing of the breaker. According to JPS, such incident of a breaker lockout is likely to exceed the five minute threshold for MAIFI and as such may be captured in SAIFI and SAIDI. However, with the deployment of JPS' advanced outage data collection, reliability performance measurement and reporting systems, it is expected that the practice described above for restoring electricity service following a momentary interruption that transitioned to a breaker lockout, will become more efficient. As a consequence of the projected improvement in service restoration, the duration of such interruptions is expected to be reduced to the extent that they can be captured in MAIFI.

In instances when the source of the fault is not permanent such as lightning strikes, there may be one or two cycles of the feeder without transitioning to a lockout. For such events, the interruption should be clearly captured in MAIFI.

In addition to the typical cause of momentary interruptions, there are other operations such as switching activities required to facilitate planned maintenance that can lead to breaker open and close operation of less than five minutes duration. Momentary interruptions caused by these events should be captured by JPS and included in the calculation of MAIFI.

In power system operations, under-frequency protection schemes are essential in protecting the System from collapsing in the case of events that can influence a reduction in System frequency. A momentary interruption may also occur in instances when under-frequency load shedding occurs, quick-start generators are started and the disconnected feeders restored within the five (5) minutes threshold. Operating the System at a higher spinning reserve could effectively minimize or eliminate momentary interruptions caused by short-term under-frequency operations. This however, would have implications for generating units' average heat rates and operating costs. Going forward, this issue will be examined within the context of JPS' spinning reserve policy and the cost of unserved-energy (COUE).

Although very limited in duration, these momentary interruption scenarios described above can have adverse effects on the quality of service provided to customers. In this regard, the issue of momentary interruptions should be properly managed and controlled by the utility. That is, there should be proper data collection systems in place to facilitate the accurate capture of momentary interruptions and thus the computation of MAIFI.

Specifically, on the matter of the collection of JPS' MAIFI data, reference is made to the Q-factor audit report, which stated that data on momentary interruptions was recorded by JPS within the same process as in place for SAIDI/SAIFI. Further, it was reported that restrictions existed by which not all momentary interruptions could be recorded, and computed.

The audit report also stated that, data on MAIFI, which was gathered within the same processes as described, is currently not reported to the OUR. MAIFI data that can be captured by the Control Center, including interruptions due to under-frequency, planned and forced transmission and distribution interruptions and recloser cycling at substations, was entered into the Control Center Outage Database. MAIFI data can be filtered out and separated from SAIDI/SAIFI data, after the data has been transferred to the JPS Reliability Management Log. This way JPS has data available on MAIFI, as far as MAIFI data can be collected.

In the audit report, the consultant noted that with the current 'state of the art' of the JPS' Power System, the interruption data and the relevant numbers of affected customers cannot be captured in all cases of momentary interruptions.

Based on the specific findings of the Q-Factor audit regarding MAIFI, despite limitations identified, the OUR is convinced that JPS has sufficient collection capability to provide a more representative and realistic outage dataset on momentary interruptions in conformance with its technical reporting requirements as stipulated in the Licence.

Additionally, the OUR is of the view that the company outage data collection, reliability performance measurement and reporting capabilities will be enhanced with the utilization of its OMS, GIS, SCADA and its other advanced data capture mechanisms. Therefore, JPS will be expected to collect the full range of momentary interruptions data for submission to the OUR during the 2014-2019 price-cap period.

With due consideration to JPS' MAIFI proposal and the drivers of momentary interruptions as well as the company's efforts to improve its outage data collection capabilities and having regard to the Q-Factor audit findings and recommendations, the Office has determined that MAIFI will not be included in the Q-Factor adjustment mechanism at the point when the baseline data is established. Instead, MAIFI will be treated as a technical standard for which an appropriate benchmark will be established by the OUR in consultation with JPS to ensure proper monitoring of momentary interruptions. Notwithstanding, MAIFI will be reviewed annually by the Office for benchmark adjustments and if necessary to determine its applicability in the Q-Factor adjustment mechanism during the 2014-2019 price-cap period.

Due to the potential adverse effects of momentary interruptions on the quality of service provided to customers, JPS is required to separately record all momentary interruptions experienced on the System each month. This outage data along with the MAIFI calculations shall be submitted to the OUR in the monthly Technical Reports. Following the issuance of the Determination Notice, the OUR will indicate the specific format in which the MAIFI data should be reported.

DETERMINATION 2

- **MAIFI will not be included in the Q-Factor adjustment mechanism at the point when the baseline data is established. Instead, MAIFI will be treated as a technical standard for which an appropriate benchmark will be established by the OUR in consultation with JPS to ensure proper monitoring of momentary interruptions. Notwithstanding, MAIFI will be reviewed annually by the Office for benchmark adjustments and if necessary to determine its applicability in the Q-Factor adjustment mechanism during the price cap period.**

- **JPS shall be required to separately record all momentary interruptions experienced on the System each month. This outage data along with the MAIFI calculations shall be submitted to the OUR in the monthly Technical Reports. After the effective date of the Determination Notice, the OUR will indicate the specific format in which the MAIFI data should be reported.**

3.5.14 Treatment of Major Events

One of the criteria for the Q-Factor, is that it should provide fair treatment for factors affecting quality of service performance that are outside of JPS' control such as natural disasters, and other Force Majeure events, as defined under the Licence. Therefore, power outages due to major storms and hurricanes are not included in the Q-Factor calculations although JPS is required to record and report them.

To ensure accurate and equitable assessment and comparison of absolute performance and performance trends over time, it is important to classify performance for each day in the dataset to be analyzed as either day-to-day or major event day. Not performing this critical step can lead to false decision because major event day performance usually tend to overshadow and disguise daily performance. Also, interruptions that occur as a result of outages on customer-owned facilities or loss of supply from independent generating entities should not be included in the calculation of the indices.

With respect to major System shutdown incidents such as those which occurred since 2006, the OUR is of the view that these incidents in particular, should be treated within the framework of major events. That is, they should be separately reported and analyzed and addressed under a different penalty system. A penalty would apply if after investigation, it is confirmed that the occurrence of such incident was caused by negligence of JPS. For these outages, the measure of unreliability would be the dollar cost of the power outage to JPS' customers.

The IEEE Standard 1366-2012 a major event and a major event day is defined as follows:

Major Event: Designates an event that exceeds reasonable design and or operational limits of the electric power system. A Major Event includes at least one Major Event Day.

Major Event Day (MED): A day in which the daily System Average Interruption Duration Index (SAIDI) exceeds a Major Event Day threshold value. For the purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than TMED are days on which the energy delivery system experienced stresses beyond that normally expected (such as during severe weather). Activities that occur on Major Event Days should be separately analyzed and reported.

The methodology for determining the threshold value for the Major Event should be in accordance with section 3.5 of the IEEE Standard 1366-2012.

3.5.15 Baseline for Implementation of Q-Factor Mechanism

3.5.15.1 Regulatory Approach

The requirement for translating the quality of service provided to customers by JPS into reliability metrics to be used in the electricity price control and adjustment mechanism must be guided by prudent regulatory principles and pragmatic approaches that satisfy certain technical and financial requirements.

The approach adopted for establishing the Q-Factor should therefore contemplate the willingness of customers to pay for different levels of quality of electricity supply. Predicting the value that customers place on quality of service is difficult, especially when there are several categories of customers and there is broad diversity in customer profile and consumption. Nevertheless, the Q-Factor can be structured to be fair and equitable to both JPS and the customers. This can be accomplished by the symmetrical design of the mechanism as stipulated in the Licence.

Under this Q-Factor approach, a starting absolute quality metric or baseline derived from the applicable reliability indices will be established. The indices will then be weighted for perceived differences in value to customers. If JPS quality of service performance is better than the baseline then the calculated Q-Factor would be added to the Non-Fuel Electricity Pricing Index (PCI). Conversely, if JPS performs worse than the baseline then the calculated Q-Factor would be subtracted from PCI.

3.5.15.2 Evaluation of JPS' 2014 OMS Data

As previously stated, an appropriate baseline for implementing the Q-Factor has not been developed since 2004 due to the unsuitability of the System outage data from which the benchmark indices were to be derived.

In its tariff application, JPS affirmed that its OMS has been successfully commissioned and is capable of accurately recording relevant outage data required for the computation of the reliability indices to be used by the OUR in setting the baseline for the Q-Factor.

As part of the JPS' Tariff Submission, JPS submitted two (2) full months (April and May 2014) of System outage data which was collected by the OMS. This data was evaluated by the OUR and used to compute the indices, SAIFI, SAIDI and CAIDI. These were compared with the corresponding months for the years 2009, 2010 and 2011 which was available to the OUR. The comparison is shown in Table 3.53 below.

Table 3.53: Comparison of Indices from OMS data and data before OMS

Comparison of Indices Calculated from OMS data (2014) and data before OMS								
	2009		2010		2011		2014 from OMS	
	April	May	April	May	April	May	April	May
SAIFI	1.82	1.51	3.42	3.32	2.43	2.72	1.16	1.67
SAIDI	119.38	141.52	199.22	261.61	153.26	153.67	143.50	209.08
CAIDI	65.56	93.43	58.66	78.83	63.13	56.51	124.01	125.47

It is recognized that a 12-month dataset would provide a more realistic comparison, so the result shown in Table 3.53 above illustrates a snap shot of SAIFI, SAIDI and CAIDI based on data collected by JPS' newly commissioned OMS and data captured by the company previously. As shown, the calculations based on the OMS data do not exhibit any significant difference relative to those based on data previously collected.

In the case of SAIFI, JPS reported that the annual average value declined from 26.22 in 2009 to 10.53 in 2013. This was based on data not captured with the OMS. The values of SAIFI for April and May 2014 extrapolated to reflect an annual value would give an indicative SAIFI of 16.98. This indicates a projected worse performance compared to that of 2013.

JPS also indicated that SAIDI for 2009 to 2013 trended downwards moving from 38 hours (2,280 minutes) per customer to 22 hours (1,320 minutes) per customer. However, if the values of SAIDI for April and May 2014 were extrapolated to reflect an annual value, the indicative value of SAIDI would be 2,115 minutes (35 hours) per customer. This implies that the projected performance for 2014 could be worse than that of 2013.

With respect to CAIDI, which is derived from SAIFI and SAIDI, the value calculated for April and May 2014 appears to be consistent with JPS' calculation of over 2 hours per interruption in 2013.

Based on the review and analysis of the System outage data collected by the JPS' OMS, it appears that there may be lingering issues with the data collection process which may require alteration and recalibration.

The OUR has acknowledged JPS' assessment of the status of the OMS, that the system had broadly met its expectations but as with all such major IT implementation it underwent post cut-over monitoring, adjustments and data integrity verification that had delayed the immediate production and reporting of reliability indices. However, such post commissioning evaluation should have been concluded in March 2014.

With regards to the setting of the Q-Factor baseline, KEMA in the audit report indicated that the accuracy of the data may not be fully realized immediately after the implementation of the advanced data collection systems although over time it is expected to improve. According to the consultant, this situation is problematic as errors in the data would necessitate an adjustment in the baseline which would tend to undermine the credibility of the system and is therefore not desired.

Taking into consideration the stated conditions pertaining to the operation of OMS and implicit concerns related to the quality of the outage data collected by the system, JPS will be required to submit a properly calibrated and complete 12-month System outage dataset to the OUR by the 2015 Annual Tariff Adjustment for a complete evaluation to determine acceptability before proceeding to establish the Q-Factor baseline. The baseline performance indicators are necessary to compare quality of service performance of the JPS at a particular Annual Tariff Adjustment and to facilitate the applicable price adjustment at subsequent Annul Tariff Adjustments based on the approved Q-Factor mechanism.

Additionally, JPS is required to submit on a monthly basis the full range of System outage data collected by its OMS and other measurement processes in a format that will be specified by the OUR subsequent to the issue of this Determination Notice.

In the event that the 12-month System outage data provided by JPS at the 2015 Annual Tariff Adjustment is found to be unsuitable for setting the Q-Factor baseline, the OUR will explore alternative options in an effort to implement the Q-Factor adjustment mechanism in fulfilment of the requirement of the Licence.

To remedy such situation, the OUR may decide to make the Q-Factor operational by setting the baseline on the basis of an external reference, e.g. benchmark of the performance of similar systems elsewhere. This has the advantage that errors in historical data used for setting the baseline do not affect the Q-Factor.

JPS requirements for implementing the Q-factor are set out in Schedule 3, paragraph 3 (B) of the Licence, which provides as follows:

> *"The Licensee shall submit to the Office no later than September 1, 2003, and every succeeding five (5) years thereafter, a proposal for new baseline values for the performance indicators contained in the Performance Based Rate-making Mechanism, the first of which shall become effective simultaneously with the Non-fuel Base Rate[.] The Licensee shall also have the option of proposing new performance indicators or mechanisms for the Office's consideration. Upon receipt of any such proposal, the Office shall conduct a review of the Licensee's proposed*

performance indicators or mechanisms and shall have the full discretion to accept, modify, reject or order the implementation of alternative performance indicators or mechanisms; provided, however, that any Performance Based Rate-making Mechanism shall include (I) an applicable price index (including, if necessary, a factor thereof) which serves as a reasonable proxy index for the measurement of the periodic change in the Licensee's non-fuel costs, and (II) a performance-based discount factor which rewards or penalizes the Licensee (as the case may be). The filing to support the application for the new PBRM will include:

- *audited financial report for the Licensed Business for the most recent Financial Year;*
- *a proposed X-factor for the next five-year period including a total factor productivity study used in determining the appropriate level of the X-factor;*
- *a report on the quality of service provided by the Licensee during the previous five-year period;*
- *proposed revisions to any of the components of the PBRM with justifications;*
- *other things specified."*

3.5.16 Applicable Indices for Q-Factor Baseline

In the 2009 Tariff Determination Notice, the OUR determined that SAIDI, SAIFI and CAIDI should be included in the Q-Factor mechanism. However, there have been questions regarding the inclusion of CAIDI in the Q-Factor since it is mathematically derived from SAIDI and SAIFI.

This issue was addressed in the Q-Factor audit report which indicated that setting a target for SAIDI and SAIFI does provide the utility the option to make a trade-off between frequency and duration, which may be undesirable for customers. The consultant cited that a utility could maintain a low SAIDI even if outage duration times increase substantially, by reducing the frequency of interruptions. Thus even though SAIDI and SAIFI performance would have been in line with the target, customers will suffer from longer average interruption durations.

The consultant stated that in order to protect customers from such effects the inclusion of CAIDI is important. The logic of redundant indicators would be true if it were considered to get rid of SAIDI. In that case, JPS would have a target only for frequency (SAIFI) and average duration (CAIDI), and from this the SAIDI target would follow automatically. However, as SAIDI remains an important and more common reliability measure, the use of all three indices as applied by the OUR can be considered acceptable.

Without prejudice to the audit recommendations for setting the Q-Factor baseline, the OUR will examine all possible options and scenarios for selecting the applicable reliability indices and the setting of the baseline values once it is satisfied that the System outage data is reliable and suitable for computing the benchmark level for each of the applicable indices.

DETERMINATION 3

- **The Q-Factor for the 2015 Annual Tariff Adjustment shall be zero.**

- **JPS shall be required to submit a properly calibrated and complete 12-month System outage dataset to the OUR by the 2015 Annual Tariff Adjustment for a complete evaluation to determine acceptability before proceeding to establish the Q-Factor baseline.**

- **In the event that the 12-month System outage data provided by JPS at the 2015 Annual Tariff Adjustment is found to be unsuitable for setting the Q-Factor baseline, the OUR will explore alternative options in an effort to implement the Q-Factor adjustment mechanism in fulfilment of the requirement of the Licence.**

3.6 Special Circumstances Factor (Z-Factor)

The Z-Factor is the allowed percentage increase in the price cap index due to events that:

(a) Affect JPS' costs;
(b) Are not due to JPS' managerial decisions; and
(c) Are not captured by other elements of the price cap mechanism.

The Z-Factor also includes the Government Imposed Obligations specified in Schedule 3 of the Licence.

Consistent with previous determinations, the OUR will adjust the materiality threshold for the activation of the Z-Factor to account for local inflation over the test year period 2008 - 2013. The materiality threshold should therefore be adjusted up from J$20 million to J$31million. See Table 3.61 below for details.

Table 3.61: Materiality Threshold 2009 and 2014 and Jamaican Inflation Factor

Jamaican Inflation Index*	
CPI @ December 2013	210.7
CPI @ December 2008	136.5
Jamaican Inflation Factor	54.36%
Materiality Threshold (J$M)	
Office Determination 2009	20
Office Determination 2014	31
*Source: Statin	

DETERMINATION 4

The Materiality Threshold for the Z-Factor shall be J$31M and is to be adjusted annually to account for Jamaican inflation.

Chapter 4: Proposed Revenue Cap Rate Adjustment Mechanism

JPS questioned whether the price cap regime which has served Jamaica for over ten (10) years is the best approach to support the power sector evolution that is now underway. The company suggested that Jamaica may be better served by a tariff control system in the form of a revenue cap, rather than a price cap.

JPS conceded that the price cap mechanism creates strong incentives for the utility to control costs by setting a path which JPS' tariffs must follow for the duration of a regulatory period. Even while accepting the advantages of price caps, JPS argued that they can create demand risk and perverse incentives. These risks and perverse incentives, it argued, arise when a utility company's tariff structure attempts to recover the fixed costs of transmission and distribution through a charge on energy sold. JPS claimed that a consequence of price cap is that utilities are perversely incentivized to sell more energy.

4.1 JPS' Proposal to Restructure Tariffs

JPS proposed as a solution to its perceived demand risk and perverse incentives, the restructuring of its tariffs. JPS stated that economic theory and regulatory best practice suggest that tariffs must be cost-reflective. According to JPS, this suggests that a utility's fixed costs should be recovered through fixed charges, while its variable costs should be recovered through variable charges. JPS contended that its current tariff structure is not cost-reflective in this way. It posited for example, that within the residential rate class, customers that are high energy consumers pay a disproportionate share of that rate class' fixed cost allocation, since these costs are mostly recovered through the variable energy charge. As another example, large commercial and industrial consumers consume significant quantities of energy. Consequently, these pay more toward fixed costs than smaller residential and commercial customers do, with the existing tariff structure.

JPS therefore requested that the fixed charges paid by its customers be increased, while energy charges are reduced. This, JPS stated, represents a rebalancing of cost causation with cost recovery, so that the utility's fixed costs are recovered through a fixed charge, rather than through a volumetric energy charge. JPS also stated that restructuring tariffs to be cost-reflective cannot occur all at once as the impact on customers, particularly in the residential class, will be too drastic. Therefore, the proposed restructuring should occur more gradually, to avoid "rate shock."

4.2 JPS' Proposed Revenue Cap Regime

Interestingly, JPS asserted that a revenue cap is a small variation to the price cap approach. Rather than capping prices, the utility company's revenues are capped for the duration of the regulatory period. JPS argued that revenue caps are now the preferred model for transmission regulation internationally, and are used successfully in small power systems such as New Zealand, Scotland

and the Republic of Ireland, as well as in large systems including England and Wales, Germany, Australia and the Philippines. JPS further stated that revenue caps optimize risk allocation and remove the utilities' incentive to sell more kilowatt hours.

JPS stated that under a pure revenue cap, the utility's revenues are fixed based on a historic test year. In the first year of the regulatory period, allowed revenue equals earned revenue in the test year, plus an inflation adjustment (to keep revenue constant in real terms). In each subsequent year, allowed revenue equals the prior year's allowed revenue plus inflation. JPS presented the formula below which it says shows the mechanics of a pure revenue cap based on a historic test year.

$$\overline{R_t} = \overline{R_{t-1}}(1 + \Delta CPI)$$

JPS stated that a key component of a revenue cap is that the utility must submit tariff adjustment submissions for each year in the regulatory period. This is similar to the process under a price cap. However, unlike with a price cap, a balancing account is established to reconcile the earned revenue in the prior year with the allowed revenue for that same year. If a utility earned more revenue in the prior year than what was allowed, it must refund customers the over-recovered amount. Conversely, if a utility earned less revenue than allowed, it is entitled to recover that amount from customers. The amount that must be refunded to, or recovered from customers, is then rolled into the revenue requirement used to set tariffs in the next rate year.

JPS asserted that under revenue cap, the company would no longer face a disincentive to assist customers in participating in distributed generation programs, such as the net billing scheme. With a revenue cap, JPS would be made whole for the approved cost of serving the customer regardless of the customer's energy demand. JPS stated further that with a revenue cap, it could become a partner in implementing a wheeling tariff, without fear of losing financially when large customers participate in the program.

JPS highlighted the unpredictability of actual demand against its revenues and proposed a rate design which requires a periodic true-up mechanism for each year of the regulatory period because of the unpredictability of actual demand. Table 4.21 below shows JPS' illustration of its proposed mechanics of the revenue true-up process. Under the proposed revenue cap mechanism, the true-up would occur in the following year, that is, during the annual tariff adjustment for year t+1. The true-up adjustment (if any), would be applied as an adjustment to the tariff basket for the rates that would take effect in year t+1. In this example JPS assumed that the proposed FX losses true-up would be approved by the OUR.

Table 4.21: JPS' Proposed Revenue Balancing Mechanism

JPS Illustration of its Proposed Revenue Cap True-up Mechanism						
			Base Year		**JPS Proposed Revenue Cap**	
		Units	Year *t*		Year *t+1*	
			Start	End	Start	End
Revenue Cap						
Unadjusted Revenue Cap	**A**	J$'000	47,361,900		47,361,900	
Performance-Based Ratemaking						
Inflation Factor (dI)		J$'000	-		2,845,536	
X-Factor (X)		J$'000	-		(165,767)	
Revenue Cap Adjustment to X (X)		J$'000	-		418,626	
Q-Factor (Q)		J$'000	-			
Z-Factor (Z)		J$'000	-			
Revenue Cap w/ PBRM	**B**	**J$'000**	**47,361,900**	**-**	**50,460,295**	**-**
Revenue Balancing Account						
Opening Balance		J$'000	-			
Interest on Balance		J$'000	-			
Total Revenue Shortage/(Overage)		J$'000	-		(51,932)	
Revenue Adjustment	**C**	J$'000	-		(51,932)	
Total FX Losses Shortage/(Overage)		J$'000	-		232,116	
FX Losses Adjustment	**D**	J$'000	-		232,116	
Closing Balance		J$'000	-		-	
Revenue True-Up						
Revenue Target		J$'000		47,361,900		50,640,479
Earned Revenue	**E**	J$'000		47,409,262		50,257,252
Revenue Shortage / (Overage)	**F**	J$'000		(47,362)		383,227
Interest on Shortage / (Overage)	**G**	J$'000		(4,570)		36,981
Total Revenue Shortage / (Overage)	**H**	J$'000		**(51,932)**		**420,208**
FX Losses True-Up						
Actual FX Losses		J$'000		2,339,359		2,479,909
Test Year FX Losses		J$'000		2,127,671		2,127,671
FX Losses Shortage / (Overage)	**J**	J$'000		211,688		352,238
Interest on Shortage/ (Overage)	**K**	J$'000		20,428		33,991
Total FX Losses Shortage / (Overage)	**L**	J$'000		**232,116**		**386,229**
Revenue Target						
Revenue Cap w/ PBRM		J$'000	47,361,900		50,460,295	
Revenue Adjustment		J$'000	-		(51,932)	
FX Losses Adjustment		J$'000	-		232,116	
Revenue Target	**O**	J$'000	47,361,900		50,640,479	
Estimate of Average Tariffs						
Energy Sales in Prior Year		MWh	3,089,826		3,093,076	
Average Non-Fuel Tariff		J$/kWh	15.33		16.37	
Average Fuel Charge		J$/kWh	27.10		27.10	
Average Tariff		J$/kWh	**42.43**		**43.47**	

JPS included the following notes to Table 4.21:

"Notes: This example assumes inflation factor is 4.15%, the X-Factor (after adjusting for the revenue cap) is -0.53%, the WACC is 19.30%, and earned revenue grows at the same rate as kWh sales growth in the base case demand scenario. Average tariffs are provided for illustrative purposes. In practice, the tariff basket is calculated annually and distributed into the various rates charged to JPS' customers, just as is currently done under the price cap mechanism.

The revenue true-up process occurs in year t+1, in 12 steps:

1. *The revenue cap for year t is calculated by applying the PBRM, such as the adjusted X-Factor, the Q-Factor, and the Z-Factor — line (a) is adjusted to arrive at line (b), a revenue cap of J$50,460,295,000*
2. *Actual earned revenue for year t, J$47,409,262,000, is populated on line (g)*
3. *The revenue shortage (or overage) is calculated by subtracting earned revenue from the revenue target—line (f) equals line (o) minus line (e), for an overage in year t of J$47,362,000*
4. *Interest is calculated on the revenue shortage (or overage) by multiplying half of the average shortage (or overage) times the authorized weighted average cost of capital. Line (g) shows that the interest on the overage is J$4,570,000*
5. *The total revenue shortage (or overage) in year t is equal to the actual revenue shortage (or overage), plus any interest—this total appears on line (h), for a total overage of J$51,932,000*
6. *The total revenue shortage (or overage) is carried forward as an addition to the balancing account in year t+1. In this example, the entire overage would be passed through to the tariffs in year t+1—this appears on line (c), for a revenue reduction adjustment equal to J$51,932,000*
7. *Similar to the revenue true-up, a separate true-up is calculated for FX losses in year t. Actual FX losses for year t appear on line (i), equal to J$2,339,359,000*
8. *The FX losses shortage (or overage) is calculated by subtracting the FX losses embedded in the test year from actual FX losses in year t—line (m) equals line (k) minus line (j), for a shortage of J$211,688,000.*
9. *Interest is calculated on the FX losses shortage (or overage) by multiplying half of the average shortage (or overage) times the authorized weighted average cost of capital. Line (k) shows that the interest on the shortage is J$20,428,000*
10. *The total FX losses shortage (or overage) in year t is equal to the FX losses shortage (or overage), plus any interest—this total appears on line (l), for a total shortage of J$232,116,000*
11. *The total FX losses shortage (or overage) is carried forward as an addition to the balancing account in year t+1. In this example, the entire shortage would be passed through to the tariffs in year t+1—this appears on line (d), for a revenue increase adjustment equal to J$232,116,000*
12. *The total revenue target that applies for tariff-setting purposes for year t+1 is then calculated. This is equal to the revenue target for year t+1, plus any revenue and FX losses*

adjustments carried out of the balancing account—this total appears on line (o), for a total revenue target for year t+1 of J$50,640,479,000.

In the example above, JPS assumed that demand follows the Base Case with Natural Gas ("base case") demand scenario from the demand forecast which was included in its submission. The revenue adjustment applied to the tariff basket for year t+1 is a reduction of J$51.9 million, or approximately 2% of the total change in the tariff basket. As a reference point, if all tariffs were calculated on an energy-only basis, this tariff basket would yield an average tariff of J$16.37 per kWh".

4.3 The JPS-Proposed Revenue Cap and the Adjusted X-Factor

In making the case for the revenue cap, JPS stated that an "adjusted X-Factor" is needed as an input to the above calculation. JPS' rationale for adjusting the X-Factor under the proposed revenue cap mechanism is that the X-Factor calculation by definition of productivity, is the ratio of outputs for a given set of inputs and in the context of a revenue cap, inputs are constrained by the cap, but outputs (such as kWh sales) increase. JPS is of the view that productivity gains are **already** embedded in the revenue cap design and by comparison, the price cap alone does not drive productivity gains.

4.4 JPS' Proposal for Revisions to the Licence

In order to implement a revenue cap, JPS stated that it would be necessary to make minor revisions to Schedule 3 of the Licence, which governs the price controls and these revisions would replace any reference to the price cap with a reference to the revenue cap.

4.5 Review and Analysis of JPS' Proposal

4.5.1 Proposed Restructuring of Tariff

JPS proposed a restructuring of its tariff to become what it terms more cost-reflective. JPS stated that the company would begin to rebalance the proportion of revenue that it earns from fixed charges and variable energy charges which would lead to a more cost- reflective tariff in terms of fixed cost recovery. JPS further stated that currently, approximately 89% of its non-fuel costs are fixed while 23% of revenues are recovered through a fixed charge. JPS therefore requested that the company should be allowed to recover 41% of revenues through fixed charges. In its 2009 tariff submission, JPS reported that approximately 75% of its non-fuel costs were fixed while only 15% of revenues were recovered through a fixed charge.

Since the 2009 Determination Notice and subsequent annual tariff adjustments, JPS has been allowed to make gradual adjustments to the customer charges of residential customers. As a result, the customer charge has moved up from 15% in 2009 to the present 23%. Further comments on the JPS' tariff structure are made in Chapter 7 - Tariff Design (Non-Fuel).

JPS contended that its cost-of-service study explains what its capacity costs are and how they make up 89% of the total cost. JPS stated that its capacity costs include the cost of the transformers, poles, lines & related equipment on the T&D side as well as the fixed costs associated with generation. However, JPS could not demonstrate how it calculated the amount of fixed cost that is attributed to the residential customer class and which would be recovered through the network access charge ("NAC"). Indeed, JPS claimed that there is no exact science for calculating the amount to be recovered through the proposed NAC. JPS further argued that the cost of service divides the costs into capacity costs, fixed costs, and variable charges (which vary with energy consumption) and it is the billing determinants which would help JPS to decide how those capacity costs or variable energy charges can be recovered.

JPS advised that the company does not have load characterization to support the differentiation within and between tiers for rate 10 and rate 20 customers. Additionally, the company advised that they cannot definitively say what the capacity costs are, given that JPS does not have demand meters for these two rate classes.

4.5.2 Price Cap versus Revenue Cap

Price caps were first developed in the United Kingdom in the 1980s to be the regulatory framework for the country's newly privatized utilities. The basic idea behind price cap regulation is that there is information asymmetry, whereby regulators would be at an information disadvantage relative to the utilities in terms of knowing how efficiently the utilities could operate. By adopting price cap regulation and allowing utilities to keep for a period of time profits they received by improving efficiency, the GOJ believed that companies would reveal their efficiency capabilities. In turn this would allow the regulator to eventually set regulated prices that reflected the companies' true abilities.

In responding to the JPS' Tariff Submission, the Jamaica Chamber of Commerce (JCC) reasoned that *"The report shows conclusively that the PBRM has caused JPS to become more efficient. Why should it therefore be changed?"* The Fair Trading Commission (FTC) is also opposing the introduction of the proposed revenue cap stating that *"A pure revenue cap regime is likely to lessen the incentives for JPS to establish an efficient tariff structure, relative to the incentives to do so under a pure price cap regime."* The Consumer Advisory Committee on Utilities (CACU) also responded to the JPS revenue cap proposal. CACU stated that, *"We also note that JPS is somewhat disingenuous when it argues that a revenue cap approach reflects a sharing of risk between the utility and the customers. In a situation of declining sales growth, which JPS obviously expects for the upcoming review period, it is the customer who would bear all the risk under a revenue cap approach."* The full text of the CACU's, the JCC's and the FTC's submission are in Appendix C of this paper. Opposition to the proposed revenue cap was also voiced by other consumers at consultations meetings on the JPS Tariff Submission. A summary of other consumers' comments is set out in Chapter 13.

A critique of revenue caps has been put forward by economists Crew and Kleindorfer (Crew and Kleindorfer 1995). Their critique purports to show that a revenue-capped firm will always set price above the monopoly level.

Steven Stoft in his analysis of Revenue Caps vs. Price Caps[9] revealed a number of potential problems with the pure revenue cap regime. These include:

1) Incentives to set relative prices inefficiently.
2) The possibility that a small reduction in the revenue cap will produce a large and unpredictable reduction in price (an effect related to the Crew-Kleindorfer effect).
3) An incentive to reduce sales regardless of the social benefit.

Decoupling of revenues from energy sales was created in order to promote energy efficiency by removing the link between selling electricity and the amount of revenue a utility earns in a given year. Under the price cap regime, if JPS sells more electricity, they would earn more revenue. This creates incentive for the JPS to sell more electricity which is consistent with supporting economic growth.

4.5.3 Demand Risk Sharing

JPS argued that the demand risk under a revenue cap is shared between JPS and the customer. JPS explained that the sharing means that customers would bear the “downside” demand risk, while JPS would bear the “upside” demand risk. The OUR is of the view that the revenue cap, as proposed by JPS, does not allow for demand risk to be shared as is stated by JPS. Demand risk only exists on the “downside” and in the proposed case the customers would bear all the “downside” demand risk. On the “upside” there would only be rewards and no risks.

A fall in aggregate demand would result in an increase in rates in the succeeding year. On the other hand, should demand increase in a given year then rates would fall in the succeeding year. In both instances, JPS’ revenue would have been protected. JPS in its computation projected a growth in demand in each succeeding year from the base year, which implicitly means that for the “upside” benefit to be realised that demand must grow above the projected increase for customers to see any real reduction in rates going forward.

It bears mentioning that the use of revenue caps in situations where the utility is actively seeking to diversify revenue streams into non-regulated areas which may in fact compete with regulated revenue streams, poses a threat of creating a perverse incentive. In this regard the Office has to be mindful that increasingly electric utilities are seeking to expand into areas of activities associated with such initiatives as: distributive generation, energy conservation and sale of equipment which could compete with the regulated business.

[9] http://stoft.com/metaPage/lib/Stoft-1995-Rev-Caps-Dmnd-Side-Mngmnt.pdf

Economist Dr Chris Decker whose research is focused on the use of economics in public policy, legal and regulatory processes, in his 2009 report[10] to the Office of Gas and Electric Markets (Ofgem) commented in respect of revenue cap that… "*a supplier's total revenue is capped ex ante such that the revenue that may be earned is constant, and is independent of fluctuations in the quantity supplied. The allowed revenue is therefore always equal to expected revenue at the time the price control is set. Consequently, under this approach, the risks associated with demand volatility fall largely on consumers, and suppliers with significant fixed costs are effectively protected from demand volatility risk: prices tend to rise when demand is falling and decrease when demand is rising, an outcome similar to that of pure rate-of-return regulation. Given the nature of this form of price-cap arrangement a supplier may have perverse incentives to reduce the volume of sales and degrade the quality of services (insofar as costs are linked to demand). In addition, in order to induce a reduction in demand, a supplier may have incentives to set inefficient price structures by setting prices above marginal cost on the most elastic services.*"

Based on its analysis and having considered the advantages and disadvantages of the price cap and revenue cap mechanisms, the OUR is of the view that the adoption of revenue cap within the context of the Jamaican electricity market would be wholly unsuitable. Furthermore, information asymmetry still exists between JPS and the regulator and this is still better addressed by price caps. The performance efficiency factor (X-Factor) is the main and essential component of the price cap which differentiates the price cap from the revenue cap. This efficiency factor is essential and must be retained.

4.5.4 Office's Determination on the Proposed Revenue Cap

Based on the above analysis on JPS' proposed revenue cap, the Office **DETERMINES** as follows:

DETERMINATION 5 **JPS' proposal for the introduction of a revenue cap is NOT APPROVED.**

[10] Characteristics of Alternative Price Control Frameworks: An Overview, February 2009 by Dr. Chris Decker. https://www.ofgem.gov.uk/ofgem-publications/52038/rpicharacteristics-alternative-price-control-frameworks270209.pdf

Chapter 5: Cost of Capital

JPS is given the opportunity to make a reasonable return on its investment through the tariff that is charged to its customers. This return is compensation for capital which is invested in the regulated asset base and is computed by the application of a rate of return to the asset base of the company. Both the rate of return and the asset base of the company must be approved by the OUR. The overall rate of return is the Weighted Average Cost of Capital (WACC) which is the weighted average cost of long-term debt and the approved rate of return on equity.

5.1 Capital Structure

In accordance with the Licence, the cost of capital that the utility is allowed to recover should be based on either the actual capital structure or *"an appropriately adjusted capital structure which adjustment is required to keep parity of the interests of the consumers and investors"*.

The OUR in the 2009 Determination Notice indicated that the appropriate capital structure was one that resulted in 48% debt and 52% equity.

Castalia, the consultant engaged by JPS, asserted that its Cost of Capital Study shows that the average gearing of energy companies that are similar to JPS is 48%. JPS reported that the company has been constrained in its efforts to obtain additional credit financing due to increased levels of non-technical losses, which is making it difficult for JPS to secure financing for its operations. JPS further stated that it has reluctantly resorted to short-term financing with the option to refinance at longer tenures when the crisis recedes.

The capital structure of JPS is funded by debt and equity. Debt is actually the cheaper source of finance for two main reasons:

1. Tax benefit: JPS gets an income tax benefit on the interest component that is paid to its lenders. Dividends to equity holders are not tax deductible.
2. Limited obligation to lenders: In the event of JPS going bankrupt, debt holders have the first claim on the company's assets (collateral), increasing their security. Since debt has limited risk, it is usually cheaper. Equity holders are taking on more risk, hence they need to be compensated with higher returns.

Table 5.11 below shows that JPS' actual gearing has increased from 38% in 2009 to 50% in 2013. Since the last tariff review the gearing ratio peaked at 53% in year 2011. JPS has increased the level of debt in its capital structure over the past five (5) years. Despite JPS' claims that the test year ratio is sub-optimal, the OUR has accepted the actual 50% gearing for use in calculating JPS' WACC for the 2014 - 2019 review period as fair and equitable.

Table 5.11: Gearing Ratio, Shareholders' Equity and Long-term debts (2009 to 2013)

Year	2013	2012	2011	2010	2009
Gearing Ratio	**0.50**	**0.52**	**0.53**	**0.42**	**0.38**
Shareholder's Equity (US$'000)	328,753	321,776	315,205	395,771	399,765
Long-term debts (US$'000)	326,442	353,572	356,295	292,279	250,213

DETERMINATION 6

The Office DETERMINES that the gearing ratio for the review period 2014 - 2019 is fifty percent (50%).

5.2 Cost of Debt

The OUR, as in previous determinations, will continue to use JPS' average borrowing cost in the computation of the cost of debt. In computing the cost of debt, the OUR relied on information submitted by JPS on all its long term debt obligations.

In determining the actual cost of debt, JPS computed the weighted average interest rate on the long term debt obligations listed in Table 5.22 below. The Office accepts this methodology for the computation of JPS' cost of debt.

Table 5.22: JPS' Average Borrowing Cost as at December 31, 2013.

JPS' Average Borrowing Cost as at December 31, 2013			
2013 LT Debt Obligations	**Amount (US$'000)**	**Interest Rate**	**Date of Maturity**
KFW Loan - DM 14M	414.00	7.00%	30/12/2015
KFW Loan - DM 7M	4,914.00	7.00%	30/12/2030
Int'l Finance Corporation	10,000.00	6.89%	30/08/2015
Int'l Finance Corporation	23,333.34	5.95%	15/09/2020
Credit Suisse	811.00	11.00%	06/07/2016
Credit Suisse	179,189.00	11.00%	06/07/2021
Citibank	6,000.00	6.63%	16/01/2015
Citibank	9,000.00	7.50%	16/01/2015
FCIB Syndicated Loan	12,000.00	7.11%	30/12/2015
FCIB Syndicated Loan	2,167.00	7.09%	30/12/2015
Espirito Santo Bank	4,008.62	6.50%	26/08/2015
Export Development Canada	2,731.00	1.91%	17/10/2015
Citibank Japan/NEXI Loan	56,875.00	2.36%	27/12/2020
Proparco Loan	47,055.00	6.18%	30/11/2020
OPEC Fund	19,444.00	5.78%	30/11/2020
Preference Shares	122.00	5.00%	n/a
Preference Shares	24,566.00	9.50%	n/a
Preference Shares	2,999.00	11.00%	n/a
Shareholder Loan	2,000.00	11.00%	n/a
Total	**407,628.96**	**8.07%**	

DETERMINATION 7

The Office determines that the pre-tax cost of debt for the period 2009 - 2014 is 8.07%

5.3 Return on Equity (ROE)

The cost of equity proposed by JPS was estimated with the use of the Capital Asset Pricing Model (CAPM). This methodology is widely used and is accepted and used in this and other determinations by the OUR in deriving the cost of equity. In computing the cost of equity and in making its case, JPS relied on the following set of papers and data produced by Dr. Aswath Damodaran, a Professor of Finance at the Stern School of Business of New York University:

- Damodaran, Aswath. "*Damodaran on Valuation: Security Analysis for Investment and Corporate Finance,*" Second edition, John Wiley and Sons, 2006
- Damodaran, Aswath. "*Levered and Unlevered Betas by Industry: Global Dataset,*" 2012[11]
- Damodaran, Aswath. "*Country Default Spreads and Risk Premiums Dataset,*" 2012[12]
- Damodaran, Aswath. "*Equity Risk Premiums (ERP): Determinants, Estimation and Implications – The 2002 Edition,*" 2012[13]
- Damodaran, Aswath. "*Measuring Company Exposure to Country Risk: Theory and Practice,*" 2003[14]
- Damodaran, Aswath. "*Estimating Risk Parameters.*"[15]
- Damodaran, Aswath. "*Volatility Rules: Emerging Market Companies*". September 2009[16]

The CAPM is represented as follows:

$$Return\ on\ Equity = R_f + \beta_e(RP) = R_f + \beta_e(MMRP + CRP)$$

Where:

R_f	= Risk free rate
β_e	= Equity beta
RP	= Risk Premium
MMRP	= Mature Market Risk Premium
CRP	= Country Risk Premium

In estimating the risk premium, two approaches can be used:

1. Multiplying the company's beta by the Equity Risk Premium
2. Multiplying the company's risk premium by the relative equity market standard deviations

JPS took the view that the first approach is the best approach. Additionally, JPS argued that because all of its revenue is from domestic sources this fully exposed the company to country risk and therefore the equity beta should be applied to the country risk premium. The OUR accepts the principle and approach.

[11] Accessed January 2014 at: http://people.stern.nyu.edu/adamodar/
[12] Ibid
[13] Ibid
[14] Ibid
[15] Ibid
[16] Ibid

5.3.1 Risk-free rate (R_f)

The **Risk-free rate** is the interest rate that can be obtained by investing in financial instruments with no default risks. JPS stated that the risk-free rate should be estimated for a point in time and should be for the same time as the valuation date. Castalia stated that the valuation date can be translated into the tariff application date which in practical terms means the most recent date for which data is available. For JPS, the most recent risk-free rate would be the best estimate of the future risk-free rate. The risk-free rate as of January 31, 2014, was the rate used in the preparation of JPS' Tariff Submission. JPS therefore used 2.70% as the risk-free rate.

There are opposing views regarding whether the risk-free rate should be approximated using a short-term security or a long term-security. A short-term security would seemingly be the better option for estimating the risk-free rate as a longer time period would be increasing the probability of default by the debtor. Also, over a short time period, less reinvestment is needed to equate actual return with expected return and so there is lower reinvestment risk. However, short-term interest rates tend to be more volatile than long-term interest rates. There is a great degree of consensus that a long-term security should be used where the analysis is long-term and a short-term security where the analysis is short-term.

The goal of JPS should be to match financing tenure to its average asset life span. Given the types of assets that JPS invests in, this would lead to the decision to use mostly longer-term debt instruments to finance these investments. In light of this, the 10-year U.S. Treasury bond is an appropriate measure of a long-term risk-free rate of return. The information can be sourced from many public sources.

The OUR agrees that the most appropriate risk-free rate to be used in the computation of the ROE is the point in time estimate as opposed to an average historical average rate. The CAPM is a forward-looking technique and as such the values chosen for the variables in the CAPM should generally be prospective even if they are estimated using retrospective data. Shapiro and Balbirer (2000, pg. 329) state that one of the common errors in using the CAPM to calculate the risk-adjusted cost of capital is "*using the historical average Treasury bond or Treasury bill return as the risk-free rate in the CAPM instead of using the actual (current) rate. You must use the current risk-free rate.*" However, the applicable point in time rate is the rate as at 31st December 2013, the end of the test year. The risk-free rate as at the 31st December is 2.90%[17].

DETERMINATION 8

The Office DETERMINES that the applicable Risk-free rate of return is 2.90%.

[17] Source: http://www.federalreserve.gov/releases/h15/update/

5.3.2 The equity beta (β_e)

According to the theory underlying the CAPM, investors should be concerned only with systematic or non-diversifiable risk since non-systematic risk can be diversified away by adding securities to their investment portfolio. Non-diversifiable risk is measured by the beta coefficient. The equity beta is a measure of the correlated volatility of an asset arising from exposure to the general market. The market portfolio of all investable assets has a beta of exactly one (1). The more sensitive a business is to overall economic conditions, the higher is its equity beta. Regression analysis with necessary adjustments is the method used in calculating the equity beta. JPS is not a publicly traded company and, as a consequence, the data available for a robust regression analysis is limited. Therefore, in calculating the equity beta, JPS calculated an equity beta for a group of similar companies via regression, and then adjusted the resulting equity beta of comparable countries to JPS' capital structure and tax rate. Given the lack of adequate data to allow for a robust regression analysis, the OUR accepts the methodology used by JPS in deriving the equity beta.

5.3.2.1 Calculating an Equity Beta for Comparable Companies

The methodology used in calculating the equity beta was outlined in the cost of capital study prepared by Castalia. In the report, Castalia outlined the steps as follows:

> *"The first step in finding the equity beta for the firm is to calculate an equity beta for a group of similar companies via regression. This regression is done by dividing the covariance of each asset in the market portfolio by the variance of the market portfolio.*
>
> *Professor Damodaran publishes data sets for companies in all sectors and all countries. To do this, he compiles data from more than 80,000 companies in the world. Professor Damodaran publishes betas for more than 95 sectors, including the power sector and the utilities sector. For each sector, Professor Damodaran publishes datasets for US-listed companies, emerging market companies, and worldwide companies. He also publishes the individual data for each of the companies in each data set. Table [5.3] shows a list of the equity beta for the most relevant data sets for JPS.*
>
> *Table [5.3]: Possible Data Sets for Equity Beta for JPS*

Levered Beta	Power	Power-Filtered	Natural Gas Utilities	Coal & Related Energy
	A	B	C	D
Global	0.84	0.98	n/a	1.18
Emerging Markets	0.87	n/a	n/a	1.02
U.S	1.35	n/a	0.46	1.47

Source: Damodaran, Aswath, "Levered and Unlevered Betas by Industry". Accessed October 2013 http://pages.stern.nyu.edu/~adamodar/

> *We recommend starting by using one of the data sets that Professor Damodaran publishes on his website: The Power Sector dataset (Column A of Table [5.3]). Out of all the datasets*

produced by Damodaran, this power dataset is the one that is more comparable to JPS. We recommend adjusting this data set to only include companies that are comparable to JPS. To do this we:

- *Include electric power utilities*
- *Exclude energy and infrastructure funds, renewable energy suppliers and manufacturers, and oil & gas exploration and distribution firms*

By adjusting the power dataset with these criteria, we reach an average levered beta of 401 power firms globally, which gives a levered beta of 0.98 and an unlevered beta of 0.49. (Column B). This set includes utilities that are more comparable with the JPS such as the Caribbean Utilities Company in the Cayman Islands, as well as electricity utilities in the US, Europe, Japan, Australia, New Zealand, Canada, and other emerging markets. We use this beta for JPS. Appendix [B] provides a complete list of the companies used."

The second step is that of de-leveraging the equity beta of the group of similar companies is then done using the following formula:

$$\beta_U = \beta_L \left[1 + \left(1 - T_{Industry}\right) \times \left(\frac{D}{E}\right)_{Industry} \right]$$

Where:

β_U	= the unlevered beta
β_L	= is the levered beta
$(1 - T_{Industry})$	= the tax shield of the firms in the sample
$T_{Industry}$	= the marginal tax rate of firms in the sample
$\left(\frac{D}{E}\right)_{Industry}$	= the weighted average capital structure of firms in the sample

The third and final step is the re-leveraging of the equity beta with JPS' tax rate and capital structure.

In using this approach JPS calculated an equity beta of 0.86. This is based on a capital structure of 48.0% debt, 52.0% equity. The company's equity beta is computed using the following formula:

$$\beta_E = \beta_A \left[1 + (1 - t) \times \left(\frac{D}{E}\right) \right]$$

Where:

β_E	= the equity/levered beta
β_A	= the asset/unlevered beta
$1 - t$	= the tax shield of the firm
D	= the percentage of the company's financing which is related to debt
E	= the percentage of company's financing which is related to equity

Given the lack of adequate data on JPS to allow for a robust regression analysis, the JPS approach in calculating the equity beta is accepted by the OUR. In using this approach and applying the Office's determined capital structure of 50% debt and 50% equity, the OUR computes an equity beta of 0.88.

DETERMINATION 9

The Office DETERMINES that the applicable equity beta is 0.88.

5.3.3 Mature Market Risk Premium (MMRP)

The mature market risk premium (MMRP) is the expected return over the risk-free rate that investors require in order to invest in risky assets in a mature market. The five main risks that comprise the risk premium are business risk, financial risk, liquidity risk, exchange-rate risk and country-specific risk. These risk premiums are estimated based upon a simple 2-stage dividend discount model and reflect the risk premium which would justify the current level of the index, given the dividend yield, expected growth in earnings and the level of the long term bond rate.
There are two approaches used in arriving at the MMRP, the implied equity risks approach and the historical equity risk approach. According to Professor Damodaran, there are a few advantages to the implied equity risk approach. The first is that it does not rely on historical data which may not hold relevance in the current market and secondly, because it does not rely on historical data, it is also more sensitive to changing market conditions. Professor Damodaran also pointed out that the implied equity risk premium approach has a high predictive power.

The historical equity risk approach uses the mean of historical returns above the risk-free rate in the US market. Professor Damodaran mentioned that there are two options for estimating the MMRP based on the historical equity risk approach; the arithmetic mean or the geometric mean. According to Damodaran, the arithmetic mean is only preferred if annual returns are uncorrelated over time and the objective is to estimate the risk premium for the next year. However, empirical studies have found that returns on stocks are negatively correlated over time and that arithmetic means are likely to overstate the premium. Furthermore, asset pricing models tend to be used to get expected returns over a period longer than one year, thereby further supporting the case to use geometric mean. Therefore, if the historical equity risk approach is chosen, the value should be estimated with a geometric mean. Another problem with this approach is that it relies on historical data which may not hold relevance in the current market.

The OUR accepts the JPS proposed nominal mature market risk premium of 5% for year 2013, which is based on papers and data published by Damodaran using an implied equity premium (*Last updated January 5, 2014*). These implied premiums are calculated using the S&P 500.

DETERMINATION 10

The Office DETERMINES that the applicable MMRP is 5.00%.

5.3.4 Country Risk Premium (CRP)

A country risk premium is usually included for emerging economies in order to attract investors to less stable and risker countries. The country risk premium is the difference between the higher interest rates that less stable and riskier countries must pay and the imposed market interest rates for the government of a given benchmark country. The benchmark country is a country with a stable, well-respected and developed business environment. These countries are often referred to as “low risk” or “developed”. The USA is an example of a benchmark country.

Country risk relates to the likelihood that changes in the business environment will occur that reduce the profitability of doing business in a country. Macro-socio-economic factors such as political instability, volatile exchange rates and economic instability (which may be induced, inter alia, by such factors as the possibilities of social disruptions and adverse weather conditions) are considerations which lead investors to be wary of overseas investment opportunities. These factors can adversely affect operating profits as well as the value of assets and thus require a premium for investing. Consequently, any added element or incremental risk that is specific to a country or specific grouping of countries will be considered by potential investors and would be embedded in the CRP. The CRP is higher for developing markets than for developed nations.

There are a number of ways of estimating country risk premiums. Economic literature suggests that of the many ways the two most widely used measures are:

1) “Synthetic” spread – country’s sovereign credit rating assigned by a relevant rating agency (S&P, Moody’s, Fitch); and
2) Sovereign bond spread – market-based measures.

5.3.4.1 The “Synthetic” Spread

There are many organizations that rate the political, social, macroeconomic and institutional risks that countries face globally. Included in the factors that credit rating agencies consider are the risk of social unrest, the impact of crime and debt service as a percentage of GDP. The sovereign credit rating can be converted into a country risk premium. For each sovereign credit rating, Damodaran (2014), has determined a typical default spread, expressed by Moody’s sovereign rating. The long-term credit rating that is assigned to Jamaica by Moody’s Investor Service is currently Caa3. Professor Damodaran estimates a sovereign default risk premium of 15.00% for countries with Caa3 ratings as of January 2014.

Damodaran (2011) notes that there are three main problems associated with the use of these risk measures. Firstly, the measures are internally consistent but may not be easily comparable among services; secondly, the methodology for estimating the country risk scores is not transparent, and observers are prevented from making a comprehensive judgment because of lack of data; and thirdly, the measures are linear and thus they do not provide a view of the comparability of the country risk between countries (a country with a risk score of 80 is not twice as risky as a country with a risk score of 40).[18]

5.3.4.2 The Sovereign Bond Spread

In contrast to the sovereign credit rating, which is assigned by credit rating agencies, there is a market-based measure, sovereign bond spread, which is used as a proxy for country risk. The actual bond spread is the difference between the yield to maturity of an emerging market sovereign bond denominated in US dollars or Euro and the yield of a comparable US or Euro bond, respectively. Actual bond spreads instantly reflect market changes and they have a wider scope. Godfrey and Espinosa (1996), and many others, such as Damodaran (2011) and Porras (2011), proposed quantifying country risk from the actual bond spread.[19]

Given that the CRP is derived directly from the capital market prices, it can therefore be seen as representing a consensus view of the level of country risk for a particular country.
The key issues are:

1) Bonds are denominated in the same currency to avoid inflationary mismatches (in this case, US dollars);

2) The bonds are of identical maturity to avoid problems associated with the yield curve (our analysis looked at the ten (10)-year yields[20]); and

[18] **Naumoski: Aleksandra, 2011** "Estimating Country Risk Premium in Emerging Markets: The Case of the Republic of Macedonia"
[19] Ibid
[20] The OUR has adopted the Nelson-Siegel model for estimating the ten (10)0-year yields on Jamaica-US dollar denominated bonds for the years in which there are no bonds trading with ten (10) years to maturity. This model is one that fits the empirical form of the yield curve with a pre-specified functional form of the spot rates, which is a function of the time to maturity of the bonds.

The Nelson-Siegel model
Good estimates of the term structure of interest rates (also known as the spot rate curve or the zero bond yield curve) are of the utmost importance to investors and policy makers. One of the term structure estimation methods, initiated by Bliss and Fama (1987), is the smoothed bootstrap. Nelson and Siegel (1987) and Svensson (1994, 1996) therefore suggested parametric curves that are flexible enough to describe a whole family of observed term structure shapes.

The Nelson-Siegel model is extensively used by central banks and monetary policy makers (Bank of International Settlements (2005), European Central Bank (2008)). Fixed-income portfolio managers use the model to immunize their portfolios (Barrett, Gosnell and Heuson (1995) and Hodges and Parekh (2006)) and recently, the Nelson-Siegel model also regained popularity in academic research. Dullmann and Uhrig-Homburg (2000) use the Nelson-Siegel model to describe the yield curves of Deutsche Mark denominated bonds to calculate the risk structure of interest rates. Fabozzi, Martellini and Priaulet (2005) and Diebold and Li (2006) benchmarked Nelson-Siegel forecasts against other models in term structure forecasts, and they found it performed well, especially for longer forecast horizons. Martellini and

3) That the bonds are of similar liquidity to avoid problems with thin trading.

If these conditions are fulfilled, because both bonds will return investors a stream of cash flows over the same period (in the same currency), then the higher yield on the emerging market sovereign bond can only be due to the fact that the cash flows are backed by the emerging country's government rather than the US government. In this sense, the US is treated as the base risk-free country against which to measure country risk.

5.3.4.3 The "Synthetic" spread versus the actual bond default spread approach

The credit rating of a country is used by individuals and entities that purchase the bonds issued by companies and governments to determine the likelihood that the government will pay its bond obligations. Credit rating agencies use their judgment and experience in determining what public and private information should be considered in giving a rating to a particular company or government.

The terms on which a government can sell bonds depend on how creditworthy the market considers it to be. International credit rating agencies will provide ratings for the bonds, but market participants will make up their own minds about this.

Table 5.31: Total Equity Return and Country Risk Premium in Jamaica (Dec. 31, 2013)

Approach	Mature Market Risk Premium	Jamaica	
		Country Risk Premium	Return on Equity
Country bond default spread with respect to US bond	5.00%*	5.58%	12.25%
Country default spread with respect to sovereign credit rating	5.00%*	15.00%*	19.83%
*Damodaran January 2014 Source: OUR Calculations			

Meyfredi (2007) used the Nelson-Siegel approach to calibrate the yield curves and estimate the value-at-risk for fixed-income portfolios. Finally, the Nelson-Siegel model estimates are also used as an input for affine term structure models.

$$y(t) = \alpha_1 + (\alpha_2 + \alpha_3)\frac{\beta}{t}\left(1 - e^{-t/\beta}\right) - \alpha_3 e^{-t/\beta}$$

The Nelson-Siegel Function

5.3.4.4 Choosing the country risk premium

With the synthetic approach, choosing the right size of the country risk premium depends on the personal assessment of the analyst and his/her expectations concerning the prosperity of the country in the long run. Table 5.31 above gives a systematized view of the results of the two approaches. The synthetic spread approach gives an abnormal CRP of 15.00%. The method of deriving the CRP using the synthetic spread approach can neither be theoretically nor empirically supported hence the results are questionable and unreliable. OUR is of the view that this measure should be discarded as not reliable for the case of Jamaica. Estimation of the CRP using the country sovereign credit rating cannot be considered a reliable measure, given that the credit rating assigned to the particular country in most cases lags the market and does not incorporate the newest information related to market movements. Further, it does not reflect the changes in the factors of default risk immediately. Besides, this measure of country risk has many other disadvantages, as noted under sub-section A above. This in turn contributes to the CRP estimate using the country rating not mirroring reality.

The CRP of 15.00%, which is used as a proxy for all countries with credit rating Caa3, should not be considered as a reliable measure. Instead, the bond default spread which reflects the risk aversion of investors at a particular moment is the more realistic measure and should be adopted. The default spread reflects the most updated market information which takes into account the current world economic environment.

JPS based its CRP proposal on an alternative “synthetic” spread approach that produces a much higher figure and as a result they have proposed that the country risk premium be 15%. The foundation of this part of the analysis is work undertaken by Professor Damodaran who is professor of finance at the New York University Stern School of Business. The approach is called the country risk premium concept (CRPC) and makes use of the sovereign credit ratings produced by rating agencies such as Moody’s although the exact structure of the methodology is not wholly transparent.

However it is unclear at this time whether this approach has gained general acceptability. For example, Lutz Kruschwitz (Chair of Finance and Banking at the Freie Universita¨t Berlin, Germany), Andreas Lo¨ffler (Chair of Finance and Banking at the Freie Universita¨t Berlin, Germany) and Gerwald Mandl (Chair of Accounting and Auditing at the Universita¨t Graz, Austria) in a joint paper in 2010[21] conclude the following:-

> “1. *It is not fair to claim that the country risk premium concept (CRPC) has a strong theoretical basis. Indeed, this is impossible within the framework of a traditional CAPM. Neither is the CRPC empirically supported, where ‘‘empirical’’ means based on a sound econometric methodology.*

[21] Kruschwitz L., Loffler A., Mandl G., Damodaran’s Country Risk Premium: A Serious Critique

> 2. *Since Damodaran's CRP can be neither theoretically nor empirically supported, the rates of return on capital that are derived by such methods are highly arbitrary."*

In view of the academic debate as well as the uncertainties surrounding this "synthetic" spread approach, the OUR did not accept this methodology for the computation of the CRP.

In responding to the OUR's draft Determination Notice, JPS objected to the CRP that is used and commented as follows:

> *"By just about every objective measures, the Jamaican economy and the electricity sector risk have not experienced a lowering of risk exposure since the 2009 rate review. Jamaica has since entered into two arrangements with the International Monetary Fund and has entered into domestic voluntary defaults (JDX & NDX) on its loan portfolio, with rating agencies maintaining conservative outlook.*
>
> *The electricity sector has failed to achieve fuel diversification and generation asset renewal with very high levels of electricity theft, GOJ receivables, falling demand and the threat of further demand destruction through the introduction of wheeling. There is no justification for the reduction of the target ROE and this should be maintained at 16%."*

In response to JPS' comments the OUR asserts that globally, yields on bonds have been trending downwards since the last Determination Notice in 2009. JPS' proposed average cost of debt in 2009 was 11.47% and in its current submission the figure is now reduced to 8.07%. This reduction is suggesting that lenders have lowered their expectations of high returns in financial markets including emerging economies such as Jamaica. In fact, JPS reported that the company was able to obtain a loan (test year balance US$57M) at an interest rate of 2.36% from Citibank Japan/NEXI with maturity in 2020. Additionally, the company was able to issue US$24.6M of preference shares at 9.5% interest.

Also, the generally accepted CAPM methodology used in estimating the expected returns on equity to JPS and the bond yield methodology used in the estimation of Jamaica's CRP is consistent with principles used in previous determinations.

The OUR computes the CRP as the difference between the yields of the Jamaican risk-free asset, i.e. the government bond[22], and the comparable mature market risk-free asset, the US government bond. This result is a CRP of 5.58% as at the end of December 2013 (the test year). This is the most reliable measure to estimate the required return on the capital invested in JPS. Appendix A shows Jamaica's CRP for the period 31st January 2007 to 31st December 2013 computed by the OUR.

[22] GOJ bond yields were obtained from the Bank of Jamaica; Source: Bloomberg

DETERMINATION 11

The Office DETERMINES that the applicable CRP is 5.58%.

JPS requested a real ROE of 19.83%. This request was based on Castalia's recommended values for a risk-free rate-of-return of 2.7%; an equity beta of 0.86; a market risk premium of 5.0%; and a country risk premium of 15.0%.

The OUR computes the return on equity as follows:

$$\begin{aligned} Return\ on\ Equity &= R_f + \beta_e \times (MMRP + CRP) \\ &= 2.90\% + 0.88 \times (5.0\% + 5.58\%) \\ &= 12.25\% \end{aligned}$$

DETERMINATION 12

The Office DETERMINES that the allowed post- tax Return on Equity is 12.25%.

5.4 The Weighted Average Cost of Capital (WACC)

The overall rate of return is the WACC and is calculated as the weighted average cost of both the long-term debt and the equity components of the capital structure. Table 5.41 below shows the comparison of the OUR determined WACC, against JPS' Proposal and the 2009 Determination.

$$WACC\ (pre-tax) = Debt\ Ratio \times Cost\ of\ Debt + Equity\ Ratio \times \frac{Return\ on\ Equity}{(1 - tax\ rate)}$$

$$WACC\ (pre-tax) = 50.00\% \times 8.07\% + 50.00\% \times \frac{12.25\%}{(1 - 0.3333)}$$

$$WACC\ (pre-tax) = \mathbf{13.22}\%$$

Table 5.41: WACC Comparison

	2009 Determination	2014 JPS Proposed	2014 OUR Determination
Cost of Debt	10.4%	8.07%	8.07%
Rate of Return on Equity (ROE)	16.0%	19.83%	**12.25%**
Tax Rate	33.3%	33.3%	33.33%
Gearing Ratio	48.0%	48.0%	50.00%
Post-tax WACC	11.66%	12.89%	8.81%
Pre-tax WACC	17.49%	19.34%	**13.22%**

DETERMINATION 13

The Office DETERMINES that the Pre-Tax Weighted Average Cost of Capital is 13.22%.

5.5 Insurance and the Cost of Capital

Although the issue of the relationship between insurance and the cost of capital was not addressed in the JPS Tariff Submission, a clear understanding of how they are related is important given the exposure of the company's assets to storm damage. The Office is therefore using the occasion for the issuance of this determination to treat with the issue explicitly.

$$\begin{aligned} Return\ on\ Equity &= Risk\ free\ Rate\ + Risk\ Premium \\ &= R_f + \beta_e(RP) \\ &= R_f + \beta_e(\mathbf{MMRP} + \mathbf{CRP}) \end{aligned}$$

The return on equity, as defined above, is the summation of the risk-free rate (Rf) and the risk premium (β_e(RP)). Where investment takes place in a developing country but originates in a developed country, the risk premium should take into account the incremental risk associated with the cross-border transaction. In this regard, the risk premium (RP) would be comprised of an MMRP and CRP.

From the perspective of utility regulation and rate setting, the decomposition of the MMRP is a key element in the appreciation of the relationship between insurance deductibles and the return on equity or investment.

5.5.1 Deductibles and Moral Hazards

An insurance deductible refers to the expense payable by the insured before the insurer pays out any money in compensation. Axis, international loss adjusters, in its assessment of the windstorm risk faced by JPS noted that for non-transmission and distribution (non- T&D) assets, the company's insurance policy carried a 'deductible of 2% of the insured value per location'[23]. Notably, while JPS' transmission and distribution (T&D) assets are not protected by conventional insurance, it

[23] Jamaica Public Service Company Ltd. Final Report: Claim for Compensation Loss and Damages by Hurricane Ivan, p.8

receives disaster coverage under a self-insurance fund, the Electricity Disaster Fund (EDF), for which the deductible threshold has been set at 0.25%[24].

In the literature spanning risk, uncertainty and insurance there is universal recognition that deductible is a device used to reduce or eliminate moral hazards among individuals and entities with insurance policies. Jennifer L. Wang, Ching-Fan Chung and Larry Y. Tzeng in their research into the phenomenon, found strong empirical evidence to 'support the notion that the increasing deductible provision helps control moral hazard'[25].

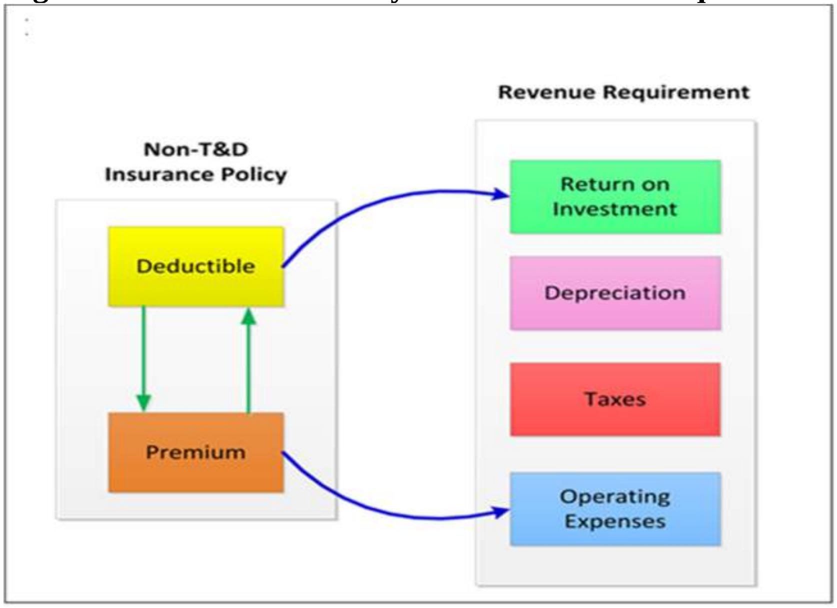
Moral hazard arises when the behaviour of the insured party increases the 'probability or magnitude of a payment associated with an event'[26]. Moral hazard is manifested in negligent or opportunistic behaviour on the part of the insured which translates to higher pay-out cost for the insurance company. In the case of an electric utility, this might mean failure to undertake basic maintenance on its plant with the full knowledge that the mildest of windstorms would see the insurance company paying for the damage which could have been avoided. Consequently, for utilities, the reality and universal practice is that there is a deductible risk that is borne by the insured to reduce the tendency towards poor maintenance practices that may prove more costly to the insurer[27]. As with other risks, the cost associated with this is captured in the risk premium of the company's return on equity.

5.5.2 Insurance Policies and Revenue Requirement

There is a trade-off between the level of deductible on an insurance policy and the size of the premium. If the deductible is high then the premium would be relatively low and if on the other hand the premium is high then the deductible would be relatively low. In a sense the deductible is a form of co-insurance in which the insured assumes a part of the risk.

[24] See, Amendments to Electricity Disaster Fund Rules of Procedures for Operation and Administration Determination Notice (March 17, 2009)
[25] Wang, et al "An Empirical Analysis of the Effects of Increasing Deductibles on Moral Hazard" Journal of Risk and Insurance, Vol. 75, Issue 3, pages 551–566,(2008)
[26] Pindyck, R and Rubinfeld, "Microeconomics", Pearson-Prentice Hall, 7th ed. (2009) p.628
[27] Harrington, S. "Rethinking Disaster Policy", Regulation, Vol. 23, No.1 (2000)

Figure 5.51: Insurance Policy and the Revenue Requirement



In tariff setting, the premium is an expense which is known and measurable and is included in the operating expense component of the revenue requirement. Deductible on the other hand, is probabilistic and must therefore be captured in the rate of return on investment as a part of the general business risk the company faces (see Figure 5.51).

5.5.3 The Components of Matured Market Risk Premium

In his examination of the anatomy of risk premium in a matured market context, Roger Morin identified five elements[28] (see Figure 5.52). They are:

- ***Interest rate risk***: which reflects the degree of economic uncertainty that may result in variability in the level of interest rate.
- ***Business risk***: which encompasses a range of factors that impact cost and revenue. This includes "demand for the company's product, the products' income and price elasticity, the degree of competition, the availability of product substitutes, the risk of technological obsolescence, the degree and quality of regulation, weather variations, and the conditions of the labour and raw material markets"[29].
- ***Regulatory risk***: which is related to the quality and consistency in regulatory decisions, as well as the fairness and balance in tariff awards.
- ***Financial risk***: which is associated with the mode employed by the company to finance its investments and is exhibited in its capital structure. This has implications for the variability in income to the company's shareholders.

[28] Morin, Roger A. "New Regulatory Finance", Public Utilities Reports, Inc. (2006), p. 35-51
[29] Ibid

- ***Liquidity risk***: which represents the potential loss the company might sustain from its inability to convert an asset into cash without significant price concessions.

The existence of a monopoly implies that market failure has occurred since competition is lacking[30]. The role of the regulator therefore is to ensure that the behaviour of the monopolist approaches that of a competitive industry. In competitive industries, deductibles would be considered a risk associated with doing business. Consequently, in the event of a catastrophe, the cost incurred is absorbed by the business since it is already covered in their business risk. In the case of a regulated industry, a similar reasoning applies. The OUR therefore views deductibles in a similar way and treats it as a part of the utility's MMRP.

Additionally, along with monopolies, externalities, predatory pricing and other types of market failures, moral hazards are considered as behaviour that should be regulated. For example, regulatory experts, Robert Baldwin and Martin Cave in exploring the question 'Why regulate?' argues that regulation is necessary to curb moral hazards since it may result in excesses "without regard to the cost being imposed on the society"[31]. The OUR therefore has a regulatory responsibility to focus on creating the environment in which the behaviour of the monopolist approaches that of a competitive industry as well as removing ambiguities where they may exist to ensure that costs associated with moral hazards are not passed on to electricity consumers. In this regard, the Office deems it critical to make it clear that insurance deductibles, both for T&D and non-T&D assets, are already embedded in the MMRP.

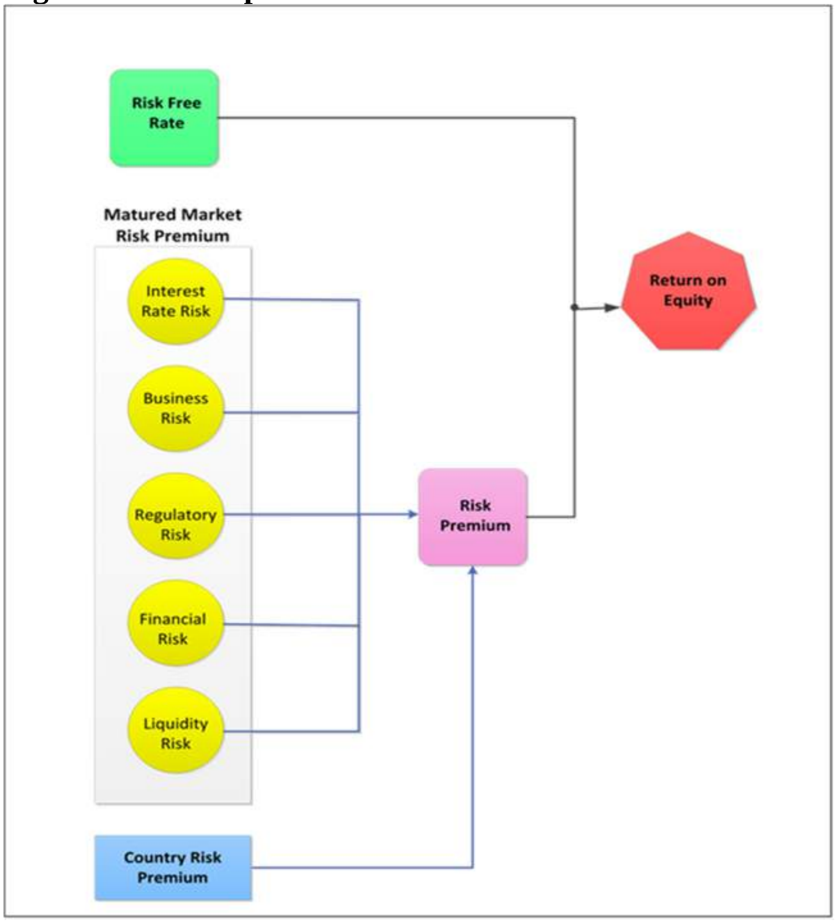
A common approach to the setting of acceptable regulatory standards is the reliance on benchmarking and industry norm. The norm in respect of disaster coverage for assets is a 2% deductible in the utility industry. However, given that JPS' assets are covered by conventional insurance as well as a self-insurance fund, the 2% deductible applies only to non-T&D assets. For T&D assets the applicable deductible is 0.25%. In this regard, the OUR therefore accepts that deductibles across the two asset categories are embedded in MMRP.

5.5.4 Country Risk Premium

CRP attempts to capture the additional risk assumed by the investor who opts to invest internationally rather than in his domestic economy. The risk involved is macroeconomic in nature and therefore captures factors such as political stability, exchange rate volatility and the vulnerability to extreme weather events. These are additional increments of risk outside of the premium that is required for a mature market. In this respect, some degree of the variability in weather is also captured in the country's risk premium.

[30] Baldwin, Robert & Cave, Martin "Understanding Regulation: Theory, Strategy and Practice" Oxford Press (1999), p.10
[31] Ibid, p 14

Figure 5.52: Components of Matured Market Risk Premium



5.5.5 The Z-Factor and Deductible

As expressed in Schedule 3 of the Licence, the Z-Factor becomes applicable when an event has occurred for which all of the following three conditions are satisfied:

a. the Licensee's costs are affected;
b. the event is not due to the Licensee's managerial decisions;
c. the costs are not captured by the other elements of the price cap mechanism.

Although natural disasters are 'acts of God' and are outside of the JPS management's control, where the affected assets are insured, whether by conventional insurance coverage or by way of the EDF, the costs to the company arising from the deductible requirements of such insurance coverage, are deemed to be captured in the return on investment component of the price cap mechanism. Consequently, deductibles are not claimable under the Z-Factor provision of the PBRM.

In fact, if such compensations are permitted under the Z-Factor provision it would amount to 'double dipping' since it is already captured in the PBRM.

In addition, to allow compensation for a deductible through the Z-Factor mechanism would represent the transfer of the company's component of the disaster risk (which is a normal business risk) to customers. Such a transfer of risk would only serve to undermine the principle of reducing (or eliminating) incidences of moral hazards, which are central to the concept of deductibles.

DETERMINATION 14

The Office DETERMINES that all insurance deductibles are included in the PBRM and therefore do not qualify for compensation under the Z-Factor.

Chapter 6: Revenue Requirement

6.1 Introduction

In accordance with Schedule 3 of the Licence, the revenue requirement shall be calculated using the following formula, unless such formula is modified in accordance with the rules and regulations prescribed by the office.

Non-fuel Revenue Requirement = Non-fuel Operating Costs + Depreciation + Taxes + Return on Investment.

The components of the revenue requirement which are ultimately approved for inclusion will be those determined by the Office to be prudently incurred costs and other costs which are determined to be reasonably incurred costs in connection with the Licenced Business and in conformance with the Licence, OUR Act, the Electric Lighting Act and subsequent implementing rules and regulations.

The components of the revenue requirement are defined in the Legal and Regulatory Framework set out in this Determination Notice.

6.2 Summary of JPS' Revenue Requirement Request

JPS submitted a request for US$464.4M as its non-fuel revenue requirement for the first year of the new regulatory period, 2014-2019. This, JPS stated, is based on the results from the audited financial statements for the 2013 test year as adjusted for known and measureable adjustments. JPS further averred that the increase is primarily driven by the expansion in the company's rate base and increases in purchased power costs and net finance costs.

Table 6.21 below shows JPS' proposed revenue requirement.

Table 6.21: JPS' Proposed Revenue Requirement

Revenue Requirement	**JPS Proposed** (US$'000)
Purchased Power Costs	104,111
Operating Expenses	150,844
Total Operational Expenses	**254,955**
Net finance costs (excl. long-term debt):	
Interest on short-term loans	1,403
Interest on customer deposits	549
Interest – Bank overdraft and other	5,721
Int. Capitalised during construction (AFUDC)	1,450
Debt issuance cost and expenses	4,829
Finance income	(1,615)
	12,338
Depreciation	**57,498**
FX Losses	**14,000**
Other Income	**(2,822)**
Other Expenses	**3,000**
Self-insurance fund contribution	2,000
Gross up for taxes on SIF	1,000
Return on Equity	**62,552**
Taxation (Gross up)	**31,276**
Long Term Interest Expenses	**23,507**
Revenue Requirement	**456,304**
Less Caribbean Cement Revenue	(4,936)
JPS Managed IPP Expenses	
Loss Reduction Fund (incl. taxes)	**13,000**
Adjusted Revenue Requirement	**464,368**

JPS stated that the increased revenue requirement over that of the amount approved in 2009 (US$357M) is driven primarily by increases in PPA costs, finance expenses and capital costs.

During the regulatory period 2009-2014, two (2) new PPAs were signed by JPS to supply 83 MW of generating capacity to the grid.

6.3 The OUR’s analysis and determinations in relation to the revenue requirement are included in the following sections of this Chapter.Non-Fuel Operating Cost

Operating expenses are the costs incurred by JPS in providing electricity services and maintaining and operating its generation, transmission, distribution and general plant assets. These costs are not associated with capital investments.

The proposed test year operating costs totalling US$281.3M are outlined in Table 6.31 below. The components of the operating costs are discussed in the subsequent subsections, which include the OUR’s comments and necessary adjustments.

Table 6.31: JPS’ Proposed Test Year Operating Costs

JPS’ Test Year Operating Costs All amounts in US$'000s					
Items	**Actual Costs**		**Adjustments**	**Adjusted Costs**	
Purchased Power Costs		**104,111**	-		**104,111**
Operating Expenses:		**143,264**	**7,580**		**150,844**
Payroll, benefits & training	58,958		7,468	66,426	
Third party services	25,830		-	25,830	
Materials & equipment	8,544		-	8,544	
Office & Other expenses	24,778		(1,250)	23,528	
Transportation expenses	-		-	-	
Insurance expenses	6,811		1,362	8,173	
Bad debt write-off	18,342		-	18,342	
Total Operating Expenses		**247,375**	**7,580**		**254,955**
Net Finance Costs:		**14,645**	**(2,307)**		**12,338**
Interest on Short-term Loans	1,403		-	1,403	
Interest rate swap	1,232		(1,232)	-	
Preference dividends	1,075		(1,075)	-	
Interest on customer deposits	549		-	549	
Bank Overdraft Interest Other	5,721		-	5,721	
Interest Income	(1,615)		-	(1,615)	
Debt issuance costs and expenses	4,829		-	4,829	
Interest Capitalized during construction	1,450		-	1,450	
Foreign Exchange Losses		**21,114**	**(7,114)**		**14,000**
TOTAL OPERATING COSTS		**283,134**	**(1,841)**		**281,293**

6.3.1 Power Purchase Costs

JPS presented its test year Power Purchase Costs of US$104.11M as part of its total operating cost for inclusion in the Non-Fuel Revenue Requirement. This represents the base amount JPS expects to pay for power supplied to the grid by IPPs on an annual basis during the 2014-2019 period. Payments will be made to IPPs in accordance to their respective PPAs. The breakdown of the test year Power Purchase Costs is shown in Table 6.32 below.

Table 6.32: Proposed Non-Fuel Power Purchase Costs

IPP	Power Purchase Cost (US$M)	Proportion
JEP	45.428	43.63%
WKPP	28.110	27.00%
WIGTON	13.825	13.28%
JPPC	16.474	15.82%
JPS Munro	0.496	0.48%
JAMALCO	-0.227	-0.22%
NET BILLING	0.004	0.00%
	104.11	**100%**

Based on a review and analysis of the performance and payments to the stated IPPs for the test year and their projected annual performance and cost for the upcoming five year period, the OUR has approved the proposed power purchase cost of US$104.11M for inclusion in the revenue requirement.

6.3.2 Operating and Maintenance Expenses

JPS proposed Operating Expenses is US$150.8M which includes adjustments to line items: Office and Other Expenses, Payroll, Benefits & Training and Insurance Expenses. The details of the adjustments are outlined below.

6.3.3 Office and Other Expenses

JPS proposed that it be allowed to record actual meter readings for residential customers in alternate months (instead of going out to read meters every month). Estimated bills would be issued in the intervening months calculated based on the last three actual readings. The company gave as the basis for this proposal that it would allow it to further reduce O&M costs to its customers. JPS estimated that this would save approximately US$1.25M annually and included this amount as savings to the customer in the revenue requirement.

The OUR is of the view that the issuance of estimated bills every other month might cause some discomfort to JPS' customers, particularly in relation to billing adjustments issues. Additionally, this change would have significant implications for the JPS Back-billing Policy and the Guaranteed Standards (specifically, EGS 7 - estimated bills and EGS8 – estimation of consumption) especially when the billing cycle is interrupted by Force Majeure events. The US$1.25M reduction on a proposed revenue requirement of US$464.4M represents a 0.03% annual savings. The OUR considers the proposed cost savings to be derived from this initiative insignificant compared with the impact on the individual customer who might be adversely affected by the reading of meters in alternate months. Therefore, the initiative is disapproved by the OUR and the appropriate adjustment to reflect this is made in the approved revenue requirement.

6.3.4 Payroll, Benefits & Training

Payroll expenses included in the audited financials for 2013 amounted to US$58.95M. JPS adjusted these costs by known and measureable changes prior to inclusion into the revenue requirement. The audited financial results included an isolated reduction of US$4.5M in pension benefits arising from the increase in the surplus identified on assessment of the Employee Pension asset by the actuary. This amount was added back to payroll expenses to ensure payroll expenses included in the revenue requirement reflect normal operational conditions. This, JPS stated, is consistent with the fact that the pension surplus (employee benefit asset) reflected in the balance sheet of the audited financial statements is also being disallowed from the rate base.

A review of the JPS' audited financial statement showed that the isolated reduction in pension benefits is in the amount of US$4.575 and not US$4.520 as reported in the submission. The error is corrected by the OUR in approving the adjustment to payroll, benefits and training expenses. Table 6.34 below shows the extract from the financial report. Table 6.33 below shows the JPS' Payroll Analysis and Table 6.35 below shows the adjustment made by the OUR.

JPS stated that the test year figures for payroll costs were also increased by 5% to reflect the across-the-board salary increase granted to employees, which came into effect on January 1, 2014. In 2011, the company signed a three-year Heads of Agreement with all of its bargaining units which secured salary increases of 4%, 5% and 5% in 2012, 2013 and 2014 respectively for all its unionized employees.

The 5% increase was approved as an increase to the payroll cost. However, given that total payroll and related expenses are 100% incurred in local currency, the OUR computes the increase on the local equivalent as at 2013 using the average billing rate for the year 2013 as the conversion rate. Table 6.35 below shows the adjusted payroll analysis computed by the OUR.

Table 6.33: JPS' Payroll Analysis

JPS' Payroll Analysis				
(US$'000)	**Actual 2013**	**5% Wage Adjustment**	**Pension Benefit Adjustment**	**Adjusted 2013**
Payroll	53,038	2,652		55,690
Employee Benefits	5,919	296	4,520	10,736
Total Payroll and Related Expenses	58,957	2,948	4,520	66,426

Table 6.34: Extract from JPS' 2013 Audited Financial Report

Credit recognised in the statement of comprehensive income:	2013 $'000	2012 $'000
Current service costs Interest cost Interest income on assets Past service cost Refund to the Company	2,273 4,860 (9,209) (7,074)	2,196 5,015 (10,095) 6,645 (8,459)
Total credit	**(9,150)**	**(4,698)**
Net credit recognised due to limitation	**(4,575)**	**(2,349)**
Note: The credit is recognised in operating and maintenance, selling, general and administrative expenses in the statement of comprehensive income.		

Table 6.35: OUR's Adjusted Payroll Analysis

OUR's Adjusted Payroll Analysis								
	Actual 2013		**5% Wage Adjustment**		**Pension Benefit Adjustment**		**Adjusted 2013**	
	JA$'000	**US$'000**	**JA$'000**	**US$'000**	**JA$'000**	**US$'000**	**JA$'000**	**US$'000**
Payroll	5,370,400	53,038	268,520	2,397			5,638,920	55,435
Employee Benefits	599,332	5,919	29,967	268	**463,245**	**4,575**	1,092,544	10,762
Total Payroll and Related Expenses	5,969,732	58,957	298,487	**2,665**	**463,245**	**4,575**	6,731,464	66,197

6.3.5 Insurance Expenses

The proposed revenue requirement includes an adjustment to the test year insurance expense of US$1.36M which represents an impending 20% increase in insurance premiums. This impending increase, JPS stated, is primarily due to trends in the global insurance market for the power sector, increasing claims worldwide and the company's recent claim associated with damage to the combined cycle plant at Bogue, St. James.

JPS further mentioned that a key underwriter concern is machinery breakdown and the associated business interruption and that major power sector loss in 2013 have exceeded US$1.3B. JPS stated that the company was not immune to this challenging situation, given the loss on Steam Turbine 14 located at the Bogue Power Station, which rendered the unit out of service for four (4) months.

The company stated that given these facts, their broker has indicated that JPS' ability to obtain proper insurance at reasonable rates will be severely challenged in the next couple years and increases such as the one imminent will continue until the aging fleet is decommissioned.

In view of the foregoing explanation for which the evidence was provided in the form of insurance premium invoice, the 20% adjustment to insurance expenses is approved by the OUR.

6.3.6 Other Adjustments

The items listed in Table 6.36 below were adjusted to the operations and maintenance cost and removed from the line item materials and equipment cost in the revenue requirement. Further details on these adjustments are outlined in the depreciation discussions in Section 6.4.1 of this Chapter.

Table 6.36: Annual Fixed and Variable O&M Expenses Removed from the Revenue Requirement

Annual Fixed and Variable O&M Expenses Removed from the Revenue Requirement (US$)						
Plant	Gross Capacity (MW)	Reference CF	Fixed Charge (US$/kW-month)*1	Variable Charge (US$/kWh)*2	Annual O&M Fixed Cost	Annual O&M Variable Cost
GT#8	14	7.78%	1.1988	0.0227	201,395	216,378
GT # 11	20	4.06%		0.0385		273,608
Total					691,381	
*1 - Average of 2009 – 2013 fixed charge provided by JPS						
*2 - Average of 2009 – 2013 variable charge provided by JPS						

6.3.7 Third Party Services Costs

In accordance with the definition of non-fuel operating cost as provided in Schedule 3, paragraph 2(2) of the Licence, the third party services cost component of JPS' proposed non-fuel operating costs was assessed on the basis of the principle of known and measurable to ascertain that the constituent transactions costs represent legitimate expenditures and are reasonably incurred in connection with the Licensed Business.

6.3.7.1 JPS' Proposed Third Party Services Cost

According to the JPS' Tariff Submission, the proportion of the proposed Non-fuel Revenue Requirement (US464.368M) attributable to the operating costs is approximately 32%. Details of the proposed operating costs are provided in Table 6.37 below.

Table 6.37: JPS' Proposed Operating Costs

(US dollars thousands)	Audited Financials	Adjustments	Application
Operating Costs:			
Purchase Power Costs	104,110	-	104,111
O&M Expenses:			
Payroll, benefits & training	58,958	7,468	66,426
Third party services	25,830	-	25,830
Materials & equipment	8,544	-	8,544
Office & Other expenses	24,778	(1,250)	23,528
Insurance expense	6,811	1,362	8,174
Bad debt write-off	18,342	-	18,342
Total O&M Expenses	**143,265**	**7,580**	**150,845**

As shown, third party services is one of the major components of JPS' proposed operating costs with an amount of US$25.83M or 17% of the total O&M expenses. However, this particular O&M cost component was not appropriately addressed in the tariff application. This brings into focus the issue of known and measurable cost.

6.3.7.2 OUR's Review of JPS' Third Party Transactions

To ensure that the relevant regulatory requirements are satisfied, the OUR conducted a review and evaluation of JPS' proposed third party transactions as a means of identifying the types of costs included and the reasonableness of these costs.

The evaluation entailed the review of JPS' historical records of its third party transaction costs and the month-by-month cost data for 2013. This involved the examination of spreadsheets which contained the description and the actual cost of all the third party services that were procured by JPS. The review also focused on trends and anomalies in the expenses, as well as costs that were not related to the provision of electricity service, unregulated costs and O&M costs related to JPS-managed IPP assets.

The results and findings of the review of JPS' third party services cost data from January 1, 2013 to December 31, 2013 are detailed in the following sections.

6.3.7.3 Details of Third Party Services

It was found that the total third party services cost of US$25.83M was comprised of two main components, "third party contracted services" with an aggregate cost of US$15.477M and "third party services - not contracted" with a cost of US$10.353M.

The cost items related to "third party services – not contracted" were not clearly classified; however, it appeared that cost items such as security expenses, software expenses, among other items, were included. Despite such limitation, these costs were examined and found to be representative and appear to be reasonable.

With respect to the third party contracted services, the detailed cost data and analysis of cost items were provided by JPS.

The third party contracted services included the following cost items:

- Photographic Services
- Contract Services - third party contractors used for T&D related services (e.g. bushing & line maintenance, streetlight repairs, replacement of poles, etc.);
- Disconnection/Reconnection and Bushing Charges - payments to contractors conducting disconnection/reconnection and bushing activities;
- Repairs & Maintenance;
- Local Consulting Services - cost of local consultants for specialty projects (e.g. HR Services, Tax advisory services, etc.);
- Foreign Consulting Services - foreign consultants used primarily on I.S. related projects (e.g. Banner/Oracle) and Rate case filing;
- Related Party Fees - cost of foreign consultants/expatriates provided by the Parent Companies for JPS-related activities. These relate to the direct costs for persons working in Jamaica (no overhead charges are paid to the Parent Company);
- Contract Services (Local – Generation);
- Waste Disposal;
- Contract Services (Foreign – Generation) - cost of overseas consultants (primarily GE & Wartsila) used for generation maintenance projects; and
- Other Third Party Services.

These cost items were evaluated and the requisite adjustments made where necessary, to reflect known and measurable changes.

Contract Services

Based on JPS' third party cost data, the cost of contract services (cost item #305 & 360) was US$2.875M at December 31, 2013. However, the OUR's examination of the cost data identified a number of questionable transaction costs that must be segregated from JPS' annual O&M expenses to be incorporated in the revenue requirement. These include transactions that are related to:

- EStore – JPS' unregulated business but associated costs were not appropriately allocated to unregulated EStore accounts;
- JPS Munro Wind Farm – JPS-managed IPP asset but costs associated with the operation of the plant were inappropriately assigned to JPS' utility O&M expenses;
- Maggotty Hydro (6.3MW) – JPS-managed IPP asset but costs incurred during plant construction were improperly assigned to JPS' utility O&M expenses;

- Costs items that are not directly or indirectly related to the provision of electricity service by JPS; and
- Non-recurring costs items.

The aggregate cost of these items amounted to US$240,555.

According to Condition 2, paragraph 7 of the Licence:

"The Licensee may engage in any other business but no profits or losses resulting therefrom shall be taken into account in the fixing of rates for the Licensed Business and shall therefore keep separate accounts for the Licensed Business as directed by the Office in accordance with Condition 5 paragraph 2."

Based on the regulatory instruments for dealing with JPS-managed IPP assets and its unregulated businesses, cost of Third Party Services related to Munro Wind Farm, JPS' Maggotty Hydro (6.37 MW) and JPS' EStore were NOT ALLOWED and therefore were excluded from JPS' proposed annual O&M expenses for the revenue requirement of its Licensed Business.

On the basis of the principle of known and measurable, and reasonable and prudently incurred costs, the other questionable expenses were also NOT ALLOWED and therefore were excluded from the Third Party Contract Services costs and the JPS' proposed annual O&M expenses.

Photographic Services

Based on JPS' third party cost data, the cost of photography services (cost item #308) was US$36,201 at December 31, 2013. However, the OUR's examination of the cost data identified a number of questionable photography transaction costs that should not be included in JPS' annual O&M expenses for the purpose of the revenue requirement. These include transactions that are related to:

- Provision of Audio & Video Services not connected to the provision of regulated electricity service;
- JPS' EStore – not connected to JPS' Licensed Business; and
- Services – not connected to the provision of the regulated electricity service.

The aggregate cost of these transactions was US$8,777. Applying the principle of reasonable and prudently incurred costs, these expenses were NOT ALLOWED and therefore were excluded from JPS' Photographic Services costs and its proposed annual O&M expenses for the revenue requirement.

Local Consulting Services

Based on JPS' third party cost data, the cost of local consulting services (cost item #370) was US$276,440 at December 31, 2013. However, the OUR's examination of the cost data revealed that a significant component of this cost was related to a street light audit conducted jointly by JPS and the local authorities in 2013. These street light audit costs were considered to be reasonable and necessary but were not allowed as an annual cost on the basis that a street light audit of that scale and scope is not undertaken by JPS annually. On the basis of fair allocation of costs, these expenses were apportioned evenly over the price cap period.

The allocation of the referenced costs in addition to adjustments for known and measurable costs resulted in the exclusion of costs totalling US$70,964 from JPS' Local Consulting Services and its proposed annual O&M expenses for the revenue requirement.

Foreign Consulting Services

Based on JPS' third party cost data, the cost of foreign consulting services (cost item #372) was US$595,972 at December 31, 2013. However, the OUR's examination of the cost data revealed that a significant portion of the cost of these services was in connection with consulting fees related to JPS' 2014-2019 rate case and the cost of specific annual benchmark studies. The consulting fees related to 2014-2019, in particular, were not allowed as annual costs on the basis that a rate review, according to the Licence, takes place every five (5) years. On the basis of fair allocation of costs, expenses related to Foreign Consulting Services for the present rate case were appropriately distributed over the price-cap period.

The allocation of the referenced costs, together with adjustments for known and measurable costs resulted in the exclusion of costs totalling US$299,517 from JPS' Foreign Consulting Services and its proposed annual O&M expenses for the revenue requirement.

Related Party Services

Based on JPS' third party cost data, related party fees (cost item #385) was US$3.688M at December 31, 2013. However, the OUR's examination of the cost data identified a number of questionable transactions that represent a significant portion of the third party contracted services costs. These include transactions related to:

- EWP Management Fees – US$208,000 per month (US$2.5M per year);
- EWP Secondment Fee – US$19,800 to US$22,000 per month; and
- Expenses for EWP and Marubeni Expats.

The notes in the financial statements in JPS' 2013 Annual Report state that the company had various transactions with related companies. According to the notes, these included the provision of technical support and related professional services.

These transactions included charges from EWP (Barbados) 1 SRL of approximately US$3.3M and charges to MaruEnergy JPSCo 1 SRL and EWP (Barbados) 1 SRL of approximately US$1.6M.

Transactions related to EWP (Barbados) 1 SRL

Of the US$3.3M referred to above, US$2.5M related to an "O&M Services Support Agreement" which JPS had entered into with EWP (Barbados) 1 SRL. This agreement was signed on 26th July 2011 and was effective for five (5) years. The terms of this agreement appeared to focus on the provision of certain services which included the review of the O&M methods and practices used by JPS at its Generation and T&D divisions. According to the contract, the review shall include the following:

- Loss reduction programme
- Operations
- Maintenance
- Cost structure and capital productivity
- T&D and generating unit protection
- Commercial availability of generation and T&D assets
- Project Management
- Annual department business plans
- Industry best practices
- Performance Measures
- Environmental, Health and Safety

The "service fee" is US$2.5M per annum payable in four quarterly instalments of US$625,000 per annum. The agreement also stipulated that JPS shall not be responsible for the payment to EWP (Barbados) 1 SRL) or the salaries of the its Secondees or any related income, social security or unemployment taxes, workers' compensation costs or other benefits and expenses.

A review of the terms and conditions of the agreement suggests that the nature of the agreement reflects that of a "call-off" contract rather than one with specific deliverables and milestones. However the cost associated with the agreement is fixed.

It is understood that there are EWP personnel currently seconded to JPS under the agreement to provide technical support and also to identify opportunities where further support can be provided. However, there is no specific information indicating that the prescribed O&M services are being delivered.

According to the audited statements, during 2013 the amount of US$2M owing to EWP (Barbados) 1 SRL for charges under this contract, was converted to a loan bearing at the rate of 11% per annum. The notes to the accounts, indicated that the loan is unsecured which does not have a fixed repayment date and interest is payable every quarter.

Given the lack of specificity in the support services to be provided by EWP and the apparent absence of appropriate measurements and metrics to evaluate performance under the agreement, the

OUR is not convinced that such support facility will be effective in delivering the expected performance improvements. Notably, the agreement has been operational for over three years now. However, improvements in critical areas such as system losses and service reliability remain questionable. Coincidentally, since the execution of the agreement an apparent downward trend in system losses was reversed and losses have been increasing steadily since. It is also important to note that based on the effective date of the agreement, there is less than two (2) years remaining in the initial term of five (5) years. This implies that if the annual service fee is allowed in the O&M expenses, the cost will be carried in the revenue requirement annually to the end of the price cap period in 2019 which would not be appropriate.

Based on the OUR's review of the O&M Services Support Agreement, the service fee for EWP (Barbados) 1 SRL to provide O&M services support to JPS is not considered to be a reasonable and prudent cost incurred in connection with the operation and maintenance of JPS' generation, transmission and distribution and supply facilities in the provision of electricity service to its customers. As such, this cost was NOT APPROVED and therefore was excluded from JPS' proposed costs annual O&M expenses for the revenue requirement. Nevertheless, the OUR is prepared, to accommodate effective efficiency improvement projects put forward by JPS under the EEIF programme.

In addition to the service fee of the "O&M Services Support Agreement", the related party transactions for 2013 also included costs defined as EWP Secondment Fee Reimbursement for two months in 2012 and costs that appeared to be duplicated which together amounted to US$83,000. Based on the principle of known and measurable, these related party services costs were NOT APPROVED and as such were excluded from JPS' Related Party Services costs and proposed annual O&M expenses.

As a result of the review, Related Party Services costs totalling US$2,583,600 were NOT APPROVED and therefore were excluded from JPS' proposed annual O&M expenses for the revenue requirement.

Contract Services (Local – Generation)

Based on JPS' third party cost data, generation services executed under local contract (cost item #387) valued US$2.578M at December 31, 2013. However, the OUR's examination of the cost data revealed that there were improper assignment of costs related to JPS' managed IPP assets, JPS Munro Wind Farm and Maggotty Hydro (6.3 MW) that must be separated from JPS' annual O&M expenses for provision of electricity services.

These IPP-related costs along with other non-recurring costs included in the cost data amounted to US$117,567. Based on the regulatory instruments for dealing with the costs of JPS' managed IPP and the application of the principle of known and measurable, these cost items were NOT

ALLOWED and therefore were excluded from JPS' Contracted Services (Local – Generation) and the company's proposed annual O&M expenses for the revenue requirement.

Contract Services (Foreign – Generation)

Based on JPS' third party cost data, the cost of generation services carried out under foreign contract (cost item #390) was US$424,724 at December 31, 2013. However, the OUR's examination identified a number of questionable costs that were considered to be non-recurring, not known and measurable costs as well as costs of maintenance activities associated with Bogue CCGT which occurred during the period of the major overhaul and turbine rotor repair and should have been accounted for under those activities. These costs combined, amounted to US$55,488.

Based on the principle of known and measurable and prudently incurred costs, these cost items were NOT ALLOWED and were therefore excluded from JPS' Contract Services (Foreign – Generation) the company's proposed annual O&M expenses for the revenue requirement.

Other Third Party Services

Based on JPS' third party cost data, the cost of other third party services (cost item #399) was US$1.255M at December 31, 2013. However, the OUR's examination of the cost data identified a number of questionable transaction costs that should not be included in JPS' annual O&M expenses to be incorporated in the revenue requirement. These include transactions that are related to:

- EStore – JPS' unregulated business.
- Duplication of costs
- Costs items that are not directly or indirectly related to the provision of electricity service by JPS.
- Certain one-time costs that were spread over the price-cap period.

The aggregate cost associated with these transactions was US$62,088. On the basis of known and measurable and prudently incurred costs, these costs were NOT ALLOWED and therefore were excluded from Other Third Party Contracted Services cost and JPS' annual O&M expenses for the revenue requirement.

Summary of Third Party Contracted Services Costs for JPS' Revenue Requirement

A summary of the Third Party Contract Services cost analysis is provided in Table 6.38 below.

Table 6.38: Third Party Contracted Services Costs for JPS' Revenue Requirement

COST ITEM	ITEM#	JPS 2013 COST	OUR APPROVED	AMT REJECTED
CONTRACT SERVICES	305&360	2,875,424	2,634,869	240,555
PHOTOGRAPHIC SERVICES	308	36,201	27,424	8,777
DISCON/RECON AND BUSHING CHARGES	367	3,726,317	3,726,317	0
REPAIRS & MAINTENANCE	369	9,764	9,764	0
LOCAL CONSULTING SERVICES	370	276,440	205,476	70,964
FOREIGN CONSULTING SERVICES	372	595,972	296,454	299,517
RELATED PARTY FEES	385	3,687,918	1,104,318	2,583,600
CONTRACT SERVICES (LOCAL) - GENERATION	387	2,578,459	2,460,891	117,567
WASTE DISPOSAL	389	10,985	10,985	0
CONTRACT SERVICES (FOREIGN) - GENERATION	390	424,724	369,236	55,488
OTHER 3RD PARTY SERVICES	399	1,254,775	1,192,686	62,088
TOTAL		**15,476,979**	**12,038,420**	**3,438,559**

As shown in Table 6.38, Third Party transaction costs totalling US$3.44M were NOT APPROVED and were therefore excluded from JPS' proposed Third Party Contracted Services costs and proposed annual O&M expenses for the revenue requirement on the grounds that they are not O&M expenses that will be prudently or reasonably incurred in furnishing normal electric utility service and in maintaining electric plant used by and useful to the company in providing such service to the Jamaican public.

As a result of the review, the Third Party Contracted Services costs ALLOWED by the Office are US$12.04M and the total Third Party Services costs APPROVED for inclusion in JPS' annual O&M expenses and the revenue requirement is **US$22.391M.**

6.3.8 Net Finance Costs

JPS stated that its test year net finance costs of US$14.2M included US$5.7M in interest costs associated with the low levels of working capital and US$4.8M for amortization of debt issuance costs which is an increase over previous years. The company indicated that the main driver of the increase is the increase debt issuance costs and interest charges on bank overdraft. The working capital costs relate to bank overdraft charges and supplier interest charges which became necessary as a result of the high levels of government receivables, the main reason for the low levels of normal working capital.

The OUR is of the view that the 2013 levels of bank overdraft and debt issuance costs is not the norm and should not persist throughout the 2014-2019 rate cap period. It is expected that JPS will prudently manage its accounts. The level of dependence on bank overdrafts for working capital support, and supplier interest charges, should be significantly reduced to acceptable levels.

JPS stated that its increasing debt issuance costs come from a higher proportion of export credit agency funding in its debt mix. Such funding it is stated has lower interest rates but higher debt issuance up-front fees. The OUR believes that improvements can be made to the mix of loan funding in order to achieve a reduction in the 2013 cost level.

In this regard, the average over the past five (5) years was used as the deemed cost on these two line items. Table 6.39 below shows details which result in an adjustment of US$3.7M to bank overdraft cost and US$1.6M to debt issuance costs and expenses.

Table 6.39: Bank Overdraft and Debt Issuance Costs and Expenses

US$'000	2013	2012	2011	2010	2009	Average 2009-2013	Adjustments
Bank overdraft and other	5,721	1,740	1,085	834	570	**1,990**	3,731
Debt issuance costs and expenses	4,829	3,636	3,329	2,679	1,534	**3,201**	1,628

6.3.9 Foreign Exchange (FX) Losses

The test year financial results presented by JPS show that the net financial impact of foreign exchange losses was US$21M. This amount was adjusted to US$14M in the proposed revenue requirement and JPS stated that this is to ensure that the amount included reflects normal operating conditions. The US$7M reduction in the amount to US$14M was said to reflect JPS' estimate as to what the rate of devaluation will be during 2014 and its impact on JPS in that year. JPS also mentioned that FX losses were not included as a recoverable expense in the 2009 rate review.

JPS argued that the company has been experiencing significantly higher levels of FX losses over the last three (3) years mainly as a result of the volatility in the foreign exchange markets and inadequate provisions in the regulatory framework to mitigate these losses.

Foreign exchange risk is inherent in the Jamaican market and evidently was a factor since the privatization of the utility company. Consistent with previous tariff determinations, careful consideration was given to the realities, treatment and the allocation of all risks both systematic and non-systematic. In this regard, the proposed inclusion of the US$14M in the revenue requirement is disapproved by the OUR. This is discussed further in Chapter 8 (Foreign Exchange Adjustment Mechanism)

JPS' proposed test year operating costs totalled US$281.3M. Taking account of the foregoing adjustments, the operating costs to be included in the revenue requirement is the total amount of US$258.83M and is approved by the OUR. Table 6.310 below shows the details of the approved amounts.

Table 6.310: OUR's Approved Test Year Operating Costs

Approved Test Year Operating Costs All amounts in US$'000s								
Items	**Actual Costs**		**JPS Pro.**	**JPS Prop. Adj.**		**OUR App.**	**OUR App.Adj.**	
Purchased Power Costs		**104,111**			**104,111**	**-**		**104,111**
Operating Expenses:		**143,264**	**7,580**		**150,844**	**66,198**		**147,736**
Payroll, benefits & training	58,958		7,468	66,426		7,240	66,198	
Third party services	25,830		-	25,830		(3,439)	22,391	
Materials & equipment	8,544		-	8,544		(691)	7,853	
Office & Other expenses	24,778		(1,250)	23,528		-	24,778	
Transportation expenses	-		-	-		-	-	
Insurance expenses	314		1,362	1,676		1,362	1,676	
Bad debt write-off	4,170		-	4,170		-	4,170	
Total Operating Expenses		**247,375**	**7,580**		**254,955**	**4,472**		**251,847**
Net Finance Costs:		**14,645**	**(2,307)**		**12,338**	**(7,666)**		**6,979**
Interest on Short-term Loans	1,403		-	1,403		-	1,403	
Interest rate swap	1,232		(1,232)	-		(1,232)	-	
Preference dividends	1,075		(1,075)	-		(1,075)	-	
Interest on customer deposits	549		-	549		-	549	
Bank Overdraft Interest Other	5,721		-	5,721		(3,731)	1,990	
Interest Income	(1,615		-	(1,615)		-	(1,615	
Debt issuance costs and expenses	4,829		-	4,829		(1,628)	3,202	
Interest Capitalized during	1,450		-	1,450		-	1,450	
Foreign Exchange Losses		**21,114**	**(7,114)**		**14,000**	**(21,114)**		**-**
TOTAL OPERATING COSTS		**283,134**	**(1,841)**		**281,293**	**(24,307)**		**258,827**

6.4 Depreciation

Condition 2, paragraph 3 of the Licence provides as follows:

"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."

In meeting this critical requirement, JPS from time-to-time, will have to invest in generation plants, T&D systems and other equipment needed to provide reliable electricity service to the country.

JPS' utility operations is a highly regulated business, as such, the OUR sets the rates that JPS charges its customers for electricity service. In accordance with its legal and regulatory remit, the OUR functions to ensure that an efficient and reliable electricity service is delivered to JPS' customers while at the same time allowing the company to reasonably recover its "cost of service" and also providing an opportunity for the company to earn a reasonable rate of return on its invested capital. Among the items included in the cost of service are operations and maintenance (O&M) costs, depreciation expense, income tax expense and fuel costs.

6.4.1 Definition

In public utility regulation, depreciation is generally defined as the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in demand and requirements of public authorities.

Depreciation, as used in the accounting sense, is a means of distributing the cost of assets less net salvage value (if any), over the estimated useful life of the assets in a systematic and rational manner. Each annual amount of such depreciation expense is part of that year's total cost of providing the utility service.

6.4.2 JPS' Depreciation Proposal

In JPS' Tariff Submission, the company proposed a total depreciation expense of US$57.5M. This proposal is comprised of:

1) Depreciation expense of US$49.17M obtained from the 2013 audited financials which was based on the useful lives specified in Schedule 4 of the Licence; and

2) An adjustment of US$8.33M derived based on recommended asset lives obtained from JPS' depreciation study which was conducted by KPMG.

According to JPS, the depreciation study was commissioned in 2013 to review the useful lives of asset classes based on industry best practice and to analyse the actual age of JPS' assets at retirement. KPMG concluded that the current asset lives indicated in the Licence were in several instances longer than the actual economic useful lives of those assets. They recommended the adjustments shown in Table 6.41 below to the current asset lives used to determine depreciation rates.

Table 6.41: KPMG's Recommended Asset Life

Activity	Asset	Current Life	Recommended Life
Generators	Steam production plant	25	25
	Hydro production plant	35	35
	Diesel generator	25	25
	Gas turbine	24	24
Transmission	Control gear/Switchgear	20	25
	Transformer	20	25
Distribution	Overhead mains	30	30
	Underground mains	30	30
	Meters	30	15
	Street lights	30	20
	Test equipment	25	15
	Supervisory control systems	25	25
General Plant	Electronic equipment	25	10
	Communication equipment	15	5
	Computer equipment	20	6
	Furniture and office equipment	20	10
	Vehicles	7	4
	Land-leasehold	50	50
	Buildings	50	50
Extracted from: JPS 2014-2019 Tariff Application			

JPS posited that if the asset lives were adjusted according to KPMG's recommendation then there would be an additional amount of test year depreciation of US$8.33M as shown in Table 6.42 below and the adjusted test year depreciation would be US$57.5M.

Table 6.42: JPS' Proposed Additional Depreciation due to Asset Life Adjustment

Category	Asset	Current Life (per Licence)	Recommended Life	Change In Annual Depreciation Charge
Distribution Plant	Meter	30	15	1,186,127
Distribution Plant	Street-light	30	20	172,890
General Plant	Electronic Eqpt (Lab Eqpt)	25	10	353,237
General Plant	Communication Eqpt	15	5	3,631,417
General Plant	Computer Equipment	15	6	2,763,109
General Plant	Furniture & Office Eqpt	20	10	192,060
General Plant	Vehicles	7	4	31,138
				8,329,978
Extracted from: JPS 2014-2019 Tariff Application				

In JPS' Tariff Submission, JPS requested that OUR accepts the recommendation of the depreciation study commissioned by JPS. According to JPS, the above additional amount should be included as a known and measureable adjustment to the depreciation expense. JPS indicated that it believes that US$57.5M is still a conservative estimate as to what it would cost to fund the annual capital expenditure needs of the business over the next three (3) years given the existing aged generation plant.

6.4.3 Regulatory Treatment of Depreciation

The regulatory treatment of the depreciation component of JPS' Non-Fuel Revenue Requirement is outlined in Schedule 3, paragraph 2(C) of the Licence which has been set out under the Legal and Regulatory Framework above.

6.4.3.1 Depreciation Calculation

The basis for the calculation of the annual depreciation expenses to be included in the non-fuel revenue requirement is set out under the said Schedule 3, paragraph 2(C) of the Licence which has been set out under the Legal and Regulatory framework above.

Additionally, Condition 15, paragraphs 4 and 5 of the Licence provides as follows:

"4. Provisions for depreciation shall be maintained separately for the following classes of property:

(1) each generating plant shall be subdivided into original plant existing at the date of this Licence and each additional generating unit;

(2) the Transmission System as a whole;

(3) the Distribution System as a whole;

(4) general property classified as follows:

(i) automotive equipment
(ii) buildings
(iii)other equipment

For annual depreciation expense purposes when the amount accumulated in the depreciation reserve applicable to a generating plant or unit is equal to its book value (depreciable property only) the generating unit or plant shall be considered as retired for the purpose of annual depreciation accruals.

The foregoing classification may be altered from time to time by the Office in consultation with the Licensee.

5. Annual depreciation allowance shall be computed by applying reasonable annual straight line depreciation rates to the value of property, plant and equipment stated at book value. The Office shall satisfy itself as to the reasonableness of the applicable depreciation rates; and from time to time determine the adequacy of the depreciation reserves and the reasonableness of the lives used, provided that in respect of the items of plant and equipment listed in Schedule 4 to this Licence, the

Office shall not establish depreciation rates lower than the respective rates set out in the said Schedule without consulting the Licensee."

6.4.4 Review of JPS' Test Year Depreciation Expense

6.4.4.1 Test Year Depreciation

Test year depreciation expenses of US$49.17M were presented by JPS as the annual depreciation expenses calculated in accordance with Schedule 4 of the Licence representing a portion of the proposed amount to be included in the Non-Fuel Revenue Requirement.

6.4.4.2 Old Harbour Steam Unit#1 - Retirement

Old Harbour steam unit #1 (OH#1) was declared retired with zero asset value at January 1, 2013. OH#1 was commissioned in 1968 and despite scheduled maintenance for interim and major overhauls by JPS to improve performance and durability, the unit has exceeded its useful life and considered to be very inefficient. Additionally, the unit was forced out of service since August 2008 due to a major failure of critical components rendering it not used and useful for the entire 2009 to 2014 price cap period. In this regard, the decision by JPS to retire the unit and remove its residual value from the asset base is appropriate and consistent with the Licence, acceptable accounting principles and prudent utility practice.

6.4.4.3 Hunts Bay GT#4 – Residual Cost

Hunts Bay GT#4, although being out of service for more than ten (10) years and denoted as 'retired' in JPS' "Fixed Asset Summary December 2013", still carried an asset value of US13,878 at January 1, 2013. This value generated an annual depreciation charge of US$360 which was included in the test year depreciation expense and JPS' proposed revenue requirement. This depreciation charge was NOT APPROVED and as such was excluded from JPS' test year depreciation expenses.

6.4.4.4 Bogue GT#8 – Out of Service

The test year depreciation expenses included an annual depreciation charge of US$116,266 for Bogue GT#8 calculated based on the unit's asset value of US$8,888,656 at December 2013. However, the unit was not in service for the entire twelve (12) months of the test year and therefore was not involved in the production of electricity during the period.

JPS' monthly technical reports, monthly fuel rate calculation documents and plant capability reports submitted with daily dispatch data to the OUR by JPS indicated that the Bogue GT#8 has been out of service since December 20, 2011. A status report on the unit was requested by the OUR on May 7, 2014. JPS responded on May 15, 2014 and stated the following:

"GT8 - out of service since December 20, 2011 – On Reserve shutdown, gas generator repairs being assessed."

In Chapter 12 of JPS' Tariff Submission (pages 279-281), the performance projections including generating units' net generation and heat rate indicate that Bogue GT#8 is planned to be out of service for the remainder of 2014 and for the entire price-cap period 2015 - 2019.

Notably, Bogue GT#8 was commissioned in 1992, and according to Schedule 4 of the Licence, the average life of the unit is twenty four (24) years with an average depreciation rate of 4.2% (refer to Figure 6.41 below).

According to JPS' fixed asset summary, the accumulated amount in the depreciation reserve applicable to Bogue GT#8 at December 31, 2013 is US$8,840,347 while its book value is US$8,888,656, translating to a net book value of US$48,309.

Based on the net book value and average life of Bogue GT#8 to date, the OUR considered this generating unit retired for the purpose of annual depreciation accruals for the price-cap period 2014-2019. Accordingly, no depreciation charge was allowed and the remaining asset value excluded from the rate base. The annual O&M cost for the unit was also subtracted from the Non-Fuel Revenue Requirement.

In a report entitled, "Update on GT8 and GT11" dated August 14, 2014, from JPS to the OUR, the company stated the following regarding Bogue GT#8:

"We agree GT8 has gone its useful life since 1992 and should not likely be returned to service. We believe this exclusion is just at this time. Any plans to retool this unit after gas has been materialized at Bogue would therefore be discussed with the OUR to obtain your agreement."

Given the condition that depreciation charges should apply to plant in service, and importantly, the principle of "used and useful" in relation to JPS' generating plants during the new price-cap period, the annual depreciation charge of US$116,266 calculated by JPS for Bogue GT#8 was NOT APPROVED and as such was excluded from JPS' test year depreciation expenses.

Figure 6.41: Depreciation for JPS' GT Units According to Schedule 4 of the Licence

Fixed Assets Detail for Power Generation

OTHER PRODUCTION PLANT (GT)

Retirement Units	% of Total Asset	Est. Life (Yrs.)	W. Avg. Life
ENGINE	43.2%		
Air Intake & Compressor System	19%	25	2.5
Turbine			
Stationary Blades	3%	10	0.3
Rotor Blades	5%	10	0.5
Rotor Shaft	3%	30	1.0
Casing	3%	30	1.0
Fuel and other Auxiliaries	6%	20	1.3
Combustion Chamber	12%	15	1.7
GENERATOR &ACC.	19.7%		
Excitation system	2%	20	0.5
Rotor	5%	30	1.4
Stator	7%	10	2.2
Casing	5%	30	1.4
Balance of Plant	1%	20	0.1
ELECTRICAL SYSTEMS	17.0%		
Stepup Transformer	3%	25	0.6
Switchgear and electrics	4%	25	1.1
Motor Control Center	4%	15	0.6
Balance of Plant	6%	25	.5
INSTRUMENT AND CONTROL	7.7%		
Instrument and Controls	8%	10	0.8
STRUCTURES AND IMPROV.	12.4%		
Foundations for Plant	11%	50	5.3
Cranes and other equipment	1%	25	0.3
Fire Protection System	1%	10	0.1
AVERAGE LIFE			24
AVERAGE DEPRECIATION RATE	4.2%		

6.4.4.5 Bogue GT#11 – Out of Service

The test year depreciation expenses included an annual depreciation charge of US$743,793 for Bogue GT#11 calculated based on the unit's asset value of US$16,059,784 at December 2013. However, the unit was not in service for the entire twelve (12) months of the test year and therefore was not involved in the production of electricity during the period.

JPS' monthly technical reports, monthly fuel rate calculation documents and plant capability reports submitted with daily dispatch data to the OUR by JPS indicated that the Bogue GT#11 has been out of service since September 2012. A status report on the unit was requested by the OUR on May 7, 2014. JPS responded on May 15, 2014 and stated the following:

"GT11 - out of service since September 19, 2012 – On Reserve shutdown, combustion components and free turbine repairs being assessed"

In Chapter 12 of JPS' Tariff Submission (pages 279-281), the performance projections including generating units' net generation and heat rate indicate that Bogue GT#11 unit is planned to be out of service for the remainder of 2014 and for the entire price cap period – 2015 to 2019. This projection of non-utilisation of the asset over the specified price-cap period does not warrant the allowance of annual depreciation charges and return on investment.

In a report entitled, "Update on GT8 and GT11" dated August 14, 2014, from JPS to the OUR, the company reported the following regarding Bogue GT#11:

"GT11 is a recently acquired (2001) and very efficient peaking unit in our fleet and is best suited to run on gas and will definitely be restored to service when our financial health permits (likely in early 2016). This unit will cost approximately $6M to return to service and was not repaired in 2013 primarily due to our financial constraints that prevented us from financing same, bearing in mind the $42M fuel penalty we experienced in 2013 and $30M penalty in 2012. The fuel penalty is a real cash burden on JPS and is causing severe financial harm to the business whereby we have not been able to finance all of the expenses of the business and due to our loan covenant challenges; we cannot take any additional borrowings.

… "GT11 is a Pratt & Whitney FT8 20 MW unit, installed at Bogue in 2001. It is the most efficient simple cycle gas turbine in our fleet. It also has the capability to burn gas at an even better heat rate and lower O&M cost (rivalling that of the CC Plant).

GT11 was taken out service Sept. 2012 due to severe hot corrosion to Combustion, Hot Gas parts and GSU issues. Restoration of this unit to service would require:

- *Major Overhaul of the Gas Generator (GG)*
- *Major Overhaul of the Power Turbine (PT)*
- *Replacement of obsolete controls*
- *GSU oil processing (possible transformer replacement)*
- *Generator and auxiliary equipment inspection/servicing*

Based on the above factors, we sincerely hope you can appreciate the importance of keeping GT11 in the rate base and depreciation expense (i.e. revenue requirement) to ensure the business is able to achieve its return of capital and be able to finance the repair (CAPEX) going forward…"

The situation regarding Bogue GT#11 as described by JPS above raises the following concerns:

- The update does not appear to provide any indication of a firm and definitive restoration plan and a specific timeline for the unit to return to service. As indicated by JPS, the restoration of the unit is contingent on its financial health which does not give any assurance that the unit will return to service in 2016. Furthermore, the update does not provide any certainty that the unit will return to service during the price-cap period 2014-2019.

- The decision not to repair the unit up to December 31, 2013 was a business decision taken by the management of JPS.

- The scope of the damage to the unit appears to be extensive and a complete replacement or rebuild of critical plant components may be required for restoration. This has cost and time implications which were not appropriately addressed by JPS.

- The issue of whether damage to equipment was due to faulty component design or manufacturing or due to improper operation and maintenance practices.

- It is unclear whether or not the reported damage to the unit can be addressed by insurance.

While JPS' statements regarding the flexibility and favourable operating characteristics of Bogue GT#11 as a peaking unit is noted, it must be recognised that the fundamental principles of "known and measureable" and "used and useful" are crucial requirements in the regulatory treatment of depreciation of utility assets. It is also important to note that the future economic benefits embodied in an asset are consumed by an entity primarily through its use.

With respect to the actual use of Bogue GT#11 over the past years, JPS' historical generation data on plant utilization levels indicates marginal usage of the unit compared to the other GTs in the System despite having relatively lower marginal cost and placed above the other GTs in the merit order. Given the cost characteristics of Bogue GT#11, from an economic perspective, the extended outage of the unit has implications for the cost of generation and electricity rates, particularly during the peak periods. Notably, this situation may have contributed to the imposition of higher electricity costs on electricity customers due to the extended use of less cost-efficient GT generating units.

The prolonged unavailability (out of service for the past 28 months) of Bogue GT#11 raises another crucial concern whereby the operational profile of the unit does not accord with the requirement of a relevant asset as set out under Condition 6, paragraph 1(c) of the Licence:

> *"relevant asset" means:*
>
> *"(c) any Generation Set owned by the Licensee that is used at a capacity factor greater than ten (10%) percent in each year of the most recent (3) years."*

The average monthly capacity factors for JPS' GT units for the period July 2011 to June 2014 are provided in Table 6.43 below. As shown, the highest monthly capacity factor for Bogue GT#11 achieved over the three (3)-year period was 4.06% in September 2011 with the unit out of service for more than 65% of the time. The utilisation of the asset as shown does not satisfy the condition of a relevant asset as defined by the Licence. The data also indicates that the unit is largely unavailable and minimally used in the generation of electricity to meet JPS' electricity customers' demand. As such, the unit was not considered to be a useful and functional asset for the purpose of depreciation accruals.

Table 6.43: Capacity Factor for JPS' GT units for the period July 2011 to June 2014

	Monthly Capacity Factor of Open Cycle GTs July, 2011 - June, 2012											
	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12
GT5	6.97%	10.96%	28.23%	17.42%	17.84%	11.68%	27.32%	17.51%	16.63%	16.63%	32.79%	42.08%
GT10	20.66%	20.43%	49.80%	39.20%	38.58%	23.88%	41.05%	11.58%	30.57%	28.05%	43.37%	53.62%
GT3	7.92%	2.26%	11.56%	10.52%	17.69%	4.11%	17.82%	7.56%	9.62%	5.95%	18.87%	32.46%
GT6	9.55%	5.34%	14.95%	14.31%	9.71%	4.07%	10.13%	4.68%	4.73%	6.58%	11.07%	17.71%
GT7	0.95%	2.42%	6.42%	2.85%	4.17%	1.06%	4.85%	3.17%	4.04%	1.71%	5.61%	12.43%
GT8	5.63%	3.75%	5.83%	7.78%	4.61%	O/S	O/S	O/S	O/S	O/S	O/S	O/S
GT9	O/S	O/S	15.42%	16.05%	13.12%	6.29%	16.40%	9.80%	9.66%	6.75%	14.56%	24.06%
GT11	1.13%	O/S	4.06%	1.01%	1.06%	O/S	1.63%	0.44%	0.96%	0.03%	0.67%	3.91%

	Monthly Capacity Factor of Open Cycle GTs July, 2012 - June, 2013											
	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
GT5	23.04%	7.73%	6.47%	10.68%	5.48%	2.76%	4.89%	4.61%	8.36%	9.81%	15.97%	10.28%
GT10	34.68%	15.95%	16.87%	17.91%	11.81%	8.44%	11.96%	9.43%	19.33%	16.62%	21.00%	18.56%
GT3	14.41%	5.10%	2.81%	7.22%	1.03%	0.55%	0.87%	0.96%	2.58%	4.44%	5.73%	8.86%
GT6	6.70%	3.62%	1.83%	2.01%	1.25%	2.02%	3.24%	1.75%	4.04%	3.18%	5.42%	4.40%
GT7	2.11%	1.60%	1.44%	4.54%	2.18%	1.37%	2.93%	2.41%	3.82%	0.91%	O/S	O/S
GT8	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S
GT9	12.47%	6.65%	3.60%	6.09%	6.40%	2.93%	0.36%	O/S	2.61%	4.18%	6.23%	5.83%
GT11	1.25%	O/S	0.02%	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S

	Monthly Capacity Factor of Open Cycle GTs July, 2013 - June, 2014											
	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14
GT5	9.81%	11.90%	28.21%	17.02%	17.16%	5.55%	5.34%	6.42%	11.63%	12.90%	3.10%	3.00%
GT10	14.29%	17.27%	39.19%	24.99%	21.03%	8.81%	10.83%	12.56%	20.20%	23.35%	19.60%	18.71%
GT3	5.93%	6.32%	16.50%	9.85%	9.73%	1.42%	0.49%	2.95%	4.68%	6.35%	6.22%	7.27%
GT6	4.35%	4.36%	6.77%	0.16%	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S
GT7	O/S	O/S	O/S	6.02%	6.20%	1.06%	0.90%	2.75%	3.96%	6.08%	4.99%	6.53%
GT8	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S
GT9	6.18%	6.48%	11.81%	7.82%	7.21%	1.84%	1.71%	5.62%	6.37%	1.89%	2.40%	7.31%
GT11	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S

Having regard to the applicable regulatory principles, allowing the pass-through of depreciation charges for JPS' Bogue GT#11, which has been out of service for twenty eight (28) consecutive months to date without any demonstrable basis, evidence or indication of a firm and comprehensive plan on when the plant will return to service, would not be considered reasonable and prudent.

Given the condition that depreciation charges should apply to plant in service, and importantly the principle of "used and useful" in relation to JPS' generating plants during the new price-cap period, the annual depreciation charge of US$743,793 calculated by JPS for Bogue GT#11 was NOT APPROVED and as such was excluded from JPS' test year depreciation expenses.

6.4.4.6 Bogue CCGT – HGPI, Turbine Repair, and Major Overhaul

A capital amount of US$13,679,658 was added to the January 1, 2013 book value of the Bogue CCGT unit of US$149,009,583 bringing the total asset value as at December 31, 2013 to US$162,689,241.

According to JPS' Fixed Asset Register the constituents of the capital addition of US$13,679,658 and depreciation details are as shown in Table 6.44 below.

Table 6.44: Capital Addition to Bogue CCGT Book Value - January 1, 2013

ITEM	Life (year)	Cost (US$)	Dep. Reserve (US$)	Net Book Value (US$)
MAJOR OVERHAUL BOGUE STEAM TURBINE#14	5	8,756,219	-	8,756,219
BOGUE GT#12 HOT GAS PATH INSPECTION MARCH 2013	2	2,003,125	751,172	1,251,953
BOGUE GT#13 HOT GAS PATH INSPECTION DECEMBER 2013	3	2,913,708	-	2,913,708
OTHER		6,606	-	
TOTAL		13,679,658		

Cost of Hot Gas Path Inspections (HGPI)

As indicated in Table 6.44, JPS carried out a HGPI on Bogue GT#12 which was reported completed in March 2013 at a cost of US$2,003,125. A HGPI was also carried out on Bogue GT#13 which was reported completed in December 2013 at a cost of US$2,913,708. The costs of these HGPIs were capitalised by JPS with the depreciable amount allocated over an accelerated life of two (2) and three (3) years for GT#12 and GT#13 respectively.

Categorisation of GT Maintenance

Gas turbine maintenance inspection types may be broadly classified as standby, running and disassembly inspections. The disassembly inspection requires opening the turbine for inspection of internal components and ranges from the combustion inspection (CI) to the HGPI to the major inspection (MI) where the turbine rotor is removed. The maintenance interval in terms of operating hours or number of starts increases as the inspections progress from CI to MI.

The purpose of a HGPI is to examine those parts exposed to high temperatures from the hot gases discharged from the combustion process. The HGPI includes the full scope of combustion inspection and also a detailed inspection of the turbine nozzles, stator shrouds and turbine buckets. Special inspection procedures may apply to specific components in order to ensure that parts meet their intended life. HGPIs may typically be carried out up to every 24,000 hours of plant operation, but is not necessarily classified as a major maintenance.

With respect to the cost of the HGPIs, the regulatory treatment takes into consideration the accounting principle of the recognition of the cost related to an item of property, plant and equipment as an asset or an expense.

According to the International Financial Reporting Standard (IFRS), IAS (International Accounting Standard) 16.7:

"The cost of an item of property, plant and equipment shall be recognised as an asset if, and only if:

(a) it is probable that future economic benefits associated with the item will flow to the entity; and
(b) the cost of the item can be measured reliably."

Under the asset recognition principle, a condition of continuing to operate an item of property, plant and equipment may be performing major inspections for faults regardless of whether or not parts of the item are replaced. When each major inspection is performed, its cost is recognised in the carrying amount of the item of property, plant and equipment as a replacement if the recognition criteria are satisfied. Any remaining carrying cost of previous inspection (as distinct from physical parts) is derecognised. This occurs regardless of whether the cost of the previous inspection was identified in the transaction in which the item was acquired or constructed.

Parts of some items of property, plant and equipment may require replacement at regular intervals. Under the recognition principle, an entity recognises in the carrying amount of an item of property, plant and equipment the cost of replacing part of such item when that cost is incurred if the recognition criteria is met. The carrying amount of those parts that are replaced is derecognised in accordance with the de-recognition provisions of the IAS 16.

The carrying amount of an item of property, plant and equipment shall be derecognised:
(a) on disposal; or
(b) when no future economic benefits are expected from its use.

While the OUR does not disagree with the IFRS accounting principles for the treatment of the cost of an item of property, plant and equipment, with respect to the regulatory principles related to the calculation of the Non-Fuel Revenue Requirement the OUR disagrees with JPS' approach regarding the treatment of the costs for Bogue GT#12 and GT#13 HGPI. It should be noted that the accelerated depreciation and rates applied to these costs are not consistent with the depreciation details set out under Schedule 4 of the Licence.

<u>Bogue GT#12 HGPI</u>
According to JPS, the cost of US$2,003,125 for Bogue GT#12 HGPI was incurred in March 2013. The amount was allocated to be depreciated over a period of two (2) years, with US$751,172 calculated as depreciation charge for the latter nine (9) months in 2013 and included in the test year

depreciation expenses. The test year depreciation expenses were part of JPS' proposed annual depreciation expenses to be included in the Non-Fuel Revenue Requirement. Notably, the Non-Fuel Revenue Requirement will be set for a five (5)-year period (2014-2019) while the cost of GT#12 HGPI as indicated by JPS will be fully depreciated within two (2) years starting from March 2013. However, it is expected that a HGPI will be carried out by JPS every two (2) – three (3) years, therefore, a similar amount of capital will be required to finance such maintenance activities.

Bogue GT#13 HGPI

According to JPS, the cost of US$2,913,708 for Bogue GT#13 HGPI was incurred in December 2013 with the depreciable amount allocated over a period of three (3) years.

The test year depreciation expenses were part of JPS' proposed annual depreciation expenses to be included in the Non-Fuel Revenue Requirement. While the Non-Fuel Revenue Requirement will be set for a five (5)-year period (2014-2019) the cost of GT#13 HGPI as indicated by JPS will be fully depreciated within three (3) years starting from December 31, 2013. However, it is expected that a HGPI will be carried out by JPS every two (2) – three (3) years, therefore, a similar amount of capital will be required to finance such maintenance activities.

Bogue ST#14 Turbine Repair and Major Overhaul

The cost of US$8,756,219 for the major overhaul of Bogue ST#14 (40 MW), the steam turbine component of the Bogue CCGT, is very high relative to the cost for the major overhaul of other steam generating units in the power system. The major overhaul of the entire Hunts Bay B6 unit (68.5 MW) for example, costs approximately US$6.8M compared to US$8.76M for Bogue ST#14 (40MW). While there may be differences in the design, steam conditions and size of the units, it is important to recognise that they basically perform the same function, utilise similar major components and support systems. Nonetheless, the cost of the major overhaul of ST#14 was significantly higher than that for Hunts Bay B6. This raises the question of whether the major overhaul cost is reasonable and prudent.

A review of Bogue ST#14 outage report dated July 18, 2013 and a subsequent update from JPS dated August 14, 2013 revealed that on June 10, 2013 there was a significant loss of lube oil from the unit's turbine oil reservoir which ultimately resulted in major damage to the Turbine Rotor, Journal Bearing #1 & #2, Inactive Thrust Pads and other turbine components. According to JPS, the extent of the damage required the removal of the turbine rotor and the contracting of a specialist turbine repair company from the USA (Turbine Generator Maintenance) to carry out onsite repairs of the turbine journal.

The review also revealed that JPS decided to immediately execute a major overhaul of the entire unit following the assessment of the damage to the turbine.

JPS Generation Maintenance Schedule (revised) for 2013 indicated that Bogue ST#14 was scheduled for major overhaul in the last week of May 2013. However, according to JPS' monthly Technical Reports and daily Plant Capability Reports, the major overhaul was not executed. It was subsequently reported by JPS that the unit was forced out of service on June 10, 2013 due to major damage to the turbine rotor and bearing caused by a loss of lube oil incident. This scenario highlights the approach of JPS regarding scheduled maintenance of its generating units. Based on worldwide statistics on the causes of steam turbine failures, the highest frequency of turbine failure causes have been loss of lube oil incidents. In steam turbine generator operations, the reliability of the turbine lube oil system is important as loss of lube oil incidents can result in extended generation outages and significant cost requirements to effect repairs to damaged components. In this regard, it is incumbent on the electric utility operating steam units to support reliable turbine operation. To ensure reliable operations, it is imperative that the company put in place an effective condition monitoring infrastructure to appropriately monitor the condition of all the critical components of its steam turbine units. It is also important for the utility to have in place written operating/maintenance procedures, maintenance management systems to schedule/track maintenance, and arrangements for conducting training of personnel on an ongoing basis.

With respect to the major overhaul of ST#14, the scale and scope of the work carried out extended beyond the usual tasks required for a major overhaul of a typical generating unit of similar configuration and capacity. The major overhaul cost data for the unit provided by JPS indicated a relatively large portion of the maintenance activities carried out on the unit was in connection with the repairs and restoration of the turbine rotor and bearings. This is evidenced by the description and magnitude of the cost items for the major overhaul as provided in JPS' "Combined Cycle Plant Addition Analysis". This brings into focus the issue of the reasonable and prudent cost incurred by JPS in the maintenance of its generation facilities.

The OUR accepts that the major overhaul of a generating unit is an important maintenance requirement that is necessary for recovering performance losses and ensuring continued unit availability and contribution to System reliability. This implies that reasonable and prudent costs of performing major maintenance/overhaul will be capitalised as a component of the plant, provided this provides future economic benefits. However, if there are costs for maintenance tasks which were not factored as part of the major overhaul such as costs incurred for repairing major plant components damaged due to operational failures, these costs will not be allowed as a capital component of the plant.

With due consideration to the relevant requirements governing the major overhaul of a generating unit, including the OEM's maintenance recommendations and prudent utility practice, among other things, the cost for executing the repairs needed as a result of the reported damage to the referenced turbine components was not accepted as a cost related to the major overhaul of ST#14.

6.4.4.7 Insurance Claim on Bogue ST#14

Generally, in power generation operations, in the event of major damage to plant, property and equipment, there is usually the avenue of insurance claims to recover the cost incurred for repairs due to such damage. With regard to Bogue ST#14, under section 6.3.2.2 of JPS' Tariff Submission, JPS indicated that it submitted an insurance claim associated with the damage to its Bogue CCGT unit. Under section 6.5.1 of the JPS' Tariff Submission, the company made reference to insurance claim settlement related to Bogue ST#14 in the amount of US$1.6M. This item was represented in the company's 2013 audited financial statements, in the "Statement of Comprehensive Income" as a constituent of "Other income" and entitled, "Insurance proceeds re Bogue combined cycle plant" with an amount of US$1.603M. Notably, the total value of the claim was not provided by JPS. Notwithstanding, the OUR is sufficiently convinced that JPS has effectively initiated insurance claim proceedings to address the cost of the repairs to ST#14 turbine rotor, journal bearings, inactive thrust pads and other damaged turbine components. Given that the cost of insuring JPS' generation assets is reflected in the existing electricity rates to the customers, it would be inappropriate for the OUR to allow the cost of the repairs to ST#14 turbine components which were damaged during the incident on June 10, 2013 in the rate base while JPS receives insurance proceeds to cover the cost of the damage to the said plant components.

6.4.4.8 OUR's Position on Bogue CCGT Capital Cost Addition

Given the available information related to the damage to the turbine and major overhaul of the unit, the OUR has disallowed the cost of the repairs to the referenced turbine component as part of the ST#14 major overhaul cost. That is, these costs will not be allowed as a capital component of the plant and will be excluded from the rate base.

From the cost data provided by JPS in its "Combined Cycle Plant Addition Analysis", a capital component in the amount of US$3.64M which was directly associated with the repair of Bogue ST#14 turbine rotor, journal bearings, inactive thrust pads and other damaged turbine components was identified and removed from the unit's major overhaul cost of US$8.76M provided by JPS.

As previously indicated, the major overhaul of a generating unit is an important maintenance requirement that is necessary to assure a certain level of System reliability. Therefore, from a regulatory monitoring perspective, it is essential that JPS, prior to undertaking a major maintenance or major overhaul of any of its generating units, provides the OUR with a detailed work schedule including all the relevant tasks to be carried out. The budgeted cost of the major overhaul including the cost of replacement parts should also be provided.

In accordance with the IAS 16 asset recognition principle, the OUR generally agrees that the prudent and reasonable cost of major inspections or major overhauls of JPS' generating units can be recognised in the carrying amount of the item of property, plant and equipment. As such, based on the principle of known and measurable and reasonable and prudent cost, the Office APPROVED the capitalisation of the cost of US$5.115M for the major overhaul of Bogue ST#14 and the appropriate depreciation charges to reflect the consumption of benefits resulting from the major overhaul.

Accordingly, the depreciation of this capitalised cost of US$5.115M was allocated over the 5-year period consistent with the schedule proposed by JPS.

A summary of the treatment of Bogue CCGT HGPI and Major Overhaul Cost is provided in Table 6.45 below.

Table 6.45: Summary of the Approved Costs for Bogue CCGT HGPI and Major Overhaul

Bogue CCGT Units	Main-tenance Activity	JPS Dep. Schedule (Year)	JPS Capital Cost (US$)	Cost Approved (US$)	Comments
GT#12	HGPI	2	2,003,125	2,003,125	The HGPI cost will be capitalized as proposed by JPS according to the schedule. The depreciation charge is already included in the Test Year Depreciation Expense.
GT#13	HGPI	3	2,913,708	2,913,708	The HGPI cost will be capitalized as proposed by JPS according to the schedule. The depreciation charge is already addressed in Test Year Depreciation Expense.
ST#14	Turbine Rotor Repair and Major Overhaul of other Plant Components	5	8,756,219	5,115,352	The cost of repairing the damaged Turbine Rotor which forced the unit out of service was estimated to be US$3.64M (based on JPS' cost breakdown). This component of the proposed capitalized cost of US$8.756M was not approved and was removed from the rate base. The remainder (US$5.115M) will be capitalized and depreciated in accordance with JPS' calculations and depreciation schedule. The depreciation charge is already addressed in the Test Year Depreciation Expense. Note that the capital cost was added at Dec 31, 2013.

6.4.5 JPS Managed IPP Assets

In the JPS Tariff Submission, the value of JPS-managed IPP assets as at December 31, 2013 was US$43.319M. These IPP assets are: JPS Munro Wind Farm which was commissioned in October 2010 and JPS Maggotty Hydro (6.37 MW) which was commissioned in the fourth quarter of 2013. Because these generation plants were procured under an IPP construct, their cost must be completely separated from JPS' capital and O&M costs for its main utility operations. In this regard, the US$43.319M representing the total value of these JPS IPP assets was excluded from the rate base.

Consistent with the relevant accounting principles, the exclusion of the value of these IPP assets also requires the exclusion of depreciation charges associated with these plants from JPS' annual depreciation expenses. As such, annual depreciation charges for Munro Wind Farm (3 MW) and Maggotty Hydro (6.37 MW) were removed from JPS' test year depreciation expenses.

6.4.5.1 Munro Wind Farm (3 MW) Annual Depreciation Charge

The asset description and depreciation calculations for Munro Wind Farm provided in JPS' "Fixed Asset Register Dec 2013" are shown in Table 6.46 below.

Table 6.46: JPS' Munro Wind Farm Depreciation Calculations

JPS' Munro Wind Farm Depreciation Calculations							
DESCRIPTION	**DATE PLACED IN SERVICE**	**DEP. METHOD**	**LIFE (YEARS)**	**COST (US$)**	**DEP. CHARGE (US$)**	**DEP. RESERVE (US$)**	**NET BOOK VALUE (US$)**
CONSTRUCTION & INSTALLATION	31-Oct-10	STL	60	165,000.00	-	-	165,000.00
CONSTRUCTION & INSTALLATION	31-Oct-10	STL	25	2,851,680.90	114,067.24	361,212.86	2,490,468.04
CONSTRUCTION & INSTALLATION	31-Oct-10	STL	25	4,399,140.00	175,965.60	557,224.40	3,841,915.60
CONSTRUCTION & INSTALLATION	31-Oct-10	STL	20	1,000,000.00	50,000.00	158,333.33	841,666.67
CONSTRUCTION & INSTALLATION	31-Oct-10	STL	25	1,647,394.32	65,895.77	208,669.93	1,438,724.39
TOTAL				**10,063,215.22**	**405,928.61**	**1,285,440.52**	**8,777,774.70**

As shown, the annual depreciation charge for JPS' Munro Wind Farm included in JPS' annual depreciation expenses at December 31, 2013 was **US$405,928.61**. This amount was NOT ALLOWED and as such was excluded from JPS' test year depreciation expenses on the basis that the plant is operated independently of JPS' utility operations.

6.4.5.2 Maggotty Hydro Plant (6.37 MW) Depreciation Charge

The asset description and depreciation calculations for Maggotty Hydro Plant (6.37 MW) provided in JPS' "Fixed Asset Register Dec 2013" are shown in Table 6.47 below.

Table 6.47: JPS' Maggotty Hydro (6.37 MW) Depreciation Calculations

JPS MAGGOTTY HYDRO (6.37 MW) DEPRECIATION CALCULATIONS						
COST DESCRIPTION	**DATE PLACED IN SERVICE**	**DEP. METHOD**	**LIFE (YEARS)**	**COST (US$)**	**DEP. RESERVE (US$)**	**NET BOOK VALUE (US$)**
PENSTOCK: CONSTRUCTION OF MAGGOTTY HYDRO 6.3 MW PIPELINE	30-Sep-13	STL	50	19,221,754.78	96,108.78	19,125,646.00
CONSTRUCTION OF MAGGOTTY HYDRO 6.3 MW POWERHOUSE	30-Sep-13	STL	50	5,438,537.96	27,192.69	5,411,345.27
CONSTRUCTION OF MAGGOTTY HYDRO 6.3 MW TURBINE	30-Sep-13	STL	25	7,544,513.49	75,445.14	7,469,068.35
CONSTRUCTION OF MAGGOTTY HYDRO 6.3 MW ACCESSORIES	30-Sep-13	STL	25	544,370.55	5,443.71	538,926.84
CONSTRUCTION OF MAGGOTTY HYDRO 6.3 MW SWITCHGEAR & ELECTRICS	01-Oct-13	STL	25	2,016,025.61	20,160.25	1,995,865.36
TOTAL				**34,765,202.39**	**224,350.57**	**34,540,851.82**

As shown in Table 6.47, the annual depreciation charge for JPS' new Maggotty Hydro (6.37 MW) plant included in JPS' annual depreciation expenses at December 31, 2013 was **US$224,350.57**. This amount was NOT ALLOWED and as such was excluded from JPS' test year depreciation expenses on the basis that the plant is operated independently of JPS' utility operations.

The depreciation information in Table 6.47 also shows that even before the plant was commissioned and declared available for use, JPS started applying depreciation charges. This approach is apparently inconsistent with the IAS 16.

6.4.6 Depreciation Charges for JPS' Metering (Fixed Asset under Distribution Plant)

In JPS' "Fixed Asset Register Dec 2013", it was observed that the company calculated annual depreciation charges for a significant number of meters using asset lives of 25 years instead of 30 years as required by Schedule 4 of the Licence (Refer to Table 6.48).

Table 6.48: Asset Life for JPS' Metering as per Schedule 4 of the Licence

Fixed Assets Details for Distribution Plant (Distribution Feeders)

Retirement Units	Sub-Components	Est. Life (Yrs.)
Metering		
	110 220 meters	30.00
	3 ph meters	30.00
	Demand meters	30.00

The use of asset lives of 25 years by JPS in the depreciation calculations for metering as opposed to applying the 30 years as required by the Licence resulted in annual depreciation charges for 2013 which were higher by US$265,266.

Consistent with the requirements of the Licence, the depreciation charges should be based on the Fixed Assets Details for Distribution Plant as per Schedule 4.

The application of asset lives of 25 years by JPS in the calculation of depreciation charges for its distribution metering assets is an apparent deviation from the requirements set out under Schedule 4 of the Licence. Therefore, the excess depreciation charge of **US$265,266** for metering was NOT ALLOWED and as such was excluded from JPS' test year depreciation expenses.

6.4.7 Adjustments to JPS' Test Year Depreciation Expenses

With due consideration to the situation regarding used and useful assets described above as well as the improper placement of depreciation charges related to JPS-managed IPPs, the test year depreciation expenses were adjusted as shown in Table 6.49 below.

Based on these adjustments, the approved test year depreciation expense to be included in the Non-Fuel Revenue Requirement is **US$47,412,437.**

Table 6.49: Adjusted Test Year Depreciation Expense for Known and Measurable

ITEM	COST (US$)	REMARKS
JPS TEST YEAR DEPRECIATION EXPENSE	**49,168,403**	
LESS:		
HUNTS BAY GT #4 DEP. CHARGE	360	
BOGUE GT #8 DEP. CHARGE	116,267	
BOGUE GT #11 DEP. CHARGE	743,793	
JPS MUNRO WIND FARM (3 MW) DEP. CHARGE	405,929	Depreciation charge based on Asset Value of US$10.063M since Oct 31, 2010.
JPS MAGGOTTY HYDRO (6.3 MW) DEP. CHARGE	224,351	Depreciation charge based on Asset Value of US$34.765M since Sep 31, 2013.
EXCESS DEP. CHARGE FOR METERING (Use of 25 years instead of 30 years)	265,266	
SUB TOTAL	**1,755,966**	
ANNUAL DEPRECIATION EXPENSE FOR REVENUE REQUIREMENT	**47,412,437**	

6.4.8 Review of JPS' Proposed Depreciation Adjustment

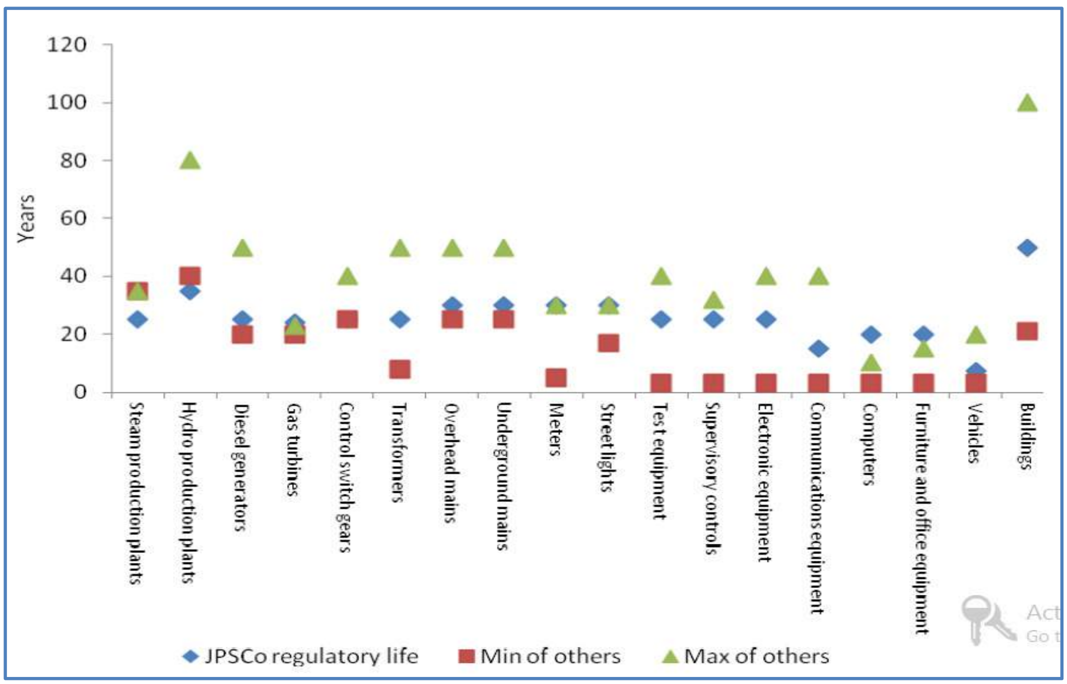
6.4.8.1 Additional Depreciation Charges due to JPS' Proposed Asset Life Adjustment

Under section 6.4.1 of the JPS' Tariff Submission, JPS proposed additional depreciation charges of US$8.33M due to asset life adjustment shown in Table 6.42 above which was informed by the KPMG depreciation study.

JPS' Depreciation Study

As reported by JPS, the company engaged KPMG to review the asset lives used for regulatory depreciation as specified in Schedule 4 of the Licence. The objective of the study was to provide a comparison of the useful lives of JPS' assets according to Schedule 4 of the Licence with asset lives for electric utilities in other countries. The study focused on five countries, Trinidad and Tobago, New Zealand, Singapore, Barbados and Guatemala. A summary of the comparison of JPS' regulatory asset lives with the range of lives from the comparator countries are shown in Figure 6.42 below.

Figure 6.42: KPMG's Comparison of JPS' Regulatory Asset Lives with a Range of Asset Lives in Comparator Countries



6.4.8.2 Examination of KPMG's Recommended Asset Lives and Asset Lives as per Schedule 4

A review of JPS' depreciation study report and the Schedule of Rates for Depreciation of JPS assets according to Schedule 4 was conducted by the OUR. The observations and findings are detailed in the following sections.

Examination of Useful Asset Lives

An examination of the assets and their useful lives in Schedule 4 of the Licence indicates that some of the asset classifications reviewed by KPMG were not represented in the manner as set out under Schedule 4 of the Licence. In some instances, the current life of certain assets as stated by the consultant deviated from those set out in Schedule 4. There was no clear basis as to how the consultant arrived at the current asset lives given in Table 6.41 above as provided under section 6.4.2 of JPS' Tariff Submission.

In the case of transmission assets, such as control gear/switchgear and transformers, according to KPMG, the current life for each of these assets is 25 years. However, according to Schedule 4, the useful life for each of the referenced assets is 20 years.

Additionally, there is no specific reference in Schedule 4 to the following assets:

- Test Equipment
- Supervisory Control System
- Electronic Equipment
- Computer Equipment

Notwithstanding, under the asset categories of Distribution Plant and General Plant, there is a classification denoted as "Other Equipment" under which the assets listed above could have been represented. However, in the Fixed Asset Details for Distribution Plant, there is no specific description of such assets.

With respect to communication equipment, under the Fixed Asset Details for High Voltage Substation for the Transmission Plant asset class, these assets have useful lives of 15 years. However, for Distribution Plant, communication equipment has useful lives ranging from 2.8 – 15 years as shown in Figure 6.43 below.

Figure 6.43: Useful Asset Lives for Distribution Plant Communication Equipment

SCHEDULE 4, *contd.*

Fixed Assets Detail for Distribution Plant (Distribution Feeders), contd.

Retirement Units		% of Total Asset	Est. Life (Yrs.)
COMMUNICATION		1.0%	
	RTU Panel	0.5%	15
	48V dc Battery & Charger	0.1%	4
	Wave Trap	0.2%	6.5
	Coupling Capacitor Potential Device	0.1%	2.8

These observations raised questions as to whether KMPG took into consideration the variations in useful lives of assets designated with the same name but are defined in different asset categories.

With regard to computer equipment, there is no clear designation in Schedule 4 for this particular asset. However, according to KPMG, the current life (per Licence) of this asset is 20 years which is at variance with the current life (per Licence) of 15 years given by JPS in Table 6-5 of the JPS' Tariff Submission.

Specific depreciation details related to assets such as test equipment, supervisory control systems and electronic equipment, among other things, are also not definitive and therefore the recommended lives for some of these assets are questionable.

For Steam Production Plant**,** in particular, the useful asset life (UAL) given in Schedule 4 is 25 years. Benchmark depreciation data show that the useful life of this asset-type ranges from 25 – 50 years. However, the results of the study indicated that the minimum and maximum useful lives of Steam Production Plant for the electric utilities studied were approximately the same at about 35 years. Despite the obvious differential in UAL of over ten (10) years there was no recommendation from the consultant for the upward adjustment of the useful life of these assets.

Similar to Steam Production Plant, the study results show that the useful lives of Hydro Production Plants range from about 40 – 80 years. However, despite the obvious differential in useful asset life of over five (5) years, there was no recommendation from the consultant for the upward adjustment of the useful life of these assets.

Given the issues involved with the representation of the useful lives of JPS' fixed assets, the OUR's position is that consistent with the provisions of the Licence, the proposal for alterations to the asset lives and depreciation rates provided in Schedule 4 requires a comprehensive review of the Fixed Asset Details of all categories of JPS' Plant which would be undertaken by the OUR in consultation with JPS. The scale and scope of such activities and the various attendant constraints however, would not allow for such review to be executed in this tariff review.

Analysis and Deduction

It was discerned from the OUR's review, that the scope for the comparison of the useful asset lives undertaken by KPMG was relatively limited, nonetheless, the study revealed that the useful lives of JPS' assets as specified in Schedule 4 of the Licence largely exist in the range between minimum and maximum useful lives of electric utility assets operating in the five (5) selected countries. In some instances, the useful lives of JPS' assets were lower than the minimum useful lives of particular assets that were compared. However, no upward adjustment in useful lives of these was recommended. Given the range of useful lives of the assets compared, it could be deduced that there was an element of selectivity with respect to specific assets for which the recommended useful lives would be more favourable to JPS' proposed depreciation expenses.

Even so, and notwithstanding the limitations, the study results indicate that the useful lives of JPS' assets as per Schedule 4 of the Licence are relatively consistent with the UAL of other utilities.

Having regard to the limited scope of the KPMG depreciation study, the OUR carried out a broader comparative review/analysis on the useful asset lives of a wide range of electric utilities in various countries including Canada, USA, India, New Zealand and Barbados. It was found, that the asset lives given in Schedule 4 of the Licence and those represented in JPS' depreciation study were largely within the boundaries of the minimum and maximum useful asset lives identified in the research. The results of this research are provided in Table 6.49.

Table 6.49: Comparison of JPS' UAL and a range of UAL researched by the OUR

Category	Asset Details	JPS' UAL per Sch. 4 of Licence (year)	Current Asset Life Given by KPMG	KPMG Recommended Assets Lives (year)	Min UAL - OUR Research (Year)	Max UAL - OUR Research (Year)
Generators	Steam production plant	25	25	25	35	50
	Hydro production plant	35	35	35	40	60
	Diesel generator	25	25	25	20	25
	Gas turbine	24	24	24	20	25
Transmission	Control gear/Switchgear	20	25	25	25	60
	Transformer	20	25	25	20	60
Distribution	Overhead mains	30	30	30	30	75
	Underground mains	30	30	30	30	45
	Meters	30	30	15	10	35
	Street lights	30	30	20	20	30
	Test equipment	-	25	15	20	25
	Supervisory control systems	-	25	25	20	25
General Plant	Electronic equipment	-	25	10	10	35
	Communication equipment	15	15	5	8	20
	Computer equipment	-	20	6	5	15
	Furniture and office equipment	20	20	10	10	20
	Vehicles	7	7	4	5	20
	land-leasehold	50	50	50	50	75
	Buildings	50	50	50	50	75

The study results indicate that the useful lives of JPS' assets as per Schedule 4 including the lives assumed by JPS for assets without clear designation in the said Schedule were found to be consistent with the UAL of a wide range of electric utilities.

On the basis of the above review and analysis, the Office considers the applicable depreciation rates and useful assets lives as set out in Schedule 4 of the Licence to be reasonable and representative and has therefore maintained them as the basis for the calculation of the annual depreciation expenses included in the approved revenue requirement. The proposed adjustment of US$8.33M due to asset life adjustment as recommended by KPMG in the Depreciation study was therefore NOT allowed.

6.4.9 Offices' Determination on JPS' Depreciation Proposal

Based on the review and analysis of JPS' depreciation proposal, the Office determines as follows:

DETERMINATION 15

- **The proposed depreciation adjustment of US$8.33M which was derived based on the recommended asset lives is NOT APPROVED.**

- **The annual depreciation amount allowed in the Non-Fuel Revenue Requirement is the Test Year depreciation expenses calculated in accordance with the useful lives of assets specified in Schedule 4 of the Licence and adjusted for known and measurable costs.**

- **The annual depreciation expense allowed for the price-cap period 2015 - 2019 shall be US$47,412,437.**

6.5 The Rate Base & Return on Investment

In the current price control mechanism, capital costs are recovered through a return on investment and depreciation allowance.

The return on investments describes the return the company is allowed to earn to reward capital investment. This is defined in Schedule 3, paragraph 2(C) of the Licence and is set out in the Legal and Regulatory Framework above.

The return on investment is calculated based on the approved Rate Base of JPS and the required rate of return. Mathematically, this is the product of the WACC and the Rate Base.

6.5.1 The Rate Base

The Rate Base comprises the assets used by JPS to provide electricity services. The principles applied in determining the value of the Rate Base calculation are as follows:

- The Rate Base includes only the assets necessary to provide electricity services
- The Rate Base is based on the depreciated value of the fixed assets
- The Rate Base includes an allowance for working capital

JPS stated that the value of the company's rate base is US$606.66M, details of which are identified in Table 6.52 below. The rate base was examined and verified against the test year audited financial statement. Table 6.53 below provides the details of the OUR's approved rate base in the total amount of US$519.89M. The JPS proposed rate base was reduced by the amount of US$86.77M. This reduction is the result of the following adjustments:

- Exclusion of the cumulative amount for capital expenditure that is the proceeds of the EEIF as at December 31, 2013 totalling US$31.1M

- Exclusion of $19.9M of capital reserves accumulated from revaluation surplus, which represents the difference between the carrying value of fixed assets and the historical cost of these fixed assets.

- Exclusion of the amount of US$9.5M which represents the value of retired plants and assets not in use and or useful on which a return is not allowed.

- Exclusion of other assets in the amount of US$4.6M which represents the cost of materials and labour incurred to wire the houses of certain customers on which a return is not allowed.

- Exclusion of US$21.6M presented as restricted cash. The amount of US$21.1M represents the Self-Insurance Fund and US$0.5M represents deposit guarantees on staff loans, IPP contracts, etc. on which a return is not allowed.

The capital expenditure adjustment is made in accordance with the Rules of Procedure for Operation and Administration of the EEIF dated March 4, 2011. See Table 6.54 below for details of the EEIF capital expenditure. The revaluation increment is excluded in order to show the total value of property, plant and equipment at historical cost. Land was carried at valuation in the 2013 audited financial report.

Itemized in Table 6.51 below are the amounts representing the retired plants and assets that are out of use and/or considered not useful. The full details of the analysis are set out at Section 6.4 - Depreciation.

Table 6.51: JPS' Retired Plants and Assets not In Use and/or Useful

Retired Plants and Assets not In Use and/or Useful	
Assets	**Book Value (US$'000)**
Old Harbour Steam Unit#1	-
Hunts Bay GT#4	13.9
Bogue GT#8	48.3
Bogue GT#11	5,791.4
Bogue ST#14 (Rotor Repair Est.)	3,641.0
Total	9,494.5

Table 6.52: JPS' Proposed Rate Base

Items		US$'000	J$'000
Property Plant and Equipment		**698,571**	**78,240,002**
Add			
Intangible Assets		9,877	1,106,190
Rural Electrification Assets		-	-
Other Asset		4,606	515,872
Long-Term Receivables		1,447	162,114
Exclusions			
Retired Plants and Assets not In-use and/or Useful		-	-
Construction Work In Progress (CWIP)		(14,516)	(1,625,792)
JPS managed IPP assets		(43,319)	(4,851,728)
EEIF Assets		-	-
Net Fixed Assets		**656,667**	**73,546,659**
Off-Sets			
Customer Deposits		(26,827)	(3,004,624)
Employee Benefits Obligations		(6,908)	(773,696)
Deferred Expenditure (Tax)		(39,917)	(4,470,704)
Deferred Revenue		(1,654)	(185,248)
Total Long Term Assets		**581,361**	**65,112,387**
Add			
Net Current Assets (Working Capital):	**US$'000**	**25,299**	**2,833,488**
Add **Current Assets:**	**253,664**		
Cash and Short-Term Deposits	3,854		
Repurchase Agreements/Restricted Cash	21,642		

Items		US$'000	J$'000
Receivables	186,877		
Tax Recoverable	420		
Inventories	40,871		
Subtract **Current Liabilities:**	**228,365**		
Bank Overdraft	1,938		
Short-Term Loans plus Current Maturity	37,492		
Payables	189,385		
Corporation Tax Payable	(1,148)		
Related Companies Balances	698		
Total Net Assets (RATE BASE)		**606,660**	**67,945,875**

Table 6.53: OUR's Approved Rate Base

Items		US$'000	J$'000
Property Plant and Equipment		**698,571**	**78,240,002**
Add			
Intangible Assets		9,877	1,106,190
Rural Electrification Assets		-	-
Other Asset		-	-
Long-Term Receivables		1,447	162,114
Exclusions			
Retired Plants and Assets not In-use and/or Useful		**(9,495)**	**(1,063,388)**
Construction Work In Progress (CWIP)		(14,516)	(1,625,792)
Capital Reserve (Revaluation Surplus)		**(19,901)**	**(2,228,912)**
JPS managed IPP assets		(43,319)	(4,851,728)
EEIF Assets		**(31,125)**	**(3,486,019)**
Net Fixed Assets		**591,540**	**66,252,462**
Off-Sets			
Customer Deposits		(26,827)	(3,004,624)
Employee Benefits Obligations		(6,908)	(773,696)
Deferred Expenditure (Tax)		(39,917)	(4,470,704)
Deferred Revenue		(1,654)	
Total Long Term Assets		**516,234**	**57,818,190**
Add			
Net Current Assets (Working Capital):	**US$'000**	**3,657**	**409,584**
Add Current Assets:	**232,022**		
Cash and Short-Term Deposits	3,854		
Repurchase Agreements/Restricted Cash	-		

Items		US$'000	J$'000
Receivables	186,877		
Tax Recoverable	420		
Inventories	40,871		
Subtract Current Liabilities:	**228,365**		
Bank Overdraft	1,938		
Short-Term Loans plus Current Maturity	37,492		
Payables	189,385		
Corporation Tax Payable	(1,148)		
Related Companies Balances	698		
Total Net Assets (RATE BASE)		**519,891**	**58,227,774**

Table 6.54: EEIF Total Capital Expenditure as at December 31, 2013

EEIF (US$'000)	2009	2010	2011				2012				2013			
	Nov-Dec Total	Jan-Dec Total	QTR 1 Total	QTR 2 Total	QTR 3 Total	QTR 4 Total	QTR 1 Total	QTR 2 Total	QTR 3 Total	QTR 4 Total	QTR 1 Total	QTR 2 Total	QTR 3 Total	QTR 4 Total
Capital Items Purchased (AMI related)	915	6,806	3,257	3,422	2,525	2,400	1,419	1,789	558	3,072	211	383	931	1,957
Associated Capital Expenses	46	340	163	171	126	120	71	89	28	154	11	19	47	98
Total Capital Expenses	960	7,147	3,419	3,593	2,651	2,520	1,490	1,878	585	3,225	221	402	977	2,055
Cumulative Total	**960**	**8,107**	**11,527**	**15,120**	**17,771**	**20,290**	**21,781**	**23,659**	**24,244**	**27,469**	**27,691**	**28,093**	**29,070**	**31,125**

6.5.2 Net Fixed Assets

JPS stated that the value of its net fixed assets which are used in the provision of electricity services is US$656.7M, and is comprised of the property, plant & equipment and intangible assets. The company stated that the test year net book value of these assets was adjusted for the removal of the net book value of its new Maggoty Hydro power plant and the Munroe wind plant. These assets will be operated as virtual IPPs with signed PPA agreements with JPS and therefore were excluded from the regulatory rate base.

JPS further advised that the value of its net fixed assets had increased by US$84.7M since 2008. The increase was said to be primarily due to the capital expenditure by the company over the last five (5) years. The company reported that it spent an average of US$65M on capital projects to maintain its fleet of generating units, to modernize and improve its transmission and distribution network and on projects aimed at reducing system losses.

The OUR's approved value for net fixed asset on which the company is allowed to earn its return is US$591.54M.

6.5.3 Working Capital

The Licence allows for the inclusion of any working capital requirements that may exist as at the test year. Usually working capital (also referred to as net current assets) is defined as the difference between current assets and current liabilities, where current assets usually include material stock and accounts receivable and the current liabilities include account payables. Working capital indicates the allowance for resources to meet short term obligations. JPS proposed a working capital of US$25.299M. However, this included US$21.642M of restricted cash related to the Self-Insurance sinking fund and deposit guarantees on staff loans and IPP contracts. The Office considers the inclusion of restricted cash in the calculation of the Working Capital as inadmissible. The amount of working capital included in the rate base was therefore US$3.657M.

6.5.4 Return on Investment Calculation

The return on investment was derived by multiplying the rate base by the WACC. JPS' proposed WACC for the 2013 test year was derived by Castalia using the CAPM model and JPS' loan portfolio data. Table 6.55 summarizes the results of the study in addition to the Office's determined results. The ROE that is proposed by JPS is US$62.6M plus US$31.3M as a gross-up for taxes. The proposed amount for long term interest expenses is US$23.5M. The OUR approved US$31.8M as the allowed ROE plus US$15.9M as the amount that will gross-up revenues to cover taxes. The approved long-term interest expenses are US$21M.

Table 6.55: JPS' Proposed and OUR's Determined Parameters for Computation of Return on Investment

Item	2014 JPS Proposed	2014 OUR Determination
Cost of Debt	8.07%	8.07%
Rate of Return on Equity (ROE)	19.83%	**12.25%**
Tax Rate	33.3%	33.33%
Gearing Ratio (Deemed)	48.0%	50.00%
Post-tax WACC	12.89%	8.81%
Pre-tax WACC	19.34%	**13.22%**
	US$'000	**US$'000**
Rate Base	**606,660**	**519,891**
Return on Equity	**62,552**	**31,837**
Taxation (Gross up)	**31,276**	**15,918**
Long Term Interest Expenses	**23,507**	**20,985**

6.6 Other Income and Expenses

6.6.1 Other Income

JPS stated that the line item ‘other income’ is predominantly comprised of proceeds from the sale of scrap, rental income and other miscellaneous settlements. It was further mentioned that during 2013, other income amounted to US$4.4M. However, this was not typical of a normal year’s operation primarily because of the inclusion of income arising from an insurance claim settlement. The settlement relates to the Bogue ST#14 Power Plant and was in the amount of US$1.6M. This amount is deemed to be a one-off payment and is not expected to recur in the future. As such, JPS’ proposal is for the adjusted amount for other income to be included in the revenue requirement as an offset is US$2.8M. The adjustment of US$1.6M is approved by the OUR.

6.6.1.1 Loyalty Reward Fund

JPS stated that other income also included an amount of US$1.037M which relates to the net amount earned from the Early Payment Incentive (EPI)/Late Payment Fee (LPF) initiative. The US$1.037M was treated by JPS as an offset to the revenue requirement. JPS has reported that the initiative is currently successful. However, despite the success in constraining the growth of residential receivables, JPS is concerned that continuing the program as it is currently constituted involves significant risks. As compliance grows above 50%, JPS claims that the company will have to fund the difference between the EPI and LPF from its own resources. JPS expressed the view that the Licence allows the company through the tariffs to recover all costs incurred in serving its customers once they are prudently incurred. Consequently, JPS believed that the costs of this program should also be embedded in the rates similar to other programs providing comparable benefits.

Additionally, JPS requested approval for an annual true-up mechanism to the program whereby the actual pay out incurred is compared to the estimated amount included in the revenue requirement. JPS claimed that this mechanism will remove any unfair gain or loss to JPS, or its customers who are funding these amounts. JPS proposed that the over or under-recovery be included as an annual adjustment for which JPS would apply annually to seek an adjustment to the actual amount of the fee charged.

In the 2013 Annual Tariff Adjustment Determination Notice, the OUR issued a no-objection to the EPI/LPF initiative proposed by JPS. The initiative was developed to help reduce the over J$1B in receivables (arrears) owed by its residential customers. The initiative however is not seen as a necessary service that is required to deliver electricity supply and therefore any loss from this initiative should not be borne by the customer. JPS is however at liberty to assess its incentive mechanism for its effectiveness and make its business decisions accordingly.

The proposal to recover any shortfall or adjustments to the tariff for any over-recovery, which may arise from this initiative, is disapproved. JPS is reminded that any adjustment to the EPI/LPF requires approval (or at the least non-objection) from the OUR.

JPS proposed an adjusted amount of US$2.8M to other income as an offset which is to be included in the revenue requirement. A further reduction of US$1.037 to the offset, which is the balance from LPF, is approved by the OUR. The total offset to the approved revenue requirement is US$1.785M.

DETERMINATION 16

The recovery of any shortfall or adjustments to the tariff for any over-recovery, which may arise from the loyalty reward initiative, is NOT APPROVED. JPS is reminded that any adjustment to the EPI/LPF requires approval or non-objection from the OUR.

6.6.2 Other Expenses

6.6.2.1 Background

Other expenses in the revenue requirement allow for the recovery of additional recurrent expenses that are not operational expenses. Contributions to the Electricity Disaster Fund (EDF) fall under this category of the revenue requirement.

The EDF was established by JPS in 2004 to address damages caused to the electricity grid by natural disasters. This was the company's response to changes in the pattern of Atlantic hurricanes that resulted in the insurance industry offering prohibitively high premiums and unattractive deductible thresholds for the coverage for the transmission and distribution grid.

Currently, customers contribute approximately J$0.28 per kWh or US$7.5 million (including tax) annually to the EDF. The EDF accumulates at a net rate (i.e. after tax adjustments) of US$5M annually. At the end of June 2014 the EDF contained US$24.7M.

In JPS' Tariff Submission, the company proposed that the annual gross accumulation rate be reduced from US$7.5M to US$3M. JPS argued in its proposal that: A gross accumulation rate of US$3M translates to an effective accumulation rate of US$2M annually after tax adjustments are made.

> *"As at December 31, 2013, the net book value of JPS' fixed assets was US$699M, with an amount of US$361M specifically related to T&D assets which are quite susceptible to natural disasters and for which JPS cannot obtain conventional insurance cover. As such, the SIF value now covers 5.8% of the uninsured value of fixed assets. We believe the recommendation to reduce the funding rate is particularly useful at this time as this will help to reduce the non-fuel tariffs."*

JPS further recommended that, in keeping with what had been done in the past, the rate of funding should be reviewed each year to ensure its adequacy based on the actual experience with natural disasters, while giving due consideration to the net book value of JPS' assets.

6.6.2.2 OUR's Analysis

In reviewing JPS' proposal there are two fundamental questions that must be answered:

1. Is the requested reduction permitted under the rules that govern the EDF?
2. Is it prudent to grant the specific reduction requested at this point?

Fund Limits
The EDF is financed through a precautionary provision approved and embedded in the tariff.

Based on Rule 1.9 of the EDF Rules of Procedure for Operation and Administration (EDF Rules), under normal circumstances, the level of the EDF should be kept within 3% to 15% of the net book value of JPS' T&D assets. Rule 1.9 of the EDF reads as follows:

> *"a) The Fund shall normally be capped at fifteen (15) percent of the net book value of JPS' T&D assets. Notwithstanding, the Office has the right to increase this 15% ceiling if it determines that JPS' T&D system is, for whatever reason, over-exposed. The actual amount in US$ terms shall be determined by the Office and is subject to periodic as well as post-disaster reviews."*
>
> *b) The lower limit of the Fund shall be twenty (20) percent of the upper limit (i.e. 3% of the net book value of JPS' T&D assets). Under special circumstances, such as a series of disasters within a single year or consecutive years with disaster, the Office may choose to waive this limit."*

Further, Rule 1.10 of the EDF Rules allows for an adjustment of the precautionary provision in the tariff under certain circumstances, one of which is the Special Regulatory adjustments. Rule 1.10 (b) of the EDF Rules provides,

> *"The precautionary provision in the tariff shall be adjusted under the following conditions:*
> *a)…*
> *b) Special Regulatory adjustment: these changes may be made to the precautionary provision from time to time, by the Office in an effort to align the level and the growth of the Fund with the perceived risks of disaster. The adjustments may be made at either a periodic or an annual tariff review."*

At the end of June 2014 the balance in the EDF was US$24.7M or approximately 6% of the net book value of JPS' T & D assets. In this regard, the EDF is now within the limits delineated by the rule and there is scope for Special Regulatory adjustments to the inflows to the EDF based on an assessment of the risks involved.

Setting the Annual Contribution

The high price of electricity is a serious cause for concern and therefore any opportunity for reducing electricity rates ought to be given serious consideration. In the case of lowering the annual accumulation in the EDF, it is a trade-off between a slightly lower tariff and the inability to deal adequately with extreme weather events. In this regard, an analysis of the likelihood of a disaster and the potential financial impact of hurricanes on JPS' network is useful.

The OUR's analysis, utilizing a binomial distribution and based on data spanning 2004 -2013, indicates that there is a 40% chance that Jamaica might be affected by at least one severe storm in any given year. The chance of experiencing two severe events in one (1) year is 7% and the likelihood of encountering three storms in a year is 1%. However, while the probability of experiencing multiple disaster events in a single year is remote, the consequences may be financially devastating. The statistics therefore suggests that the EDF should be in a position to deal with at least one severe tropical cyclone in two (2) out of every five (5) years.

Figure 6.61: Severe Storms (2004-2013)

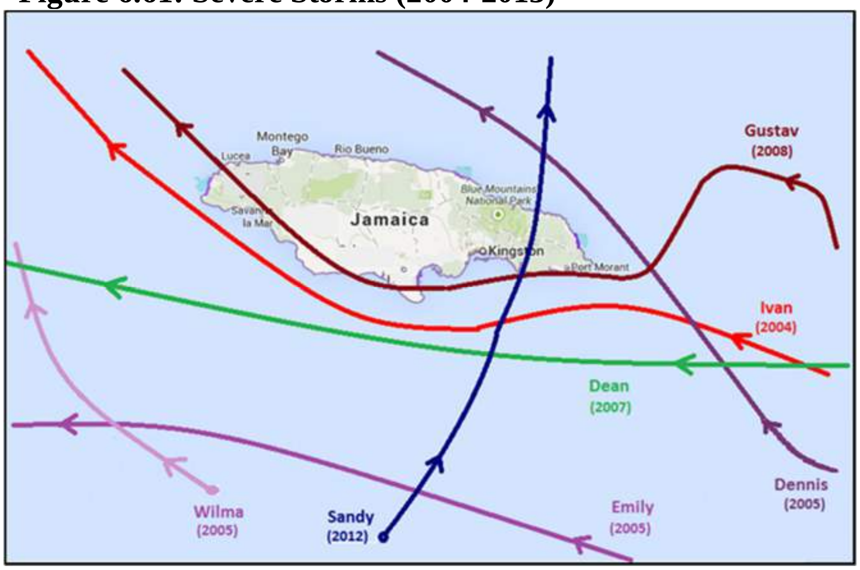


Table 6.61: Compensation Payments for Storm Damages

Year of Event	Tropical Cyclone	Compensation (US$)	Source of Payment
2004	Ivan*	7,378,577	Customer Bill
		9,613,938	EDF

2005	Dennis, Emily & Wilma	1,545,689	EDF
2007	Dean	8,759,256	EDF
2008	Gustav	2,225,608	EDF
2012	Sandy	4,655,905	EDF
	Total	**34,178,973**	

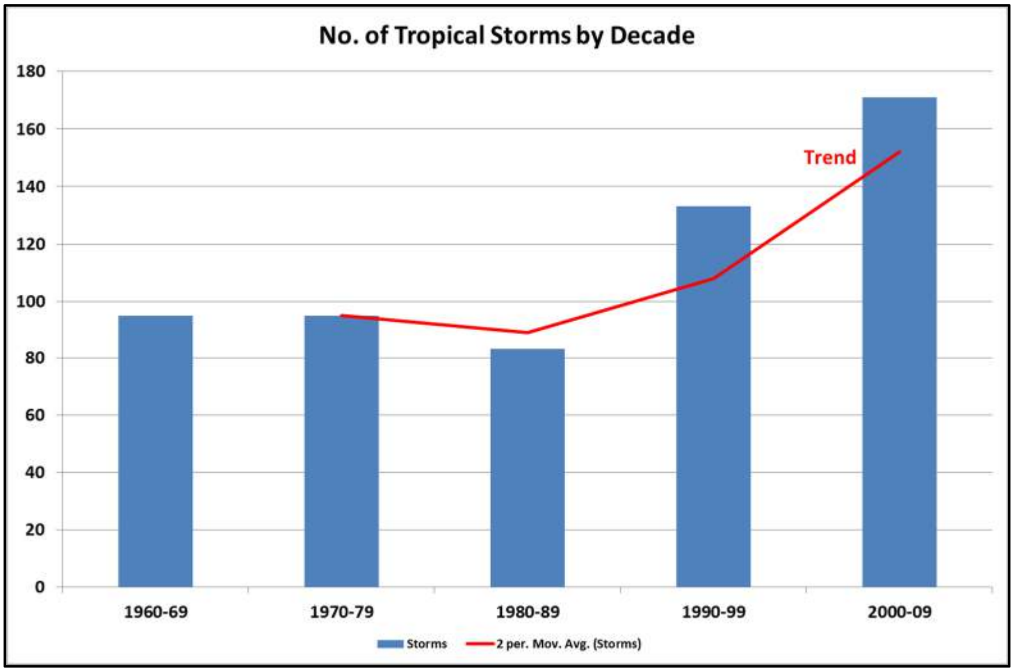
***Note:** Originally, a compensation of US$7.4 million was paid directly by customers to JPS in their bills for Hurricane Ivan. In Oct 2012 the OUR was directed by the Electricity Appeals Tribunal to approve additional compensation to JPS.*

Since 2004, JPS submitted five claims in connection with damages inflicted on the electricity grid by seven tropical cyclones (see Figure 6.61 above). The company has received a total of US$34.2M in gross compensation for these claims of which US$26.8M was paid from the EDF (see Table 6.61 above). This means that based on the average annual compensation to JPS over the ten (10)-year period 2004–2013, the expected annual pay-out from the EDF in relation to disasters is US$3.4M. It may therefore be argued that the proposed net US$2M annual contribution is US$1.4M less than the expected pay-out per year. Therefore, assuming that no interest is accrued on the balance in the EDF and the pattern of hurricane in the future perfectly mirrors the experience over the last decade as well as that US$3.4M is paid out annually for compensation, then;

- if no more contributions were made to the EDF, it would take seven (7) years to exhaust it.
- if US$3M flows into the EDF annually, then it would take approximately sixty two (62) years to exhaust it.

Notwithstanding, an analysis of Atlantic cyclones over the period 1960-2009 has revealed that the number of tropical storms occurring in each decade has been on the increase since the 1990. While a total of eighty three (83) storms occurred during the 1980s, it increased to 133 and 171 in the 1990s and 2000s respectively (see Figure 6.62). Furthermore, over the four (4)-year period 2010-2013, there had been a total of seventy four (74) storms so far. If this trend continues the Caribbean will see approximately one hundred and eighty five (185) storms during the current decade. In this respect, it would be tantamount to regulatory complacency to assume that the current accumulated balance in the Fund is a secure buffer against the random acts of nature.

Figure 6.62: Tropical Storms in the Caribbean



Against this background, if JPS' proposal is to be accepted additional measures would have to be implemented to better manage the risks associated with disasters. This would require a reorientation of the engineering mind set and improvements in administrative processes to compensate for the reduction in the contribution. In this regard, the following will be necessary:

1. a review of the T&D codes and standards to ensure that the design of the network is done in robust and cost-effective manner to buttress the system against the escalating risk associated with tropical cyclones;

2. stricter adherence to the maintenance of T&D infrastructure to reduce their vulnerability to high velocity winds and deluge; and

3. the speedier settlement of claims (while giving due regard to the loss-adjustment process) since the carrying cost of disaster claims can be substantial.

While conceding that reducing the annual contribution (net of tax) to the EDF from US$5M to US$2M diminishes, to some degree, the capacity to pay out full compensation from the EDF in an extreme and highly improbable event, the OUR is of the view that the risks are manageable. Furthermore, when balanced against the accumulation in the EDF and benefits of the reduction on the tariff in a high price environment, the risk seems plausible.

In respect of the impact on the tariff, cutting back the net annual contribution to US$2 will lead to a reduction of approximately 0.15 US c/kWh or J$0.17 per kWh at an exchange rate of US$1 = J$112. The OUR has taken the view that, consistent with JPS' proposal reinforced by the additional measures outlined above, it would be prudent at this time to reduce the contribution to the EDF.

The OUR has therefore decided that the annual inflows to the EDF should be reduced from its present level of US$7.5M gross (i.e. US$5.0M net of taxes) to US$3.05M (i.e. US$2.0M net of taxes). The OUR will also be reviewing the contribution annually to ensure that it is properly aligned to the perceived risks of disaster.

DETERMINATION 17

The Office DETERMINES that the annual payment into the Electricity Disaster Fund (EDF) shall be reduced to US$3.0M gross (US$2.0M net of taxes).

6.7 Other Adjustments to Revenue Requirement

6.7.1 Caribbean Cement Company Limited Revenue

JPS reported that annual non-fuel revenues over the period 2009-2013 for Caribbean Cement Company Limited (Caribbean Cement) remained flat at US$4.9M. This, JPS claimed, was the case even though there has been an 11% reduction in sales. The Caribbean Cement's average consumption was reduced from 93,000 MWh per annum in 2008 to 83,000 MWh per annum in 2013 as the construction industry has been in decline over the past five (5) years. This negatively affected the demand for the product and this was exacerbated by increased competition from cheap imported cement in the Jamaican market.

The exclusion of the Caribbean Cement's revenue of US$4.9M from the revenue requirement is necessary as there is a long standing contractual agreement with JPS and this very large customer. The exclusion is approved by the OUR.

6.7.2 JPS' Managed IPP/Unregulated Expenses

JPS has reported total expenses on its unregulated assets for the test year to be US$604K. This amount was inadvertently not removed from the JPS' proposed revenue requirement. Table 6.71 below shows the itemized amounts which is removed from the OUR's approved revenue requirement.

Table 6.71: **Expenses for JPS' Managed IPP/Unregulated Assets**

JPS' Managed IPP/Unregulated Expenses for year ending December 31, 2014	
Asset	**Total Expenses (US$'000)**
Munro Wind Farm	155
EStores	449
Total	**604**

6.7.3 Electricity Efficiency Improvement Fund (EEIF)

The EEIF was introduced in the last rate case filing in 2009 to fund loss reduction activities. Over that tariff period, it was used primarily to purchase capital equipment to construct Residential Automated Metering Infrastructure (RAMI) for the purpose of controlling losses in inner-city areas. JPS stated that the programme was successfully implemented in several communities in the parishes of Kingston, St. Andrew, St. Catherine and St. James.

In JPS' Tariff Submission, JPS proposed the introduction of a Community Renewal Programme which the company claimed is a softer approach for controlling losses. Among other things, JPS stated that the programme would fund a subsidized billing programme to help poor customers who are currently illegal consumers of electricity to transition to legitimate paying customers. In this regard, JPS recommended the continuation of the EEIF for the purpose of funding this and other new initiatives aimed at reducing System losses.

The EEIF was set up specifically to augment and fast-track JPS' efforts to reduce overall system losses. Disappointingly, JPS' actual recorded rolling twelve-month average system losses increased from 23.98% as at December 2009 to 25.87% as at December 2013. This worrying trend of increasing system losses has continued without abatement and JPS reported at month ending April 2014 actual losses figure of 26.35%.

The Office approved a stimulus of US$13M in the 2009 Determination Notice to augment and fast-track JPS' AMI programme. With the status of the programme to date not fulfilling expectations of a reduction and curtailment of losses, adjustment on how to effectively utilize the EEIF becomes necessary.

The OUR remains resolute that this high level of System losses is unsatisfactory and for this reason will continue to support the loss reduction activities geared towards arresting and reducing this problem. Further comments on the EEIF are provided in Chapter 10 of this Determination Notice.

Based on the current situation regarding the overall efficiency of the electricity System, the Office sees the urgent need for efficiency improvement measures which can ultimately result in a reduction in the average price of electricity to consumers. Accordingly, the Office **APPROVED** the continuation of the Electricity Efficiency Improvement Fund (EEIF) with an expanded scope to support a wide range of efficiency improvement projects that can be implemented by JPS. The Office's Determination on the EEIF is set out as follows:

DETERMINATION 18

1. **The amount for the EEIF shall be US$13M per annum and shall be reviewed by the Office at the Annual Tariff Adjustments during the price-cap period.**

2. **The revenues for the EEIF shall be recovered through a separate line item on customers' bills and the rate shall be J$0.4886/kWh.**

3. **The EEIF shall only be used for efficiency improvement projects which shall be subject to review and approval by the Office.**

4. **The Office will prescribe the rules that will govern the continued operation of the EEIF after the effective date of this Determination Notice.**

6.8 OUR's Approved Revenue Requirement

Table 6.81 shows the itemized entries for the OUR's approved revenue requirement of **US$383.65M**.

Table 6.81: OUR's Approved Revenue Requirement

Revenue Requirement	JPS Proposed (US$'000)	Office Determined (US$'000)
Purchased Power Costs	104,111	104,111
Operating Expenses	150,844	147,736
Total Operational Expenses	**254,955**	**251,847**
Net finance costs (excl. long-term debt):		
Interest on short-term loans	1,403	1,403
Interest on customer deposits	549	549
Interest – Bank overdraft and other	5,721	1,990
Int. Capitalised during construction (AFUDC)	1,450	1,450
Debt issuance cost and expenses	4,829	3,202
Finance income	(1,615)	(1,615)
	12,338	**6,979**
Depreciation	**57,498**	**47,412**
FX Losses	**14,000**	-
Other Income	**(2,822)**	**(1,785)**
Other Expenses	**3,000**	**3,000**
Self-Insurance Fund (SIF) contribution	2,000	2,000
Gross up for taxes on SIF	1,000	1,000
Return on Equity	**62,552**	**31,837**
Taxation (Gross up)	**31,276**	**15,918**
Long Term Interest Expenses	**23,507**	**20,985**
Revenue Requirement	**456,304**	**376,194**
Less Carib Cement Revenue	(4,936)	(4,936)
JPS Managed IPP Expenses		**(604)**
Loss Reduction Fund (incl. taxes)	**13,000**	**13,000**
Adjusted Revenue Requirement	**464,368**	**383,654**

Chapter 7: Tariff Design (Non-Fuel)

7.1 Non-Fuel Revenue Requirement and Tariff Design Relationship

7.1.1 Introduction

This chapter discusses and outlines the set of tariffs that the Office considers will allow JPS to obtain the Non-Fuel Revenue Requirement of US$386.96M as determined in Chapter 6.

A Cost-of-Service study (COS) is an analytical tool that assigns, or allocates each relevant component of cost on an appropriate basis to determine the relative costs to serve various customers with similar end uses and demand. This is accomplished by separating the revenues, investments, and expenses between the various rate classes based on an analysis of the causative nature of the costs incurred for the service provided. While certain costs are readily identifiable to a particular customer or customer class, many parts of an electric system are planned, designed, constructed, operated and maintained jointly to serve all customers. Costs incurred to serve all customers are referred to as joint or common cost and must be allocated to the customer rate classes based on the type or classes of customers, their load characteristics, their number, and various other implied customer-related investment and expense relationships. Once JPS' revenue requirement is determined, the COS is used to determine the rate that should be applied to each customer class to achieve it on a cost-oriented basis.

In 2009, pursuant to the 2009-2014 Tariff Review process, the OUR took the position that in order to design tariffs based on unbundled costs, these costs need to be identified, categorized and allocated, using justifiable segmentation in a cost-of-service study. The OUR argued that it is important that costs should be allocated appropriately into justifiable cost categories, as all costs do not have the same driver. The OUR also determined that JPS should use the FERC accounting method as the framework for its COS, but that JPS may expand its model to allow for more sophisticated costs allocation. The Office's position on these issues has not changed.

OUR's approach to assessing JPS' proposed Revenue Requirement allocation and tariff design is informed by the following:

- Customer perspective: simple, fair, equitable and affordable rates; and
- Company perspective: cost-reflective rates which, when applied to the billing determinants, will yield revenues equal to the Non-Fuel Revenue Requirement to cover all costs required for reliable, safe operation and to achieve a reasonable return on deployed capital.

Typically, there are three fundamental steps required to develop a cost-of-service study of any type. These are:

- Functionalization,
- Classification, and

- Allocation.

Functionalization

The first step separates the investment and expenses of the company into specific categories based upon utility operations involved in providing electric service. For JPS, the functional investment categories associated with providing electric service are production, transmission, distribution, and general plant. Expenses in these categories include: production, transmission, distribution, customer services, and administrative and general expenditures.

Classification

The second step, classification, identifies the “cost causative” characteristics of the investment and expenses within each function. Typically, these “cost causative” characteristics are:

- Energy-related - those costs that vary with the customers' energy consumption. These generally refer to costs incurred by the utility which vary with the megawatt-hours (MWh) of energy consumed by the customer.
- Demand-related - those costs that are incurred as a consequence of the loads imposed on the system by all customers. These generally refer to costs incurred by the utility in order to provide the capacity necessary to serve the customers’ maximum load throughout the year.
- Customer-related - those costs that vary with the number of customers. These generally refer to costs incurred by the utility to connect a customer to the distribution system, as well as costs related to customer metering, customer billing and administration.

Allocation

- Energy costs - costs associated with fuel costs and the variable operations and maintenance expenses. These costs are allocated based on the annual MWh consumed by the customers in the various rate classes, adjusted for losses.

- Demand costs - costs associated with the production, transmission and distribution functions. Demand costs at each respective service level are allocated based on the MW demand imposed by the customers.

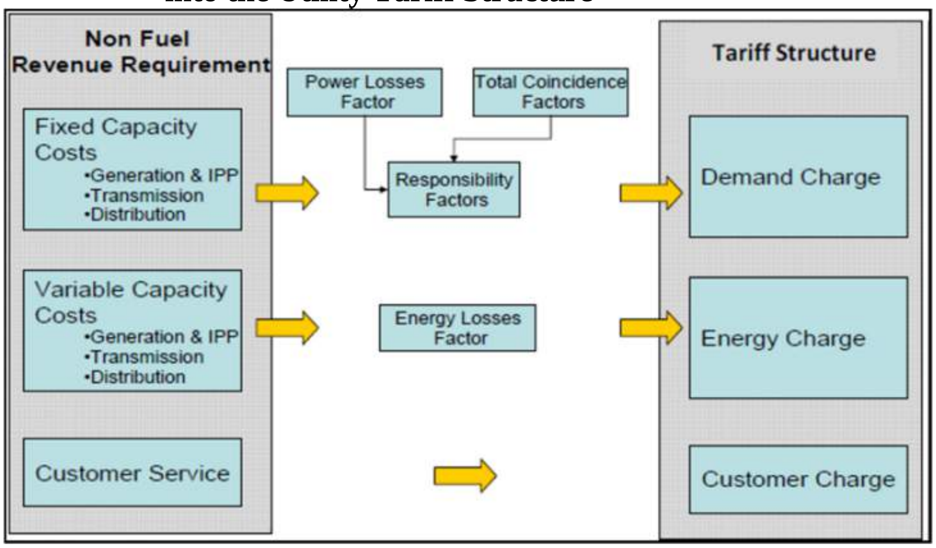
- Customer cost - costs associated with the customer component of certain distribution facilities along with the costs associated with the customer service function. The customer component of distribution facilities vary with the number of customers. Customer service costs are also associated with meter reading, customer accounting, collections, etc.

7.2 JPS' Proposal

JPS applied the Average Cost approach as a starting point and then looked at an alternative Two-Part Tariff approach as the final basis on which the tariff was designed. Thecompany claimed that it followed the principle of cost causality from a JPS cost-of-service study. The "cost causer pays" rule says that costs should be assigned to customers so that the party that causes a cost to be incurred will pay for those costs. Failure to reflect cost causation in the tariff structure would result in cross-subsidies, whereby some customers would subsidize other customers. Perpetuating cross-subsidies undermines both competition and efficiency goals.

Figure 7.21 summarizes the purported relationship between the Non-Fuel Revenue Requirement and the Tariff Design.

Figure 7.21: JPS' Allocation of the Non-Fuel Revenue Requirement into the Utility Tariff Structure



JPS posited that Non-Fuel Administrative Costs are allocated between the standard utility functions: generation, transmission, distribution and commercial, with consideration to the number of employees working in each function.

JPS further posited that the cost allocation by function is obtained from JPS' accounting systems. Operating expenses (OPEX) are separated into the following functions:

1. Generation
2. Transmission
3. Distribution
    a. Low Voltage
    b. Medium Voltage
4. Customer Services

5. General Services

In its proposal, JPS allocated Distribution costs between voltage classes based on the type of network components deployed in each voltage level.

JPS stated that the utility rate base (net rate base and depreciations) is allocated by utility function:

1. Generation (Steam, Hydraulic, Other)
2. Transmission (High Voltage)
3. Distribution (Medium Voltage, Low Voltage and Customer Service)
4. General Property

Table 7.21 presents the JPS' proposed Test Year Non-Fuel Revenue Requirement elements allocated by function.

Table 7.21: JPS' Proposed Test Year Non-Fuel Revenue Requirement Elements Allocation by Function

Function	Unit	Rate Base	Debt	Return on Investment	Income Tax	Depreciation	Total Cost of Capital	OPEX	Revenue Requirement
Generation	USD 000	177,133	6,864	18,264	9,132	26,241	**60,500**	129,277	**189,777**
Transmission	USD 000	57,338	2,222	5,912	2,956	7,516	**18,606**	5,350	**23,956**
MV Distribution	USD 000	156,848	6,078	16,172	8,086	9,381	**39,717**	17,022	**56,739**
LV Distribution	USD 000	49,531	1,919	5,107	2,554	2,962	**12,542**	12,326	**24,868**
Commercial	USD 000	44,040	1,706	4,541	2,270	3,664	**12,181**	29,755	**41,936**
General Services	USD 000	121,770	4,718	12,555	6,278	7,734	**31,286**	95,807	**127,093**
Total	**USD 000**	**606,660**	**23,507**	**62,551**	**31,276**	**57,498**	**174,833**	**289,536**	**464,369**

The Non-Fuel Revenue Requirement used for tariff design is assigned by the type of the costs. JPS' proposed costs were allocated between fixed and variable costs, as shown in Table 7.22.

Table 7.22: JPS' Proposed Allocation of Fixed v. Variable Costs

	Cost (USD 000)		
Cost of Service Components	**Fixed**	**Variable**	**Total**
Depreciation	57,498		**57,498**
Cost of Capital - Working Capital		4,893	**4,893**
Cost of Capital - Generation PP&E	34,259		**34,259**
Cost of Capital - T&D PP&E	51,006		**51,006**
Cost of Capital - Commercial PP&E	8,518		**8,518**
Cost of Capital - General Services PP&E	18,658		**18,658**
OPEX – PPA	83,289	20,822	**104,111**
OPEX – Generation	15,861	9,306	**25,167**
OPEX - T&D	26,023	8,674	**34,697**
OPEX - Commercial	22,316	7,439	**29,755**
OPEX - General Services	95,807		**95,807**
Total Cost of Service	**413,235**	**51,134**	**464,369**
Share of total cost of service (%)	**89%**	**11%**	

JPS posited that fixed capacity costs are related to the maximum demand of each voltage class by time period: peak, partial peak, and off peak. Variable costs are related to energy consumption of each customer class, and commercial costs are related to the number of customers in each customer class.

JPS argued that the part of variable costs that should be linked to energy charges is around 7.5% and has to do with:

- The cost of capital of the Working Capital: mainly used for fuel purchases
- PPA variable costs (around 20% of total PPA costs)
- Generation variable costs related to plants maintenance

JPS further argued that the revenue requirement of each cost component is multiplied by the allocation factors[32] for each customer class to determine each class' charges.

JPS argued that sometimes, the ideal solution must be modified because of metering constraints. For example, residential customer meters cannot measure demand, therefore fixed capacity costs must be recovered through the energy and customer charges.

[32] Parameters calculated based on a JPS Load Characterization Campaign

7.2.1 JPS' Load Characterization Study

JPS posited that its Load characterisation studies are designed to obtain information on the market served, to identify the responsibility of each customer class for power delivery costs. JPS stated that the use of the load characterisation methodology results in a fairer allocation of costs to individual customers and across customer classes. JPS argued that the data required to determine cost responsibility is based on demand data and energy consumption of each ratepayer. JPS acknowledged that sometimes the data is not available for all customer classes, because of their type of metering device. JPS posited that given these restrictions on data availability, the load characterisation study gathers data that JPS posited gave adequate allocation of costs of each of the functions involved in the operation of the utility: generation, transmission, and distribution.

The load characterisation study submitted by JPS included data from 2012 and 2013. JPS posited that data was collected from individual customers. JPS stated that the study that was carried out in 2013 allowed not only the classes' patterns calculation but the construction of the energy balance for the last finished year (2012) at that time. JPS further stated that generally, medium and large customers have electronic meters with memory and are accessed remotely and therefore, a complete census can be carried out with these customers. The street lighting customer class has a unique operational profile. The load profiles in this class have a flat profile with an instantaneous demand at sunset and a drop to zero at sunrise. JPS claimed that given the operational profile of this class, it does not justify its inclusion in a measurement campaign to estimate the typical consumption behaviour. JPS posited that the consumption pattern of this class is calculated by choosing a city as a geographic center and downloading the relevant sunrise and sunset data. The street lighting data, together with the annual energy from the base year, allows the calculation of the profile. Small customers are sampled because of the number and the type of meters used to determine a consumption pattern.

In order to establish the load characteristic of all rate classes, JPS indicated that it considered the number of customers in each class, and the type of meter used by each class and arrived at the optimum sampling design as follows:

- RT 10: Stratified Sample
- RT 20: Stratified Sample
- RT40 STD: Stratified Sample
- RT40 TOU: Census
- RT50 STD: Census
- RT50 TOU: Census

JPS indicated that after some analysis and allowing for diverse constraints (financial, manpower, and time), it developed a methodology for achieving the initial analysis. It claimed that the methodology, combined with available data, allowed it to estimate the behaviour of its customers with minimal statistical error.

According to JPS, the following data for calculating the parameters and load profiles for each voltage level and sub-category was considered:

Table 7.23: JPS' Reported Electricity Flow and Losses by Voltage Level

	Unit	2012	Losses (% of Net Generation)
Net Generation	**MWh**	**4,154,446**	
Transmission Losses	MWh	112,170	2.70%
	%	2.70%	
Caribbean Cement Company	MWh	87,173	
Energy injected at MV	**MWh**	**3,955,103**	
MV Losses	MWh	74,780	1.80%
	%	1.89%	
RT 50 MV Power Service (TOU)	MWh	113,766	
RT 50 MV Power Service (Std)	MWh	408,237	
Energy injected at MV/LV	**MWh**	**3,358,319**	
MV/LV Losses	MWh	54,008	1.30%
	%	1.61%	
RT 40 LV Power Service (TOU)	MWh	128,089	
RT 40 LV Power Service (Std)	MWh	669,982	
Energy injected at LV	**MWh**	**2,506,240**	
LV Technical Losses	MWh	166,178	4.00%
	%	6.63%	
Non Technical Losses	MWh	644,346	15.51%
	%	25.71%	
RT 60 LV Street Lighting	MWh	70,060	
RT 20 LV General Service	MWh	600,501	
RT 10 LV Residential Service	MWh	1,025,155	

JPS indicated that by using electricity flow data from 2012 on total energy generated and purchased, energy losses by voltage level (%), and energy sold by customer class, it was able to account for the end-use of all energy generated as shown in Table 7.23 above.

JPS stated that electricity flow data was gathered for each hour and each day, to determine the load profile for the residential class (RT 10) and that the residential class was the only class lacking sufficient information to calculate its profile directly.

JPS also indicated that the electricity flow by hour was calculated using a top-down process starting with net generation and that net generation was determined by the subtraction of energy losses and corresponding sales of each customer class to determine the load profile of each customer class.

JPS' reported numbers regarding load profiles collected and validated by class are indicated in Table 7.24 below.

Table 7.24: JPS' Load Profiles

Rate	Stratum	Range	Sample size
RT20	1	0 - 300 kWh/mo	63
RT20	2	300 - 1000 kWh/mo	102
RT20	3	1000 - 3000 kWh/mo	226
RT20	4	3000 - 6500 kWh/mo	180
RT20	5	> 6500 kWh/mo	207
RT40STD	1	0 - 60 kW/mo	125
RT40STD	2	60 - 110 kW/mo	80
RT40STD	3	110 - 190 kW/mo	70
RT40STD	4	190 - 360 kW/mo	52
RT40STD	5	> 360 kW/mo	33
RT40TOU	1		118
RT50STD	1		101
RT50TOU	1		23
CCC	1		1
Total			1,381

7.2.1.1 Parameter Results

JPS provided the estimated parameters shown in Table 7.25 as the result of its analysis

Table 7.25: Parameters

Group	KonP	KpaP	KoffP	LF	ICF	TCF LV onP	TCF LV paP	TCF LV offP	TCF MV&TR onP	TCF MV&TR paP	TCF MV&TR offP
RT10	15.0%	37.3%	47.7%	38.6%	51.5%	50.3%	51.5%	49.4%	50.3%	31.1%	48.5%
RT20	11.3%	52.2%	36.5%	50.2%	80.5%	50.2%	47.9%	43.0%	50.2%	80.5%	41.9%
RT60	22.8%	10.7%	66.5%	49.4%	100.0%	100.0%	100.0%	100.0%	100.0%	0.0%	100.0%
RT40 (STD)	11.8%	51.6%	36.6%	64.2%	95.0%				65.7%	94.3%	56.9%
RT40 (TOU)	11.0%	45.1%	43.9%	76.1%	91.3%				93.7%	93.5%	78.7%
RT50 (STD)	13.2%	46.0%	40.8%	75.2%	93.7%				85.0%	91.7%	78.5%
RT50 (TOU)	12.0%	43.7%	44.3%	74.5%	89.9%				98.1%	95.9%	87.7%
CCC	12.1%	38.8%	49.2%	91.6%	100.0%				92.7%	84.6%	95.4%

Note: The peak demand of the 3 blocks in MV, TR and Generation occur at the same moment, therefore TCF MV&TR onP, TCF MV&TR paP and TCF MV&TR offP are the Total Coincidence Factors for the three voltage levels.

7.2.2 JPS' Proposed Billing Determinants

The JPS' proposed test year billing determinants are as shown in Table 7.26 below.

Table 7.26: JPS' Proposed Test Year Billing Determinants

Customer Class	Customers	Energy (MWh)	Demand kVA/Month		
			STD and On-Peak	Partial-Peak	Off-Peak
RT 10 LV Res. Service ≤ 100 kWh	222,531	118,508			
RT 10 LV Res. Service 101-500 kWh	301,954	710,037			
RT 10 LV Res. Service > 500 kWh	14,116	157,095			
RT 20 LV Gen. Service ≤ 100 kWh	24,842	11,145			
RT 20 LV Gen. Service 101-1000 kWh	28,235	135,779			
RT 20 LV Gen. Service 1001-7500 kWh	8,588	304,169			
RT 20 LV Gen. Service > 7500 kWh	992	201,647			
RT 60 LV Street Lighting	236	44,715			
RT 40 LV Power Service (Std)	1,601	645,804	187		
RT 40 LV Power Service (TOU)	121	121,303	24	28	26
RT 50 MV Power Service (Std)	104	411,322	95		
RT 50 MV Power Service (TOU	27	105,893	23	26	25
Total	**603,346**	**2,967,417**	**328**	**54**	**51**

The proposed billing determinants presented by JPS differ from the actual figures for the test year 2013. JPS stated that this was due to known and measurable parameters that were predicted for the next tariff period. Some categories are split in tiers for tariff design purposes.

JPS posited that the quantities by tier of consumption are based on the 2013 sales data. In terms of energy sales, JPS stated that reductions are expected for streetlights because of LED technology replacement for current lamps. JPS also stated that it expects that 1/4 of all streetlights will be replaced each year beginning in 2014.

Table 7.27 below shows JPS' proposed RT60 sales which are based on energy sales for 2013 and include the presumed effects of LED retrofits on such sales.

Table 7.27: JPS' Expected RT60 Energy Consumption

Street Lighting	2014	2015	2016	2017	2018	Average
Level of replacement	25%	50%	75%	100%	100%	
Projected demand (MWh)	62,916	52,804	42,692	32,580	32,580	44,715

JPS used the average expected energy consumption for streetlights (presented above in Table 7.27), as the energy billing determinant for RT60.

7.2.3 JPS' Proposed Non-Fuel Tariffs (JPS' Costs Classification)

JPS in its tariff submission posited that the average cost approach for tariff setting is widely used. JPS further submitted that it is an easy-to-calculate tariff, based on criteria determining that each category should pay according to its impact and responsibility regarding the cost of service. They argued that these rates, which are meant to recover the costs of providing the service, do not consider the socio-economic factors that ultimately constrain the actual set of tariffs that are implemented. Also, this cost allocation method focuses on costs but fails to consider if the demand, composed of different customer types, will have the ability and the willingness to consume and pay for electricity service at the average cost. JPS stated that it is for these reasons that the two-part tariff approach was carried out as the alternative, as it aimed to deal with the socio-economic factors facing demand and simultaneously, thereby allowing JPS to meet its non-fuel revenue requirement.

Table 7.28 shows JPS proposed revenue requirement by customer class using the average cost approach.

Table 7.28: JPS' Proposed Revenue Requirement by Customer Class

Customer Class	Unit	Network Access Charge	Energy Charge	Demand kVA/Month			Total Revenues
				STD and On-Peak	Partial-Peak	Off-Peak	
RT 10 LV Res. Service < 100 kWh	USD 000	16,022	10,903	0	0	0	26,925
RT 10 LV Res. Service 100-500 kWh	USD 000	43,481	109,480	0	0	0	152,962
RT 10 LV Res. Service > 500 kWh	USD 000	3,049	36,332	0	0	0	39,381
RT 20 LV Gen. Service < 100 kWh	USD 000	2,683	2,240	0	0	0	4,923
RT 20 LV Gen. Service 100-1000 kWh	USD 000	5,082	26,473	0	0	0	31,555
RT 20 LV Gen. Service 1000-7500 kWh	USD 000	2,577	57,525	0	0	0	60,101
RT 20 LV Gen. Service > 7500 kWh	USD 000	476	23,644	0	0	0	24,120
RT 60 LV Street Lighting	USD 000	113	9,390	0	0	0	9,503
RT 40 LV Power Service (Std)	USD 000	1,537	0	66197	0	0	67,734
RT 40 LV Power Service (TOU)	USD 000	116	0	4524	4396	441	9,477
RT 50 MV Power Service (Std)	USD 000	100	0	29485	0	0	29,585
RT 50 MV Power Service (TOU	USD 000	26	0	3792	3866	418	8,102
Total		**75,262**	**275,988**	**103,999**	**8,263**	**858**	**464,369**

7.2.4 JPS' Proposed Two-Part Tariff Design

JPS proposed a two-part tariff approach wherein a variable charge equal to the long-run marginal cost and the revenue gap, in terms of the utility's total costs, is recovered through a fixed charge, known as Network Access Charge (NAC). JPS argued that under this regime, there are no social welfare losses and a "first best" situation is maintained.

JPS further posited that for achieving this type of structure the long-run marginal costs are first calculated for each function and voltage level and then multiplied by the responsibility factors of each category of user. Then the revenue gap has to be recovered through a NAC.

JPS' proposed tariff structure has tariff charges derived from marginal costs, to which a fixed monthly charge per customer (NAC) is added. JPS proposed that this mechanism should ensure that the different types of users pay according to their willingness to pay. In this way, lower-income sector classes should pay a lower rate because they have a lower NAC.

7.3 OUR's Comments and Determinations on JPS' Submissions

Functionalization
The OUR acknowledges in principle JPS' proposal regarding allocated cost, in particular functionalization, which separates the investments and expenses of the company into specific categories. This is based upon utility operations and modalities involved in providing electricity service. These would include:

1. Generation (Steam, Hydraulic, Other)
2. Transmission (High Voltage)
3. Distribution (Medium Voltage, Low Voltage and Customer Service)
4. General Property

Classification
The OUR is however of the view that the classification of these costs does not sufficiently identify the "cost causative" characteristics of the investment and expenses within each function. Although JPS posited that the load characterization study was devised to obtain information on the market, they served to identify the responsibility each customer class imposed for delivery costs. The OUR is of the view that this approach represents only one dimension of capturing the true costs of the "cost causer'. For example, all customers on the network indirectly benefit from reliability-related network reinforcements, but it is hard to determine how much each user should be charged for such costs using Load Characterisation alone.

The OUR is of the view that "cost causation" should focus on the selection and development of an allocation methodology that recognizes the relationships between customer requirements, load profiles and usage characteristics on the one hand, and the costs incurred by the company in serving those requirements on the other. Typically, the electricity usage of residential customers and small commercial customers' electricity usage is not measured by demand meters and as such a "cost causative" methodology for classification should reflect that reality. The OUR is of the view that all cost classifications attributable to the residential and small commercial customers should be energy related, i.e. variable in nature, and be distinct from customer-related costs.

Additionally, the OUR is of the view that there is a variety of choices and trade-offs attendant to designing electricity tariffs for any electricity system. The JPS' tariff design must not only be influenced by the technical and economic characteristics of the system, but also by the secondary policy objectives that the relevant policymakers wish to achieve, whilst allowing the company to recover the costs of building and maintaining the network. JPS' 2014 Load Characterization study has resulted in a rate rebalancing where the Rate 10 and in particular, the Lifeline rates and Rate 20 are expected to share greater responsibilities for the costs of providing the services for the proposed 2014 structure when compared to the 2013 existing tariff structure. The OUR disagrees with this approach as it is of the view that it runs contrary to the long-standing policy objective of preserving a lifeline rate that is affordable.

Further, Condition 14 (2) of the Licence provides that the Licensee may be required to provide a special concessional or lifeline tariff for residential customers, which does not cross-subsidize the allowed revenue across retail customer classes. Condition 14(2) reads:

> *"In accordance with policy directives issued by the Minister, the Office may require the Licensee to provide a concessional or lifeline tariff for residential customers in such a manner that will not compromise the allowed revenue across retail customer classes served by the Licensee."*

The OUR is of the view that JPS has not presented a tariff design which demonstrates the true costs that the residential and small commercial customers cause, notwithstanding the Load Characterization study. In the absence of this information, the possible inherent danger is that cross-subsidies between these two rate classes are likely and this will undermine both competition and efficiency goals. In fact, the tariff model presented by JPS indicates that the proposed tier with consumption above 500kWh for the residential rate class was used as a "catch all" tier in the allocation of cost between residential and small commercial customer classes.

The OUR is not convinced that JPS' Load Characterisation study resulted in a fair allocation of costs responsibilities and their "cost causative" characteristics. Typically, these "cost causative" characteristics are:

- *Energy-related* - those costs that vary with the customers' energy consumption; this generally refers to costs incurred by the utility that vary with the megawatt-hours (MWh) of energy consumed by the customer and should be recovered in the energy charge.

- *Demand-related* - those costs that are incurred as a consequence of the loads imposed on the system by all customers; this generally refers to costs incurred by the utility in order to provide the capacity necessary to serve the customers' maximum load throughout the year. In the absence of demand meters for the Residential, Small Commercial and the Rate 60 customers to measure this demand sufficiently accurately, this demand-related cost should be recovered in the energy charge to avoid smaller customers subsidizing the larger customer.

- *Customer-related* - those costs that vary with the number of customers; this generally refers to costs incurred by the utility just to connect a customer to the distribution system, and for customer metering, billing and administrative costs. Customer-related cost should be recovered in fixed customer service charge.

The OUR is of the view that the failure of JPS to reflect "cost causation" in the tariff structure is likely to result in cross-subsidies, with some classes of customers possibly subsidising others.

7.3.1 Tariff Design Approaches

Allocation

Various cost allocation criteria have been proposed and implemented in different parts of the world, not only within utilities. Some of the more important or well-known approaches are:

a. Average Costs

b. Marginal Costs (in its various forms)
    - Ramsey
    - Equi-proportional Mark-up
    - Two-Part Tariff

One of the most important concepts in rate design is cost causality. That is, if a new customer is added to the utility, that customer is required to cover any additional costs the utility incurs in providing service to him. If this new customer is willing to pay for those costs (marginal costs) along with some additional amount (large or small) then the rest of the customers may not object to the inclusion of this customer since his additional contribution will reduce the burden on them. This in essence is the core of the marginal cost-pricing concept.

Marginal Costs

Marginal cost approaches are aimed at determining the incremental costs caused by the consumption of additional units by the customers. Customers are then asked to pay this charge for each unit of the product they consume. In monopolistic industries, such as electricity markets, these costs are typically smaller than the average cost of producing the requisite level of production. Therefore, if marginal cost pricing is used exclusively, this will result in revenue inadequacy. In order to ensure that the company has sufficient revenues, a complementary mechanism would have to be put in place to ensure that the remaining revenue requirement is recovered. There are several different methods that deal with this issue of revenue adequacy, each having advantages and drawbacks.

When tariffs are based on marginal costs, it is the considered view that customers are better off since this approach attempts to provide rates that are affordable, reflective of caused cost and forward looking[33]. It is expected that under this methodology more customers would find it

[33] Represent the least cost which would be incurred in providing the requisite level of service over the relevant period.

attractive to consume the utility's services and this would result in a bigger customer base to pay for its fixed infrastructure, reducing the unitary impact.

Cost Allocation Criteria

The first step in cost allocation is to separate customer service costs from other costs. These costs are simple to allocate on a per customer basis. These costs are related to the commercial cycle: reading, billing and collecting. Customer service costs also include telephone customer service costs and costs of capital for meters and dedicated services. For the remaining costs and regardless of the approach, average or marginal, there is some allocation criterion that is required. Average costs allocation will affect the whole revenue requirement while marginal costs allocation will only impact incremental costs. The remainder of the costs (shared costs) will be recovered from consumers based on other criteria different from cost allocation. At this stage responsibility factors will be required.

Network Costs: Responsibility Factors

It is ideal when a state of affairs obtains wherein each customer pays the costs he causes, but unfortunately, in reality, applications and their constraints make it very difficult to achieve this goal. The generation facilities, the transmission facilities, the primary line extension and sometimes the secondary line extension are assets shared by many users, making it very difficult or impossible to link each asset or portion of each asset to each customer in an accurate way. For this reason, it is important to calculate responsibility factors for each customer class to help determine the contribution of each class to the cost of the shared facilities. Notwithstanding this, the OUR is of the view that the marginal capacity costs of the residential, small commercial and the rate 60 customers should be expressed in terms of energy costs and this should be reflected in the tariff design consistent with the mode of measuring the usage by the consumer.

Results from Two-Part Tariff Approach

The Two-Part tariff approach proposed by JPS finds favour with the OUR, consistent with the Office's decision in relation to the 2009 Determination Notice. The Office's 2009 tariff determination explicitly required JPS to conduct a COS outlining the Tariff Functionalisation, Classification and Allocation methods as described by the Office, but JPS did not satisfy the Office's requirements. In view of this, the OUR has determined that the 2009 determined tariff structure which incorporates the subsequent annual adjustment up to 2013 shall form the basis on which the determined Revenue Requirement be allocated. Consequently, the Two-Part tariff approach proposed by JPS is adopted by the OUR.

Essentially, the Two-Part tariff structure involves starting from the long-run marginal costs calculated for each activity and voltage level and this is multiplied by the responsibility factors of each category of user. The resulting revenue gap is recovered through a complementary mechanism. JPS in its submission referred to this mechanism as network access charge (NAC). The long-run marginal cost of each voltage level is calculated by applying the Average Incremental Cost formula to the Total Cost variations due to the demand growth.

JPS posited that the minimum charges the customers must pay are those which reflect marginal costs. The OUR in accepting the principle of marginal cost, agrees. JPS further posited that each category charge is calculated considering the constraint that it must be lower than the difference between the cost of the best alternative to network electricity and the marginal cost. The OUR agrees in principle that the revenue gap resulting from the difference between marginal revenue and total revenue requirements will have to be recovered through a complementary mechanism of a fixed charge per customer, as is outlined below.

7.3.2 Determination

The Office determines as follows:

DETERMINATION 19

The OUR has DETERMINED that the 2009 determined tariff structure which incorporated the subsequent annual adjustment up to 2013 shall form the basis on which the 2014 determined Revenue requirement is allocated.

The OUR has retained the existing tariff structure as approved in the 2009 Determination Notice as mentioned and explained in the previous section. The rates which are shown in Table 7.31 are based on the approved 2013 billing determinants and weights shown in Tables 7.33 and 7.34.

Table 7.31: OUR's Approved Non-Fuel Rate Schedule

Class		Block/ Rate Option	Customer Charge	Energy-J$/kWh	Demand-J$/KVA			
					Std.	Off-Peak	Part Peak	On-Peak
New Rates								
Rate 10	LV	--100	390	7.00				
Rate 10	LV	> 100	390	18.07				
Rate 20	LV		820	13.61				
Rate 40	LV - Std		6,200	4.38	1,587.07			
Rate 40	LV - TOU		6,200	4.38		66.92	698.32	894.12
Rate 50	MV - Std		6,200	4.05	1,421.81			
Rate 50	MV - TOU		6,200	4.05		63.40	618.68	793.78
Rate 60	LV		2,500	22.50				

In its submission, JPS posited that its fixed costs represent 89% of JPS' total non-fuel costs and that it is seeking to recover 41% of the total fixed costs in the revenue requirement through fixed charges. JPS argued that the gap between fixed costs and fixed revenues is still high. The current level of fixed cost that is recovered in fixed revenues is 23%. JPS indicated that its proposal to increase fixed revenues allocation by means of the adopted tariff design have to do with:

1. Increasing NAC by consumption tier for those classes that do not have demand measurement; and

2. The removal of the energy charge for RT40 and RT50. This measure is offset by an increase in the demand charges.

As previously indicated, the OUR is of the view that JPS did not present a convincing case to demonstrate the level of fixed costs that the residential customers cause on the network nor the level of fixed cost that this class of customers could best afford. JPS itself also recognized that there are significant challenges in carrying out rate restructuring that seeks to recover a large portion of its cost through fixed revenue recovery.

As also previously stated, where residential customers do not have demand meters and are therefore not charged demand charges, the fixed charges are to be recovered through the customer charge. The customer charge now includes some amount of the cost of the transformers, poles, lines & related equipment on the T&D side, as well as the fixed costs associated with generation. The customer charge that is shown on the JPS bill was originally designed to cover the cost of meters, meter maintenance, bill delivery, etc. Based on its own computation, the OUR is not convinced that this ratio should be increased. In any case, the OUR maintains that JPS has not presented a cost-of-service study to substantiate its request. The Office therefore does not approve the increase in fixed cost recovery and rules that this will remain at 23%.

DETERMINATION 20

JPS' fixed cost recovery shall remain at 23%. JPS shall be allowed to recover its Revenue Requirement by 23% fixed charges and 77% variable charges.

Tables 7.32, 7.33 and 7.34 below show the allocation of costs to the respective rate classes that are approved by the OUR. The allocation is based on the existing tariff structure with 23% of costs recovered in fixed revenues and 77% in variable revenues.

Table 7.32: OUR's Approved Total Non-Fuel Tariff Basket

		Block/ Rate Option (kWh)	12 Months Test Year Customer Revenue (J$)	Energy Revenue (J$)	Demand (KVA) Revenue (J$)				Total Demand Revenue (J$)	Total Revenue (J$)
					Std.	Off-Peak	Part Peak	On-Peak		
Rate 10	LV	<100	1,041,445,080	829,553,970	-	-	-	-		1,870,999,050
Rate 10	LV	>100	1,479,207,600	15,669,063,495	-	-	-	-		17,148,271,095
Rate 20	LV		616,544,880	8,883,809,569	-	-	-	-		9,500,354,449
Rate 40	LV - Std		119,114,400	2,828,619,531	3,624,517,296	-	-	-	3,624,517,296	6,572,251,227
Rate 40	LV - TOU		9,002,400	531,309,247	-	24,907,919	248,664,055	255,306,166	528,878,140	1,069,189,787
Rate 50	MV - Std		7,737,600	1,665,854,744	1,215,921,562	-	-	-	1,215,921,562	2,889,513,906
Rate 50	MV- TOU		2,008,800	428,865,415	-	38,607,274	366,976,668	391,469,455	797,053,397	1,227,927,612
Rate 60	LV		7,080,000	1,227,665,631	-	-	-	-		1,234,745,612
TOTAL			**3,282,140,760**	**32,064,741,602**	**4,840,438,858**	**63,515,193**	**615,640,723**	**646,775,621**	**6,166,370,395**	**41,513,252,757**
Percentage Allocation			7.91%	77.24%	11.66%	0.15%	1.48%	1.56%	14.85%	100%

Table 7.33: OUR's Approved Non- Fuel Tariff Basket Weights

Class		Block/ Rate Option (kWh)	Customer Charge	Energy- J$/kWh	Demand-J$/KVA				Total
					Std.	Off-Peak	Part Peak	On-Peak	
Rate 10	LV	<100	2.50871%	1.99829%	0.000%	0.000%	0.000%	0.000%	4.41%
Rate 10	LV	>100	3.65322%	37.74473%	0.000%	0.000%	0.000%	0.000%	41.41%
Rate 20	LV		1.48518%	21.39994%	0.000%	0.000%	0.000%	0.000%	22.88%
Rate 40	LV - Std		0.28693%	6.81377%	8.7310%	0.000%	0.000%	0.000%	15.81%
Rate 40	LV - TOU		0.02169%	1.27985%	0.000%	0.0600%	0.59900%	0.6150%	2.60%
Rate 50	MV - Std		0.01864%	4.01283%	2.92900%	0.000%	0.000%	0.000%	6.90%
Rate 50	MV - TOU		0.00484%	1.03308%	0.000%	0.09300%	0.88400%	0.94300%	3.021%
Rate 60	LV		0.01705%	2.95759%	0.000%	0.000%	0.000%	0.000%	2.98%
TOTAL			**7.91%**	**77.24%**	**11.66%**	**0.15%**	**1.48%**	**1.56%**	**100.00%**

Table 7.34: OUR's Deemed Test Year Billing Determinants

Class		Block/ Rate Option (kWh)	December 2013 No. Customer	Energy kWh	Demand-KVA			
					Std.	Off-Peak	Part Peak	On-Peak
Rate 10	LV	<100	222,531	118,507,710				
Rate 10	LV	>100	316,070	867,131,350				
Rate 20	LV		62,657	652,741,335				
Rate 40	LV - STD		1,601	645,803,546	2,283,780			
Rate 40	LV - TOU		121	121,303,481		372,224	356,087	285,538
Rate 50	MV -STD		104	411,322,159	855,192			
Rate 50	MV -TOU		27	105,892,695		608,934	593,163	493,174
Rate 60	STREETLIGHTS		236	57,100,727				
Total			**603,346**	**2,979,803,003**	**3,138,972**	**981,158**	**949,250**	**778,712**

Accordingly, the OUR is not of the opinion that the nature of the Revenue Gap or what JPS refers to as NAC, is such that it should be a fixed charge per customer. There are variable and fixed components attributable to each customer group. The OUR is of the view that customer charges should be determined by allocating the total revenue requirement attributable to customer service to each tariff class based on a multiplier and number of customers for each tariff class. There are certain generation costs that vary with customer energy consumption such as the cost of wear and tear of the electricity plants in service. Rate 40 and Rate 50 tariff classes have separate energy charges and demand charges. For Rate 10, Rate 20 and Rate 60, the fixed costs are to be recovered through energy charges as they do not have a separate demand charge nor are there demand meters for these rate classes. A detailed cost-of-service study and functionalization, which was not presented by JPS, can determine the proportion of fixed charges and variable energy charges. Acknowledging the existence of customers with very different consumption levels in all categories, a major portion of this cost was allocated to energy as stated in the 2009 Determination Notice.

The distribution of revenue expected to be derived from the customer charge and the demand charges are grouped together whilst the revenue derived from the energy charges are separated and highlighted in Table 7.35 below as fixed and variable revenues:

Table 7.35 OUR's Allowed Fixed and Variable Revenue Allocation (J$)

			FIXED REVENUE		**VARIABLE REVENUE**	**TOTAL REVENUE**
Customer Class		Block Rate Option	Customer Revenue	Demand Revenue	Energy Revenue	
Rate 10	LV	<100	1,041,445,080	-	829,553,970	1,870,999,050
Rate 10	LV	>100	1,479,207,600	-	15,669,063,495	17,148,271,095
Rate 20	LV		616,544,880	-	8,883,809,569	9,500,354,449
Rate 40	LV - Std		119,114,400	3,624,517,296	2,828,619,531	6,572,251,227
Rate 40	LV - TOU		9,002,400	528,878,140	531,309,247	1,069,189,787
Rate 50	MV - Std		7,737,600	1,215,921,562	1,665,854,744	2,889,513,906
Rate 50	MV- TOU		2,008,800	797,053,397	428,865,415	1,227,927,612
Rate 60	LV		7,080,000	-	1,227,665,631	1,234,745,631
TOTAL			3,282,140,760	6,166,370,395	32,064,741,602	41,513,252,757
Percentage share			**8%**	**15%**	**77%**	

The OUR is of the view that the criteria of cost reflectiveness and economic price signalling are principles that should be part of the rate setting exercise. From an economic perspective, marginal cost tariffs are ideal for sending price signals since, theoretically, decision-makers tend to make optimal choices by focusing on the costs and benefits at the margin. On the other hand, it is the average tariff that allows the full recovery of the costs that the company faces. In light of this, insistence on the application of either the marginal cost tariff or the average cost tariff can lead to sub-optimal results in an economy.

The OUR has the regulatory purview to facilitate JPS' recovery of its embedded cost revenue requirement because these costs were incurred in the past in order to meet its responsibility to produce and deliver electricity. The OUR is of the view that instead of recovering the NAC through a fixed charge per customer, part of it can be recovered through another type of charge (energy or demand charge). The fixed and variable proportion can be determined by doing a cost-functionalization and causality analysis.

7.3.3 Rate Structure by Class

In this section charges to recover Non-Fuel Costs per category are presented.

7.3.3.1 Residential Tariff RT10

For residential service, JPS presented three tiers of consumption for its residential customers. The applicable charges are as follows:

RT10 – 1st Tier (Consumption levels between 0 – 100 kWh/month):
RT10 – 2nd Tier (Consumption levels between 101 – 500 kWh/month)
RT10 – 3rd Tier (Consumptions over 500 kWh/month)

The OUR has rejected the tier structure and will maintain the current structure of a lifeline rate and a single tier customer charge as JPS has not presented a tariff design which demonstrates the true cost that the residential customers incur. This is so, as JPS does not have demand meters for its residential (Rate 10) and small commercial (Rate 20) customers. In the absence of this information, the danger is that cross-subsidies between these two rate classes are likely and this will curtail any desired efficiency goals. In fact, the tariff model presented by JPS indicates that the proposed tier with consumption above 500kWh for the residential rate class was used as a “catch all” tier in the allocation of cost between residential and small commercial customer classes.

The OUR is not convinced that this proposition offers any greater benefits to the consumer and the less than efficient allocation of costs does not justify the change at this time. The OUR has no objection to JPS seeking to rebalance its tariff structure at the next tariff review period based on the tiered structure. The OUR will evaluate such proposals on their merit at the time of filing, taking all regulatory impact assessments into consideration.

In light of the reasoning set out above in respect of the risk of cross-subsidy and the absence of a suitable tariff structure and model, the OUR does not approve the tiered structure proposed by JPS.

7.3.3.2 Pre-paid Metering

JPS’ Proposal
JPS proposed the introduction of a pre-paid tariff class for residential customers who want to have greater control over their usage and better management of their household budget. According to JPS, some of the expected benefits to be derived by customers are:

- Control over their energy usage and budget: customers can determine the maximum amount of electricity they wish to purchase monthly and the frequency of purchases.
- Point of payment flexibility to purchase top-up supplies.
- Potential for energy savings: studies show that pre-paid customers consume less energy and have lower monthly bills than their post-paid counterparts.
- No security deposit.
- Avoid the payment of certain fees: pre-paid customers will not be charged disconnection, reconnection fees, or late payment fee.

Pre-paid metering would be made available on an opt-in basis subject to the availability of Standard Transfer Specification (STS) pre-paid meters. A customer may choose to opt-out and return to post-paid service subject to a transition period to be agreed with the OUR provided that the customer provides an adequate customer deposit in accordance with standard contract terms and pays an administrative switching fee. JPS further indicated that customers in high loss areas desirous of pre-paid metering will be provided with an AMI pre-paid meter based on a schedule agreed with the OUR.

The tariff for pre-paid service will be made up of a base fee and an incremental transaction fee. The base fee is derived by taking a weighted average of the kWh rate charged to residential (RT10) customers for post-paid service. JPS stated that the *"incremental transaction fee reflects the cost to develop the more elaborate and expensive payment infrastructure that is required to facilitate issuing of encrypted codes used to top up meters as well as the use of a more sophisticated payment network with a higher transaction cost"*. The base rate is recalculated each month using the same weights, network access charges, and energy charges but with a new monthly fuel/IPP charge and foreign exchange rate factor. The new rate will take effect on the 10th day of each month. The weights will be updated during the annual tariff adjustment based on consumption data from the preceding year. The pre-paid tariff is calculated using the following formula:

$$Prepaid\ Tariff = \frac{\sum_i Cons_i * ER_i}{\sum_i Cons_i}$$

Where:

$Cons_i$ is the total consumption of customers whose monthly consumption falls within consumption interval **i**.

ER_i is the effective J$/kWh tariff rate faced by customer whose monthly consumption is equal to the average consumption at each consumption interval **i**.

The current weights are as indicated in **Table 7.36 below.**

Table 7.36: JPS' Proposed Residential Customer Class – Tier Weights Class

Class	Energy sales (MWh)	Initial Weights
RT 10 LV Res. Service < 100 kWh	118,508	12.02%
RT 10 LV Res. Service 100-500 kWh	710,037	72.04%
RT 10 LV Res. Service > 500 kWh	157,095	15.94%
Total	985,639	100.00%

JPS stated that in addition to the pre-paid tariff, customers will also be charged a per transaction processing fee payable to third party vendors at point of sale. This fee covers the development and operation cost of the more elaborate payment infrastructure needed to support the prepaid energy service. JPS indicated that based on its discussions with vendors, this fee will be approximately $50 per transaction, which is comparable to the fee currently being charged by external payment agencies.

According to JPS, a three-month technical pilot was initiated in June 2013 using AMI metering technology. The company then commenced a commercial pilot in October 2013 using customers in Stadium Gardens and Delacree Park/Palm Grove. From the commercial pilot, JPS reported that although customers saw the merit of the pre-paid service, they did not take up the service for the following reasons:

- **Little or no incentive to switch (from post-paid to pre-paid)**
- **Unavailability of online top-up options**
- **Prepaid rates deemed to be higher**
- **Fear of being without power when the credit is depleted and customer is strapped for cash**

JPS explained that the programme will be revisited using stand-alone STS metering technology.

JPS reported that it had commissioned a market research survey in February 2014 to determine the level of demand for pre-paid service. Approximately five hundred (500) household heads and/or persons responsible for paying bills were interviewed. The results are as follows:

- Interested – 29%
- Unsure – 28%
- Not interested – 43%

JPS advised that it has decided to introduce the service in Portmore due to the diversity of its residents. It reported that a new six (6)-month technical and commercial pilot using STS meters would have commenced in April 2014.

After consultation with JPS, the company revealed that the transition period for the switch between post-paid and pre-paid service would range between ten to fifteen (10-15) days. This period is required to satisfy certain administrative requirements and to make the necessary technical arrangements. The period excludes time that may be required for infrastructure modification or Government Electrical Inspectorate (GEI) re-certification that may be necessary. JPS also indicated that the proposed administrative switching fee is to discourage random switching between the two forms of service by assigning a price that reflects the minimum level of administrative cost associated with switching. The initial request to switch between post-paid and pre-paid service will not attract a charge. For subsequent requests to switch, the proposed charge is $1500. JPS also clarified that the incremental transaction fee and the transaction processing fee are the same. The pre-paid pilot projects in Stadium Gardens and Delacree Park/Palm Grove were aborted due to a lack of interest by residents. This was also consistent with the results of a commissioned survey which showed that consumers have very little interest in pre-paid electricity service.

JPS indicated that with regard to pre-paid service, sale of electricity will be recorded at the point of sale rather than at use as it is expected that consumption will take place shortly after purchase. For this same reason, the purchased credit will not expire. The rate the pre-paid customer pays will also be based on the rate at the date of purchase rather than the rate at the point of use. JPS explained that the consumer should have certainty about the kWh of electricity purchased at the time the credit is bought as this will reduce customer confusion. Further, the fuel and IPP component of the pre-paid rate will be the same as it is for the post-paid service.

JPS stated that it would be reluctant to offer STS pre-paid meters in areas with high losses. AMI pre-paid meters are preferred in such situations. Where AMI meters are already in place, the pre-paid solution can be offered on a select basis in such communities subject to minimal reconfiguration.

JPS stated that the introduction of pre-paid service is an alternative option for customers who want to manage their budget and cash flow. It also said that the pre-paid rate is not for all residential customers but instead for low usage rate payers consuming less than the average monthly RT10 consumption. Additionally, the pre-paid tariff was designed to provide a disincentive for general RT10 customers from switching to pre-paid service. JPS claimed that customers will be informed that pre-paid service is not the cheaper option. JPS contended that the higher cost for pre-paid service is associated with supporting services such as maintenance of the meters, repairs, replacements, recalibration and top-up facilities, among other things. JPS included analysis which showed that using its originally proposed pre-paid flat rate, only RT10 customers using 45kWh/month or less benefit financially from switching to pre-paid service. This represented 20% of the RT10 customers. If all these customers were to switch to pre-paid service, JPS estimated that it would not be able to recover US$2.8 million/year in non-fuel costs. JPS agreed that the tariff for pre-paid metering is higher than that for post-paid metered customers who consume between 45kWh–500 kWh. However, this was deliberate given that the intent is not to create an incentive for general RT10 customers to switch to pre-paid service for the purpose of reducing tariff.

Review of JPS' Proposal

Switching between Post-paid and Pre-paid Service

JPS indicated that a prepaid customer may opt out of the service subject to a transition period to be agreed with the OUR. JPS has indicated that the length of the transition period is ten - fifteen (10-15) days.

The OUR therefore approves a maximum transition period of fifteen (15) days. Unless there is a need for re-certification by the GEI, the customer should not be left without electricity supply during the transition period. JPS also stated that a pre-paid customer transferring to post-paid service will need to provide an adequate customer deposit. However, JPS made no mention of how the customer deposit will be treated when a post-paid customer switches to pre-paid service. It is the OUR's position that in such a scenario, the customer deposit plus any accrued interest less any outstanding balance on the account should be returned to the customer.

JPS also indicated that there would be an administrative switching fee levied where a pre-paid customer wants to switch back to post-paid service. A fee of $1500 was proposed as the administrative switching fee which is to cover the minimum administrative cost associated with switching. The fee will also provide a disincentive to random switching between the two forms of electricity services. JPS proposes that the disconnection/reconnection fee of $1500 be used as a proxy for the switching fee. JPS is proposing that there be no initial cost to switch from post-paid to pre-paid service, but if the customer switches back to post-paid within twelve (12) months without cause, then the switching fee should be applied. This is essentially the same as saying there is no switching fee as the customers will always be able to indicate a cause for switching. However, the Office finds it reasonable that JPS will want to limit indiscriminate switching between the two forms of service. As such, the Office approves the administrative switching fee of $1500 with the proviso that the customer should be allowed to switch from post-paid to pre-paid and back to post-paid within twelve (12) months without being charged the administrative switching fee. There should be no initial cost to switch from post-paid to pre-paid service.

According to JPS, customers in higher losses areas who want to avail themselves of pre-paid electricity service will be provided with an AMI pre-paid meter based on a schedule to be agreed with the OUR. The OUR cannot see any reason why it would need to agree on a schedule for the deployment of an AMI meter in such cases. Given that AMI pre-paid meters will be used in high losses areas, it seems that customers in these areas will find it more difficult to switch to the pre-paid service if the AMI meter is not yet in place. This is because it is unlikely that JPS will install an AMI pre-paid meter to serve an individual customer. Even in cases where the AMI meter is in place, JPS stated that pre-paid service will only be offered on a select basis. JPS further advised that it is reluctant to use STS pre-paid meters in high losses areas. The OUR can understand the rationale for not wanting to use STS meters in high losses areas as the meter would be accessible to the customer for possible tampering. The OUR is of the view, however, that where the AMI meter is already in place, there is no justification for the service to be offered on a select basis.

JPS stated in its comments that pre-paid service is not designed for all residential customers but instead for low usage rate payers consuming less than the average monthly RT10 consumption. Additionally, JPS argued in its comments on the draft Determination Notice that the pre-paid tariff was designed to provide a disincentive for general RT10 customers to switch to this service. This position was not mentioned in the JPS' Tariff Submission. In fact, JPS derived its pre-paid rate using consumption data for all RT10 customers, which seems to run counter to the position stated in its comments. Given JPS' claims about the potential benefits of pre-paid service, the OUR finds it strange that JPS would intentionally design the pre-paid tariff to dis-incentivise the majority of residential customers from switching to the service. This may explain why the pre-paid pilots had to be aborted for lack of interest.

JPS attempted to justify pre-paid tariffs being higher than post-paid tariffs on the basis of the need for maintenance of the meters, repairs, replacements, recalibration and top-up facilities, among other things. The OUR finds this explanation to be without merit as regular post-paid meters also need to be repaired, maintained, and replaced. JPS provided no data or explanation as to why these costs would be higher for pre-paid meters relative to post-paid meters.

OUR acknowledges that the top-up facility for pre-paid service does indeed add additional costs relative to post-paid service. However, the cost associated with the top-up facility is separated from the base rate for pre-paid service and as such it cannot be used as an explanation as to why the base rate for pre-paid service would be higher when compared to that of post-paid service. JPS indicated that if all customers using less than 45 kWh were to switch to prepaid service it would not be able to recover US$2.8 million in non-fuel costs. However, it should be noted that 77% (those using 46 kWh–500 kWh) of RT10 customers would be worst-off financially from a switch to pre-paid service. Therefore, if all RT10 customers were to switch from post-paid to pre-paid, the net effect would be a significant windfall profit to JPS if the rate originally proposed by JPS was approved.

Deriving the Pre-paid Tariff

JPS indicated that the pre-paid tariff will be made up of a base fee and an incremental transaction fee. JPS explained that the base fee is calculated by using the weighted average of the kWh rate charged to residential customers for post-paid service[34]. JPS stated that the incremental transaction fee reflects the cost to develop a more elaborate and expensive payment network. However, the company did not provide any data on the cost of this infrastructure or how the actual incremental fee was determined. JPS stated that in addition, the pre-paid tariff customers will also be required to pay a per transaction processing fee of approximately $50 per transaction to third party vendors at the point of sale. The company subsequently clarified that the incremental transaction fee and the transaction processing fee are the same. The proposed incremental fee to be levied by the third party vendor of $50 is consistent with the fee being charged to other utility bill payers. The OUR takes no issue with this incremental transaction fee of $50.

[34] **An expression of the formula actually used by JPS is**

$$\boldsymbol{Prepaid\,Tariff = \frac{\sum_i (Cons_i * ER_i)}{\sum_i Cons_i}}$$

The proposed prepaid tariff base rate (energy charge) is US$0.22 or J$24.64 per kWh with no NAC. For comparison purposes, the flat fee base rate proposed for pre-paid tariff was compared to the effective flat rate that would be paid by post-paid consumers of varying consumption levels. The analysis was done using the JPS' proposed NAC and energy charge for each consumption tier. Table 7.37 below shows that JPS' pre-paid base rate is significantly higher than the effective flat fee of J$17.36 that would be paid by a post-paid consumer using 100 kWh per month. In fact, it can be seen that only post-paid consumers using above 500 kWh would pay a higher effective flat rate than that proposed for pre-paid consumers. In effect, this means that consumers using less than 500 kWh per month would be worst-off by switching to pre-paid electricity service. This would mitigate the benefit these consumers would derive from the potential energy saving from managing their consumption that is likely to result from switching to pre-paid service. As calculated, only post-paid users with an average monthly consumption above 500 kWh would see a benefit from switching to pre-paid service.

Table 7.37: JPS' Proposed Residential Non-Fuel Rates

Energy Usage (kWh)	Effective Flat Fee (J$/kWh)
Prepaid	24.92
PostPaid	
100	17.02
200	24.14
300	24.27
400	24.33
500	24.37
600	26.60

Source: JPS

Based on how the base rate for pre-paid service was derived, pre-paid customers with an average monthly consumption of less than 500 kWh would in effect be providing a subsidy to pre-paid customers with an average monthly consumption of more than 500 kWh. This is a direct result of how the base rate was calculated.

In its comments on the draft Determination Notice, JPS suggested the use of a flat rate for pre-paid service equivalent to the average post-paid rate being paid by a customer using 155 kWh. Based on the approved post-paid rates, the average post-paid non-fuel rate for a customer using 155 kWh is J$13.40. Table 7.38 below shows that at this rate customers switching from post-paid to pre-paid service using less than 150 kWh per month would be required to pay a higher rate per kilo-watt-hour for electricity. Those customers consuming 200 kWh or more per month would benefit from a switch from post-paid to pre-paid service.

As illustrated in Table 7.38 below, at the rate of $13.40, if all post-paid customers were to switch to pre-paid, JPS would lose approximately J$81.93M in revenue each month (J$983.12M annually). Such a scenario would in short order render the JPS bankrupt. However, it is unlikely that all customers will be interested in pre-paid services. The customers most likely to be interested in the service will probably be those in the lowest consumption band (0 kWh – 300 kWh). Of note, customers consuming in the lifeline band would transfer J$24.65M in surplus revenue to JPS each month (J$295.79M annually). The net effect if all customers in the 0 kWh – 300 kWh band switched to pre-paid service is that the JPS would make a windfall of J$3.41M monthly (J$40.99M annually). This means that customers in the lifeline band who switched to pre-paid service would be providing a subsidy to customers in the 101 kWh – 300 kWh consumption bands who would have switched to pre-paid service as well as providing a windfall to the JPS. JPS indicated in its response to the draft determination, that the prepaid service *"is designed for low usage ratepayers consuming on average under the monthly average. Additionally, the tariff was designed to prevent the incentive for general Rate 10 customers to switch to pre-paid metering"*. However, it is the OUR's view that the pre-paid tariff as proposed by JPS would have the opposite effect as it discourages those consuming less than the monthly average while at the same time it actually incentivises the majority of R10 customers to switch to pre-paid service as they would be paying a significantly lower effective rate relative to post-paid customers with equivalent consumption.

Table 7.38: Analysis of Windfall Using JPS' Proposed Pre-paid Flat Rate

Analysis of Windfall Using JPS Proposed Prepaid Flat Rate				
Customer Bands	JPS Proposed avg Prepaid Rate	Monthly Postpaid Revenue	Monthly Prepaid Revenue	Windfall
0-100	13.40	J$ 107,553,598.85	J$ 132,202,757.46	J$ 24,649,158.61
101-150	13.40	J$ 169,030,710.73	J$ 184,291,289.59	J$ 15,260,578.86
151-200	13.40	J$ 191,565,627.85	J$ 184,826,514.97	-J$ 6,739,112.88
200-250	13.40	J$ 158,943,267.38	J$ 144,023,327.02	-J$ 14,919,940.37
251-300	13.40	J$ 115,957,850.20	J$ 101,123,340.92	-J$ 14,834,509.27
301-350	13.40	J$ 82,682,480.94	J$ 70,277,856.81	-J$ 12,404,624.13
351-400	13.40	J$ 58,855,145.22	J$ 49,115,270.08	-J$ 9,739,875.14
401-450	13.40	J$ 42,963,167.14	J$ 35,360,712.93	-J$ 7,602,454.21
451-500	13.40	J$ 32,476,256.49	J$ 26,444,682.88	-J$ 6,031,573.61
501-1000	13.40	J$ 123,212,096.74	J$ 97,858,332.59	-J$ 25,353,764.15
1001-1500	13.40	J$ 35,569,990.12	J$ 27,465,548.90	-J$ 8,104,441.22
<1501	13.40	J$ 66,347,449.31	J$ 50,241,010.28	-J$ 16,106,439.03
Total		**J$ 1,185,157,640.98**	**J$ 1,103,230,644.43**	**-J$ 81,926,996.55**
			US$	- 731,491.04

Whilst the OUR in principle is in favour of the pre-paid electricity service, the Office will not approve the deployment of the service under the current pricing construct as it could potentially provide a substantial undeserved windfall to JPS at the expense of the most vulnerable customers or potentially bankrupt JPS. The Office expects the base rate to be derived in such a way that consumers in the lowest consumption band are not put at a disadvantage by switching to pre-paid service. The general nature of pre-paid service is that it is attractive to users in the lower socio-economic groups. As such, persons in the lowest consumption band are likely to be the ones interested in pre-paid service. It is worth noting that one of the reasons for the low take-up of the pre-paid service during the commercial pilot was that customers identified that the rate to be charged for pre-paid service was higher than the rates charged for post-paid service.

The benefit of the lifeline rate must be accrued to all customers even under pre-paid metering. As such a tiered structure similar to that which currently exists under post-paid metering also has to be used for pre-paid service. JPS has indicated that the STS pre-paid meters are not capable of handling this sort of tiered pricing. Therefore, by necessity pre-paid service will need to be offered using the AMI metering technology until JPS is able to find a more flexible stand-alone meter.

Therefore, the rate for pre-paid service is as follows:

First 100	10.90
All subsequent	18.34

With this tiered structure, if all customers switched to pre-paid service, JPS would earn an additional J$1.63M in revenue monthly (J$19.61M annually) as shown in Table 7.39 below. However, in this case, there is no transfer from the most vulnerable consumers to high energy users or to JPS. The rate to be paid by consumers in each consumption band would be almost equivalent between pre-paid and post-paid users. As such, this rate structure does not negatively impact either JPS or its customers. The pre-paid rate is therefore designed such that consumers will be relatively indifferent between pre-paid service and post-paid service with respect to price.

Table 7.39: Analysis of Windfall Using JPS' Proposed Pre-paid Tiered Rate

Analysis of Windfall Using OUR Proposed Prepaid Tiered Rate					
Customer Bands	Post Paid Rate	Avg Prepaid Rate	Monthly Postpaid Revenue	Monthly Prepaid Revenue	Windfall
0-100	10.90	10.90	107,553,598.85	107,553,598.85	-
101-150	12.29	12.30	169,030,710.73	169,139,236.12	108,525.39
151-200	13.89	13.90	191,565,627.85	191,799,718.49	234,090.64
200-250	14.79	14.81	158,943,267.38	159,180,614.20	237,346.82
251-300	15.36	15.39	115,957,850.20	116,149,264.52	191,414.33
301-350	15.76	15.79	82,682,480.94	82,827,412.22	144,931.29
351-400	16.05	16.08	58,855,145.22	58,962,516.81	107,371.59
401-450	16.28	16.31	42,963,167.14	43,043,823.09	80,655.95
451-500	16.45	16.49	32,476,256.49	32,538,541.58	62,285.09
501-1000	16.87	16.90	123,212,096.74	123,459,820.70	247,723.96
1001-1500	17.35	17.39	35,569,990.12	35,645,134.34	75,144.22
<1501	17.69	17.73	66,347,449.31	66,492,187.14	144,737.83
Total			**1,185,157,640.98**	**1,186,791,868.08**	**1,634,227.10**
				US$	14,591.31

The approved pre-paid rate is therefore $10.90 for the first 100 kWh within the thirty (30)-day consumption cycle and $18.34 for each additional kWh thereafter within the thirty (30)-day consumption cycle.

DETERMINATION 21

1. **The approved maximum transition period is fifteen (15) days for a customer who opts out of pre-paid service in favour of going back to post-paid service.**

2. **A customer switching between pre-paid and post-paid service or vice versa should not be left without electricity supply during the transition period, unless a need for GEI re-certification demands that this be the case.**

3. **The customer deposit plus any accrued interest less any outstanding balance on the account shall be returned to a post-paid customer who has switched to pre-paid service.**

4. **The administrative switching fee of $1500 is approved with the proviso that customers should be allowed to switch from post-paid to pre-paid service and back to post-paid within twelve (12) months without being charged the administrative switching fee. There should be no initial cost to switch from post-paid to pre-paid service.**

5. **The incremental transaction fee to be levied by the third party vendors of $50 is approved.**

6. **The approved pre-paid rate is $10.90 for the first 100 kWh within a 30-day consumption cycle and $18.34 for each additional kWh thereafter within that 30-day consumption cycle.**

7.3.3.3 Proposed Community Renewal Tariff

Through the proposed Community Renewal Programme, communities currently not paying for electricity are invited by JPS to connect to the system under promotional conditions, paying just for Long Run Marginal Cost. This JPS stated is a temporary programme aimed at recovering non-technical losses.

JPS proposed the following tariff structure for this customer class:

- **NAC: applicable whether there is consumption. It covers the customer service marginal costs.**

- **Energy charge: This charge is paid for every kWh of consumption and it covers capacity marginal cost.**

JPS proposed that the rate will only be applicable for the first 200 kWh/month. Any higher consumption amount would be charged at the normal rate. According to the proposed tariff design, the non-fuel rate schedule and its comparison with the adjusted current rate schedule are as shown in Table 7.310 below.

Table 7.310: JPS' Proposed RT10 Community Renewal Rate Schedule

	Proposed Rates		Current Rates		Variation %	
Class	Network Access Charge (USD/Cust./ month)	Energy Charge (USD/kWh)	Customer Charge (USD/Cust./ month)	Energy Charge (USD/kWh)	NAC vs Customer Charge	Energy Charge
RT 10 Community Renewal Program	0.000	0.069	3.815	0.069	-100%	1%

The OUR is not, in principle, opposed to the introduction of the community improvement tariff by JPS. Further comments are provided on this at Section 10.2 *(Proposed Community Renewal Programme)* of this Determination Notice.

7.3.3.4 General Service – RT20

JPS has proposed the introduction of four tiers in this category. The proposal is for four different fixed charges and four energy charges. These are outlined as follows:

- RT20 – 1st Tier (Consumption levels between 0 – 100 kWh/month)
- RT20 – 2nd Tier (Consumption levels between 101 – 1000 kWh/month)
- RT20 – 3rd Tier (Consumption levels between 1000 – 7500 kWh/month)
- RT20 – 4th Tier (Consumptions over 7500 kWh/month)

Charges differ between that paid by customers in the first tier, the second tier and the third tier.

JPS' proposal was that the customer's twelve-month moving average energy consumption will determine his/her tier for billing purposes. However, in its considerations leading up to this determination, the OUR has rejected the tier structure and has indicated that it will maintain the current structure of a single tier customer charge. For reasons previously stated and reiterated hereafter, the OUR does not approve the tiered structure proposed by JPS (See Section 7.4.16 for further details).

JPS has not presented a tariff design which demonstrates, sufficiently, the true cost that the small commercial customers incur. In the absence of this information, the danger is that cross-subsidies between these two rate classes are likely and this will undermine any desired efficiency goals. The OUR is not convinced that the JPS proposition regarding four tiers offer any greater benefits to the consumer and the less than efficient allocation of costs does not justify the change at this time. JPS may seek to rebalance its tariff structure at the next tariff review based on the tier structures. The

OUR will evaluate such proposals on their merit at the time of filing, taking all regulatory impact assessments into consideration.

7.3.3.5 Street Lights and Traffic Lights – RT60

JPS has proposed that the Street Lighting category tariff structure remains the same:

- Proposed NAC: applicable whether or not there is consumption. It covers the customer service marginal costs and a portion of the Revenue Gap.

- Proposed Energy charge: This charge is paid for every kWh of consumption and it covers capacity marginal cost and a portion of non-fuel costs that are part of the Revenue Gap.

The Ministry of Local Government and Community Development (MLGCD) has the responsibility for the payment of the charges for street lighting. In a response to JPS' Tariff Submission, the MLGCD, among other things, requested the following:

- Given the difference in costs of LED lights the tariff should include rates for LED lights.
- The Energy charge for customer-owned and maintained lamps should be reduced by removing the cost of maintenance and capital cost of replacement.
- The tariff should recognise that streetlight management systems now allow for flexible streetlight operation including dimming with significant additional energy saving.

The full text of the MLGCD is attached hereto as Appendix C to this Determination Notice.

JPS has advised that no standardization has been done on the possible lamps to be installed and so there is no accurate assessment for the capital and O&M component of the tariff. As mentioned under Section 7.3 - "JPS' Proposed Billing Determinants", in terms of energy sales, reductions are expected for streetlights because of LED technology replacement for current lamps. In JPS' Tariff Submission, JPS posited that the company expects that 1/4 of all streetlights will be replaced each year beginning in 2014. Based on energy sales in 2013, JPS projects demand to fall from 62,916MWh in 2014 to 32,580MWh by 2017 due mainly to the effects of LED retrofits.

The OUR mandates that JPS obtains the necessary information in order to ascertain the capital and O&M cost components, ascertain the number and effective demand for the LED streetlights and presents to the OUR an appropriate revised tariff design within six (6) months of the effective date of this Determination Notice.

DETERMINATION 22

The Office MANDATES that JPS obtains the necessary information in order to ascertain the Capital and O&M cost components; ascertain the number and effective demand for the LED streetlights; and presents to the Office an appropriate revised tariff design within six (6) months of the effective date of this Determination Notice.

7.3.3.6 Large Commercial Customers – RT40 and RT50

The tariff structure for Power Service Low Voltage category shall be the current tariff structure.

DETERMINATION 23

The Office DETERMINES that the tariff structure for Power Service Low Voltage category shall be the current tariff structure.

7.3.3.7 Proposed Wholesale Tariff (WT)

JPS proposed a WT for the largest users of energy and demand on the grid. The WT is intended for customers with demand exceeding 1 MVA, and JPS stated that it should be an incentive for customers with the potential to self-generate to remain on the grid thereby keeping downward pressure on per unit cost for all customers using the network.

Therefore, the WT will be offered to the largest customers that opt not to wheel, which may substantially influence the decision of entities who may be considering whether to wheel. JPS stated that failure to offer such a WT could lead to JPS' largest customers choosing to wheel out of their own self-interest, but which would eventually result in a sub-optimal outcome for the country, and which would distort the efficient regulated tariff structure.

JPS proposed that the WT have four declining blocks in recognition of the lower Best Alternative Option (BAO) for larger generation equipment. JPS stated that Retail minus tariff (R-), WT and Economic Development Tariffs (EDT) are analogous tariff design approaches that aim at efficiently using the system with global optimal cost minimization criteria for the electricity sector as a whole.

JPS stated that the retail minus concept requires that for those customers who do not consume a service that is bundled into the retail tariff, the cost of that service is to be discounted from the retail tariff. This discount is increasing with energy consumption (decreasing blocks). The WT, because of its nature, will offer increasing discounts to higher volume consumers and therefore a minimum demand requirement to qualify as wholesale customer needed to be determined.

In order to calculate the WT, JPS considered the BAO for the largest customers (those who would be eligible for the new tariff). Also, for the same revenue requirement, any tariff rebalancing (as would be required with the wholesale tariff) entails increasing some customer class tariffs in order to reduce others. JPS further stated that adjusting price structures—or rebalancing, as it is often called—could, but does not necessarily involve cross-subsidies. For example, if one generator may supply power to both residential and industrial customers, it is not possible to say exactly what part of the cost of the common rate base is attributable to each customer class. Therefore, one customer class can end up paying more than another, without necessarily subsidizing the other. A cross-subsidy exists if—and only if—the tariff charged to the residential rate class is greater than its stand-alone cost, and the benefits are passed to those customers who would qualify for the WT (and thus would pay less than their incremental costs).

The CACU and the JIE are among those supporting the introduction of the wholesale tariff. In a response to the JPS' Tariff Submission, the JIE stated that *"This will allow JPS to respond to market changes within a short period of time as technology is changing rapidly. This is within the context of price cap (i.e. rates will be less than the full cost of providing service). This will encourage larger customers to remain on the grid and hence reducing the upward pressure of prices on the remaining customers."* The Jamaica Chamber of Commerce (JCC) also supported the initiative in principle "as an inducement to keep the bigger users online". The JCC, however, made suggestion for an independent study. The full text of the CACU's, the JIE's and the JCC's submissions are in Appendix C of this Determination Notice.

The OUR does not approve the introduction of the Wholesale Tariff structure given that JPS has not presented a suitable tariff design and a satisfactory model to support its request.

DETERMINATION 24

JPS' proposed Wholesale Tariff structure was NOT APPROVED on the grounds that JPS has not presented a suitable tariff design and a satisfactory model to support its request.

Chapter 8: Foreign Exchange (FX) Adjustment Mechanism

8.1 Foreign Exchange Risk Exposure

JPS posited that while the company's tariff structure permits monthly adjustments to billing rates to compensate for fluctuations in the exchange rate, the adjustments do not address the settlement risk which the company faces. JPS claimed that the settlement risk (i.e. setting of monthly billing FX rate to collection) and conversion risk (from collection of Jamaican dollar billing until US dollar funds can be purchased on the local foreign exchange markets until US dollar denominated obligations have been paid) are manifested in the level of FX losses which the company incurs in its financial statements. JPS further argued that any significant currency fluctuation or changes by the Office to restrict indexation of tariffs to exchange rates could adversely impact the company's financial performance.

JPS stated that the company is currently facing significant foreign exchange exposure due to limitations in its non-fuel tariff indexation mechanism and on the settlement of business transactions. While the non-fuel index mechanism partially offsets the currency risk to billed revenues, there is no mechanism in place to adequately address the settlement risk or post billing exposure.

8.2 Risk on Non-Fuel Adjustment Mechanism

JPS recovers revenues through tariffs which are set on an assumed Base Exchange Rate which exposes the company to significant currency and settlement risks. Consequently, the Licence permits the company to adjust billing rates each month to account for movements in the exchange rate between the US dollar and Jamaican dollar.

The adjustment mechanism allows for a 76% foreign cost factor which means that the formula indexes 76% of the non-fuel base tariffs to the exchange rate movement. The factor was set in the Jamaica Public Service Company Limited - Tariff Review for period 2004 - 2009 - Determination Notice dated June 25, 2004 Document No. Elec 2004/02.1 ("2004 Determination Notice") based on a currency composition of the Company's cost of 76% US dollar-related costs and 24% local costs.

Table 8.21 below summarizes JPS' reported test year expenses based on its 2013 audited financial accounts including their relative proportions of the total expenses as well as the US dollar-component of the actual costs. As represented by JPS, 80% of its non-fuel costs incurred were US dollar-related costs.

Table 8.21: Test Year Currency Composition of Costs

Currency Composition of Costs				
	Actual Costs		US$ Component of Actual Costs	
	Expense US$000	% of Total Expense	US$ Equivalent US$000	Percentage
Power Purchased (non-fuel)	**104,111**	**9%**	**104,111**	**100%**
O&M Expenses	**143,265**	**12%**	**143,265**	**38%**
Payroll, benefits & training	58,958	5%	58,958	0%
Third party services	25,830	2%	25,830	28%
Materials & equipment	8,544	1%	8,544	100%
Office & Other expense	24,778	2%	24,778	60%
Insurance expense	6,811	1%	6,811	100%
Bad debt write-off	18,342	2%	18,342	91%
Depreciation	**49,168**	**4%**	**49,168**	**100%**
Net Finance Costs	**61,777**	**5%**	**61,777**	**99%**
Finance Income	(3,065)	0%	(3,065)	100%
Interest on customer deposits	549	0%	549	0%
Interest on Short-term debt	1,403	0%	1,403	100%
Interest on Long-term debt	31,383	3%	31,383	100%
Other Net-Financing costs	31,507	3%	31,507	100%
Other Income	**(4,425)**	**0%**	**(4,425)**	**0%**
Non-operational expenses	**4,341**	**0%**	**4,341**	**0%**
Sinking fund contribution	**7,500**	**1%**	**7,500**	**100%**
Return On Rate Base	**75,711**	**6%**	**75,711**	**100%**
Return on Equity	50,474	4%	50,474	100%
Taxation	25,237	2%	25,237	100%
Total Non-Fuel Expenses	**441,448**	**38%**	**441,448**	**80%**
Total Fuel Expenses	**728,745**	**62%**	**728,745**	**100%**
Total Expenses	**1,170,193**	**100%**	**1,170,193**	**92%**

In the JPS' Tariff Submission, JPS indicated that based on the cost composition provided in Table 8.21 above, it proposes that the existing foreign cost factor of 76% in the foreign exchange adjustment mechanism be reset to reflect the currency composition of costs as at 2013, the price cap test year.

The proposed indexation is as follows:

$$\boldsymbol{Tariff_m = Tariff_b \times \left[1 + 0.80\left(\frac{EXC_{m-1} - EXC_b}{EXC_b}\right)\right]}$$

Where:

Tariff$_m$	= Adjusted tariff for the month
Tariff$_b$	= Unadjusted tariff for the month calculated on Non-Fuel base rates.
EXC$_b$	= Base Exchange rate for Jamaican Dollars into United States Dollars
EXC$_{m-1}$	= The Exchange Rate which is shown on the face of the bill that is the arithmetic mean of the daily weighted average of rates at which financial institutions in Jamaica sell United States Dollars for Jamaican Dollars on the Spot Market (the "Spot Market Weighted Average Selling Rate") issued by the Bank of Jamaica for the month, two months preceding the month of billing. If no such rate is issued on any particular day by the Bank of Jamaica or, if the current system for determining the rate at which United States Dollars are exchanged for Jamaican Dollars shall have changed then, for the purpose of this provision, the rate for each such day shall be the weighted average of the rates at which Commercial Banks in Jamaica sell United States Dollars for Jamaican Dollars on each such day as determined by the Licensee. Where the billing period exceeds one month, that rate shall be the arithmetic mean of the monthly average exchange rates determined in accordance with the foregoing.

JPS also contended that reviewing the adjustment factor every five (5) years exposes the company to increased foreign exchange risk as the currency composition of the costs incurred by JPS changes significantly between reviews. This it argued, is mainly because the proportion of US dollar-related costs increases as the Jamaican dollar depreciates. It further asserted that while the company has made significant efforts to manage expenses to minimize its US dollar exposure, successive rounds of depreciation of the Jamaican dollar has resulted in an ever-increasing proportion of costs being US dollar-related. JPS claimed that to adequately account for the impact to exchange rate variability on its operations it found it prudent to change its reporting currency to the US dollar in 2008.

JPS proposed that the regulator should allow an annual review of the currency cost components of the company using the audited financial statements of the calendar year prior to each annual rate adjustment. The results of this review is proposed to be used to update the foreign exchange adjustment formula to reflect any changes in the relative proportion of US dollar-related costs to local costs.

8.3 OUR's Position on JPS' Currency Composition of Cost

Based on the relative proportions of the approved non-fuel costs, the Office DETERMINES that the foreign cost factor to be applied in the foreign exchange adjustment mechanism shall be increased from 76% to 80%.

In JPS' Tariff Submission, JPS claimed that reviewing the foreign cost factor every 5 years exposes the company to increased foreign exchange risk as the currency composition of the costs incurred by JPS fluctuates significantly between reviews. However, the OUR rejects this claim on the grounds that the movement in the foreign cost factor from 76% in 2004 to JPS' reported factor of 80% in 2013, a change of 4% over a ten (10)-year period can hardly be considered so significant as to warrant an annual review. Given that the price cap regime is applicable over an extended period, the Office is of the view that incorporating the variability in certain operational parameters and activities of temporary and short-term nature at each Annual Tariff Adjustment may not accord with the objectives of the price cap regime.

DETERMINATION 25

1. **The Office DETERMINES that the foreign cost factor in the foreign exchange adjustment mechanism shall be 80%.**

2. **JPS' proposal to allow an annual review of the currency cost components of the Company using the audited financial statements of the calendar year prior to each annual rate adjustment is NOT APPROVED.**

8.4 Foreign Exchange Losses/Gains

The annual inflation adjustment clause is the mechanism through which JPS adjusts its non-fuel tariffs to reflect annual changes in the USA and Jamaica consumer price indices. The procedure involves the application of an adjustment formula dI, to the base non-fuel tariffs to keep these tariffs constant in real terms. It is important therefore that the formula accurately accounts for price movements to ensure cost-reflective tariffs. This position was shared by JPS and in its 2004 Tariff Submission, the company reviewed the computation of the annual inflation adjustment formula and submitted a proposal for its modification to the OUR.

Their observations then were:

1. The formula in the Rate Schedule is a stylized equation, which overlooks an element of the expression. Consequently, successive application of the formula as it then exists to the rate base lead to the under-recovery of revenues.

2. The formula in the Licence was different from the formula in the Rate Schedule. The difference was caused by an omission of an exchange rate term, which seemed to be typographical in nature.

3. Neither formula accurately derived the correct inflation adjustment required.

The OUR agreed to the modification and in the 2004 Determination Notice made the following determination:

"The Office has determined at the time that the annual inflation adjustment formula, dI is given as:-

$$dI = 0.76* \Delta e + 0.76*\Delta e *0.922 *i\ US + 0.76*0.922 *iUS + 0.24* ij$$

Where:

f_{us} = US factor = 0.76

f_j = Local (Jamaica) factor = 0.24

The above equation suggest that the debt factor (d) as determined by the OUR, is 0.078 or 7.8%. The debt factor in 2003 was 40% and JPS proposed an adjustment to 60% in 2004."

In the JPS' Tariff Submission, JPS stated the following:

> *"The above formula suggests that 76 percent of all costs incurred by JPS are US$ related and 24 percent are local Jamaican dollar costs. The equation also suggests that 8 percent of the US dollar related costs pertain to debt financing costs and hence should not be subject to US inflation adjustments. These parameters were determined in the 2004 Tariff Review and were retained in the 2009 Tariff Review Determination. The regulator opted to retain the parameters despite evidence included in the 2009 Tariff Submission that showed US dollar related costs to be 79 percent of all non-fuel costs."*

Figure 8.41 below shows an extract from JPS' 2004 Tariff Submission showing the details of the then proposed inflation formula.

Figure 8.41

The annual inflation adjustment factor (dI)

JPS proposes that the inflation adjustment formula (dI) to be used with the 2004 tariffs, be changed to reflect the true inflation costs incurred on JPS. Therefore, any inflationary movements should be applied to the base non-fuel tariffs using:

$$dI = f_{us}\Delta e(1 + (1 - d)i_{us}) + f_{us}(1 - d)i_{us} + f_j i_j$$

Instead of

$$dI = f_{us}\Delta e(1 + di_{us}) + f_{us} di_{us} + f_j i_j$$

as currently stated in the Licence, here:

$\Delta e \equiv$ Change in the Base Exchange rate

$i_{us} \equiv$ US inflation rate (as defined in the licence)

$i_j \equiv$ Jamaican inflation rate (as defined in the licence)

$f_{us} \equiv$ US factor, which refers to the portion of non-fuel costs that are denominated in US dollar terms

$f_j \equiv$ Local (Jamaica) factor, which refers to the portion of non-fuel costs that are denominated in local currency

$d \equiv$ Debt factor, where the debt factor, d accounts for portion of US related non-fuel cost that is accounted for by debt financing costs.

In addition, for 2004, JPS proposes resetting f_{us}, f_j and d to reflect the current proportions of US- and domestic-related costs as well as debt-financing costs, based on the audited accounts for the financial year 2003. That is, f_{us} should be set to be 76%, with a corresponding f_j factor of 24%. The debt factor, d, will also be revised to reflect 60% of US denominated costs being debt related. For 2005 onwards, JPS proposes that these figures be reviewed and reset accordingly, to reflect the current proportions of costs.

Specifically, for 2004, JPS proposes setting f_{us}, f_j and d be set based on the audited accounts for the financial year 2003. As shown in Table 10.1, this would imply that f_{us} be revised to reflect a 76% US factor, with a corresponding change in the f_j factor to 24%. The debt factor d will also be revised to reflect 60% of the US non-fuel costs being debt related.[27] For 2005 onwards, JPS proposes that these figures be reviewed and reset accordingly, to reflect the current proportions of US- and domestic-related costs as well as debt-financing costs (See Section 12).

Table 10.1: Foreign and Local Cost Component for financial period ended December 2003[1]

	Actual Costs		US$ component of Actual Costs (J$ Equivalent)	
	J$000	% of Total Expense	%	J$000
TOTAL NON-FUEL EXPENSES	18,365,676	59%	76%	13,949,690
Purchased Power (non-fuel)	3,477,385	11%	100%	3,477,385
O&M Expenses	6,189,680	20%	31%	1,925,465
Sinking (self-insurance) fund contribution[2]	126,000	0%	100%	126,000
Debt Related Expense[3]	8,572,611	28%	98%	8,420,841
Depreciation	*1,960,574*	*6%*	*100%*	*1,960,574*
Interest on Customer Deposits	*151,770*	*0%*	*0%*	-
Net Financing costs[4]	*-262,731*	*-1%*	*100%*	*-262,731*
Return on Debt	*1,091,442*	*4%*	*100%*	*1,091,442*
Pre-Tax Return on Equity	*5,631,556*	*18%*	*100%*	*5,631,556*

Notes: [1]Figures are based on unaudited accounts, as on February 15th 2004. At time of submission of this report, audited accounts are not available. They will be available in March 2004; [2] Self-Insurance Fund Contribution taken from the Revenue Requirement for the Test Year Period (see Table 6.1). [3]Debt Related Expense captures those US costs that do not move with US inflation. [4]Net Financing Costs excludes Interest on long-term debt, which is captured in the WACC.

In JPS' Tariff Submission, JPS sought to make the case that only twelve percent (12%) of all US$-related costs as at December 2013 was related to debt financing as summarized in Table 8.41 below.

Table 8.41: JPS' Proposed Debt Factor as a Percentage of US$-Related Costs as at December 2013

Debt Financing Costs	US $
Int on Customer Deposits	549
Net Financing Costs	9,965
Interest on LT Debt	31,383
	41,897
Total Non Fuel US Costs	351,798
Debt factor	**12%**

Table 8.42 below shows JPS' total non-fuel expenses for the years 2004 and 2013 and the breakdown that separates the US dollar cost component from the actual line item costs.

As shown in the Table 8.42 below, JPS in 2004 declared that the debt-related expenses that should not be subject to US inflation adjustment were:

- Depreciation
- Net Financing costs
- Return on debt
- Pre-Tax Return on Equity

The balances on these accounts were used to compute the debt factor of 60% in 2004.

The OUR agrees with the principle used by JPS in its 2004 Tariff Submission wherein depreciation, although accounted for as an expense item was not subjected to US inflation adjustment given that it is not a cash expense (output) item. Also, return-on-equity which is a profit on investment was rightly not subjected to annual US inflation adjustment.

Table 8.42: Total Non-fuel Expenses for Years 2004 and 2013

Non-Fuel Expenses	**Actual Costs**		**US$ component of Actual Costs J$ Equivalent**	
	(J$'000) 2004	(US$'000) 2013	(J$'000) 2004	(US$'000) 2013
Total Non-Fuel Expenses	**18,365,676**	**456,040**	**13,949,691**	**366,307**
Power Purchased (non-fuel)	3,477,385	104,111	3,477,385	104,111
O&M Expenses	6,189,680	143,265	1,925,465	54,081
Sinking (Self-insurance) fund contribution	126,000	7,500	126,000	7,500
Debt Related Expense	**8,572,611**	**201,164**	**8,420,841**	**200,615**
Depreciation	*1,960,574*	*49,168*	*1,960,574*	*49,168*
Interest on Customer Deposits	*151,770*	*549*	-	-
Net Financing costs	*(262,731)*	*29,547*	*(262,731)*	*29,547*
Return on Debt	*1,091,442*	*31,383*	*1,091,442*	*31,383*
Pre-Tax Return on Equity	*5,631,556*	*90,517*	*5,631,556*	*90,517*
Fuel Expenses	**12,570,818**	**728,745**		
Total Expenses	**30,936,494**	**1,184,785**		
Non-Fuel Component of Total Expenses	59%	38%		
US Component of Non-Fuel Cost	76%	80%		
Debt Factor (d) US related non-fuel cost that is accounted for by	**60%**	**55%**		

Based on the foregoing principle, the OUR computes a value of 55% for the debt factor for the year 2013.

The OUR is of the view that for clarity the debt factor should be renamed and redefined as follows:

Debt factor is renamed the Non-US Adjusted Factor = all that portion of the US component of the total non-fuel expenses that is not subject to US inflation adjustment.

Consequently, the annual adjustment formula shall be:

$$\boldsymbol{dI} = USP \times \left(\frac{EXn - EXb}{EXb}\right)(1 + USAF \times INFus\,) + (USP \times USAF \times INFus) + (1 - USP)\ \times INFj$$

Where:

EX_b	=	Base US Exchange Rate
EXn	=	Applicable US Exchange rate at Adjustment Date
$INFus$	=	US Inflation as defined in the Legal and Regulatory Framework.
$INFj$	=	Jamaica Inflation as defined in the Legal and Regulatory Framework.
USP	=	0.80 (US portion of the total non-fuel expenses)
$USAF$	=	0.45 (the US Adjusted Factor which represents that portion of the US component of the total non-fuel expenses that is not subject to US inflation adjustment)

DETERMINATION 26

The Office DETERMINES that the annual adjustment formula shall be:

$$\boldsymbol{dI = USP \times ((EXn - EXb)/EXb)(1 + USAF \times INFus\,) + (USP \times USAF \times INFus) + (1 - USP)\ \times INFj}$$

8.5 Risk on the Settlement of Business Transactions

JPS stated in the JPS' Tariff Submission that the FX risk on the settlement of business transactions is the risk that the amount of functional currency exchanged to settle a transaction will be different from its equivalent contract value. Further, JPS stated that these transactions may be payments to JPS by customers for electricity services, receivables, or payments by JPS for goods and services and other payables.

JPS has indicated that the average settlement period for receivables, and for accounts payables, averages fifty-two (52) days, particularly due to the delinquency of the GOJ over the last three (3) years and fluctuation in the exchange rate during this settlement period gives rise, it argued, to significant foreign exchange exposure, up to two percent (2%) in a single month. On accounts payables, JPS reported that it takes fifty seven (57) days on average to settle its obligations. For the 2013 financial year, JPS reported that it incurred US$21M of FX loss which the company attributed to this foreign exchange exposure. Table 8.51 below shows the total foreign exchange losses reported by JPS for the last three (3) years.

Table 8.51: JPS' Reported Foreign Exchange Losses – 2011 to 2013

	2011	2012	2013
		US$	
Receivables	2,349,326	15,579,331	30,223,586
Payables	1,175,521	(1,076,236)	(2,406,024)
Cash	(331,036)	(1,692,895)	(9,559,426)
Other	81,787	2,068,456	2,855,995
	3,275,598	14,878,655	21,114,132

JPS argued that the company is specifically exposed to FX risk on accounts receivables that are denominated in Jamaican dollars while having to settle most of its obligations in US dollars. The company's receivables are primarily from electricity sales transactions that are conducted on a post-paid basis.

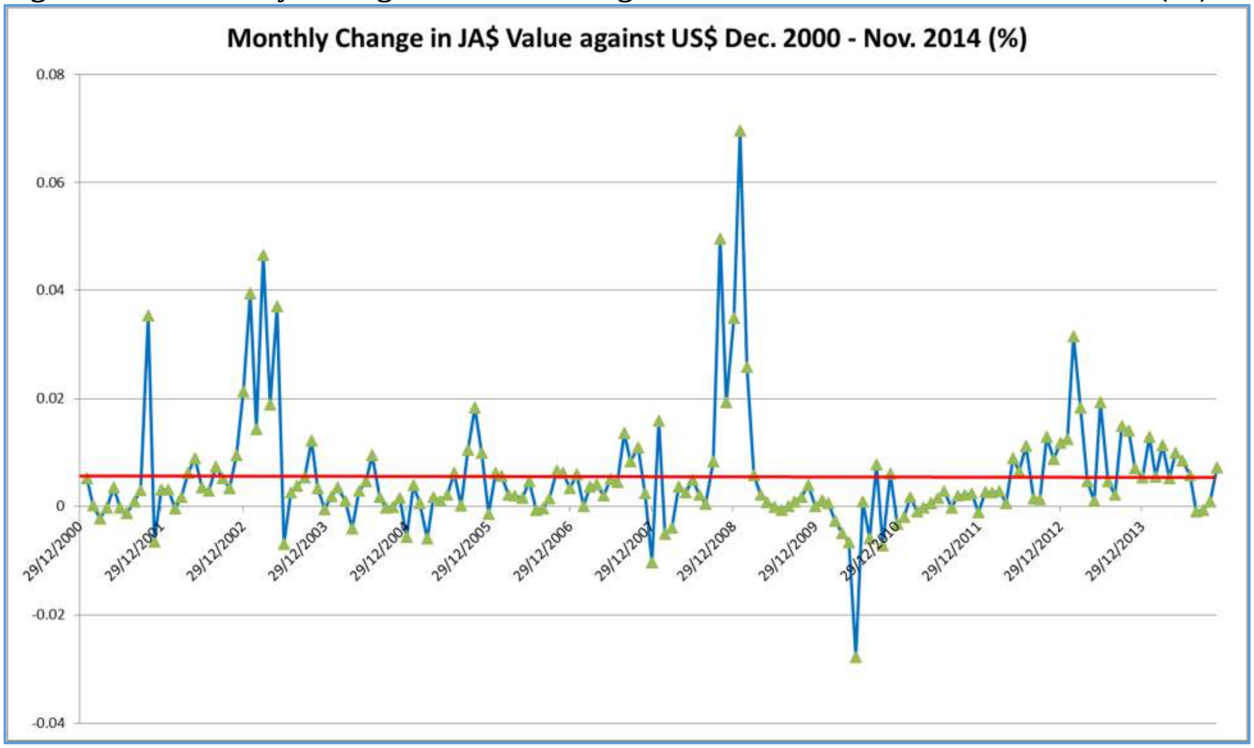
JPS asserted that the company manages FX risk on business transactions by closely monitoring the foreign exchange market and maintaining adequate liquid resources in appropriate currencies. The company indicated that it tries to manage the timing of payments of foreign currency liabilities. It argued however, that it has little control over this exposure and there is no reasonable opportunity to hedge, due to illiquid markets. As a result, the company believes that the exposure to this risk should be mitigated through the regulatory tariffs.

JPS proposed that the OUR allows the inclusion of a separate revenue requirement item for the FX losses incurred on business transactions. The amount of US$14M was included for this in the revenue requirement proposed by JPS. This amount is based on the amount identified in the test year (2013) audited financials and adjusted for the 2014 estimate. Additionally, JPS requested the implementation of an annual "true-up" mechanism to reconcile the actual FX losses incurred compared to the amount embedded in the revenue requirement.

8.5.1 OUR's Review of JPS' Proposal

A close examination of the monthly change in the value of the Jamaican dollar against the United States dollar since December 2000 to November 2014 (see Figure 8.52 below) shows that the trend has remained very flat with occasional peaks and troughs, during times of major adjustments such as what was recently experienced under the current IMF program. The recent volatility in the rate is not expected to continue during the next five years and indeed, some level of stabilization is already evident.

Figure 8.52: Monthly Change in JA$ Value against US$ Dec. 2000 – November 2014 (%)



8.6 OUR's Position on JPS' FX Losses

According to JPS, its FX losses are largely influenced by the delinquency of the GOJ in making payment on time over the last three years. In its "Comments on OUR's 2014-19 Tariff Review Draft Determination" dated July 21, 2014, JPS stated that GOJ accounts are settled on average in more than 120 days. The company also indicated that the GOJ had total receivables outstanding amounting to J$4.5B at December 31, 2013 and J$6.2B at March 31, 2014, with J$2.9B outstanding for street lights services and a further J$1.3B due from NWC alone.

With respect to the FX losses situation, the Office takes the position that the solution to this problem lies in JPS exerting greater diligence and efforts to recover its revenues and any attendant costs, directly from the customers who are causing this condition.

The inclusion of a separate revenue requirement item for the FX losses incurred on business transactions does not accord with the provisions of the Licence and therefore is disallowed by the

OUR. Consequently, the “true-up” mechanism to reconcile any incurred FX losses is NOT APPROVED.

The inclusion of a separate revenue requirement item for the FX losses incurred by JPS on business transactions and the proposed “true-up” mechanism to reconcile FX losses are NOT APPROVED for the following reasons:

1) It would be inconsistent with the provisions of the Licence.

2) The Licence now allows JPS to adjust its base foreign exchange rate on a monthly basis.

3) The problem arises largely because of the size of the JPS receivables, which JPS explained is largely due to Government of Jamaica (GOJ) debt. The Office takes the position that JPS should exert greater effort to recover its revenues, especially with respect to the GOJ, which is also a significant shareholder of JPS.

4) The entire amount of the JPS receivables is included in the Rate Base and JPS is therefore earning a return on these receivables.

5) JPS has the option to make all IPPs payments in Jamaican Dollars at an invoice exchange rate. Since these payments are also in arrears, JPS is aggravating its exposure by choosing to make these payments in United States Dollars.

6) In its most recent agreement with Petrojam (also largely a GOJ-owned entity) JPS created unusual exposure based on its agreed terms. JPS further aggravated this situation by having its payables to Petrojam growing.

DETERMINATION 27

1. **The inclusion of a separate revenue requirement item for the FX losses incurred on business transactions is NOT APPROVED by the Office.**

2. **The proposed “true-up” mechanism to reconcile any incurred FX losses is NOT APPROVED.**

Chapter 9: Fuel Cost Recovery - Heat Rate Target

9.1 Introduction

9.1.1 Background

A significant portion of JPS' monthly operating expenses is the cost of fuel consumed by JPS-owned and IPP-owned generating plants in the production of electricity supplied to its customers.

The total fuel cost depends on the following factors:

1) The price JPS and IPPs pay for fuel;
2) The fuel conversion efficiencies (heat rates) of JPS and IPPs' generating plants;
3) The quantity of electrical energy required to be generated; and
4) The proportion of electricity generation provided by different generating plants.

Fuel rates change whenever one or more of the above factors are altered.

Over the price-cap period, October 2009 to June 2014, approximately 71% of the monthly average fuel consumption was attributable to JPS' plants while 29% was due to IPP plants with commensurate monthly average fuel costs of US$40.11M and US$15.54M respectively. The relative proportions of these costs are illustrated in Figure 9.11 below.

Presently, all the fuel used for electricity generation is supplied by Petrojam to JPS and IPPs under long-term fuel supply agreements (FSA) in which the fuel prices (US$/Barrel) are based on a pricing formula.

The main fuel types used are heavy fuel oil (HFO) and automotive diesel oil (ADO). HFO is predominantly used in steam generating units and reciprocating diesel engine generators while ADO is used in simple cycle gas turbine (SCGT) and combined cycle gas turbine (CCGT) generating units.

The prices of these fuels are hugely influenced by international fuel markets and, as such, are subject to large variability and unpredictability. This suggests that the prices of fuel oil used for electricity generation are largely outside the control of JPS and IPPs. Since October 2009, HFO prices have ranged from US$33.50 per barrel to US$113.13 per barrel while ADO prices varied between US$62.50 per barrel and US$160.52 per barrel. Monthly fuel rates ranged from 9.82 US¢/kWh to 27.54 US¢/kWh over the period.

Currently, fuel charge represents approximately 67% of a residential customer's electricity bill.

Figure 9.11: Relative Proportions of JPS' and IPPs' Monthly Average Fuel Cost and Net Generation (October 2009 – June 2014)

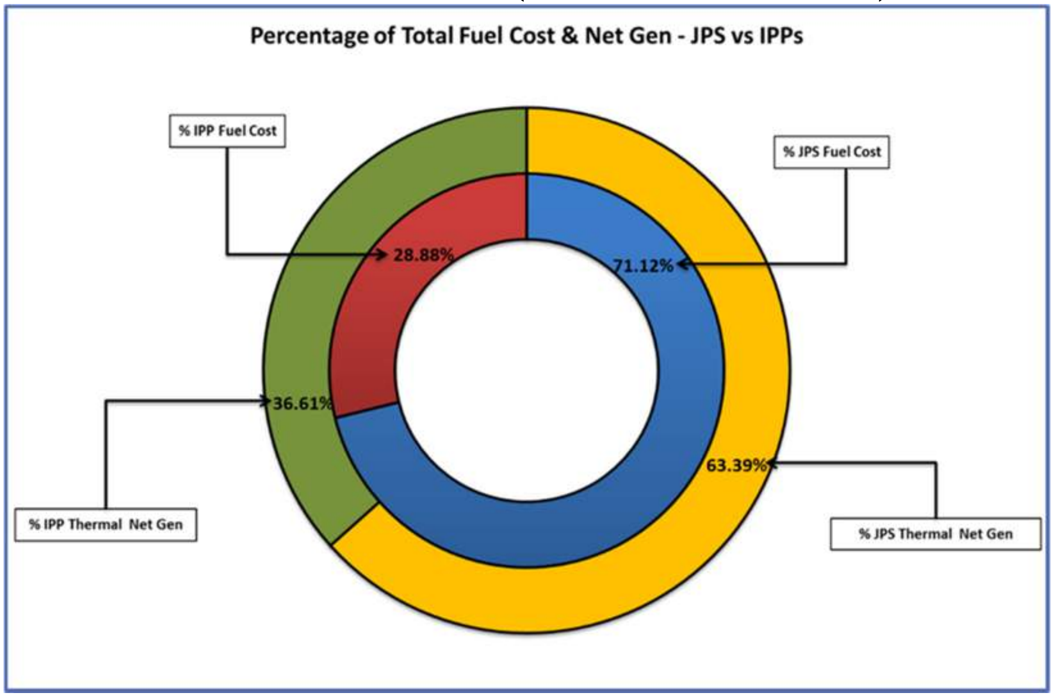


Figure 9.11 above also shows the monthly average net generation corresponding to the respective proportions of JPS' and IPPs' monthly average fuel costs. As shown, IPPs account for approximately 37% of the monthly average net generation but just about 29% of the monthly average fuel cost. The data also indicates that the IPPs' monthly average net generation and fuel cost are approximately 60% and 40% respectively of those for JPS. This electricity production and cost comparison implies that higher utilisation of the IPPs could result in lower fuel costs.

9.1.2 Scope

This Chapter addresses, among other things, three (3) fundamental aspects of JPS' Fuel Cost Adjustment Mechanism (FCAM):

1) The determination of the appropriate heat rate target to be used as an efficiency adjustment parameter in the Fuel Rate Calculations each month;

2) The establishment of the appropriate fuel cost pass through equation that accords with the relevant provisions of the Licence; and

3) The development of a prudent and practicable framework for continuous monitoring and periodic auditing of the monthly Fuel Rate Calculations and the management and utilisation of fuel in the production of electricity.

9.2 Fuel Cost Adjustment Mechanism

In regulated electricity markets, a utility is usually allowed a reasonable opportunity to recover costs and to earn the approved return on investment. Having regard to this regulatory principle, it is accepted that there is need for appropriate adjustment mechanisms under which reasonable and prudent costs incurred by the utility can be recovered, if during the period between rate adjustments certain cost factors change dramatically and unpredictably due to conditions outside the control of the utility. This is typical for the recovery of fuel costs in utility operations. Given that the FCAM adjusts for decreases as well as increases in fuel prices, its use should provide a more accurate tracking of fuel cost over time and more realistic price signals to electricity consumers. The converse also holds that the use of certain cost adjustment mechanisms can potentially divert certain costs from the rate case process and can therefore mask the true impact on ratepayers. It may also encourage utilities to relax their responsibility to manage risks associated with specific costs, particularly fuel costs, thereby shifting the burden to ratepayers.

In FCAMs where electricity rates change relatively quickly in response to price changes, the losses and the gains are usually shifted quickly to the ratepayers; and therefore utilities have less incentive to minimize costs than when benefits go to shareholders. This can sometimes put upward pressure on electricity rates. Given this reality, it is necessary for the regulator to have in place specific performance requirements, and monitoring and enforcement systems to limit the potential adverse effects on electricity rates and the eventual burden on electricity customers.

9.2.1 Licence Requirements for Fuel Cost Adjustment

With respect to the application of the FCAM, Schedule 3, EXHIBIT 2 provides as follows:

> *"The cost of fuel per kilo-watt-hour (net of efficiencies) shall be calculated each month on the basis of the total fuel computed to have been consumed by the Licensee and Independent Power Producers (IPPs) in the production of electricity as well as the Licensee's generating heat rate as determined by the Office at the adjustment date and the IPPs generating heat rate as per contract with the IPPs and system losses, as determined by the Office at the adjustment date of total net generation (the Licensee and IPPs).*
>
> *The fuel cost portion of the monthly bill computed under the appropriate rate schedule will be 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*

The total applicable energy cost for the period is:

(a) the cost of fuel adjusted for the determined heat rate and system losses and which fuel is consumed in the Licensee's generating units or burned in generating units on behalf of the Licensee for the calendar month which ended one month prior to the first day of the billing period plus;

(b) the fuel portion of the cost of purchased power (including IPPs), adjusted for the determined system losses, for the calendar month which ended one month prior to the first day of the billing period; and

(c) an amount to correct for the over-recovery or under-recovery of total reasonable and prudent fuel costs, such amount shall be determined as the difference between fuel costs billed, using estimated fuel costs, and actual reasonable and prudent fuel costs incurred during the month which ended one month prior to the first day of the billing period.

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

The kWh sales in the billing period is the actual kWh sales occurring in the billing period which ended one month prior to the first day of the applicable billing period.

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 ten (10) days prior to the end of the month just preceding the applicable billing month and shall become effective on the first billing cycle on the applicable billing month."

9.2.2 Fuel Cost Adjustment Formula

The existing efficiency adjustment formula that is applied to the total fuel cost consumed in the production of electricity each month is defined by *Equation 9.1*.

Equation 9.1: $$\boldsymbol{Pass\ through\ Cost = Fuel\ Cost \times \frac{Heat\ Rate\ Target}{Heat\ Rate\ Actual} \times \frac{(1 - Losses\ Actual)}{(1 - Losses\ Target)}}$$

Where:

a) Fuel Cost – represents the applicable sum of JPS' and IPPs' fuel cost;
b) Heat Rate Target – the System heat rate target determined by the OUR;
c) Heat Rate Actual – the monthly average heat rate for the entire generation system;

d) Losses Target – the System losses target determined by the OUR; and
e) Losses Actual – the recorded System energy losses including technical and non-technical losses expressed as a percentage of System net generation each month.

Presently, the System heat rate target is 10,200kJ/kWh and the System losses target is 17.5%.

From Equation 9.1, it can be seen that the adjustment factor related to heat rate is represented as:

Heat Rate Adjustment Factor = (Heat Rate Target/Heat Rate Actual)

The elements of the heat rate adjustment factors which are key efficiency parameters are addressed in this Chapter while the elements of the System losses adjustment factor are addressed in detail in Chapter 10.

9.3 Other Legal Requirements

Other legal requirements that govern the treatment of fuel cost and purchased power are set out below.

9.3.1 Economic Purchasing of Electricity

With respect to the economic purchasing of electricity by JPS, Condition 19 of the Licence provides as follows:

"1. The Licensee shall purchase electricity at the best effective price reasonably obtainable having regard to the sources available, contractual arrangements and Government policy.

2. In the discharge of its obligations under paragraph 1, the Licensee shall:

(a) have regard to any considerations liable to affect its ability to discharge its obligations under this Licence in the future, including the future security, reliability and diversity of sources of electricity available for purchase.

(b) operate in accordance with the approved arrangements (or those specified by the Office) and not discriminate in its dealings as operator of the System, and in the operation of the merit order and any accounting and other systems which reflect the terms of the arrangements set out between itself and any other generator of electricity."

9.3.2 Merit Order Dispatch

Regarding the economic dispatch of generating units by JPS, Condition 23 provides as follows:

> *"1. The Licensee shall establish and operate as part of the Generation Code a merit order system, for Generation Sets that are subject to central despatch.*

2. The Licensee shall schedule and issue direct instructions for the despatch in accordance with a merit order system of all available Generation Sets of each authorized electricity operator which are required or are agreed to be subject to such scheduling and instructions.

3. Subject to the factors in paragraph 4, the Licensee shall schedule and issue direct instructions for the despatch of such Generation Sets as are at such times available to generate or transfer electricity:

(a) in ascending order of the marginal cost in respect of any hour for the generation and delivery or transfer of electricity into the System, to the extent allowed by Transmission System operating constraints based on "Equal Incremental Cost-System" principles; and

(b) as will in aggregate and after taking into account electricity delivered into or out of the System from or to other sources be sufficient to match at all times (so far as possible in view of the availability of Generation Sets) demand forecast taking account of information provided by authorised electricity operators, together with an appropriate margin of reserve for security operation.

4. The factors referred to in paragraph 3 above include:

(a) forecast demand (including transmission losses and distribution losses);
(b) economic and technical constraints from time to time imposed on the System or any part or parts thereof;
(c) the dynamic operating characteristics of available Generation Sets; and
(d) other matters provided for in the Generation Code.

5. The Licensee shall provide to the Office such information as the Office shall request concerning the merit order system or any aspect of its operation."

9.4 Heat Rate Adjustment Factor

As previously indicated, the heat rate factor in *Equation 9.1* is represented as:

Heat Rate Adjustment Factor = Heat Rate Target/Actual Heat Rate

To the extent that the actual heat rate is less than the target, the ratio will result in a monetary benefit to JPS and vice versa.

9.4.1 Heat Rate

Heat rate is a measure of the technical efficiency of a thermal power plant or generating unit. It is defined as the amount of fuel energy input used by a generating unit or power plant to generate one kWh of electricity. This is mathematically represented as *Equation 9.2*.

Equation 9.2: $$Heat\ Rate(BTU/h) = \frac{Energy\ Input\ (BTU/h)}{Power\ Output\ (kW)}$$

9.4.1.1 Generating Plant Heat Rates

A generating plant heat rate is normally represented as its fuel conversion efficiency at rated capacity (full-load heat rate). However, its average heat rate is based on its operation along its Input-Output Curve. 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 supply mix.

9.4.1.2 Heat Rate Deviation

Most power plants have a target or design heat rate that they try to achieve during operation. If the actual heat rate does not match the target, the difference between the actual and target heat rate is the heat rate deviation. Most heat rate deviations are small in relation to the overall heat rate. For instance, an 80 Btu/kWh upward deviation is only 1% of an 8,000 Btu/kWh heat rate. This may not mean much on the face of it; however, if the fuel cost associated with the heat rate deviation and energy generated is calculated, it puts into perspective the adverse effect on the operating cost of the plant. This may create the impetus for generator owners to improve the heat rate of their respective plants.

Heat rate and thermal performance improvement are integral parts of any serious effort for cost reduction or containment in an electric generating plant. As the generation sector becomes more competitive, cost containment and the ability to provide energy at the lowest possible cost become important issues.

Service-related degradation in plant heat rate and power output may occur over the lifecycle of the plant due to normal equipment wear. This, however, can be remedied during scheduled maintenance for interim and major overhaul. In some cases, replacing old parts with upgraded components or retrofitting new technology design improvements during a major overhaul, can surpass the original performance and durability of the plant.

9.4.1.3 System Heat Rate

The average System heat rate is dependent on the average heat rate and Net Energy Output (NEO) of each generating unit dispatched.

9.4.2 Principles for Applying System Heat Rate Target

As stated in previous JPS Tariff Determination Notices, the heat rate target for the electricity generation system was considered a prudent and appropriate measure which was adopted to permit the efficient pass-through of fuel costs incurred by JPS to its customers. The target is set on a periodic basis by the OUR to ensure that electricity ratepayers are provided with fair and reasonable fuel rates. The target is also aimed at providing JPS with an incentive to improve the fuel conversion efficiency.

The heat rate target further seeks to ensure that JPS operates the system to minimize the total cost of electricity generation by adhering to the economic dispatch of all available generating units, subject to system constraints, as required by the Licence and the Generation Code.

The following regulatory principles have been applied in setting the System heat rate target:

1) The target should hold JPS accountable for the factors which are under its direct control;
2) The target should reflect legitimate System constraints provided that JPS is taking reasonable action to mitigate these constraints; and
3) The establishment of the target shall be in accordance with the applicable provisions of the Licence.

Since 2001, the heat rate target has been established based on the entire generation System including renewable energy (RE) generation facilities.

9.5 Heat Rate Performance

The OUR's review and analysis of the System heat rate target, average System heat rate and the average actual heat rates of JPS' thermal generating plants are set out in the ensuing sections.

9.5.1 System Heat Rate Target (October 2009 – June 2014)

Since 2004, the target heat rate used in the FCAM has been set to reflect a System-based heat rate.

In the 2009Determination Notice, the Office determined that the System heat rate target should be reviewed and reset annually and should take into account new generation additions to the grid. The heat rate target set by the OUR for the period October 2009 to June 2010 was 10,400kJ/kWh.

The first reset of the System heat rate was done at the 2011-2012 Annual Tariff Adjustment when it was reduced from 10,400kJ/kWh to 10,350kJ/kWh. The downward adjustment of 50kJ/kWh represented the impact of the addition of the Wigton Windfarm Limited ("Wigton") Phase II wind power generation facility to the grid in 2010 with contracted capacity of 14 MW.

The second reset of the target was done at the 2012 Annual Tariff Adjustment when it was moved downwards from 10,350kJ/kWh to 10,200kJ/kWh. The reduction of 150kJ/kWh was due to the following:

- The addition of an extra 4 MW of renewable generating capacity for Wigton Phase II project to the grid which increased the total contracted capacity to 18 MW.

- The addition of the West Kingston Power Partners' 65.5 MW land-based Medium Speed Diesel (MSD) Generation Complex (WKPP Generation Complex) to the grid in July 2012.

Since the adjustment in June 2012, the System heat rate target has remained at 10,200kJ/kWh.

The System heat rates proposed by JPS in the 2009 Tariff Submission and the subsequent annual tariff adjustment submissions and the targets approved by the OUR are shown in Table 9.51 below.

Table 9.51: JPS' System Heat Rate Proposals and Targets 2009-2014

System Heat Rate Proposals and Targets 2009-2014			
Adjustment Period	**Proposed by JPS (kJ/kWh)**	**Set by OUR (kJ/kWh)**	**JPS' Proposal in 2009 to set the System heat rate target to 10,700 from June 2010 onwards, no target was proposed in the 2010 Tariff Adjustment Submission.*
2009-2010	10,850	10,400	
2010-2011	10,700*	10,400	
2011-2012	10,611	10,350	
2012-2013	10,300	10,200	
2013-2014	Proposal to suspend System heat rate target and pass-through fuel cost unadjusted.	10,200	

9.5.2 System Heat Rate Performance (October 2009-June 2014)

Over the duration of the price-cap period, the average System heat rate for each annual tariff adjustment period showed a downward trend with significant improvements during the periods July 2012 to June 2013 and July 2013 to June 2014. This improved System efficiency was mainly due to the addition of the Wigton Phase II and the WKPP Generation Complex to the grid.

The average annual System heat rate for the five (5) adjustment periods are set out in Table 9.52 below.

Table 9.52: System Heat Rate Performance (October 2009 – June 2014)

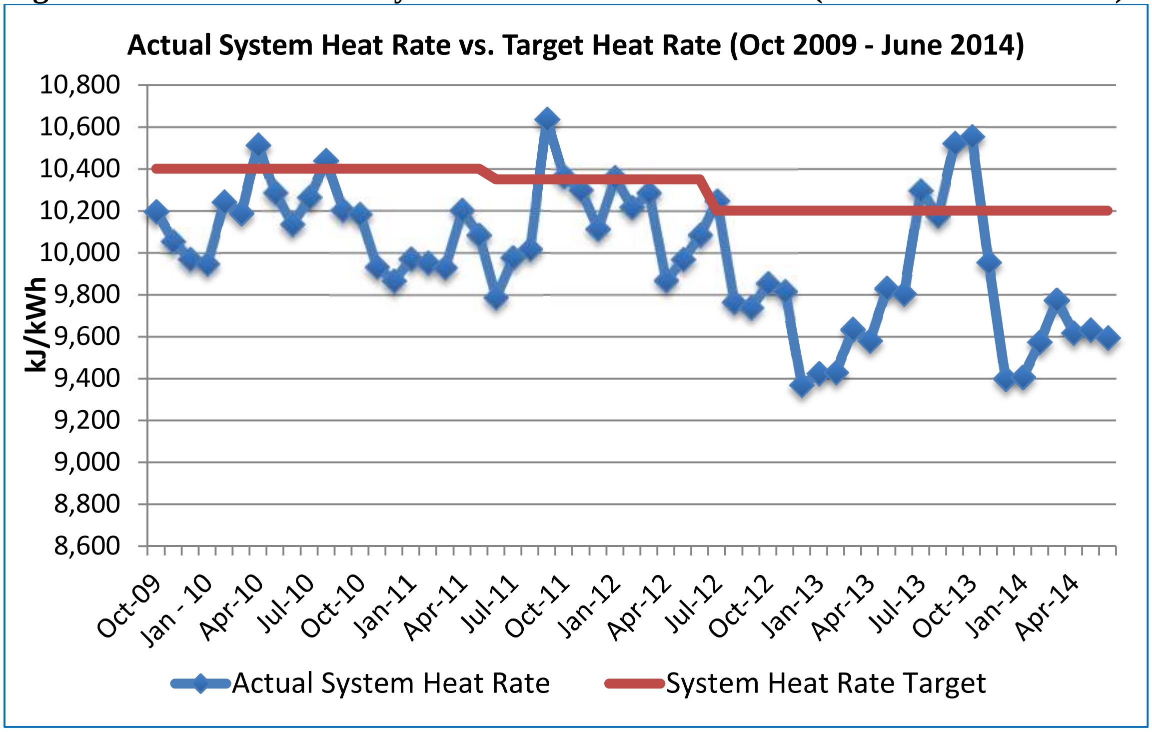
Average Monthly System Heat Rate (kJ/kWh)					
	2009-2010	**2010-2011**	**2011-2012**	**2012-2013**	**2013-2014**
	Target 10,400	**Target 10,400**	**Target 10,350**	**Target 10,200**	**Target 10,200**
July		10,264	9,977	10,249	10,298
August		10,439	10,018	9,765	10,177
September		10,203	10,636	9,739	10,522
October	10,197	10,183	10,365	9,855	10,554
November	10,055	9,932	10,301	9,816	9,954
December	9,970	9,867	10,114	9,369	9,398
January	9,948	9,970	10,360	9,424	9,406
February	10,241	9,953	10,218	9,429	9,573
March	10,189	9,929	10,286	9,634	9,772
April	10,513	10,201	9,868	9,581	9,617
May	10,285	10,083	9,969	9,828	9,631
June	10,137	9,788	10,085	9,805	9,593
Average	**10,171**	**10,068**	**10,183**	**9,708**	**9,875**

The monthly average System heat rate performance compared to the target for the period October 2009 to June 2014 is shown in Table 9.52 above and Figure 9.52 below. As shown, the monthly average System heat rate performance was quite favourable to JPS as the target was achieved 86% of the time or forty nine (49) months out of the fifty seven (57)-month period.

The System heat rate for September and October 2013 in particular was relatively high with figures of 10,522kJ/kWh and 10,554 kJ/kWh respectively. The data indicates that the system heat rate for these months was worse than the target by 322kJ/kWh and 354kJ/kWh respectively.

According to JPS, this adverse heat rate performance was due to significant forced outages of JPS' Bogue ST14 and JEP's Barge #2 during the period September 2013 to December 2013. Despite the few instances of negative deviation from the target, on average, the System heat rate target was comfortably achieved by JPS in each of the five (5) annual adjustment periods.

Figure 9.52: Illustration of System Heat Rate Performance (Oct 2009 – June 2014)



9.5.2.1 Analysis of the Average System Heat Rate (October 2009 – June 2014)

An analysis of the System heat rate dataset given in Table 9.52 above was carried out with a view to providing a more in-depth examination and scientific assessment of the System heat rate performance.

A summary of the analysis of the System heat rate dataset is shown in Table 9.53 below.

Table 9.53: Summary of the System Heat Rate Performance (Oct 2009 – June 2014)

Period	No. of Heat Rate Values	Min	1st Quartile	Median	Mean	3rd Quartile	Max	Range	IQR	Std. Dev
Oct 2009 - Jun 2010	9	9,948	10,055	10,189	10,171	10,241	10,513	565	186	173
Jul 2010 - Jun 2011	12	9,788	9,931	10,027	10,067	10,201	10,439	651	271	192
Jul 2011 - Jun 2012	12	9,868	10,008	10,166	10,183	10,315	10,636	768	308	218
Jul 2012 - Jun 2013	12	9,369	9,543	9,752	9,707	9,819	10,249	880	276	243
Jul 2013 - June 2014	12	9,398	9,588	9,701	9,875	10,207	10,554	1,156	619	417

The analysis indicates that the System heat rate target was satisfactorily achieved within the minimum to the third quartile of the recorded System heat rate values. The mean and the median are measures of the centre of the data. As shown in Table 9.53 above, the mean and the median are not wide apart for the respective heat rate sample for each of the annual tariff adjustment period. This indicates that the distribution is largely symmetrical. This symmetry is further demonstrated by the similar differences between the median and the first quartile and the median and the third quartile. Symmetry of the distribution is also evident by the similar size of the differential between the median to the minimum System heat rate value and the median to the maximum System heat rate value. The spread of the data is represented by the range; inter quartile range (IQR) and standard deviation (std. dev.). The statistical summary for July 2013 to June 2014, in particular shows that the mean, range and standard deviation of the System heat rate dataset are not robust as they are very sensitive to outliers or extremely large or small values.

The large spread in the System heat rate data exhibited by the range, IQR and standard deviation for the stated period was due to the reported major forced outage of JPS' Bogue ST#14 between June – November 2013 and JEP's Barge #2 between September and December 2013. Based on reports from JPS, these outage events on aggregate had an adverse impact on the System heat rate during the outage period.

Despite the few recorded unusual and extreme System heat rate observations over the five (5)-year price-cap period, overall the statistical summary of the data indicates that on average, JPS was able to easily achieve the System heat rate target for each month of the five (5) annual tariff adjustment intervals.

The favourable System heat rate performance over the referenced period undoubtedly yielded immense boon to JPS' performance. The reported System heat rate performance was not however attributable to any major improvement in the efficiency of JPS' thermal generating system. As previously noted, the System heat rate performance was largely influenced by the increased participation of wind generation (Wigton II in 2011) in the Power System as well as the addition of the WKPP Generation Complex in 2012. The contributions from these facilities in terms of net generation and heat rate (WKPP Complex) had a substantial positive impact on the System heat rate performance each month subsequent to their respective Commercial Operations Date (COD).

Although the System heat rate performance relative to the target over the period improved markedly, which was apparently favourable to JPS, it did not translate to lower fuel cost to electricity customers.

9.5.3 Assessment of JPS' Generating Heat Rate (October 2009 – June 2014)

Similar to the System heat rate, the heat rate performance of JPS' thermal generating system over the period October 2009 to June 2014 was also reviewed and analysed.

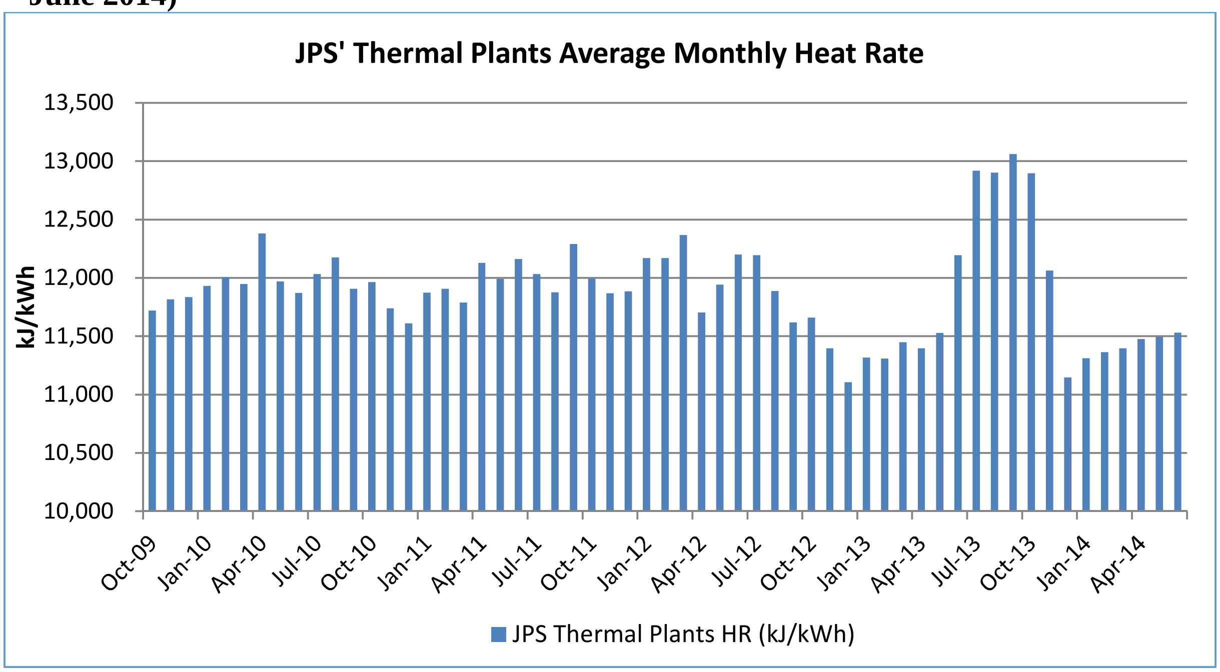
A summary of JPS' thermal generating system average monthly heat rates is provided in Table 9.54 below.

Table 9.54: JPS' Thermal Plants Heat Rate Performance (Oct 2009 – June 2014)

JPS' Thermal Plants Average Monthly Heat Rate (kJ/kWh)					
	2009-2010	**2010-2011**	**2011-2012**	**2012-2013**	**2013-2014**
July		12,032	12,032	12,196	12,919
August		12,176	11,878	11,888	12,903
September		11,907	12,292	11,618	13,061
October	11,720	11,964	11,994	11,659	12,896
November	11,815	11,740	11,868	11,397	12,064
December	11,835	11,611	11,884	11,107	11,149
January	11,932	11,874	12,169	11,317	11,313
February	12,005	11,908	12,170	11,309	11,363
March	11,949	11,789	12,367	11,450	11,397
April	12,381	12,128	11,704	11,398	11,476
May	11,970	11,993	11,943	11,528	11,496
June	11,871	12,163	12,201	12,196	11,531
Average	**11,942**	**11,940**	**12,042**	**11,589**	**11,964**

A graphical representation of JPS' monthly generating heat rates is shown in Figure 9.53 below.

Figure 9.53: Illustration of JPS' Thermal Plants Heat Rate Performance (October 2009 – June 2014)



9.5.3.1 Statistical Analysis of JPS' Thermal Plants Heat Rate (Oct 2009 – June 2014)

A descriptive statistical summary of the average heat rate of JPS' thermal generating plants for the period October 2009 to June 2014 is shown in Table 9.55 below.

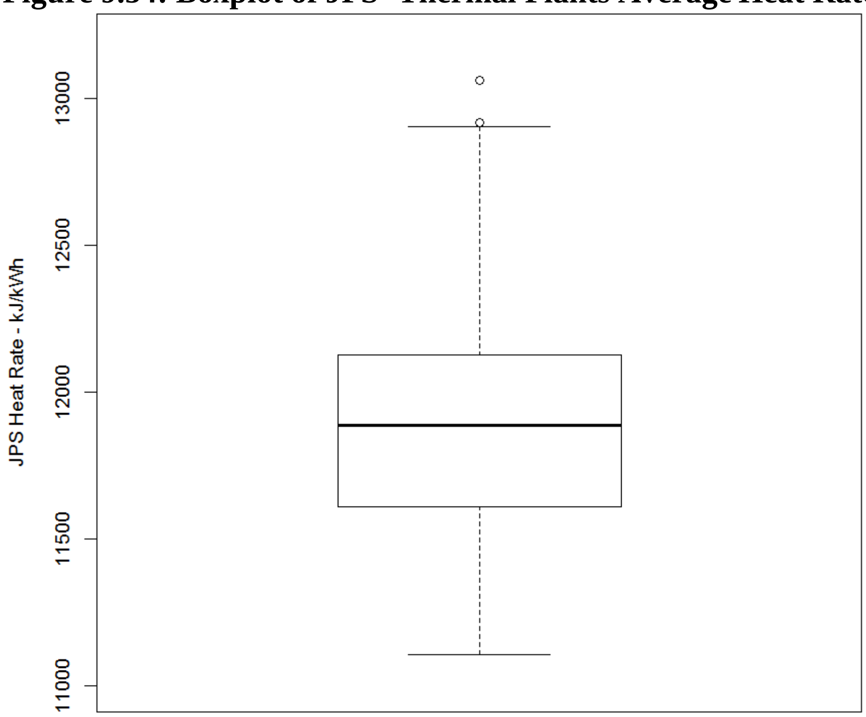
Table 9.55: Statistical Analysis of JPS' Thermal Plants Average Monthly Heat Rates

Period	No. of Heat rate Values	Min	1st Quartile	Median	Mean	3rd Quartile	Max	Range	IQR	Std. Dev
Oct 2009 - June 2014	57	11,107	11,611	11,888	11,892	12,128	13,061	1954	517	425

The statistical analysis indicates that JPS' thermal plants heat rate dataset for the period October 2009 – June 2014 contained unusually large heat rate observations that are outside of the inner fences of the dataset and were recognized as outliers. These extreme observations had a negative influence on the mean, range and standard deviation of the heat rate dataset. Reports from JPS indicated that the unusually large heat rate values recorded for its thermal generating system were primarily due to the major forced outage of its Bogue ST#14 unit during the period June to November 2013. Notably, however, based on a review of the reports submitted by JPS, the OUR considered that this outage event was within JPS' control.

The extreme heat rate observations are illustrated in the boxplot of the heat rate dataset provided in Figure 9.54 below.

Figure 9.54: Boxplot of JPS' Thermal Plants Average Heat Rate Dataset



To limit the influence of the extreme observations in the statistical analysis of JPS' thermal generating plants heat rate for the referenced price-cap period, a trimmed heat rate dataset was developed. This was necessary to obtain a more representative heat rate sample that would more likely reflect JPS' electricity generation operations in which its thermal generating units are appropriately operated in accordance with their required equivalent availability (EA) and designated maintenance schedules. The trimmed data set was created by deleting a number of the smallest and largest data values from the original heat rate dataset in order to eliminate their influence on the statistical calculations. The results are set out in Table 9.56 below.

Table 9.56: Results of the Original and Trimmed Heat Rate Dataset for JPS' Thermal Plants

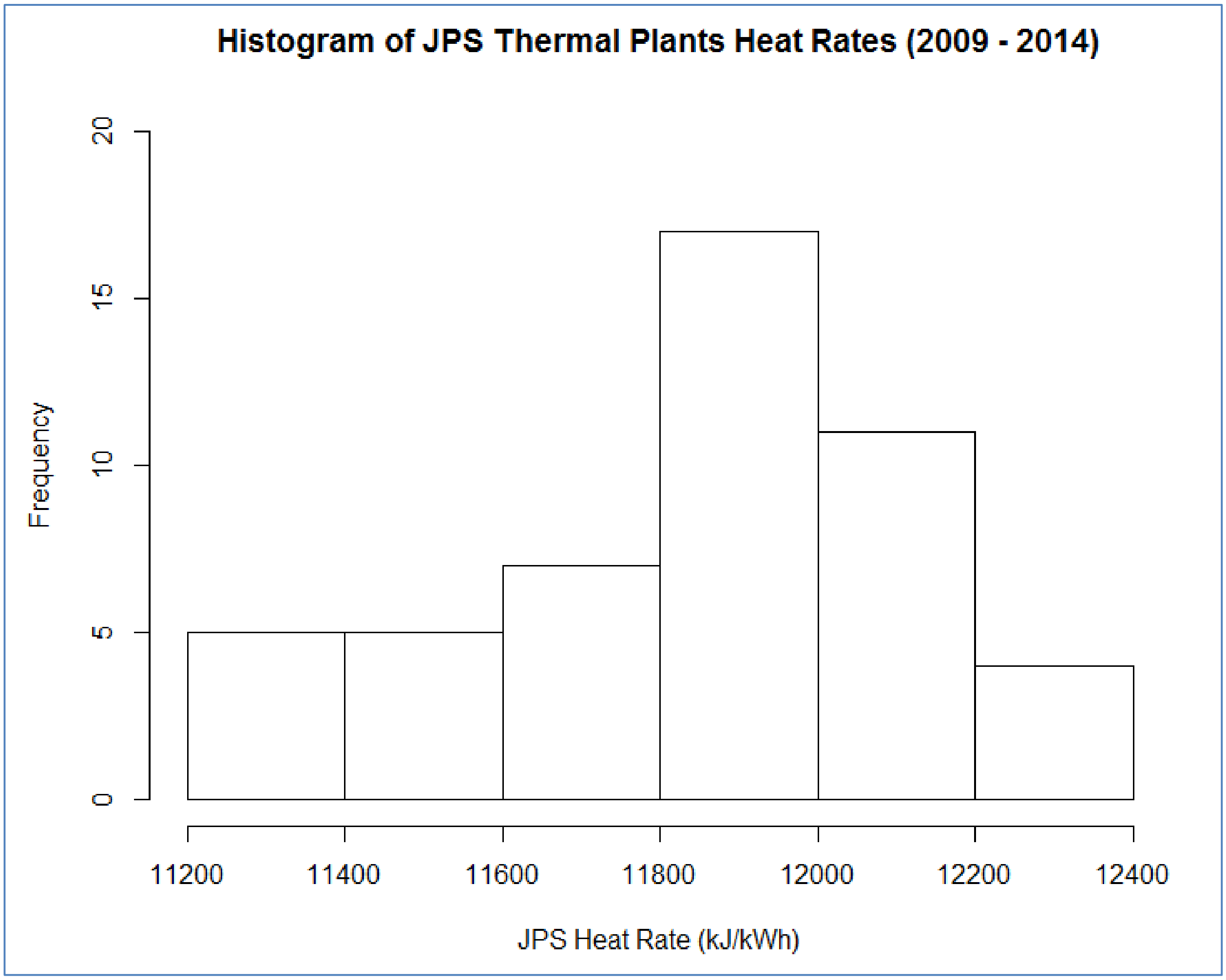
	No. of Heat rate Values	Min	1st Quartile	Median	Mean	3rd Quartile	Max	Range	IQR	Std. Dev.
Original Data Summary	57	11,107	11,611	11,888	11,892	12,128	13,061	1,954	517	425
Trimmed Data Summary	49	11,317	11,659	11,888	11,862	12,032	12,381	1,064	373	281

As shown in Table 9.56 above, the trimmed heat rate dataset provides a more normalized distribution of JPS' thermal plants heat rate performance than that represented by the original dataset. As shown, the middle of the data is the same for both datasets because the median is a robust statistic and resistive to the effect of extreme observations. Therefore, removing the unusually large heat rate values from the sample did not change the middle observation, which is, 11,888kJ/kWh. In contrast, the spread of the trimmed heat rate dataset in terms of the range and standard deviation, which are not robust statistics, were significantly reduced as a consequence of the removal of the unusually large observations.

The shape of the trimmed heat rate dataset is represented by the histogram in Figure 9.55 below. The histogram represents a uni-modal (one peak) distribution with the mode occurring in the heat rate range of 11,800kJ/kWh to 12,000kJ/kWh. The distribution is slightly left-skewed indicating that JPS' average monthly generating heat rate for the price-cap period 2009-2014 was slightly more concentrated in the upper heat rate range, particularly, the 11,800kJ/kWh to 12,000kJ/kWh range.

It can be deduced from the statistical analysis that JPS' monthly generating heat rate for the period October 2009 to June 2014 frequently resides in the 11,800kJ/kWh to 12,000kJ/kWh range. However, due to the recent major overhaul and refurbishment of some of JPS' key generating units, it is expected that with the same generation system configuration, the company will achieve lower monthly generating heat rates, consistent with those achieved since December 2013, for the period January 2015 to May 2015.

Figure 9.55: Histogram of the Trimmed Heat Rate Dataset



9.6 Regulatory Treatment of IPPs' Fuel Cost

As previously indicated, IPPs account for approximately 30% of the quantity as well as the cost of fuel used for supplying electrical energy to the grid. The main IPPs with conventional thermal generation facilities are:

- Jamaica Energy Partners (JEP)
- West Kingston Power Partners (WKPP)
- Jamaica Private Power Company (JPPC)
- Jamalco

These IPPs supply capacity and energy to the grid under long-term PPAs with JPS. The PPAs govern all the operational and commercial activities/transactions related to electricity supply to the grid.

9.6.1 IPPs' Contracted Heat Rates

The contracted heat rates for the above-named IPPs are shown in Table 9.61 below.

Table 9.61: IPP Contracted Heat Rates

IPPs Contracted Heat Rates						
IPP	**Technology**	**Contracted Cap. (MW)**	**Fuel Type**	**Heat Rate (Btu/kWh)**	**Heat Rate (kJ/kWh)**	**Remarks**
JEP	MSD	124.36	HFO	8,166	8,615	Single Heat Rate point
WKPP	MSD	65.5	HFO	8,122	8,569	Single Heat Rate point
JAMALCO	Steam-Cogen	11.0	HFO	9,004	9,500	Single Heat Rate point
JPPC	SSD	60.0	HFO	7,680*	8,103*	Heat Rate Curve ** (8,103 kJ/kWh - based on average for July 2013 to June 2014)*

9.7 JPS' Heat Rate Target Proposal

JPS indicated in its tariff application that the system heat rate performance over the five-year price cap period will depend on several factors affecting the economic dispatch which include:

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

JPS argued that while all the above factors influence the resultant System heat rate, the company has sole direct control over only a few.

The mechanism used to calculate the pass-through Fuel Cost on a monthly basis under the current tariff operates according to the following formula:

$$Pass\ Through\ Cost = Fuel\ Cost \times \frac{Heat\ Rate\ Target}{Heat\ Rate\ Actual} \times \frac{(1 - Losses\ Actual)}{(1 - Losses\ Target)}$$

JPS postulated that the heat rate target should continue to be based on all the generating units in the System (both JPS and IPPs), since fuel optimization through economic dispatch seeks to optimize overall system variable cost. According to JPS, this approach is similar to the approach used in setting the 2009 –2014 heat rate target where average performance was considered indicative of future performance subject to the addition of new capacity or the retirement of existing ones. JPS also contends that in such analysis, the effect of some of the heat rate influencing factors were not properly accounted for since average performance does not exactly mimic the cumulative effect of the actual monthly heat rate penalty/reward system. Average heat rate performance for a year does not fully capture the effect that a wide range of monthly heat rate values would have on a monthly penalty/reward calculation, especially given the monthly variation in fuel prices and foreign exchange rates throughout a given year. In that regard, the company expressed the view 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 argued that it cannot influence the availability or reliability of the IPPs and should not be exposed to any additional penalties (fuel and heat rate) because of any failure to perform. JPS asserted that it faces increased performance risk from the IPPs as their plants age over time and as they expand their generating capacity as a percentage of the system installed capacity.

JPS indicated that over the years, the OUR has set a heat rate target that requires continuous improvement by JPS, which is ultimately to the benefit of the customers. The system wide target (to include IPPs) was set at 11,900 kJ/kWh in 2002, then revised downwards to 11,600kJ/kWh in 2003, to 11,200kJ/kWh in 2004 and finally to 10,200kJ/kWh in 2012. This represents a required 14% improvement in the use of fuel over the last decade. However, despite the System heat rate performance since 2009, the System is still prone to wide monthly variation.

JPS proposed the following with respect to heat rate target for the rate cap period 2014 - 2019:

- Maintaining the current Heat Rate target of 10,200 kJ/kWh for the next year;

- 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 proposed 381 MW LNG project in 2016; and

- A review of the Heat Rate target for 2017, should the new 381 MW project not be completed by 2016, given the fact that JPS's existing power plants (292 MW) slated for retirement in 2016 would not be to able perform against a guaranteed heat rate target after 2016.

9.8 OUR's Review of JPS' Heat Rate Proposal

9.8.1 Background

In the two (2) previous JPS five (5) year Tariff Determinations, the concept of a System heat rate target was incorporated in the FCAM.

The rationale for the application of a System heat rate target was premised on the expectation that this efficiency measure, among other things, would accomplish the following:

- Provide JPS with the incentive to minimize overall fuel expenses by improving the relative efficiency of converting fuel input energy to electrical energy by its electricity generating system; and

- Encourage the Grid Operator (JPS) to minimize the total cost of electricity generation by adhering to the economic dispatch of all available generating units subject to system constraints.

The regulatory principles that were applied in setting the System heat rate target are set out under section 9.4.2.

Based on the monthly fuel cost data and observations and findings from a number of generation assessments, the application of the target did not seem to accomplish the objectives as expected. The position is that the System heat rate was expected to operate as a mechanism to encourage improvement in the thermal efficiency of JPS' generating system and reduction in the cost of fuel used for electricity generation. The generation performance data since 2009 shows that the System heat rate as presently calculated has improved significantly but was primarily due to the addition of the Wigton II wind generation facility and WKPP Complex to the grid in 2011 and 2012 respectively. Although the System heat rate has improved markedly over the 2009-2014 price-cap period, this improvement in fuel conversion efficiency did not translate into lower fuel rates to electricity customers. This raises the issue of whether the focus was concentrated on the realization of rewards through the optimization of System heat rate instead of the imperative of fuel cost optimization.

9.8.2 System Heat Rate Equation

The System heat rate currently used by JPS is defined as the ratio of the fuel input energy (kJ) to the electrical energy output (kWh) of the generating units including RE generation facilities. This is represented by the algebraic formula set out as *Equation 9.3*.

Equation 9.3:

$$System\ Heat\ Rate = \frac{Input\ Energy\ (kJ)}{[Net\ Generation\_Thermal\ (kWh) + Net\ Generation\_RE(kWh)]}$$

Where:

1. Input Energy is the total fuel input energy (kJ) used by thermal plants (JPS and IPPs) for the generation of electricity during the billing period.

2. The electrical energy output includes:

   a) Net Generation (Thermal) - net generation in (kWh) from all thermal plants (JPS and IPPs) utilised in the billing period, excluding plants supplying dump energy; and

   b) Net Generation (RE) - net generation in (kWh) from non-combustible RE generation facilities.

The System heat rate is calculated by substituting the values of the defined input and output energy in *Equation 9.3*.

9.8.3 Comments on JPS' Proposed Heat Rate Target

Currently, the applicable System heat rate target is 10,200kJ/kWh. JPS proposed in its application that the heat rate target should be maintained at the value of 10,200kJ/kWh for the next year and the adjustment for the known impact of new generation added to the grid made at the annual tariff review.

In addition to the proposed System heat rate target, JPS provided System heat rate projections for the period 2014 to 2019. Supporting documentation and information related to the projected heat rates were also submitted by JPS. The projections took into account certain assumptions regarding new generation capacity additions and major re-configuration of the Bogue CCGT unit within the 2016 to 2017 timeframe. However, due to the perceived uncertainties with the planned large-scale base-load generation capacity project and lack of firm information on the proposed conversion of Bogue 120 MW CCGT to operate on compressed natural gas (NG), the OUR focused its attention mainly on the heat rate target and System heat rate projections for the 2014 to 2015 timeframe.

A summary of JPS' proposed heat rate is shown in Table 9.81 below.

Table 9.81: JPS' Heat Rate Projections - 2014 -2015

Category	2014	2015
JPS Heat Rate – Thermal (kJ/kWh)	11,670	11,577
System Heat Rate –Thermal (kJ/kWh)	10,390	10,404
System Heat Rate –Thermal & RE (kJ/kWh)	9,697	9,528
Proposed System Heat Rate Target (kJ/kWh)	**10,200**	-

The proposed heat rates were calculated based on generation dispatch simulations done by JPS for the stated periods.

The annual summary of the simulated generation dispatch for 2014 and 2015 is shown in Table 9.82 below.

Table 9.82: Summary of JPS' Generation Dispatch Simulations for Proposed Heat Rate Target

Generating Units NEO and Capacity Factors from JPS' Dispatch Simulations						
Plant Description			**2014**		**2015**	
Unit	**Generator**	**Plant Cap. (MW)**	**Net Gen (MWh)**	**Cap. Factor (%)**	**Net Gen (MWh)**	**Cap. Factor (%)**
OH#2	JPS	60.0	211,639	40.0	218,285	42.0
OH#3	JPS	65.0	279,281	49.0	333,040	58.0
OH#4	JPS	68.5	370,840	62.0	410,828	68.0
HB B6	JPS	68.5	296,992	49.0	343,579	57.0
HB GT#5	JPS	21.5	7,901	4.0	5,247	3.0
HB GT#10	JPS	32.5	27,398	10.0	21,020	7.0
RF#1	JPS	20.0	150,291	86.0	138,625	79.0
RF#2	JPS	20.0	137,057	78.0	151,356	86.0
Bogue GT#3	JPS	21.5	7,164	4.0	3,290	2.0
Bogue GT#6	JPS	18.0	747	0.5	866	0.6
Bogue GT#7	JPS	18.0	3,918	2.5	1,718	1.0
Bogue GT#9	JPS	20.0	9,429	5.4	647	0.4
Bogue CCGT	JPS	114.0	833,040	83.4	772,002	77.3
JEP	**IPP**	**124.36**	**543,121**	**50.0**	**456,434**	**42.0**
JPPC	IPP	60.0	463,606	88.0	468,370	89.0
Jamalco	IPP					
WKPP	IPP	65.5	484,866	85.0	452,018	79.0
Hydro and As-Available Purchases			295,151		370,488	

As highlighted in Table 9.82 above, the projected utilization of JEP's Generation Complex in 2014 and 2015 is relatively low with capacity factors of 50% and 42% respectively. These projections are substantially lower than historical dispatch levels and could be indicative of sub-optimal dispatch of the generation system. This issue will be discussed in greater details under Section 9.11 (Discussion & Analysis).

9.9 OUR's Heat Rate Evaluation

9.9.1 Methodology

In response to JPS' heat rate proposal, the OUR conducted its own heat rate evaluation for the period July 2014 to June 2019. The evaluation took into consideration, among other things, the net generation and peak demand forecast, the existing thermal generation system with no new baseload capacity addition, and some of the assumptions made by JPS in arriving at the annual System heat rate projections and proposed heat rate target.

The evaluation entailed detailed simulations of the entire generating system to obtain the input energy (kJ) requirement and the NEO in kWh for each thermal generating unit utilized to meet the forecasted system net generation and peak demand. Notably, the peak demand and net generation forecast were developed by JPS and were submitted to the OUR as part of its generation dispatch input assumptions used for deriving its System heat rate projections.

The heat rates for JPS' generating units used in the evaluation were based on the units' heat rate test data and other reported heat rate data submitted to the OUR by JPS.

The simulations and analyses used to obtain the net generation for the thermal generating units to calculate JPS' thermal generating heat rate as well as the System heat rate were based on economic generation dispatch subject to generation system constraints and also network constraints.

9.9.2 Evaluation Scenarios

For the heat rate evaluation, two (2) main scenarios were investigated, viz:

9.9.2.1 Heat Rate Evaluation Scenario #1 (unconstrained)

This scenario encompassed the dispatch of the generating system with the objective to achieve the lowest cost of generation without consideration for transmission system operating constraints.

9.9.2.2 Heat Rate Evaluation Scenario #2 (constrained)

This scenario focused on the dispatch of the generating system taking into account the effect of transmission system operating constraints. In particular, the network situation which JPS claims requires the operation of its Bogue CCGT as a base-load unit (with capacity factor in excess of 80%) or a reliability Must-Run unit.

9.9.3 Heat Rate Calculation

The aggregate input energy requirements and the corresponding electrical energy output were used to calculate the heat rate for JPS' thermal generation system based on the heat rate *Equation 9.2* in Section 9.4.1.

The System heat rate involving only the thermal generating plants was also calculated using *Equation 9.3* in Section 9.8.2.

The NEO from RE generation facilities was not included in the System heat rate calculation.

The heat rates derived from evaluation were analysed within the scope of a detailed analysis which included statistical analyses of JPS' historical and projected heat rate datasets to establish the appropriate heat rate target to be used in the FCAM in accordance with Schedule 3, EXHIBIT 2 of the Licence.

9.10 Heat Rate Evaluation Results

It is important to note that the simulation models used in the heat rate evaluation attempted to replicate, as close as possible, the existing System configuration and operation. As such, it is recognised that there may be slight variations in the modelling of the System relative to the actual System configuration which may be reflected in the simulations. However, based on the level of model calibration that was undertaken, the OUR does not believe that any such variation had any substantial influence on the simulation results. Notwithstanding, the heat rate evaluation results were considered to be indicative and were used as heat rate references for establishing the relevant heat rate target.

The heat rate evaluation results are shown in Table 9.101 below.

Table 9.101: Heat Rates Derived from OUR's Evaluation

Calculated Heat Rates – kJ/kWh			
	PLANT CATEGORY	SCENARIO #1 (Unconstrained Case)	SCENARIO #2 (Constrained Case)
Jul 2014 – June 2015	JPS Thermal Units	11,670	11,171
	IPPs and JPS Thermal Units	10,035	9,925

9.10.1 Results for Heat Rate Evaluation Scenario #1

It is important to note that the simulation models used in the heat rate evaluation attempted to replicate, as close as possible, the System configuration and operation. As such, it is recognised that there may be slight margins of errors associated with the simulations. Therefore, the heat rate evaluation results are considered to be indicative and will be used as heat rate references for establishing the relevant heat rate target.

Under Scenario #1, the calculated heat rate for JPS' thermal plants for the tariff adjustment period July 2014 to June 2015 is 11,670 kJ/kWh. Additionally, the System heat rate for the thermal generating plants (JPS and IPPs) was calculated to be 10,035 kJ/kWh. The relatively low System heat rate was influenced by the unconstrained dispatch of generating units resulting in almost full utilization of dispatchable firm-capacity IPP plants, which comparatively have higher conversion efficiencies than JPS' thermal plants. In this scenario, the net generation for the IPPs accounted for approximately 50% of the total net generation.

Conversely, the relatively high generating heat rate for JPS' thermal plants was primarily due to very low utilization of the Bogue CCGT unit. Although the unit has relatively low fuel conversion efficiency, it operates on expensive ADO resulting in a relatively high variable cost. Due to the high variable cost of the unit, its output was significantly restricted in the unconstrained generation dispatch process as the objective of the optimization was to achieve the lowest cost of electricity generation.

9.10.2 Results for Heat Rate Evaluation Scenario #2

For Scenario #2, the calculated generating heat rate for JPS' thermal plants for the tariff adjustment period July 2014 to June 2015 was 11,171 kJ/kWh. Additionally, the System heat rate for the thermal generating plants (JPS and IPPs) was calculated to be 9,925 kJ/kWh.

In comparison to the results for Scenario #1, the calculated generating heat rate for JPS thermal plants and the System heat rate were respectively lower. This result was apparently due to the effect of the operating constraints that were applied to the generation dispatch.

Under this scenario, the generation dispatch was simulated to reasonably reflect the operation of the System. The dispatch operation was subject to operating constraints to ensure both System reliability/security and cost minimization. The Bogue CCGT unit, in particular was forced to operate as a base-load unit to address System security issues indicated by JPS. The constraints were incorporated in the optimization model and the generating units were dispatched to achieve minimum generation cost with all the constraints satisfied.

The simulation results also indicated that although JPS' generating heat rate was lower for Scenario #2, the cost of fuel consumed by its thermal generating units in the production of electricity was significantly higher. This was due to the relatively high utilization of the Bogue CCGT unit which has relatively high variable cost but was utilized as a Must-Run generating unit to address System security issues. The relatively high utilization of the unit resulted in an annual fuel cost for the unit that represents over 20% of the total annual fuel cost for the generation system. This situation has had a profound impact on the monthly fuel rate.

9.10.3 Effect of System Constraints

In the operation of a power system, network operating constraints and credible contingencies due to among other things, System topology and configuration are likely to be encountered which must be addressed in order to maintain System security and reliability. However, the notion of adopting a mitigation strategy which predominantly involves the use of relatively high variable cost generation to address certain network-related issues may not be the most cost efficient and economical solution, especially over the long term.

In spite of the requirement to ensure System security and reliability, the perpetuation of the generation strategy described above could potentially become a perverse incentive in which the drive to achieving lower generating heat rates could derail the principal objective of realizing lower fuel rates.

Heat rate is essentially a technical parameter which is insensitive to the cost of fuel. Therefore, a particular generation technology and fuel type may achieve a relatively low heat rate in the production of electricity but at a very high fuel cost. Under the current FCAM, if the dynamic of low heat rate - high fuel cost of a particular generating unit is such that it results in an actual heat rate that is significantly lower than the heat rate target, the resultant efficiency adjustment to a very high fuel cost caused by the same generating unit could be excessive and become a perverse incentive.

9.10.4 Achieving the Calculated Heat Rates

Recognising the effects of System operating constraints, the results of the heat rate evaluation indicate that based on the existing configuration of JPS' thermal generating system, its monthly average generating heat rate can be achieved within the range of the calculated heat rates for Scenario #1 and Scenario #2 shown in Table 9.101 during the period January 2015 to May 2015. A similar situation is expected for the System monthly average heat rate over the same period.

9.11 Discussion and Analysis

9.11.1 System Heat Rate Equation

9.11.1.1 Overview

In the current calculation of the fuel cost per kWh each month, an actual and a target System heat rate is used for efficiency adjustments. The System heat rate includes the heat rates and net generation of thermal IPPs and the NEO from non-combustible RE generation technologies.

Although this arrangement has applied over the last two price-cap regimes, it is not what is provided for in the Licence. Specifically, Schedule 3, paragraph 3 (D) provides as follows:

> *"Fuel Rate Adjustment Mechanism: The Licensee shall apply the Fuel Rate Adjustment Mechanism that is in force on the date of this Licence. The Fuel Cost Mechanism that is in force on the date of this Licence is described in Exhibit 2."*

The provisions of Schedule 3 EXHIBIT 2 are outlined in Section 9.2.1.

A technical review of the application of the System heat rate target, one of the efficiency measures used to adjust the cost of fuel used in the production of electricity on a monthly basis, indicates that its use has not effectively achieved the stated objectives.

With the expectation of increased participation of IPPs in the Jamaican Power System in the medium to long-term, the use of a System heat rate for adjusting the total fuel cost will become less relevant as IPPs will eventually account for the larger portion of the total fuel cost. The IPPs with thermal generating plants usually have single point guaranteed or contracted heat rate which will be the basis for passing through their respective fuel cost. Under such scenario, the fuel cost risk will be largely shifted to the IPP thereby reducing the necessity of a System heat rate for efficiency adjustment of the total fuel cost.

Although the use of a System heat rate in the fuel cost adjustment mechanism is not consistent with Licence requirements and should no longer be allowed, it will be adopted as a key performance indicator (KPI) for monitoring System efficiency.

9.11.1.2 The Inclusion of RE Generation in the Heat Rate Equation

Energy from renewable resources is projected to play an increasing role in electricity generation with government policy dictating that 12.5% of net generation should be supplied by renewable resources by 2015, increasing to 20% by 2030.

Renewable energy generation facilities can be classified into two groups: those that use combustible resources and those that use non-combustible resources. RE facilities using combustible resources include waste to energy, biomass plants, etc. These have similarities to conventional generation and can be classified as thermal generation facilities with associated heat rates. There are currently no renewable energy facilities using combustible resources in commercial operation but in the event that such facilities are brought online they would be treated in keeping with all IPPs using thermal generation facilities.

Presently, approximately 6% of the total net generation for the electricity system is supplied by renewable energy generation facilities using non-combustible renewables such as hydro and wind. Although their contribution to System net generation is relatively small, the economic and environmental benefits are appreciable. Notwithstanding their obvious benefits, the fact is that energy is extracted and transformed into electricity without the burning or combustion of a fuel. Since power from non-combustible renewables is produced without fuel combustion there is no input energy (BTU or kJ input), hence no heat rate. Technically, this implies that the NEO from non-combustible renewables should not be included in JPS' generating heat rate or the System heat rate calculation.

Based on the mathematical orientation of the System heat rate formula defined as *Equation 9.3*, the RE net generation is represented as an independent variable in the denominator and has no connection to the input energy in the numerator. Since there is no input energy (BTU or kJ value) for wind and hydro, including the NEO for these renewables creates a distorting effect on the subject of the equation. As observed in the monthly heat rate calculations, this construct has influenced significant reductions in the actual System heat rate without any efficiency improvements in JPS' thermal generating units. From these observations, it can be deduced that this arrangement has distorted the heat rate calculations and diminished the incentive for improving efficiency in JPS' thermal generating plants.

The inclusion of the NEO from non-combustible renewables in the heat rate calculation, compounded by their increased penetration in the System, may have also increasingly weakened the incentive for JPS to adhere to economic generation dispatch practices and to produce electricity at minimum cost. Historical JPS generation data indicates that net generation from wind and hydro resources reduced the System heat rate by an average of approximately 600kJ/kWh each month during the period October, 2009 to June, 2014. This translates to significant monetary benefits to JPS.

With heat rate being a function of the energy input and net generation of thermal plants, the introduction of increasing RE generation in the heat rate equation will result in increasing non-linearity in the relationship. This could significantly skew the results of the calculation rendering the System heat rate non-representative of the electricity system to which it applies.

Much of the value of non-combustible renewable such as wind power is expected to be derived from the savings in operating costs associated with reducing generation from peaking and intermediate generating unit. However, this is dependent on the orientation of the System load and the correlation of the renewable generation and the System peak.

In the Jamaican context, despite the obvious limitations of wind generation in terms of its intermittency, it provides great value in reducing fossil fuel consumption and dependence on imported fuel oil. In the existing generation supply mix, the all-in cost (US₵/kWh) of all the utility-scale wind generation facilities is significantly lower than the variable cost of the other generating units in the System.

Since the wind generation facilities have significantly lower variable operating costs than other generating units in the System, economics dictates that the operation of these renewable facilities will tend to cause generating units with higher variable operating costs (fuel and Variable O&M) to operate at lower levels.

It is understood that the fuel consumed by thermal plants operating in the System is a function of their operating or dispatch point. It is also accepted that fluctuations in the output of non-dispatchable renewable generation (such as wind generation) due to the intermittency of the renewable resource, may require conventional generating units in the System to adjust their output or dispatch point to balance the intermittent effect of the wind. However, the OUR disagrees with JPS' view that the dispatch point of a particular generating unit is directly dependent on the level of contribution of non-dispatchable renewable plants in the energy mix and that the overall system input energy is inextricably linked and has a proportional relationship at all times to the level of renewable generation on the system.

It is important to stress that the key factor associated with System balancing is the amount of random power fluctuations, caused by unpredictable changes in load and generation. Fluctuations in the output of renewable generation (such as wind generation) may place additional duty on other generating units for both response and reserve capacity. Nevertheless, the quantity of generation required to manage unscheduled wind generation will not be on a "MW for MW" basis, thus the equivalent amount of conventional capacity required to produce the aggregate net generation of the wind generation facilities is significantly lower than the installed or contracted capacity of the wind generation facilities. Furthermore, in power generation operations, response and reserve requirements are not specifically assigned to back-up a particular type of generating plants, such as wind generation facilities, but rather to deal with the overall uncertainty in the balance between demand and generation. The individual fluctuations in load and generation are not generally correlated, which has an overall smoothing effect with a consequent reduction in the generation requirements for balancing. This indicates that JPS' position on the proportionality between conventional thermal plants fuel input energy and generation is misrepresented and exaggerated.

It also bears noting that continuing to include the NEO from non-combustible renewables in circumstances where JPS is free to compete in a tender for renewables may hand the company an advantage as it may be able to discount its offers taking into to consideration the potential gains from future reduction in system's rate.

In consideration of the above arguments, the NEO from non-combustible renewables has not been factored in the System heat rate equation and the relevant heat rate target.

9.11.1.3 The Inclusion of IPPs’ Generation in the System Heat Rate Equation

Having regard to the analysis with respect to the distortionary effect of the existing approach to computing the System heat rate and with reference to the provisions of Schedule 3, EXHIBIT 2 of the Licence, the inclusion of the IPPs’ net generation and heat rates as part of a System heat rate to be used in the FCAM has not been allowed.

The practice of factoring the IPPs’ performance parameters in both the System heat rate and the heat rate target in the FCAM can also distort the incentives for JPS to carry out economic generation dispatch of all available generating units and to produce electricity at minimum cost.

The existing IPPs’ generating plants have guaranteed or contracted heat rates. These contracted heat rates will be constant throughout the 20-year PPA term. An IPP contracted heat rate usually does not represent the true efficiency of the IPP generating plant as it tends include a buffer to allow for degradation and other risks associated with the plant’s efficiency. Because the fuel cost is calculated based on the contracted heat rate, the IPP bears the heat rate risk. That is, if the IPP plant turns out not to be as efficient as planned, the IPP will not be able to recover the full cost of the fuel utilized and consequently will have to absorb the associated loss. Nonetheless, any additional cost that stems from the buffer included in the IPP contracted heat rate will be absorbed by electricity customers. In this regard, to impose additional cost to electricity customers by including the IPPs’ efficiency parameters in the System heat rate equation is not considered fair and reasonable. Moreover, continuing to include the IPPs’ efficiency parameters in the System heat rate for efficiency adjustment of the total fuel cost could be said to be tantamount to transferring IPPs’ heat rate risks which electricity customers have already paid to JPS as a monetary benefit.

Additionally, the fact that IPPs’ contracted heat rates will be fixed throughout the 20-year PPA term means that there will be no scope for efficiency improvements from such plant over the entire project life. This also means that there will be no additional efficiency contribution from such plant to the System heat rate unless new IPP generating capacity is introduced. Against this background, the notion of including the IPPs’ efficiency parameters in the System heat rate calculation could give a false impression that efficiency of JPS’ System has significantly improved overtime which is not necessarily the case. Actually, the reported improvements in System efficiency by JPS are not due to any major improvement in the efficiency of the company’s owned generating plants but largely due to the impact of lower heat rate IPP thermal generating plant that was added to the System over time.

Another crucial factor is that all the thermal IPPs have significantly lower heat rates than JPS’ thermal plants due to the nature of the generation technologies involved. While the heat rates of IPP plants are lower, the variable cost of operation may not be lower in all cases. As a result of the dynamics of plant operating cost and efficiency characteristics, in attempting to meet the monthly heat rate target, the company’s drive towards achieving the highest possible efficiency to maximize incentive, it may override the fundamental objective of utilizing the most efficient and least cost combination of generation plants for producing electricity to supply the demand.

9.11.1.4 Aggregation of JPS' and IPPs' Fuel Cost for Heat Rate Adjustment

The aggregation of JPS' and IPPs' fuel costs and then subjecting the aggregated cost to heat rate adjustment according to *Equation 9.1* in section 9.2.2 also raises the following:

1) The adjustment of the IPPs' fuel cost (already adjusted by their own contracted heat rate as per their respective PPA) by an heat rate adjustment factor, defined as: ***(System heat rate target/actual System heat rate)*** which also includes net generation and contracted heat rates of the IPPs is not appropriate. This approach was not considered to be reasonable and prudent as it embodies an element of double-counting and therefore was not permitted.

2) As stipulated in the provisions of Schedule 3, EXHIBIT 2 of the Licence, the IPPs' portion of the total fuel cost should be based on the IPPs' generating heat rate as per the PPA. Therefore, the adjustment of the IPPs' fuel cost by an additional heat rate factor is not consistent with the Licence.

The IPPs' portion of the total fuel cost should not be subject to any efficiency adjustment apart from System losses.

9.11.2 Economic Dispatch and System Constraints

Economics dictates that there is a priority order of dispatching generating units based on their variable operating costs. Generating units with relatively low variable costs (fuel and operation & maintenance) tend to be operated most of the time, and given the highest priority. Generating units that experience significant savings when not operating will be given lower priority. The prioritized, or "merit order", dispatch means power plants with the lowest variable costs are operated most frequently, and those with the highest variable costs are operated least frequently. In a generic sense, generating plants can be grouped into three (3) broad categories: peaking, intermediate load, and base-load units. Peaking units have the highest operating costs, base-load units the lowest operating costs, and intermediate load units are in between. During System operation, these categories of generating units are usually "stacked up" according to the merit order based on their variable operating cost to meet customer demand. Base-load generation is normally at the bottom of the stack, intermediate next, and peaking generation on top as needed. The ordering of generating unit dispatch is aimed at minimizing the overall operating costs. A typical merit order for the Jamaican Power System is shown in Table 9.111 below.

In the ideal case of economic generation dispatch, plants are dispatched purely on the basis of position in the merit order. However, due to System operating constraints, the merit order may have to be altered to facilitate security constrained economic dispatch (SCED). The issue of network constraints in the Jamaican power system is of significant importance, particularly the situation surrounding the Must-Run mode of operation of the Bogue CCGT unit.

According to JPS, Bogue CCGT is being operated as a base-load unit or a reliability Must-Run unit to provide voltage and reactive power support in that region of the network. The underlying problem is that this unit operates on ADO making it one of the most expensive units in the System in terms of variable cost.

As shown in Table 9.111 below, Bogue CCGT is represented as a mid-merit unit in JPS' merit order table. Despite its merit order position, the unit is operated as base-load with average capacity factors in excess of 80%. The utilisation of this unit at such capacity factors has resulted in the consumption of huge quantities of ADO each month, translating to very high fuel costs for the unit. Actual generation data shows that Bogue CCGT fuel cost alone accounts for approximately 23% of the System's total fuel cost (JPS and IPPs) on a monthly basis. This has undoubtedly placed upward pressures on the monthly fuel rates.

Table 9.111: Merit Order for Thermal Generating Units (January to July 2014)

MERIT ORDER – THERMAL GENERATING UNITS										
GENERATING UNIT	OWNER	CATE-GORY	MERIT ORDER	AVERAGE VARIABLE COST (US$/MWh)						
				JAN 2014	FEB 2014	MAR 2014	APRIL 2014	MAY 2014	JUNE 2014	JULY 2014
JAMALCO	IPP	Base-load	1	114.26	111.59	111.69	111.83	110.84	110.09	110.56
ROCKFORT RF1	JPS	Base-load	2	140.61	139.41	141.01	141.62	147.60	148.68	146.25
ROCKFORT RF2	JPS	Base-load	3	140.84	139.63	141.24	142.01	148.00	149.08	146.64
JPPC	IPP	Base-load	4	150.79	150.90	151.61	152.41	152.09	151.71	152.02
WKPP	IPP		5	159.42	160.11	164.28	163.91	160.89	163.24	162.39
JEP – OH	**IPP**		**6**	**167.69**	**168.74**	**170.75**	**173.22**	**172.74**	**173.37**	**171.33**
HUNT BAY B6	JPS		7	187.64	186.02	188.16	186.57	191.23	188.97	186.09
OLD HARBOUR OH4	JPS		8	188.34	186.71	188.88	187.27	192.15	193.83	190.67
OLD HARBOUR OH3	JPS		9	196.08	194.38	196.64	194.96	199.95	201.88	198.69
OLD HARBOUR OH2	**JPS**		**10**	**196.19**	**194.48**	**196.75**	**195.08**	**200.06**	**209.79**	**214.01**
BOGUE CCGT	**JPS**		**11**	**200.77**	**198.10**	**201.03**	**199.82**	**201.81**	**200.57**	**199.17**
BOGUE GT11	JPS		12	276.80	273.17	275.35	271.31	273.79	231.01	227.05
BOGUE GT12	JPS		13	286.61	282.80	294.68	304.69	307.72	272.07	270.15
BOGUE GT13	JPS		14	295.20	291.28	300.54	306.30	309.35	305.83	303.70
HUNT BAY GT10	JPS	Peaking	15	320.22	316.00	318.53	313.84	316.72	307.45	305.30
HUNT BAY GT5	JPS	Peaking	16	343.93	339.40	342.12	337.08	340.17	314.85	312.73
BOGUE GT9	JPS	Peaking	17	348.94	344.36	347.10	342.02	348.83	338.03	335.64
BOGUE GT3	JPS	Peaking	18	358.03	353.33	356.15	350.93	355.14	349.12	346.66
BOGUE GT6	JPS	Peaking	19	384.32	379.28	382.30	376.69	380.13	353.60	351.11
BOGUE GT7	JPS	Peaking	20	384.92	379.87	382.90	377.29	381.33	377.75	375.09
BOGUE GT8	JPS	Peaking	21	390.39	385.27	388.34	382.64	386.14	379.35	376.67
Data Source: JPS Merit Order Listing submitted to the OUR on a fortnightly basis										

Based on the configuration of the Jamaican Power System, the transfer of bulk power from generating plants across the network within the required voltage, thermal and stability limits may result in sub-optimal operations. Notwithstanding these considerations, the notion of adopting a mitigation strategy which predominantly involves the use of relatively high variable cost generation to address certain network-related issues may not be the most cost-efficient and economical solution, especially over the long-term.

From an operational perspective, transmission adequacy affects how much generation can flow and how much grid reliability concerns will constrain different generating plant production and deliverability patterns. Addressing key transmission constraints improves access to load for almost every generator as well as improving grid reliability. Therefore, the OUR cannot overemphasize the importance of the transmission planning processes that address long-term economics as well as reliability, and the issue of building a more robust transmission network that will enable electricity customers to save money by reliably accessing more efficient generation than is possible with the current System configuration.

With respect to the issues emanating from JPS' treatment of System constraints, specifically the Must-Run operation of the Bogue CCGT unit to address System security requirements, JPS is required to undertake an assessment of the System to evaluate the implications and the impact of network constraints and credible contingencies on economic generation dispatch and optimal power flow in the transmission system. The assessment should also seek to identify technically feasible and economical options that could remedy the reported network problem in the Bogue area of the Power System. A report of the System assessment should be submitted to the OUR within twelve (12) weeks from the date of this Determination Notice.

DETERMINATION 28

JPS is required to undertake an assessment of the System to evaluate the implications and the impact of network constraints and credible contingencies on economic generation dispatch and optimal power flow in the transmission system. The assessment should also seek to identify technically feasible and economical options that could remedy the reported network problem in the Bogue area of the Power System. A report of the System assessment should be submitted to the OUR within twelve (12) weeks from the effective date of this Determination Notice.

9.11.3 Generation Dispatch Issues

While it is recognized that the price of fuel oil is largely outside the control of JPS, the process of converting fuel to electricity to serve its customers lies firmly within the company's control.

Since fuel cost accounts for a substantial portion of JPS' total cost of electricity service, the issue of economic generation dispatch overlaid with the objective of producing electricity at minimum cost is of vital importance to the country and will be given close regulatory attention.

A review of JPS' historical and projected generation dispatch data revealed a number of issues. These are discussed below as follows:

9.11.3.1 JPS' Generating Units Variable Operations & Maintenance Cost

It was observed in JPS' Wescouger generation dispatch simulation files for 2014 – 2019, which was included in JPS' Tariff Submission that the variable Operation & Maintenance (VOM) costs (US$/MWh) for JPS' generating units were not included in the dispatch calculations. However, the VOM costs for the IPP plants were included. Evidence of this is shown in Figure 9.111 below which represents JPS' projected dispatch for July 2014.

Figure 9.111: JPS' Projected Dispatch for July 2014

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Output 1.1A - Production Cost Summary -- Tue 1JUL14(H 0:30)-Thu31JUL14(H24:00)
Area= JPS Period= ALL HOUS Case=JPS Study

--- Unit ---		Hrs	- No-		------------	Costs (K$)	------------			Energy	Cap.	$
Id	Name	On Line	St Up	Sh Dn	Start Up	O+M	Fuel	Emisn	Total	Output (MWh)	Fact (%)	Per MWh
1	OLHARB#4	744	0	0	0.0	0.0	6912.9	0.0	6912.9	33402.	66.	207.
2	OLHARB#3	744	0	0	0.0	0.0	6060.2	0.0	6060.2	27758.	57.	218.
3	OLHARB#2	383	15	15	73.8	0.0	3917.5	0.0	3991.2	17220.	39.	232.
5	HUNTBAY6	744	0	0	0.0	0.0	5766.6	0.0	5766.6	28806.	57.	200.
9	ROCKFOR1	744	0	0	0.0	0.0	1973.5	0.0	1973.5	13303.	89.	148.
11	ROCKFOR2	744	0	0	0.0	0.0	1965.3	0.0	1965.3	13303.	89.	148.
15	GT 9	72	0	1	0.0	0.0	446.3	0.0	446.3	1080.	7.	413.
17	GT 7	48	0	1	0.0	0.0	203.9	0.0	203.9	480.	4.	425.
19	GT 6	48	0	1	0.0	0.0	210.7	0.0	210.7	480.	4.	439.
20	GT 5	88	8	9	2.5	0.0	361.1	0.0	363.5	882.	6.	412.
24	GT 3	74	1	2	0.2	0.0	315.4	0.0	315.6	740.	5.	426.
6	JPPC	744	0	0	0.0	440.0	5757.2	0.0	6197.2	41945.	94.	148.
12	JEP	476	36	35	0.0	990.0	6158.9	0.0	7148.9	43669.	47.	164.
8	CCycle03	744	0	0	0.0	0.0	16138.5	0.0	16138.5	71803.	85.	225.
10	WKPP65MW	674	11	10	0.0	586.3	5792.3	0.0	6378.6	41115.	84.	155.
25	RIO-A	744	0	0	0.0	0.0	0.0	0.0	0.0	1674.	100.	0.
26	RIO-B	744	0	0	0.0	0.0	0.0	0.0	0.0	536.	100.	0.
27	LW RIVER	744	0	0	0.0	0.0	0.0	0.0	0.0	2797.	100.	0.
28	UW RIVER	744	0	0	0.0	0.0	0.0	0.0	0.0	1964.	100.	0.
29	MAGOTTY	744	0	0	0.0	0.0	0.0	0.0	0.0	3616.	100.	0.
30	ROAR-R	744	0	0	0.0	0.0	0.0	0.0	0.0	2745.	100.	0.
31	CS	744	0	0	0.0	0.0	0.0	0.0	0.0	201.	100.	0.
32	MAGG-B	744	0	0	0.0	0.0	0.0	0.0	0.0	2247.	100.	0.
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	Totals		71	74	76.	2016.	61980.	0.	64073.	351765.		

The non-inclusion of the VOM cost for JPS generating units in the dispatch calculations is not a fair dispatch practice and suggests a bias in favour of JPS' plants. Furthermore, the practice is not consistent with Condition 23 of the Licence and the relevant provisions of the Generation Code which require the VOM costs to be included in the variable operating costs of each generating unit.

With respect to the use of the VOM in the generation dispatch calculations, Section 3.2 (Merit Order Scheduling) of the Generation Code provides as follows:

"The Grid Operator shall establish a Merit Order based on the real or contracted Variable Operating Cost component of each Generating Unit or Complex, whichever is applicable.

The Variable Cost of each Generating Unit or Complex is the sum of the Variable Operating & Maintenance Cost (VOM) and the Fuel Cost. In mathematical form:

Merit Order Cost ($/MWh) = Fuel Cost ($/MBTU) × Full Load Heat Rate (MBTU/MWh) + VOM ($/MWh)."

VOM costs are O&M costs that are a function of the operation of a generating unit. These may include yearly maintenance, consumables and water supply costs, as well as environmental costs that vary with the utilization of the generating unit.

The omission of the VOM cost from the variable operating cost of JPS' generating units which is used in establishing the merit order that influences the generation dispatch process suggests that the VOM costs for JPS' generating units do not vary with electricity production and are treated in the electricity rates as fixed cost. From a regulatory and power plant economics perspective, this practice is inappropriate on the basis that the variable operating cost of a power plant which includes fuel and VOM costs are a function of the utilization of the plant. If the plant has a capacity factor of zero, then the variable cost in absolute terms is zero.

Under the current price control mechanism, the fixed and variable O&M costs for JPS' generating units are estimated by the company and included in the non-fuel operating costs which represent a major component of the Non-Fuel Revenue Requirement. However, the projected level of utilization of each generating unit on which the Variable O&M cost is based may not be realized during actual operation, and electricity customers may have to absorb costs for operation that did not occur. This brings into focus the issue of the pass-through of reasonable and prudent costs incurred by JPS.

If JPS' generating units are not used or under/over utilized in a given billing period, this could result in a significant variance between the variable O&M cost allowed in the Non-Fuel Revenue Requirement and the actual Variable O&M cost incurred due to the non-utilization or under/over utilization of the units. This situation is more profound when JPS' generating units are out of service for extended periods as was the case with Bogue ST#14 in 2013 and the case with Bogue GT#8 (since 2011) and GT#11 (since 2012). Based on the existing tariff structure, during these prolonged outages of the generating units, JPS continued to receive compensation for the units' variable O&M

cost (embedded in the approved rates) while the units were not utilized in the production of electricity.

For the price-cap period 2014-2019, JPS is required to include the VOM costs in the variable cost of its generating units for merit order scheduling and generation dispatch to ensure transparency in the process and that costs are appropriately allocated and reflected in the rates to electricity customers.

For variances between the approved level of variable O&M cost for JPS' generating units and the actual variable O&M cost incurred as a result of the actual utilization of the units in a given billing period, JPS is required to adjust the fuel cost to correct for the over-recovery or under-recovery of the total reasonable and prudent variable O&M costs.

With respect to the treatment of JPS' generating units variable O&M costs, the Office determines as follows:

DETERMINATION 29

For the price-cap period 2015-2019, JPS shall include the variable O&M costs in the variable cost of its generating units for merit order scheduling and generation dispatch to ensure transparency in the process and that costs are appropriately allocated and reflected in the rates to electricity customers.

For variances between the approved level of variable O&M cost for JPS' generating units and the actual variable O&M cost incurred as a result of the actual utilization of the units in a given billing period, JPS shall adjust the fuel cost to correct for the over-recovery or under-recovery of the total reasonable and prudent variable O&M costs.

9.11.3.2 Utilization of IPP Plants

Historical generation dispatch data reported for the period January to July 2014 indicated that some IPP plants have not been utilized up to previous dispatch levels. This is demonstrated by the actual capacity factors of the generating plants shown in Table 9.112 below:

Specifically, the utilization of the JEP Complex has seen reductions since 2011 from a capacity factor of 79% to 61.5% up to the end of July 2014. The lower utilization of the JEP Complex and other IPP plants has cost implications.

Table 9.112: Average Capacity Factor for Generating Plants since 2011

		Average Capacity Factor				Remarks
Operating Thermal Units	**Capacity**	**2011**	**2012**	**2013**	**Jan-Jul 2014**	
JPS	**MW**	**%**	**%**	**%**	**%**	
Bogue GT#3	21.4	9.62	10.36	6.12	8.25	
Bogue GT#6	17.9	10.66	6.08	3.30	-	O/S –since Oct 2013
Bogue GT#7	17.9	3.77	3.78	2.02	4.30	
Bogue GT#8	14	6.16	O/S	O/S	O/S	O/S – since Dec 2011
Bogue GT#9	19.9	4.26	10.03	5.13	5.39	
Bogue GT#11	19.9	0.99	0.73	O/S	O/S	O/S – since Oct 2012
Bogue CC #12	37	79.66	76.66	67.49	65.90	Component Generators of Bogue CCGT
Bogue CC #13	37	85.35	82.83	74.22	79.70	
Bogue CC #14 (HRSG)	37	84.76	80.70	51.07	83.48	
Bogue CCGT	111	83.26	80.06	64.26	76.36	
HB GT#5	21.4	17.39	17.56	12.09	7.53	
HB B6	64.4	70.09	67.00	64.63	47.36	
HB GT#10	32.1	31.86	27.82	19.10	17.93	
RF #1	19.5	80.53	83.71	81.05	87.64	
RF #2	19.4	89.35	80.51	88.19	71.79	
OH #2	57.4	55.52	50.18	32.46	39.17	
OH #3	62.5	56.33	58.04	58.58	61.30	
OH #4	64.6	55.06	48.19	66.53	69.33	
IPPs						
JPPC	60	81.33	80.40	81.73	79.99	
Jamalco	11	-	-	-	-	Ave Cap - 0.5MW
WKPP	65.5	-	59.01	87.72	81.35	
JEP	124.4	79.06	70.48	69.45	61.54	

Projected Utilization of JEP Complex

With respect to the generation resource mix, generation dispatch including SCED is a complex but relatively mechanical process that should identify the required set of generation resources to be dispatched to meet electricity demand at the lowest cost given the available resources and prevailing grid conditions at the time.

Nonetheless, as highlighted earlier in Section 9.8, JPS' generation dispatch forecast for 2014 and 2015 has projected a relatively low utilization for the JEP Generation Complex located at Old Harbour. On the assumption that there will be no major alteration to the existing System configuration in 2014 and 2015, the JEP Complex was projected to be dispatched at an average capacity factor of 50% and 42% for 2014 and 2015 respectively. In the dispatch forecast files, JPS did not define any specific constraint or other operating factors that would necessitate or justify the low utilization of the JEP Complex and the apparent sub-optimal generation dispatch.

The JEP Generation Complex is located at the same Old Harbour site (not declared a transmission-constrained location by JPS) as the JPS Old Harbour (OH) generating plant. Accordingly, both JPS' OH generating units and the OH JEP's Complex are connected to the grid via the same substation. This suggests that there are no major connectivity issues between the two generation plants and any possible effect of network constraints would be common to both facilities.

JPS' weekly merit order table and its Wescouger software generation dispatch simulation files for 2014 and 2015, indicate that the JEP Complex has a lower variable cost than all the JPS OH generating units and other JPS plants. However, as evidenced by the same data set, the JEP Complex is being dispatched and scheduled to be utilized at lower levels than JPS' plants located at the same site and other plants interconnected at different points on the grid, which have much higher variable operating cost.

According to JPS, the utilization of generating plants within their capability limits from a minimum system demand of 400 MW to a maximum demand of over 600 MW would indicate that the inability of most of the large steam units at Old Harbour to cycle offline at nights and return in the morning to meet the day peak versus the flexibility of JEP's diesel generating sets to do so can result in higher overall utilization of the Old Harbour steam sets. It is noted that there may be an inherent limitation of the large steam units at Old Harbour to operate in cycling mode, based on their design characteristics.

The OUR accepts that every type of electric power generation technology has its own peculiar advantages and disadvantages. Some generation technologies possess different cost and operating characteristics that would enable greater operational flexibility than others. Steam plants tend to generate at relatively consistent levels, but are subject to significant maintenance outages for repair work. These plants have limited ability to adjust to the dynamic nature of demand, and may take days to reach full output from a complete shutdown. Reciprocating diesel engine and gas turbine (GT) power plants tend to be relatively flexible in changing output to meet the dynamic characteristics of demand throughout the day, but GTs fuelled by ADO usually have relatively high variable operating costs. As described, some generation technologies possess different cost and operating characteristics that would enable greater operational flexibility than others. However, where a particular generating plant has a relatively low variable cost and is not constrained off or de-rated due to network security contingency requirements, then power system economics dictates that the plant should be utilized ahead of other less efficient plants in the System in order to supply the electricity demand at minimum cost.

As indicated, it is recognized that there may be an inherent limitation of JPS' steam units at Old Harbour to operate in cycling mode, based on their design characteristics. However, contrary to JPS' claim, generation dispatch data provided by the company indicated that Old Harbour unit 2 (OH#2) is being operated and projected to operate in a manner that is reflective of cycling operations. As shown in Table 9.113 below, OH#2 was planned for at least 15 starts and 15 shutdowns in each month of 2014. The unit's online hours are also shown. This mode of operation of OH#2 constitutes a deviation from the operational requirements of this type of power plant and prolonged utilization of the unit in this mode may result in major failure of critical equipment and components that could compromise System reliability. The situation is not consistent with JPS' claim regarding cycling its OH steam units.

Table 9.113: JPS' Generating Units Planned Starts and Shutdowns for 2014

	Jan-14			Feb-14			Mar-14			Apr-14			May-14			Jun-14		
	Hrs On Line	St Up	Sh Dn	Hrs On Line	St Up	Sh Dn	Hrs On Line	St Up	Sh Dn	Hrs On Line	St Up	Sh Dn	Hrs On Line	St Up	Sh Dn	Hrs On Line	St Up	Sh Dn
OH4	744	0	0	672	0	0	744	0	0	720	0	0	744	0	0	720	0	0
OH3	744	0	0	436	1	1	744	0	0	720	0	0	744	0	0	720	0	0
OH2				423	16	15	555	14	14	496	8	8	499	17	17	467	17	16
B6	744	0	0	672	0	0	21	0	1	343	1	0	744	0	0	720	0	0
RF1	744	0	0	556	1	1	744	0	0	720	0	0	744	0	0	720	0	0
RF2	69	0	1	511	1	0	744	0	0	720	0	0	744	0	0	720	0	0
GT10	158	32	31	37	14	14	278	14	15	105	15	16	164	27	27	77	20	20
GT9	10	4	4				192	0	1	68	0	1	72	1	1			
GT7	44	8	8				2	1	1	68	0	1	81	1	1	2	1	1
GT6	24	6	6															
GT5	91	18	18	6	3	3	240	0	1	74	3	4				45	19	19
GT3	66	9	9				120	1	1	70	1	2				10	5	5
JPPC	744	0	0	672	0	0	730	2	1	714	1	1	744	0	0	720	0	0
JEP	591	25	24	484	24	24	489	26	25	443	30	30	410	36	35	573	21	21
GT12													23	10	10			
BOCC	647	0	1	672	0	0	744	0	0	720	0	0	744	0	0	720	0	0
WKPP	720	4	4	644	6	6	668	11	10	627	16	16	654	15	15	707	3	3
RIO-A	744	0	0				79	0	0	720	0	0	744	0	0	720	0	0
RIO-B	744	0	0				79	0	0	720	0	0	744	0	0	720	0	0
LW RIVER	744	0	0	672	0	0	744	0	0	720	0	0	744	0	0	720	0	0
UW RIVER	744	0	0	672	0	0	744	0	0	720	0	0	744	0	0	720	0	0
MAGGOTTY	744	0	0	672	0	0	744	0	0	720	0	0	744	0	0	720	0	0
ROAR-R	744	0	0	672	0	0	744	0	0	720	0	0	744	0	0	720	0	0
CS	744	0	0	672	0	0	744	0	0	720	0	0	744	0	0	720	0	0
MAGG-B	495	0	0	672	0	0	744	0	0	720	0	0	744	0	0	720	0	0

	Jul-14			Aug-14			Sep-14			Oct-14			Nov-14			Dec-14		
	Hrs On Line	St Up	Sh Dn	Hrs On Line	St Up	Sh Dn	Hrs On Line	St Up	Sh Dn	Hrs On Line	St Up	Sh Dn	Hrs On Line	St Up	Sh Dn	Hrs On Line	St Up	Sh Dn
OH4	744	0	0	645	0	1	319	1	0	744	0	0	720	0	0	744	0	0
OH3	744	0	0	744	0	0	720	0	0	429	0	1				679	1	0
OH2	383	15	15	408	16	15	437	15	15	429	15	15	483	16	16	251	11	10
B6	744	0	0	744	0	0	720	0	0	744	0	0	720	0	0	744	0	0
RF1	744	0	0	744	0	0	599	1	1	744	0	0	720	0	0	744	0	0
RF2	744	0	0	744	0	0	720	0	0	628	1	1	720	0	0	744	0	0
GT10				8	4	4	197	20	20	94	11	12	173	30	31	72	0	1
GT9	72	0	1	48	0	1	96	1	1	21	0	1	48	0	1			
GT7	72	0	1	26	1	2	102	4	4	48	0	1	50	1	2			
GT6	48	0	1				2	1	1									
GT5	48	8	9	69	9	10	127	12	12				29	13	13			
GT3	88	1	2	53	2	3	87	7	7	48	0	1	55	3	4	48	0	1
JPPC	74	0	0	744	0	0	720	0	0	744	0	0	720	0	0	744	0	0
JEP	744	36	35	509	29	28	555	19	19	528	25	24	607	18	17	407	35	35
GT12																		
BOCC	476	0	0	744	0	0	720	0	0	744	0	0	720	0	0	744	0	0
WKPP	744	11	10	723	4	4	696	5	5	700	6	5	708	2	2	681	14	14
RIO-A	674	0	0	744	0	0	720	0	0	744	0	0	720	0	0	744	0	0
RIO-B	744	0	0	744	0	0	720	0	0	744	0	0	720	0	0	744	0	0
LW RIVER	744	0	0	744	0	0	720	0	0	744	0	0	720	0	0	744	0	0
UW RIVER	744	0	0	744	0	0	720	0	0	744	0	0	720	0	0	744	0	0
MAGGOTTY	744	0	0	744	0	0	720	0	0	744	0	0	720	0	0	744	0	0
ROAR-R	744	0	0	744	0	0	720	0	0	744	0	0	720	0	0	744	0	0
CS	744	0	0	744	0	0	720	0	0	744	0	0	720	0	0	744	0	0
MAGG-B	744	0	0	744	0	0	720	0	0	744	0	0	720	0	0	744	0	0

In "JPS' Comments on OUR's 2014-2019 Tariff Review Revised Draft Determination" dated December 5, 2014, the company stated that Old Harbour #2 has cycling capability. However, the company did not provide the relevant documentation to confirm that the unit possesses the technical capability to perform cycling duty on a continuous basis.

The admission by JPS that its OH#2 steam generating unit (categorised as base-load) is being operated in cycling mode raises significant concerns about the company's philosophy regarding the operation of its generation assets. The notion that the unit is being operated in cycling mode to achieve lower System fuel operating cost appears to be a counter-productive and precarious strategy on the grounds that there are: (a) more flexible and cost-efficient plants available which are under-utilized; and (b) the susceptibility of the unit to major failures as a result of prolonged cycling operations.

It is recognised in the electricity supply industry that cycling operation increases the risk for major damage caused by excessive cycling, thermal stresses and frequent load cycling especially in units designed for base-load operation. This condition has been found to be a dominant failure mode for damage and failure of many fossil fuel plant components particularly when generating plants are extensively utilized in cycling mode.

This generation operations strategy that is being executed by JPS is very troubling and appears to resemble previous practices that may have been instrumental in the severe and catastrophic failure of other generating units over the past years.

Although the risk of operating a base-load generating unit in cycling mode is recognised, based on JPS' statement which affirms that OH#2 has cycling capability and therefore can operate as a flexible generation resource, then the indicated constraint on the dispatch of the OH JEP Complex to facilitate flexible operations should be relaxed, to allow higher utilization of the OH JEP Complex to enhance the fuel cost optimization process.

Notably, JPS has posited that it would not be in its best interest to bias the dispatch against OHJEP Complex since that puts the company's ability to meet its target heat rate at further risk and jeopardizes recovery of its fuel cost. While there is some logic to the position articulated by JPS, based on the constituents and algebraic structure of the System heat rate equation, the energy contribution from non-combustible renewables such as wind and hydro may provide sufficient buffer to insulate JPS from fuel cost penalties when the OH JEP Complex is dispatched at much lower levels than JPS' high variable cost generating units.

The deliberate suppression of cost-efficient IPP generation in the dispatch process to favour JPS' generating units would be unacceptable and contrary to the fundamental objective of producing electricity at minimum cost. While the OUR makes no claim that this is in fact the case, it intends to exercise greater regulatory oversight in the dispatch process with the aim to minimize, if not completely eliminate, any such temptation or possibility.

According to Condition 23 of the Licence, JPS is required to dispatch available generation sets in ascending order of the marginal cost in respect of any hour for the generation and delivery or transfer of electricity into the System, to the extent allowed by transmission system operating constraints. The under-utilization of relatively low variable-cost generation by JPS without appropriate justification would constitute a breach of the Licence.

Without prejudice to any generating entity or generation owner, it must be recognized that the economic generation dispatch process should not function to allow priority dispatch to JPS' generating units while IPP plants are utilized on an as-needed basis.

If the current transmission system configuration is not adequate to accommodate a certain level of generation from the IPP plants located at Old Harbour, which has not been designated a transmission-constrained location within the System, then the situation needs to be appropriately assessed by JPS and reported to the OUR. This also applies to other critical locations within the System.

9.11.3.3 Transparency of the Generation Dispatch Process

Lack of appropriate policies and procedures as well as lack of transparency of the details of JPS' dispatch procedures and whether these procedures are being fairly administered have emerged as issues that may be impacting the generation dispatch operations and ultimately the fuel rate. This is considered to be a critical issue that will be examined by the OUR as part of its fuel monitoring framework.

Having regard to all the generation dispatch-related issues discussed above, the OUR will undertake a complete audit of JPS' dispatch processes subsequent to the effective date of this Determination Notice. The audit will seek to ensure that the generation dispatch is being conducted by JPS in a fair and transparent manner and in accordance with the Licence and the relevant Codes.

In addition to the audit, the OUR will establish a dispatch monitoring framework to facilitate continuous monitoring of JPS' dispatch operations. This will be specifically addressed under Section 9.12.

- *Schedule A*: Final computation of Fuel & IPP charges including adjustments for volumetric sales difference. Inputs are referenced from other sheets in the submission.
- *Schedule B*: Summary of Fuel & IPP charges for each rate class according to the Licence.
- *Schedule C*: Summary calculation of volumetric adjustment.
- *Schedule D*: Calculation of IPP surcharge based on actual vs. estimated operations and maintenance cost.
- *Generation*: System net generation and net generation of individual plants.
- *Fuel Oil Analysis*: Summation of volume and cost for fuel used by JPS plants and fuel cost estimates for IPP plants.

- *Heat Rate Analysis*: System heat rate calculation based on individual plants input and output energy.
- *Power Purchase (IPP) Cost Data*: Calculation of fixed and variable payments due to IPPs based on PPA.
- *Petrojam Weekly Billing Prices and Tax Refund for Bogue CCGT*
- *SAC Calculation*: Monthly generation tariff for net-billing customers based on the Standard Offer Contract.

9.11.4 Fuel Rate Calculation Issues

Fuel rate calculations and supporting documentation are submitted by JPS to the OUR on a monthly basis as part of its regulatory reporting requirements. These calculations are reviewed and validated by the Office to ensure that the Fuel & IPP charges used for billing JPS' electricity customers each month are accurate and reflective of the cost of fuel incurred by JPS and IPPs in the production of electricity in the period. Data sheets submitted as part of the fuel rate calculations are:

- *Schedule A*: Final computation of Fuel & IPP charges including adjustments for volumetric sales difference. Inputs are referenced from other sheets in the submission.
- *Schedule B*: Summary of Fuel & IPP charges for each rate class according to the Licence.
- *Schedule C*: Summary calculation of volumetric adjustment.
- *Schedule D*: Calculation of IPP surcharge based on actual vs. estimated operations and maintenance cost.
- *Generation*: System net generation and net generation of individual plants.
- *Fuel Oil Analysis*: Summation of volume and cost for fuel used by JPS plants and fuel cost estimates for IPP plants.
- *Heat Rate Analysis*: System heat rate calculation based on individual plants input and output energy.
- *Power Purchase (IPP) Cost Data*: Calculation of fixed and variable payments due to IPPs based on PPA.
- *Petrojam Weekly Billing Prices and Tax Refund for Bogue CCGT*
- *SAC Calculation*: Monthly generation tariff for net-billing customers based on the Standard Offer Contract.

The OUR's monthly review of the fuel rate calculations including the supporting data sheets over the price cap period October 2009 to June 2014 has revealed a number of issues and discrepancies including the timeliness of the fuel rate calculation submissions. Some of these issues are discussed below.

9.11.4.1 Inconsistencies in Fuel Oil Statements

The fuel oil consumption and the corresponding energy generation are critical to the total fuel cost and the overall efficiency of the electricity generating system. A small deviation or error in these parameters can have a sizable impact on the fuel rate used for billing electricity customers. As such, the monthly fuel oil statement submitted by JPS requires careful review and evaluation.

It was observed over the referenced period that there were several instances of inconsistencies between parameters in the fuel oil statements and other JPS documents reporting the same parameters. In accordance with prudent utility practice, JPS ought to ensure that the relevant parameters or factors used in the calculation of the monthly fuel rate are accurate and reflective of the actual system performance each month. This is applicable to, inter alia, the data sheets listed above that are included in the fuel rate calculation submission to the OUR each month.

Table 9.114: Inconsistencies with Fuel Usage Recorded Across Fuel Rate Calculation Sheets

Month	Unit	Volume Used (litres)		Difference (litres)
		Heat Rate Calculation Sheet	Fuel Oil Statement	
Jan-2014	RF1+RF2	3,793,749	3,756,085	37,664
Mar-2014	RF1+RF2	5,060,492	4,999,801	60,691
Apr-2014	RF1+RF2	5,384,793	5,365,300	19,493
May-2014	RF1+RF2	5,406,087	5,391,212	14,875
Jun-2014	RF1+RF2	5,596,334	5,540,843	55,491
Jul-2014	RF1+RF2	5,096,695	5,053,018	43,677
	GT3	2,185,908	2,155,327	30,581
Aug-2014	RF1+RF2	5,161,548	5,116,795	44,753
Sep-2014	RF1+RF2	5,773,020	5,684,882	88,138
Oct-2014	RF1+RF2	5,511,356	5,462,802	48,554

9.11.4.2 Adjustment for Volumetric Sales Difference

The computation of the adjustment for volumetric sales difference in the monthly fuel rate calculation is presently devoid of details and presents a challenge for the OUR in the validation process. With respect to the issue of adjustments for volumetric sales difference, the Office determines as follows:

DETERMINATION 30

For the price cap period 2015-2019, JPS shall be required to:

- **Clearly define the adjustment for volumetric sales difference; and**
- **Provide separate data sheets setting out clearly and precisely and with sufficient details how the volumetric sales difference for each month is determined.**

9.11.4.3 Reconciliation of IPPs' Estimated Cost and IPPs' Actual Fuel Cost

It was observed in several instances that the estimated IPP fuel costs and the payment for the actual fuel cost to the IPPs one (1) month later, shows discrepancies which are unexplained. With respect to the issue of the reconciliation of IPPs' estimated fuel cost and IPPs' actual fuel cost, the Office determines as follows:

DETERMINATION 31

For the price-cap period 2015-2019, JPS shall be required to:

- **Clearly set out with sufficient detail the basis for the estimation of IPP fuel costs for each month including all the relevant parameters and assumptions;**
- **Clearly account for any differential between the estimated and actual fuel costs and provide details how such differential is reconciled in accordance with the relevant provisions of the respective PPA; and**
- **Include Petrojam's fuel invoices for IPPs' fuel purchases which should include unit price, quantity and delivery dates in the monthly Fuel Rate Calculation Submission.**

9.11.4.4 JPS-Managed Renewable IPP Assets

The JPS' Munro (3 MW) Wind Farm and JPS' Maggotty (6.37 MW) Hydro plant were procured and treated as independent generation assets which are not included in asset base of JPS' utility business.

Accordingly, the performance and payments to the plants should be reported in a similar fashion and included in the fuel rate calculation as is done for the existing IPPs. JPS has not been responsive in providing the relevant information for its Munro Wind Farm since it was commissioned in 2010. Notably, the OUR has only received two (2) submissions on the performance of and payment to the plant since commercial operations date (COD). With respect to monthly performance and transactions related to JPS-managed renewable IPP assets, OUR DETERMINES as follows:

DETERMINATION 32

For the price-cap period 2015-2019, JPS shall be required to:

- **Include the full details of the monthly performance and payments for both Munro Wind Farm and Maggotty Hydro and any other generating facility owned by JPS and governed by a similar ownership structure in the monthly Fuel Rate Calculation submission to the Office.**

9.11.5 Impact of Forced Outage of IPP Plants

As previously stated, the net generation and heat rates of IPPs are currently factored in the System heat rate calculation. However, major forced outages (greater than contracted hours) of one or more IPPs and their impact on the System heat rate have emerged as a critical issue which has raised questions about the current heat rate construct. This issue is addressed in detail below.

9.11.5.1 Forced Outage of JEP's Barge #2

With respect to the forced outage of JEP's Barge #2 in 2013, the OUR was notified by JPS by way of letter dated September 27, 2013 that a failure on DG#11 resulted in a fire which forced the entire Barge #2 out of service. The report further indicated that DG#9 was expected to return to service on September 19, 2013 but was actually restored on September 27, 2013 and JPS was unable at that stage to provide a definitive schedule for the return to service of units DG#10 and DG#11. According to JPS, at the time of the incident Bogue ST#14 unit was also out of service due to a major forced outage.

In a subsequent submission dated October 25, 2013 from JPS requesting Force Majeure relief, the company indicated that the latest update from JEP was that units DG#10 and DG#11 would return to service on October 31 and December 31 respectively.

JPS indicated that JEP's Barge #2 is one of the most efficient generating plants on the System and plays a pivotal role in achieving the System heat rate target. According to JPS, the extended unplanned loss of the units had an adverse effect on the System heat rate target for which it was seeking Force Majeure relief.

JPS acknowledged that it is aware that in the setting of the heat rate target, the Office considered and included an allowance for planned and some forced outage on the System. However, the Company doubted the OUR's planning scenario would have contemplated a double contingency involving the loss of two of the newest and most efficient units in the System.

JPS' request for Force Majeure relief stated as follows:

"Given the circumstances, we write to seek the Office's approval of force majeure regulatory relief from the heat rate impact of the forced outage of the Doctor Bird Barge #2 due to the fire as this was entirely outside of our control. JPS proposes that the direct fuel cost associated with the heat rate variance due to the barge being out of service be passed through the fuel charge with step adjustments as each unit is returned to service."

The reported incident of forced outage of JEP's Barge #2 and the claim of System heat rate deterioration due to the outage which influenced JPS' request for Force Majeure relief depicts a situation which gives credence to the position that the IPPs' plants should not be factored in the System heat rate target.

In JPS' heat rate proposal the following was stated:

"JPS cannot influence the availability or reliability of the IPPs and should not be exposed to any additional penalties (fuel and heat rate) because of any failure to perform. JPS faces increased performance risk to the IPPs as their plants age over time and as they expand their generating capacity as a percentage of the system installed capacity. A failure to achieve the target level of availability and reliability by the IPPs has the largest negative effect on the system heat rate, all factors remaining constant. Since the performance guarantees (e.g. liquidated damages) that the IPPs provide for under-performance is effectively refunded to the customer through the IPP fuel surcharge/adjustment, it is JPS that suffers the penalty when the system heat rate worsens because of the poor performance of IPPs."

This argument proffered by JPS is consistent with its position in its heat rate proposal in JPS' Tariff Submission and which on the surface would seem to suggest that the company was not in favour of a heat rate target that included the IPPs' plant efficiency parameters.

In JPS' heat rate proposal, the company argued that it cannot influence the availability or reliability of the IPPs and should not be exposed to any additional penalties (fuel and heat rate) because of any failure to perform. JPS indicated that it faces increased performance risk to the IPPs as their plants age over time and as they expand their generating capacity as a percentage of the system installed capacity. According to JPS, a failure to achieve the target level of availability and reliability by the IPPs has the largest negative effect on the system heat rate, all factors remaining constant.

The argument put forward by JPS suggests that it is exposed to heat rate risks from IPP plants. The logical conclusion from this is that to alleviate this exposure, a sensible strategy is to disassociate the IPPs' efficiency components from the System heat rate.

9.11.6 Forced Outage of JPS' Generating Units

As reported by JPS, major forced outage of some of its critical generating units over the 2009-2014 price-cap period adversely impacted its heat rate performance.

Notably, the forced outage rates and equivalent availability (based on design and operational specifications) of all the generating units operating in the System are taken into account in the setting of the heat rate target. It also bears underscoring that forced outage of JPS' generating units not caused by *Force Majeure* events are fundamentally a maintenance issue which is considered to be within the company's control. As such any adverse heat rate effect that results from the forced outage of its generating units has to be absorbed by JPS.

9.11.7 Plants Heat Rate Test Data

It was observed that the heat rate test data for JPS' thermal generating plants were not current and reflected the same values submitted two (2) years ago and included heat rate test data for Old Harbour unit #1 which has been out service since 2008.

According to Section 3.2.1(ii) of the Generation Code:

> *"The Heat Rate data for each Generating Unit is necessary to determine its variable fuel operating cost. All contracts for new generating capacity shall have a guaranteed Heat Rate curve or point.*
>
> *The Heat Rate Tests for each Generating Unit, not having a guaranteed curve or point, shall normally be conducted at least twice annually or as stipulated by contract. The schedules for the Heat Rate Test for all Dispatchable Generating Units shall be developed by the Grid Operator at least one Month before the end of the preceding Year. The Heat Rate Test schedules may be adjusted within the Year to accommodate unforeseen circumstances, subject to agreement between the Generator and the Grid Operator. Such schedules for Heat Rate Test shall be submitted to the OUR by the Grid Operator."*

9.11.8 JPS' Generating Plant Maintenance

9.11.8.1 General

Maintenance is an important factor in extending the useful life of power generation facilities, or at least extending the mean time to the next failure for which repair cost may be significant. An effective maintenance policy can reduce the frequency of service interruptions and the associated consequences. Essentially, having an effective maintenance schedule is very important for a powersystem to operate economically with an acceptable level of reliability.

The availability and efficiency of JPS' thermal generating units are key factors that will impact the determined generating heat rate. Therefore, if plants are not properly maintained there is the risk of catastrophic failures that can adversely impact the System reliability, efficiency and economics.

9.11.8.2 Execution of Planned maintenance

With respect to JPS' operations, there are several observations which raise concerns about the company's generation maintenance policy and practices. These are discussed below:

In accordance with the Generation Code, JPS is required to develop a two (2)-year generation maintenance schedule each year that sets out the timelines when generating units in the System will be subjected to routine and major maintenance. The OUR's observations indicate however that after the development of the schedules, the actual maintenance activities in many instances tend to deviate significantly from the scheduled timelines.

An example of this was an overdue major inspection on Hunts Bay unit B6 turbine condenser which should have been undertaken in 2006 that was apparently completed during the major overhaul of the unit in 2014. It would be expected that for a unit of this type, given its age and position in the merit order, major inspections would be carried out more frequently than as per the manufacturer's original recommendations, particularly if strict maintenance regimes have not been followed.

Other generation maintenance issues relate to the treatment of Bogue GT#8 and GT#11 which have been out of service for an extended period.

For GT#11, in particular, JPS has indicated that the unit is relatively new and one of the most efficient peaking units in its generation fleet and is best suited to run on gas. Reports from JPS confirmed that the unit had been out of service since September 19, 2012. Nevertheless, the company stated that it took the decision not to have it restored until 2016. Refer to Section 6.4.4.5 (Depreciation) for details on the outage of the unit.

Regarding GT#8, JPS indicated that the unit was commissioned in 1992 and had now exhausted its useful life and would not likely be returned to service.

9.12 Fuel Cost Monitoring Framework

9.12.1 Background

The FCAM is intended to efficiently pass-through JPS' fluctuating fuel expenses from month to month. The fuel adjustment proceeding is continuous and operates to the company's benefit by preventing it from needing to submit a rate filling to the Office whenever fuel prices change. However, this process does not relieve the regulator of its responsibility to review the prudence of these costs.

9.12.2 JPS' Fuel Management Policies and Procedures

Having cognizance of a number of issues that emerged in the electricity sector in connection with JPS' handling of the fuel used in the production of electricity, the OUR in 2012 engaged an independent consultant to carry out an audit of fuel management by JPS. A report on the Audit of the Jamaica Power System's Fuel Management Policies and Practices dated 31st October 2013 was issued.

The summary of the main findings of the audit are stated as follows:

> *"JPS policies and procedures appear weak in several areas, including responsibilities and required training of the personnel, standard formats for reports and spread sheets, fuel inventory and equipment and accounting practices. The consultant was expecting to evaluate*

several dozens of procedures regarding all tasks a Power System Operation Department should perform, such as demand forecasting, system dispatch, system deviations, monitoring system conditions, information to market participants, weekly planning, monthly planning, outage and maintenance coordination, out of merit dispatch, security constraints dispatch, among many others, but none were presented. All of these reasons, including the fact that the policies and procedures provided relates to the last year of the audited analysis makes it difficult to establish a complete audit trail to assess the underlying problems impacting the fuel management systems over that period. JPS is just starting developing policies and procedures and it is important to continue through that path to ensure operations follow international best practices.

Not having fuel policies and procedures clearly written and available to all personnel can lead to errors and inconsistent actions. Undocumented practices and procedures are not subjected to organizational reviews, and as such different approaches are adopted across the company leading to a situation where inconsistency and inefficiency can develop."

Specific details of some of the findings of the audit are listed below:

- A limited number of policies and procedures documents regarding fuel management were presented during the visits to the JPS plants. Several processes and practices are not yet well documented.

- While JPS states that all updated information is available to all plants' personnel, there are no records of any feedback system existing to make sure that everybody understands the policies. Also no documents regarding control standards were seen to ensure that there is a comprehensive fuel planning process.

- Another problem existing with policies and procedures lies in the fact that responsibilities for the different activities are not clearly defined, which makes it difficult to establish an audit trail.

- There are no safeguards to protect from data corruption and manipulation since policies and procedures are not correctly implemented in this manner. This is mainly due to the lack of documented information systems and the fact that responsible personnel for the different tasks are not specified.

- There is a lack of procedures regarding the standardization of reports. This includes the formatting of documents and spread-sheets, causing documents from different plants to be difficult to compare in order to obtain the same type of information, and also posing a risk to the integrity of the system as each plant generates their own versions of reports. Right now oversight is expensive as each plant requires understanding of its own reporting system.

- No evidence is provided of tracking after the point where the fuel is stored in tanks, or regarding inventory policies or meter locations.

- The consultant did not see documents at any of the JPS plants to indicate that records were kept for inspection and testing for future reference, so that an audit trail can be established based on such records.

The relevant findings and the recommendations of the fuel audit as approved by the Office will be incorporated in the OUR's fuel monitoring framework.

9.12.3 Monitoring Framework

To ensure that the total fuel expenses each month are prudently incurred, the OUR will monitor the actual fuel and relevant power purchase costs associated with the production of electricity.

To enable this, JPS will be required to submit documentation and information to the Office as specified below.

9.12.3.1 Monthly Fuel Rate Calculation

JPS shall submit to the Office each month the complete Fuel Rate Calculations including among other things, the Set of Schedules for the application of the fuel charge to each rate class, SOC rate, purchased power cost, quantity of fuel purchased and fuel inventory.

The Fuel Rate Calculation to be submitted to Office shall conform to the format and manner detailed below:

1) The Fuel Rate Calculation for each month shall be submitted in an appropriate electronic format on the same day the calculation is completed by JPS and prior to applying such fuel rate to customers' bills. The electronic submission shall include all the relevant schedules and IPP cost components. Notwithstanding, the official hard copy of the complete Fuel Rate Calculation including the IPPs' transactions shall be submitted to the Office within ten (10) days after the month for which the fuel rates were calculated.

2) The calculation of the IPPs' payments as per Schedule 6 of the respective PPAs which are included in the Fuel Rate Calculation submission to the Office shall be accompanied by a supporting Microsoft Excel file with all the calculations relating to the payments to each IPP.

3) Any and all unusual or extra-ordinary cost item that JPS intends to recover through the medium of an adjustment to the monthly Fuel Rate Calculation, shall first be submitted to the Office for review and approval. Such submission shall be presented in sufficient detail including any relevant calculations or models to facilitate the evaluation of the appropriateness of such cost item.

4) The following types of cost shall not be included in the monthly total fuel cost:

(a) O&M expenses related to generating plants or storage facilities;
(b) Foreign Exchange (FX) adjustment for JPS' fuel transactions;
(c) Cost related to fuel procurement administrative functions; and
(d) Fuel additives neither blended with fuel prior to burning nor injection into the boiler firing system with fuel.

9.12.3.2 Fuel Management Report

JPS shall submit to the Office each Quarter a Fuel Management Report pertaining to management and consumption of fuel used in production of electricity for each month in the Quarter.

1) The report shall include among other things, the following:
    a) Budgeted and actual fuel consumption and cost;
    b) Quantity of fuel purchased;
    c) Quality of fuel purchased, including heating value, sulphur content, etc.
    d) Fuel invoices showing quantity purchased; and
    e) Fuel inventory levels – the method used for accounting for the fuel should be indicated and the tracking of the fuel should be evident.
    f) The projected and actual fuel consumption and cost for each month.

2) The management of the fuel shall be in accordance with the Licence, the Generation Code and JPS' fuel policies and procedures.

3) The report shall cover JPS' fuel-related activities and transactions for each month in the Quarter and shall be submitted to the Office within fourteen (14) days after the end of the Quarter.

9.12.3.3 Heat Rate Test Report

JPS shall submit to the Office a report on the heat rate test results of its thermal generating units and IPP plants (as applicable) in accordance with provisions of the Generation Code.

9.12.3.4 Generation Dispatch

JPS shall submit the following documentation and information regarding merit order scheduling and generation dispatch to the Office by the timelines specified.

1) A daily generation dispatch report including JPS' projected/optimal and actual generation dispatch subject to system constraints as well as the dispatch deviations as required by the Generation Code. Also, the report shall:

    a) Clearly indicate all instances of out-of-merit generation, alteration to the projected/optimal dispatch due to forced outage of generators and forced deration of plant capacity. The specific circumstance or reason for such out-of-merit dispatch operation shall be provided with adequate details.

b) Include JPS' Plant Capability Report.

JPS shall be required to submit this information electronically to the Office by COB each day.

2) Weekly dispatch data which shall include JPS' weekly Merit Order listing, plant variable cost calculations and the weekly Unit Commitment Schedule. Daily adjustments to the weekly projections shall be included in the daily generation dispatch report submitted to the OUR.

3) The generation dispatch simulation files for the daily, weekly and monthly dispatch projections.

This submission shall:

a) include the Wescouger files and/or other dispatch simulation software files which contain all the input assumptions including generator and system constraints, and optimal generation dispatch projections.
b) be provided to the OUR on a weekly basis by COB each Friday with dispatch information for the following week.

4) A monthly report which summarises all out-of-merit generation operations with the reasons why they have occurred. For transparency, these reports will be issued to the electricity generation sector. This report shall be submitted to the OUR within ten (10) days after the applicable month.

9.12.3.5 Technical Reports

JPS shall submit as part of its monthly technical report to the Office, the key generation performance parameters and network issues that impact the consumption and cost of fuel. The report shall be submitted to the OUR within five (5) days after the applicable month and shall include among other things, the following:

1) System Performance Parameters
   a) Gross and net System peak demand for each day in the applicable month. The time of the peak for each day should be stated;
   b) Available generation capacity and reserve margin for each day;
   c) The actual Spinning Reserve for each half hour in the 24-hour load cycle;
   d) System net generation for the month;
   e) JPS' plant total net generation for the month;

f) IPPs' plants net generation for the month;
g) System Heat Rate.

2) Generator Merit Order
   a) Merit Order for each week in the month;
   b) The summary Merit Order for the month; and
   c) Discontinue the inclusion of merit order data for plants that are declared retired by JPS.

3) Generating Units' Performance Data
   a) The equivalent availability of each generating unit in terms of hours and percentages;
   b) Forced outage rate of each generating unit;
   c) The number of starts and stops for each generating unit during the month;
   d) Progress of planned generator maintenance that occurred in the month for both JPS and IPP plants;
   e) Update on maintenance activities due to forced outages occurring during the month;
   f) Details of projected maintenance for the following month;
   g) Discontinue the inclusion of generation availability data for plants that are declared retired by JPS;
   h) The projected and actual net generation of each generating unit for each month; and
   i) The projected and actual average heat rate of each JPS generating unit for each month.

9.12.3.6 Generation Maintenance

1) JPS shall submit to the Office a generation maintenance plan in accordance with the provisions of the Generation Code.

2) The budgeted cost for all major maintenance of JPS plants including major inspections (MI), and major overhauls shall be submitted to the OUR prior the commencement of the maintenance activity.

3)

9.12.3.7 Continuous Review and Monitoring

The Office will systematically review the Fuel Rate Calculations and dispatch processes on a continuous basis to ensure that the JPS' fuel procurement, fuel management and generation dispatch decisions are reasonable and cost-effective.

An integral part of the fuel monitoring framework will involve periodic audits of the Fuel Rate Calculations and generation dispatch processes by the Office to verify that these activities are conducted appropriately and in accordance with the requirements of the Licence and Generation Code.

9.13 FCAM for the 2015-2019 Price-Cap Period

9.13.1 Fuel Cost Pass-Through

Having regard to the provisions of Schedule 3, paragraph 3 (D) of the Licence and EXHIBIT 2 of the said Schedule, the fuel cost pass-through that shall be applied by JPS in the Fuel Rate Adjustment Mechanism each month is represented algebraically in ***Equation 9.4***.

Equation 9.4:

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

Where:

- JPS Heat Rate Actual - represents 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 - represents JPS' thermal plants generating heat rate determined by the Office.

9.13.2 Adjustment Parameters

9.13.2.1 Heat Rate Target

As set out in Schedule 3, EXHIBIT 2 of the Licence, the heat rate target shall be JPS' generating heat rate as determined by the Office at the adjustment date.

Therefore, JPS' proposal for the use of a System heat rate target for efficiency adjustment was **NOT APPROVED.**

Notwithstanding, the System heat rate shall be used as a performance indicator for monitoring the efficiency of the thermal generation system and JPS' generation dispatch operations. As such, JPS shall continue to calculate and include the System heat rate in the monthly Fuel Rate Calculation submission.

DETERMINATION 33

- **JPS' proposal for the use of a System heat rate target for efficiency adjustment was NOT APPROVED.**

- **JPS shall continue to calculate and include the System heat rate in the monthly Fuel Rate Calculation submission.**

9.14 OUR's Determined Heat Rate

9.14.1 JPS' Heat Rate Target

Based on the results of the OUR's heat rate evaluation, a heat rate target of 12,010 kJ/kWh was determined for JPS' thermal generating system for the period January 2015 to May 2015. This determined heat rate shall be used to adjust the cost of fuel consumed in JPS' generating units each month.

Given the factors involved, the OUR believes that the determined heat rate is fair, reasonable and consistent with the technical capability of JPS' thermal generating system. The heat rate target also provides the incentive for JPS to improve the fuel conversion efficiency of its thermal generating plants and realize monetary benefits.

This heat rate target will be reviewed and reset by the OUR at each Annual Tariff Adjustment during the 2015 to 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 Power System; and

4) The retirement of existing generation facilities.

9.14.1.1 Discussion on Heat Rate Target

Heat Rate Target and Total System Optimization

JPS indicated that over the last ten (10) years, the System heat rate has continuously improved year over year as a reflection of a more fuel efficient System that includes IPPs (conventional and renewable). JPS argued that to continue to accommodate such efficiency improvements, its other thermal plants will by necessity have to change their operating point and would reflect a new optimized efficiency point not driven by a change in unit heat rate but solely due to a new generating mix and dispatch. JPS argued further that using a JPS thermal heat rate target could give the false impression that the JPS thermal units are having a worsening heat rate and JPS would thus be unjustly penalized (not able to adequately recover for fuel used) while operating to facilitate the inclusion of more efficient generators and a more efficient System.

The OUR concurs that the System heat rate as currently calculated has improved markedly over the past five years. It is important to recognize however that the reported System heat rate performance was not attributable to any major improvement in the efficiency of JPS' thermal generating plants. Notably, the System heat rate performance was largely influenced by the increased participation of wind generation (Wigton II in 2011) in the Power System as well as the addition of WKPP Generation Complex in 2012. Since the commissioning of these generating facilities, their contribution in terms of net generation and heat rate (WKPP Complex) has had a substantial positive impact on the System heat rate performance each month.

In the operation of the System, incremental generating capacity is added from time to time to ensure that electricity demand is satisfied in an economical, efficient and reliable manner. Adding new power plants to an existing portfolio of generation resources and loads, may result in operational changes to the pre-existing generation system, as well as the economics of the individual existing generating units. For example, adding a base-load thermal generating unit may reduce the frequency of dispatch for higher variable-cost generating units. Similarly, adding a peaking unit may reduce the need to vary the output of intermediate units. When a dispatchable firm-capacity IPP is added to the System, the operation of such generating facility will be incorporated in the generation dispatch optimization process. This will determine the appropriate level of utilization of each generating unit in the System, including the incremental generating unit and not merely an accommodation of the additional IPP generation in lieu of JPS' own generating units, as appears to be the suggestion in JPS' submissions.

In the case of renewables, particularly wind generation, the situation is quite different. The peculiarities of wind generation are well known. Wind generation is variable, relatively uncontrollable and less predictable than most other types of generation. Despite the limitations of wind generation, it provides great value in reducing fossil fuel consumption and dependence on imported fuel oil.

Since wind generation has no fuel costs and low variable operating costs, many analyses of the effects of wind on Power Systems treat wind as a Must-Run generation resource, contributing variability and uncertainty characteristics that are somewhat similar to load. Due to this inherent variability of wind generation, the output of other generating units in the System will be adjusted to balance the intermittent effect of the wind.

Just as incremental demand has the potential to change the fuel consumption at power plants throughout a Power System, the addition of wind generation also affect the operation of other generating plants in the System. In general, adding wind generation to the System decreases overall fuel consumption, and avoids fuel costs that would otherwise be incurred in the absence of the wind generation. Wind generation facilities usually have very low variable operating costs; therefore during operation they may tend to cause generating units with higher variable operating costs (fuel and Variable O&M) to operate at lower levels. The extent of fuel costs savings resulting from wind generation are generally dependent on the price of the renewable, the cost of the generation response and reserve requirement for balancing the fluctuations in the output of the wind generation facility. With respect to the impact of wind generation in the System, it is important to note that high participation of low variable-cost wind generation can alter the marginal cost of generation across the entire System.

In context, it is important to recognize that much of the value of non-combustible renewables such as wind generation in the Jamaican electricity System is expected to be derived from the savings in operating costs associated with reducing generation from peaking and intermediate generating units. However, this is dependent on the orientation of the System load and the correlation of the renewable generation and the System peak.

In the existing generation supply mix, the all-in costs (US₵/kWh) of all the utility-scale wind generation facilities are significantly lower than the variable cost of almost all the other generating units including base-load units. Therefore, in the generation dispatch process, economics dictates that these relatively low variable cost wind generation facilities will tend to displace generation from generating units with higher variable operating costs (fuel and Variable O&M) causing them to be utilized at lower operating levels.

Under the current tariff regime, the cost of maintaining generation capability to balance fluctuations in load and generation is already accounted for in the non-fuel electricity rates. Therefore, the cost impact of the addition of wind generation to the system is mainly due to the cost incurred when thermal generating units are required to either increase or decrease generation in response to the intermittent effects of wind.

Since the all-in cost of all the wind generation facilities in the System is significantly lower than the variable cost of the generating units from which generation is displaced, the cost savings resulting from the energy displacement from conventional plants will tend to outweigh the cost of balancing the fluctuations in the output of the wind generation facilities, on the grounds that the level of generation required for balancing is not on a “MW to MW” basis. The equivalent amount of conventional capacity required to produce the aggregate net generation of the wind generation facilities is significantly lower than the installed or contracted capacity of the wind generation facilities.

From the analysis, it can be deduced that the use of a System heat rate and target that include the energy contribution from non-dispatchable renewables such as wind could effectively nullify the cost savings achieved from the energy supplied by low-variable cost wind generation facilities.

In recognition of the above considerations, JPS’ thermal generating heat rate target was determined based on the utilization of its generating units in the dispatch process, subject to their respective technical capability, as well as the impact of the operation of the other generating units in the System, including the renewable generation facilities.

Given all the above considerations and the principal objective of achieving the lowest operating cost which is largely dependent on the entire generation mix, including renewables, the OUR rejects JPS’ argument that: (a) a JPS thermal heat rate target could give the false impression that the JPS thermal units are having a worsening heat rate, and (b) JPS would thus be unjustly penalized (not able to adequately recover for fuel used) while operating to facilitate the inclusion of more efficient generators and a more efficient System.

Consistent with the provisions of the Licence, the Office is of the view that the use of a JPS thermal generating heat rate target is the appropriate measure to be used by JPS to adjust the cost of fuel consumed in its generating plants in the production of electricity. The Office also believes that the determined heat rate is fair and reasonable and consistent with the technical capability of JPS' thermal generating system.

9.14.2 Expected Heat Rate Performance

Based on the technical characteristics of JPS' thermal generating units, 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;
- Maintenance schedule;
- Forced outage rates; and
- Spinning reserve requirements.

It is expected that over the period January 2015 to May 2015, the heat rate target will be achieved by JPS in the process of generating and supplying electrical energy to grid.

Other factors which are favourable to JPS in achieving the determined heat rate include, among other things:

a) Increased fuel conversion efficiencies achieved for a number of JPS' generating units over the 2009-2014 price-cap period;

b) The expected efficiency improvements from the recently completed major overhaul of critical base-load units, particularly Hunts Bay B6;

c) JPS' 2014 generation maintenance plan which indicates that there will be a major overhaul of Harbour unit #3 (OH#3) from November to December 2014. Reports from JPS indicate that the major overhaul of OH#3 is expected to improve the unit's heat rate from 12,950 kJ/kWh to 12,000 kJ/kWh;

d) The expected efficiency improvements of the recently completed hot gas path inspection (HGPI) of Bogue GT#12 and GT13 and the major overhaul of Bogue ST#14;

e) The expected efficiency improvements from scheduled major maintenance and major overhaul of other JPS generating units during the period; and

f) Expected benefits from other existing and planned efficiency improvement programmes.

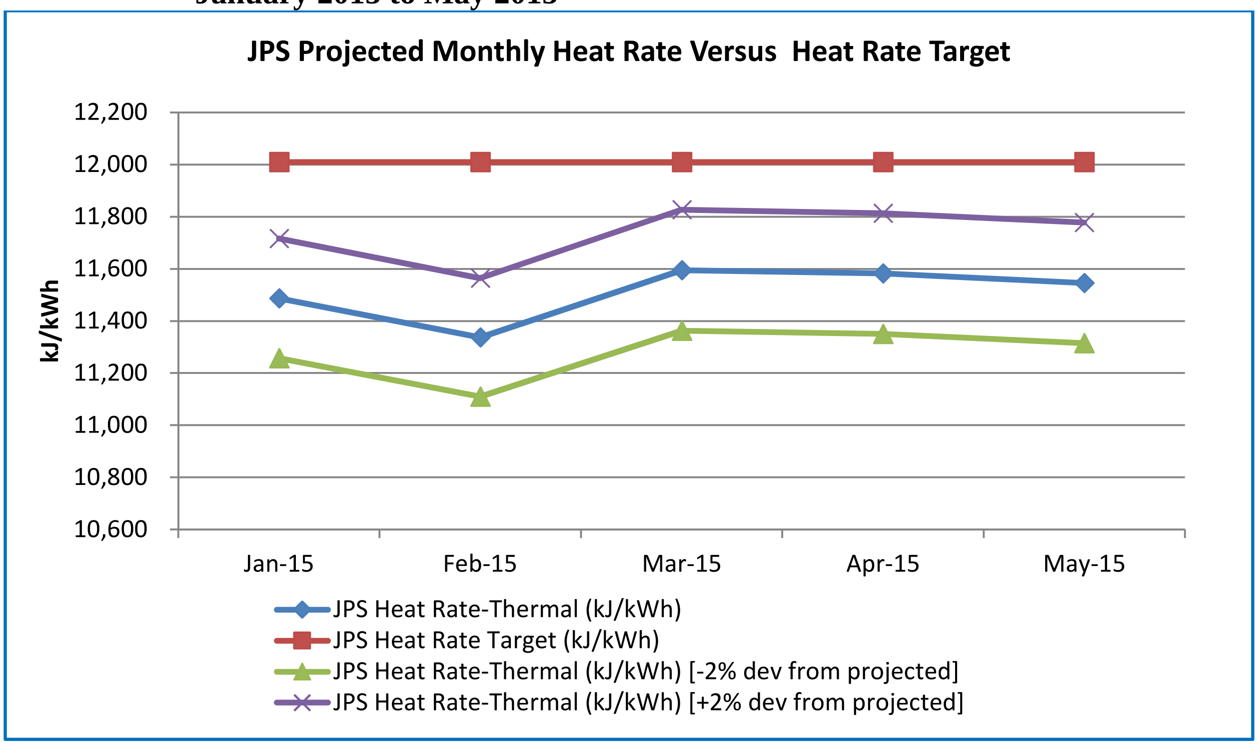
9.14.3 JPS' Heat Rate Projections versus Heat Rate Target

9.14.3.1 Comparison of JPS' Heat Rate Projections vs. OUR's Determined Target

A comparison of JPS' monthly generating heat rate projections against the OUR's determined heat rate target is illustrated in Figure 9.141 below. The projected heat rates adjusted to reflect positive and negative deviations of 2% were also compared against the heat rate target. The details of this heat rate comparison are presented in Table 9.141 below.

Based on JPS' monthly heat rate projections, the new heat rate target for the period January 2015 to May 2015 offers the company a reasonable degree of flexibility by allowing an average monthly heat rate buffer of 501 kJ/kWh. This buffer allows JPS sufficient latitude to insulate it from adverse effects attributable to tolerable deviations in generation dispatch.

Figure 9.141: JPS' Projected Monthly Heat Rate versus Target Heat Rate – January 2015 to May 2015



The variances between JPS' projected monthly heat rates and the OUR's determined heat rate are presented in Table 9.141 below. The projected monthly heat rates with a 2% positive and negative deviation and the respective variances when compared to the heat rate target are also presented.

As the results indicate, even with an adverse deviation of 2% above the projected monthly heat rate, on average, the heat rate target is achievable.

Based on the centre and spread of JPS' projected heat rate dataset, the statistical distribution can be described as symmetric, which indicates a degree of balance in the data.

Table 9.141: Target Heat Rate, JPS' Projected System Heat Rate - July 2014 to May 2015 and Actual Heat Rate Achieved to Date

Month	Heat Rate Target Set by OUR	JPS Actual Heat Rate	Var-iance w.r.t Projected	JPS Projected Heat Rate	Variance w.r.t Target	JPS Heat Rate [+2% deviation from projected]	Variance w.r.t Target	JPS Heat Rate [+2% deviation from projected]	Variance w.r.t Target
Jul-14	12,010	**12,276***	**577**	**11,699**					
Aug-14	12,010	**11,645**	**-7**	**11,652**					
Sep-14	12,010	**11,352**	**-409**	**11,761**					
Oct-14	12,010	**11,349**	**-269**	**11,618**					
Nov-14	12,010			**11,531**					
Dec-14	12,010			11,468	-542	11,239	-771	11,697	-313
Jan-15	12,010			11,487	-523	11,257	-753	11,717	-293
Feb-15	12,010			11,337	-673	11,110	-900	11,564	-446
Mar-15	12,010			11,595	-415	11,363	-647	11,827	-183
Apr-15	12,010			11,582	-428	11,350	-660	11,814	-196
May-15	12,010			11,546	-464	11,315	-695	11,777	-233
2015 Average	12,010			**11,509**	**-501**	**11,279**	**-731**	**11,740**	**-270**

**- GT #12 which is a component of Bogue CCGT was offline due to major overhaul*

9.14.3.2 Historical Look at JPS' Projected vs. Actual Generating Heat Rate

The results of a retrospective look at JPS' generating heat rate performance against projections for the period June 2012 to May 2013 is shown in Table 9.142 below.

Table 9.142: JPS' 2012-2013 Projected Heat Rate vs Actual Heat Rate Performance

JPS' 2012-2013 Projected Heat Rate vs Actual Heat Rate			
Month	JPS Projected Heat Rate	JPS Actual Heat Rate	Variance
Jun-12	11,509	12,201	692
Jul-12	11,473	12,196	723
Aug-12	11,523	11,888	365
Sep-12	11,431	11,618	187
Oct-12	11,472	11,659	187
Nov-12	11,467	11,397	-70
Dec-12	11,475	11,107	-368
Jan-13	11,539	11,317	-222
Feb-13	11,423	11,309	-114
Mar-13	11,358	11,450	92
Apr-13	11,297	11,398	101
May-13	11,638	11,528	-110
Average	**11,467**	**11,589**	**122**
Source: Heat Rate Projections submitted by JPS in the 2012-13 Annual Tariff Adjustment Submission			

As shown in Tables 9.141 and 9.142 above, the projected heat rate performance for the 2012-2013 period and the 2014-2015 period are similar. Given the relatively close convergence of the projected and actual heat rate achieved by JPS over time, the OUR is convinced that the heat rate target of 12,010 kJ/kWh will be comfortably achieved during the prescribed period.

9.14.4 Adjusted Fuel Cost due to Proposed Pass-through Mechanism vs Required Mechanism

A fuel cost analysis was undertaken by the OUR to examine the impact of the determined heat rate target for JPS in the FCAM stipulated in Schedule 3, EXHIBIT 2 of the Licence compared to the pass-through mechanism proposed by JPS.

It should be noted that the fuel cost was only adjusted for the determined heat rate and System losses and was not factored in the analysis.

The result of the analysis is presented in Table 9.143 below. As shown, the cost savings that would have been realized by JPS' customers if the FCAM as per Schedule 3 of the Licence was applied for the July 2012 to June 2013 is **US$19,912,386.**

This implies that the required FCAM is a more reasonable fuel pass-through arrangement for JPS' electricity customers.

While the new heat rate target and modified fuel cost adjustment mechanism may curtail benefits flowing to JPS, there is still an opportunity for the company to improve the efficiency of its thermal generation system and benefit from the new fuel pass-through arrangement.

Table 9.143: Fuel Cost Analysis with Current and Modified Fuel Cost Adjustment Mechanism

Comparison of Actual Total Fuel Cost with Total Fuel Cost if Modified Efficiency Adjustment Mechanism is Used

Current Heat Rate Adjustment Mechanism	Modified Heat Rate Adjustment Mechanism
$Fuel\ Cost\ Net\ of\ Efficiencies = Total\ Fuel\ Cost \times \left(\frac{System\ Heat\ Rate\ Target}{Actual\ System\ Heat\ Rate}\right)$	$Fuel\ Cost\ Net\ of\ Efficiencies = IPP\ Fuel\ Cost + \left(JPS\ Fuel\ Cost \times \left(\frac{JPS\ Thermal\ Heat\ Rate\ Target}{Actual\ JPS\ Thermal\ Heat\ Rate}\right)\right)$

	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13
SYSTEM NET GENERATION [MWh]	368,716	361,304	350,142	328,240	335,407	344,037	344,653	306,864	338,105	340,206	350,850	355,636
ELECTRICITY SALES [MWh]	278,484	272,381	264,328	248,580	252,440	258,118	258,908	229,684	252,425	253,376	261,137	263,924
SYSTEM LOSSES PERCENT [%]	24.47%	24.61%	24.51%	24.27%	24.74%	24.97%	24.88%	25.15%	25.34%	25.52%	25.57%	25.79%
MAX. PASS-ON LOSSES ALLOWED [%]	17.50%	17.50%	17.50%	17.50%	17.50%	17.50%	17.50%	17.50%	17.50%	17.50%	17.50%	17.50%
SYSTEM HEAT RATE [kJ/kWh]	10,249	9,765	9,739	9,855	9,816	9,369	9,424	9,429	9,634	9,581	9,828	9,805
PERMITTED BILLING HEAT RATE [kJ/kWh]	10,200	10,200	10,200	10,200	10,200	10,200	10,200	10,200	10,200	10,200	10,200	10,200
JPSCO THERMAL HEAT RATE [kJ/kWh]	12,196	11,888	11,624	11,659	11,397	11,107	11,317	11,339	11,395	11,398	11,528	12,196
ADJUSTED HEAT RATE TARGET [kJ/kWh]	12,010	12,010	12,010	12,010	12,010	12,010	12,010	12,010	12,010	12,010	12,010	12,010
BILLING EXCHANGE RATE	89.6876	89.8177	89.9339	91.0914	91.8892	92.9776	94.1377	97.1066	98.8865	99.3481	99.4495	101.3752
FUEL COST JPSCo. [J$'000]	4,439,825	3,806,826	3,830,935	3,776,869	3,744,694	3,554,519	3,464,639	3,198,963	4,024,675	4,078,090	4,186,952	3,903,912
FUEL COST IPPs [J$'000]	812,567	2,026,675	2,192,429	1,937,030	1,771,192	1,857,861	2,104,703	2,146,180	2,308,849	2,055,316	1,867,939	2,167,349
TOTAL FUEL COST [J$'000] [JPSCo & IPPs]	5,252,391	5,833,501	6,023,364	5,713,899	5,515,886	5,412,380	5,569,341	5,345,143	6,333,524	6,133,405	6,054,890	6,071,261
TOTAL FUEL COST PER kWh OF SALES [J$/kWh] [IPPs & JPSCo]	18.861	21.417	22.787	22.986	21.850	20.969	21.511	23.272	25.091	24.207	23.187	23.004
ADJUSTED FUEL COST PER kWh OF SALES [J$/kWh]	18.770	22.371	23.866	23.792	22.704	22.829	23.282	25.175	26.565	25.770	24.065	23.930
ADJUSTED FUEL COST PER kWh OF SALES [J$/kWh] - MODIFIED CALCULATION	18.618	21.560	23.269	23.444	22.648	22.088	22.330	24.096	25.951	25.072	23.856	22.778
TOTAL FUEL COST NET OF HEAT RATE ADJUSTMENT [J$'000]	5,227,280	6,093,351	6,308,483	5,914,134	5,731,431	5,892,545	6,027,790	5,782,276	6,705,751	6,529,592	6,284,316	6,315,749
TOTAL FUEL COST NET OF HEAT RATE CORRECTION [J$'000] - MODIFIED CALCULATION	5,184,855	5,872,605	6,150,579	5,827,620	5,717,301	5,701,390	5,781,425	5,534,446	6,550,737	6,352,545	6,229,769	6,011,720
TOTAL FUEL COST [US$'000] [JPSCo & IPPs]	58,283	67,841	70,146	64,925	62,373	63,376	64,032	59,546	67,813	65,724	63,191	62,301
TOTAL FUEL COST [US$'000] [JPSCo & IPPs] - MODIFIED CALCULATION	57,810	65,384	68,390	63,976	62,220	61,320	61,415	56,994	66,245	63,942	62,643	59,302

	US$
TOTAL FUEL COST NET OF HEAT RATE ADJUSTMENT FOR THE YEAR (SYSTEM HEAT RATE APPROACH):	769,550,815.48
TOTAL FUEL COST NET OF HEAT RATE ADJUSTMENT FOR THE YEAR (in accordance with EXHIBIT 2, Schedule 3):	749,638,429.70
DIFFERENCE	19,912,385.77

*cells with modified numbers are shaded

9.15 Office's Determination on Fuel Cost Recovery - Heat Rate

Based on its evaluation of JPS' heat rate proposal, the Office **DETERMINES** as follows:

DETERMINATION 34

- **Net generation from non-combustible renewables such as wind, hydro and solar shall not be included in JPS' generating heat rate calculation.**

- **The Independent Power Producers' (IPPs') fuel cost shall only be adjusted for efficiency by the System losses factor: (1-System Losses Actual) / (1-System Losses Target).**

- **The fuel cost pass-through formula that shall be applied by JPS in the Fuel Rate Adjustment Mechanism in accordance with paragraph 3 (D) and EXHIBIT 2 of Schedule 3 of the Licence is:**

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

- **JPS' generating heat rate target shall be 12,010 kJ/kWh for the period January 2015 to May 2015.**

- **The heat rate target will be reviewed by the Office at each Annual Tariff Adjustment during the price cap period.**

- **JPS shall comply with the fuel cost monitoring framework set out under Chapter 9, Section 9.12 and other requirements of this Determination Notice.**

9.16 Bogue Plant Reconfiguration Fund

To ensure optimal operation of the electricity System and the minimization of the total variable cost of electricity production by JPS, the Office is of the view that it is imperative that JPS' Bogue CCGT unit be reconfigured to accommodate the utilization of gas-based fuels such as natural gas (NG) or alternatives, which are cheaper than ADO. In this regard the Office APPROVED the establishment of a BPRF with the following conditions:

1) The amount for the BPRF shall be US$15M which shall be accumulated over a 12-month period commencing on the effective date of this Determination Notice.

2) The revenues for the BPRF shall be collected by JPS through a separate line item in the monthly FUEL RATE CALCULATION. This means that JPS shall apply equal amounts of US$1.25M to the fuel rate on a monthly basis over the stated 12-month accumulation period.

3) For avoidance of doubt, the BPRF shall be terminated after the designated 12-month period when the Fund has accumulated to the amount of U$15M.

4) The BPRF shall be used firstly and primarily for the reconfiguration of the Bogue CCGT to accommodate the use of gas-based fuels.

5) JPS shall be required to submit to the Office by February 28, 2015 a complete proposal for the implementation of this project, which shall include among other things, a credible feasibility study, procurement strategy, project costs and a project implementation schedule.

6) Any portion of the BPRF remaining after the execution of the reconfiguration of the Bogue CCGT may be used to support capital projects aimed at improving the efficiency of other JPS-owned generating facilities. However, in pursuance of such projects, JPS shall be required to submit proposal(s) to the Office for review and approval before such funds can be committed.

7) The Office will prescribe rules that will govern the administration and utilization of the BPRF after the effective date of this Determination Notice.

Chapter 10: Fuel Recovery – System Losses Target

10.1 Introduction

10.1.1 General

Energy losses in an electricity system can be defined as the difference between the amount of energy (generated and purchased) injected into the System and the amount of energy sold to customers. These losses are experienced in the form of technical losses and non-technical losses.

Technical loss is the component of System losses that is inherent in the physical delivery of electric energy. It includes line (conductor) loss, transformer loss, and losses in metering equipment, including the electrical burdens of instrument transformers.

Non-technical loss on the other hand is primarily caused by human interference, whether intentional or not. Essentially, non-technical losses are usually caused by actions external to the operation of the power system and are mainly due to electricity theft, erroneous meter readings or billing errors.

Technical losses are well understood and their reduction is finite and essentially an engineering issue. However, non-technical losses, although well understood, have evolved into a complex form and as such their reduction require innovation and persistence.

This review of JPS' System losses is concerned with ensuring that losses in both categories are at efficient levels and the approved incentive mechanism will therefore seek to encourage efforts by the company to keep both technical and non-technical losses down, while protecting rate paying consumers from excessive inefficiencies of the utility.

10.1.2 Background

JPS' System losses performance data for the past sixteen (16) years indicate the following:

- 1998 to 2001 – System losses on a 12-month rolling average basis were relatively flat in the range of 16 - 17% although there was a 4 - 5% sales growth per annum;

- 2001 to 2004 – System losses on a 12-month rolling average basis increased from 16.4% to a high of 19.1% in 2004 while sales growth was in the region of 4 – 5% per annum;

- 2004 to 2009 – System losses on a 12-month rolling average basis increased from 19% to over 24%. During the same period, electricity sales increased by over 8%; and

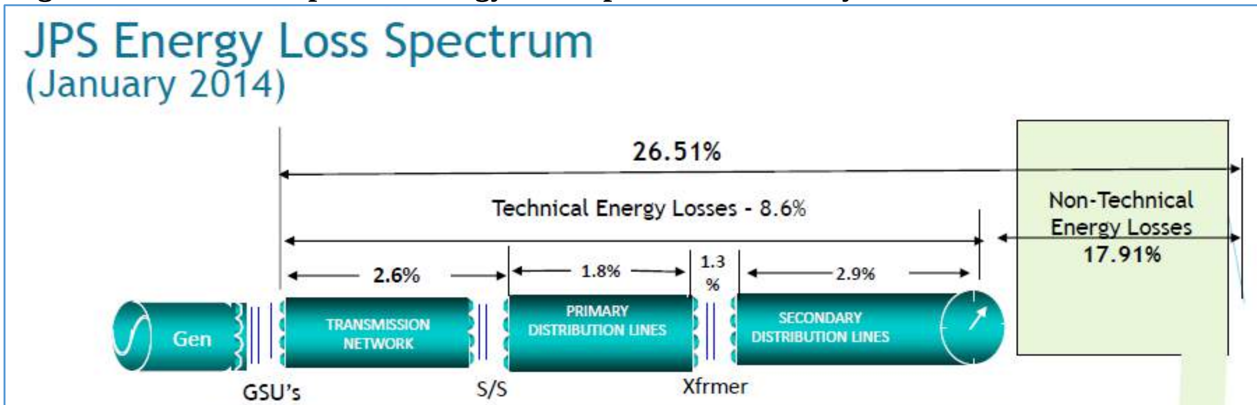
- 2009 to 2014 – System losses on a 12-month rolling average basis increased from 24% to over 26%. During the same period, electricity sales declined by approximately 5%.

The performance indicates that since 2001, at the commencement of privatization of the company, System losses have increased steadily each year to nearly 30% of total net generation.

10.1.3 Current System Loss Situation

System losses are primarily related to JPS' transmission and distribution (T&D) operations with the larger portion of the losses confined to the distribution system. The company's most current energy loss spectrum submitted to the OUR, which was developed in January 2014 is shown in Figure 10.11 below. The spectrum indicates that at that instant, technical energy losses were estimated at 8.60% of net generation while non-technical losses represented accounted for 17.91% net generation or 67% of total System losses.

Figure 10.11: JPS' Reported Energy Loss Spectrum - January 2014



Description/Category		No. of Cust.	Bill Sales (MWH)	Energy Loss (MWH)	% Loss
Billed Customers	Streetlight/Stoplight/Interchange (R 60)	256	9,637	684	0.20%
	Large C&I (Rate 40 & 50)	1,874	112,768	4,072	1.19%
	Medium C&I (rate 20)	4,323	26,606	1,541	0.45%
	Small C&I (rate 20)	58,651	19,389	1,051	0.31%
	Residential (rate 10)	543,052	86,225	15,594	4.36%
Sub-Total		**608,156**	**254,625**	**22,941**	**6.51%**
Internal Bleeds/Unquantified				5,523	**1.56%**
Un-metered Consumers		**180,000**		**33,660**	**9.85%**
TOTAL		**788,156**	**254,625**	**61,944**	**17.91%**

Currently, the System loss target set by the OUR is 17.5% of total net generation. This target is used by JPS as an efficiency adjustment parameter in the FCAM. To the extent that System losses exceed this target, JPS is prohibited from passing through the corresponding portion of the total fuel cost to its customers and must absorb such cost. To the extent that System losses are better than the target, JPS is permitted to pass through fuel costs on a dollar for dollar basis plus additional revenues as a bonus.

In its tariff application, JPS contended that both the technical and non-technical energy loss situation comes with its own challenges due primarily to the existing T&D infrastructure, customer distribution across the network and socio-economic conditions, coupled with the volatility of fuel price and foreign exchange movements in Jamaica.

JPS argued that:

(i) the system loss target of 17.5% set by the OUR has unfairly imposed on JPS the responsibility for theft losses;

(ii) it is unjust and unreasonable to punish the company for a third-party crime;

(iii) since fuel now represents approximately 70% of total cost of electricity, the increased theft of electricity is in response to the high cost of energy and the generally challenging economic conditions in Jamaica; and

(iv) there should be revisions (in accordance with its recommendations) to the measures implemented for System losses.

10.1.4 Scope

This Chapter seeks to address, among other things, three (3) fundamental aspects of the FCAM:

1) The determination of a System losses target to be used as an efficiency adjustment parameter in the monthly Fuel Rate Calculations.

2) The application of the actual System losses and System losses target in the FCAM in accordance with the relevant provisions of the Licence.

3) The development of a prudent and practicable framework for continuous monitoring of the System losses and their impact on fuel rates.

In addition to the stated objectives, the Chapter also examines the loss reduction initiatives and programmes proposed by JPS.

10.2 Treatment of System Losses in the Fuel Cost Adjustment Mechanism

10.2.1 Licence Requirements

The treatment of JPS' System losses in the FCAM is set out in Schedule 3, EXHIBIT 2 of the Licence. The relevant provisions are also outlined in the Legal and Regulatory Framework in this Determination Notice.

10.2.2 Existing Fuel Cost Pass-Through Formula

The existing efficiency adjustment formula used in the monthly Fuel Rate Calculations is defined by *Equation 9.1* set out under Chapter 9 and shown below as follows:

$$\boldsymbol{Pass\ through\ Cost = Fuel\ Cost} \times \frac{\boldsymbol{Heat\ Rate\ Target}}{\boldsymbol{Heat\ Rate\ Actual}} \times \frac{(\mathbf{1} - \boldsymbol{Losses\ Actual})}{(\mathbf{1} - \boldsymbol{Losses\ Target})}$$

Where:

a) Fuel Cost – represents the sum of JPS' and IPPs' fuel cost each month;
b) Heat Rate Target – the System heat rate target determined by the OUR;
c) Heat Rate Actual – the monthly average heat rate for the entire generation system;
d) Losses Target – the System losses target determined by the OUR; and
e) Losses Actual – the recorded System energy losses including technical and non-technical expressed as a percentage of System net generation each month.

Presently, the System losses target is 17.5% while the System heat rate target is 10,200 kJ/kWh.

10.2.3 System Loss Factor

The System loss factor in the fuel cost adjustment mechanism is represented by the ratio:

(1-System Losses Actual) / (1-System Losses Target)

As indicated above, to the extent that the actual System losses are less than the target, the ratio will result in a monetary benefit to JPS. Conversely, in the event that the actual System losses are greater than the target, the ratio will result in a penalty to JPS.

10.3 JPS' System Losses Performance

10.3.1 Background

A review of JPS' reported System losses over the period 2004 - 2014 raises a number of significant and interesting issues. The review also revealed significant variation in the distribution of losses in the various categories. JPS' reported energy loss spectrums for specific periods are represented in Table 10.31 below.

Table 10.31: JPS' Reported Energy Loss Spectrums 2004 - 2014

JPS Energy Loss Breakdown Over Time							
Loss Category	**2004**	**2006**	**2007**	**2008**	**Mar-11**	**Dec-12**	**Jan-14**
	(%)	**(%)**	**(%)**	**(%)**	**(%)**	**(%)**	**(%)**
Technical losses							
Transmission Network	2.2	2.6	3.5	2.4	3.7	2.72	2.60
Primary Distribution Lines	2.2	2.3	1.3	1.8	1.4	2.14	1.80
Distribution Transformers	1.6	2.3	1.2	1.8	1.1	1.24	1.30
Secondary Distribution Lines	3.0	3.0	4.0	3.6	3.8	3.90	2.90
	9.0	**10.2**	**10.0**	**9.6**	**10.0**	**10.00**	**8.60**
Non-Technical Losses							
Streetlight/Stoplight (R 60)						0.08	0.20
Large C&I (Rate 40&50)		1.3	1.3		0.25	0.16	1.19
Medium C&I (rate 20)							0.45
Small C&I (rate 20)		1.6	2.4		1.39	1.62	0.31
Residential (rate 10)		4.5	4.5		3.43	6.52	4.36
Sub-Total		**7.4**	**8.2**		**5.07**	**8.38**	**6.51**
Internal Bleeds/Unquantified		1.8			0.13	0.06	1.56
Un-metered Households		4.8	4.2		6.46	6.53	9.85
		14.0	**12.4**	**12.9**	**11.7**	**14.97**	**17.92**
TOTAL		**24.2**	**22.4**	**22.5**	**21.7**	**24.97**	**26.52**

From the review, it was found that the transmission losses given in JPS' 2006 to 2008 energy loss spectrums included the losses of the generator step-up transformers (GSUs). This does not represent an accurate measurement on the basis that the generation facilities are metered on the high voltage side of the GSUs and therefore would capture the losses in these transformers.

Historical technical losses data indicates that the losses associated with the GSUs are approximately 0.4%. JPS' 2006 energy loss spectrum with the boundaries of the various categories of losses is shown in Figure 10.31 below.

Although the energy loss spectrum for January 2014 shows that the transmission network losses are measured from the high voltage side of the GSUs, the transmission losses for 2006 and January 2014 are identical. With no fundamental change in the configuration of the transmission system since 2007, this raises concerns as to whether transmission losses are being measured appropriately.

Figure 10.31: JPS' 2006 Energy Loss Spectrum

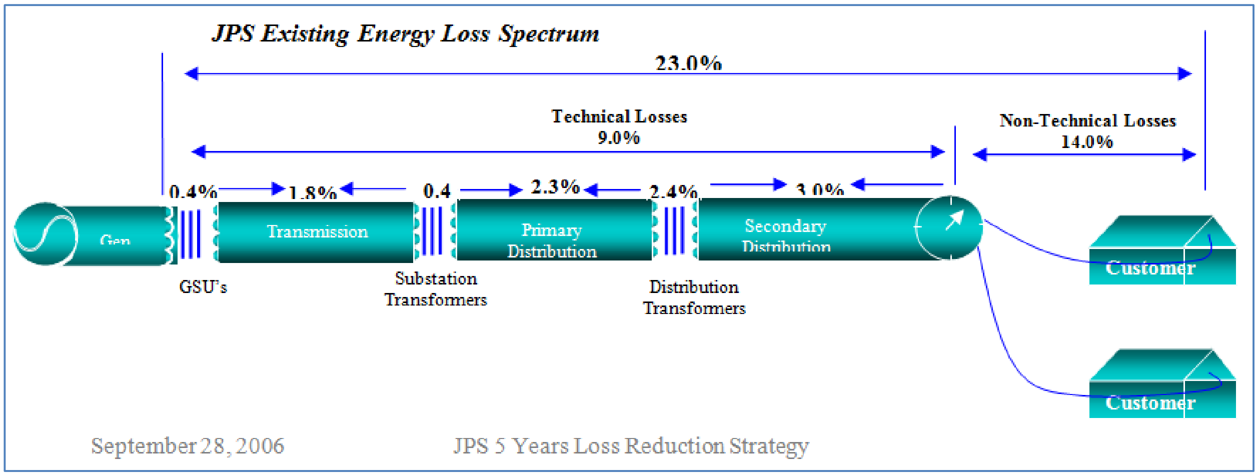


Table 10.31 above shows that at the beginning of 2014, losses attributable to large commercial and industrial (C&I) customers were reported as 1.19% of net generation mirroring the 2006 and 2007 losses level of 1.3% for the same category.

Losses due to the residential customers reflected the 2006 and 2007 levels although there were fluctuations in 2011 and 2012.

The losses due to the Rate 20 category up to December 2012 were reported as an aggregate value for all the Rate 20 customers; however, in the January 2014 energy loss spectrum, the losses figure was separated into two constituents, that is losses due to small and medium C&I customers. As shown, aggregate losses due to Rate 20 customers have trended downwards with more than a 50% reduction from 1.62% in December 2012 to 0.76% in January 2014. While losses equivalent to 0.76% of net generation has been reported by JPS, it appears to be incongruent with the position that a substantial portion of the non-technical losses was attributable to Rate 20 customers.

The data also shows a significant jump in losses due to un-metered households from 6.53% in December 2012 to 9.85% in January 2014. During the same period, it was reported that losses due to metered residential customers decreased from 6.52% to 4.36% of net generation. This suggests that there may be an element of redistribution of the losses in the various categories at the intervals when a spectrum of losses is established.

Overall, the orientation of the energy loss breakdown shown in Table 10.31 above, suggests that there may be inconsistencies or inherent problems in the methodology used for the estimation of the System losses. As previously indicated, the data as presented, at the least, raises the question of whether there is some form of reshuffling or reallocation of the quantity of losses in the various categories of the energy loss spectrum especially at the intervals when the losses are estimated.

10.3.2 JPS' 2009–2014 System Losses Projections and Proposed Targets

In JPS' 2009 Tariff Submission, the company indicated that it intends to intensify its battle against losses on both the technical and commercial sides. The company also stated that:

> *"JPS expects to reduce system losses from 22.9% to 18.3% over the rate cap period primarily as a result of its loss reduction initiatives. This represents almost a 1% point reduction per annum for the next five (5) years as a result of a cumulative CAPEX and O&M expenditures of approximately US $45M. JPS sincerely believes this to be the most optimistic forecast given the current socioeconomic environment and outlook. The Company is nevertheless acutely aware of the OUR's profound concern that JPS be given the correct signals to continuously commit adequate resources and exercise best effort to combat losses. In recognition of the need to demonstrate a continued commitment to reduce losses and share the cost burden with customers, JPS is proposing the imposition of a 2% stretch target."*

Table 10.32 below outlines JPS' proposed schedule of loss reduction targets for the 2009-2014 price-cap period.

Table 10.32: JPS' Proposed Loss Reduction Schedule for the Price-cap Period (2009-2014)

Proposed System Losses Target

	Actual	Forecast					
	Dec-08	Jun-09	Jun-10	Jun-11	Jun-12	Jun-13	Jun-14
Projected System losses	22.9%	22.5%	21.5%	20.5%	19.7%	18.9%	18.3%
Stretch target		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Proposed Losses Target		**20.5%**	**19.5%**	**18.5%**	**17.7%**	**16.9%**	**16.3%**

Analysis of the Losses Spectrum

	Actual	Forecast					
	Dec-08	Jun-09	Jun-10	Jun-11	Jun-12	Jun-13	Jun-14
Non-technical losses	13.0%	12.9%	12.2%	11.4%	10.8%	10.2%	9.8%
Technical losses	9.9%	9.6%	9.3%	9.1%	8.9%	8.7%	8.5%
Total losses	**22.9%**	**22.5%**	**21.5%**	**20.5%**	**19.7%**	**18.9%**	**18.3%**

With due consideration to JPS' 2009-2014 loss reduction proposal, in the 2009 Determination Notice, the Office held 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 loss target initially from 15.8% to 19.5% in 2009/2010 then a reduction to 17.5% in 2011/2012. Subsequent targets would be determined at the Annual Tariff Adjustments. The Office also directed JPS to establish a fund to finance OUR's endorsed System loss projects.

The OUR's review of JPS' System loss performance including a comparison of actual losses against JPS' System loss projections for the period October 2009 to May 2014 are summarised in the following sections.

10.3.3 System Loss Target

As stated above, JPS' System losses target set by the OUR for the period October 2009 to June 2010 was 19.5%.

The first reset of the System loss target was done at the 2011 Annual Tariff Adjustment when it was reduced from 19.5% to 17.5%. The downward adjustment of 10% is consistent with OUR's Determination of System losses as outlined in the 2009 Determination Notice. Since the adjustment in June 2012 the System loss target has remained at 17.5%.

The System losses targets proposed by JPS and the targets approved by the OUR in 2009 and each subsequent Annual Tariff Adjustment are shown in Table 10.33 below.

Table 10.33: JPS' 2009-2014 System Losses Proposals and OUR Approved Targets

JPS' System Losses Proposals and OUR's Approved Targets 2009-2014			
Period	**Proposed by JPS 2009 Tariff Application (%)**	**Proposed by JPS - Annual Adjustment (%)**	**Approved by OUR (%)**
2009-2010	20.5	-	**19.5**
2010-2011	19.5	-	**19.5**
2011-2012	18.5	19.5	**17.5**
2012-2013	17.7	18.5	**17.5**
2013-2014	16.9	**Proposal for full pass through of fuel costs.**	**17.5**
2014-2015	**16.3**		

Despite JPS' proposal for the reduction in System losses target to below 16.3% over the 2009-2014 period and the approval of funding by the OUR to achieve the reduction in losses, JPS sought to pass through higher amounts of losses to paying customers, and by 2013 was proposing to pass through the full amount of losses at over 26% to customers.

10.3.4 System Losses Performance (October 2009 – June 2014)

The monthly average System loss performance compared to the target for the period October 2009 to June 2014 is shown in Table 10.34 below.

Table 10.34: JPS' Monthly System Losses (October 2009 – June 2014)

JPS Monthly System Losses (%)					
Month	**2009-10**	**2010-11**	**2011-12**	**2012-13**	**2013-14**
	JPS Proposed Target – 20.5%	JPS Proposed Target – 19.5%	JPS Proposed Target – 18.5%	JPS Proposed Target – 17.7%	JPS Proposed Target – 16.9%
	OUR Approved Target - 19.5%	OUR Approved Target - 19.5%	OUR Approved Target - 17.5%	OUR Approved Target - 17.5%	OUR Approved Target - 17.5%
July		22.94	22.16	24.47	25.96
August		22.75	22.31	24.61	26.07
September		22.58	22.82	24.51	26.33
October	23.99	22.27	23.04	24.27	26.66
November	23.98	22.24	22.87	24.74	26.57
December	23.32	21.80	23.24	24.97	26.64
January	23.25	21.78	23.53	24.88	26.51
February	23.43	21.89	23.57	25.15	26.58
March	23.47	21.65	23.74	25.34	26.68
April	23.63	21.74	23.83	25.52	26.77
May	23.58	21.72	24.13	25.57	26.76
June	23.46	21.87	24.25	25.79	26.68
Average	**23.57**	**22.10**	**23.29**	**24.99**	**26.52**

The System loss data indicated that between October 2009 and May 2011, JPS was on track to reducing System losses, realizing almost a 10% reduction from 23.99% in October 2009 to 21.72% in May 2011. Since May 2011, System losses have increased steadily each month from 21.72% to nearly 27% in 2014. This coincided with certain strategic, contractual and structural changes made by JPS in 2011 regarding its approach to loss reduction.

JPS has proffered various reasons for the continued upward movement in System losses. However, from a regulatory perspective, this ever-increasing System losses trajectory has created considerable cause for concern and needs to be vigorously addressed by JPS. The continued escalation in System losses seems to suggest that there may be unexplained causes or variables influencing it that may not be properly understood by the utility. The worsening situation also implies that there may be profound issues and underlying problems entrenched in the management and operational strategy being deployed to tackle, curtail and control the spiralling energy loss situation.

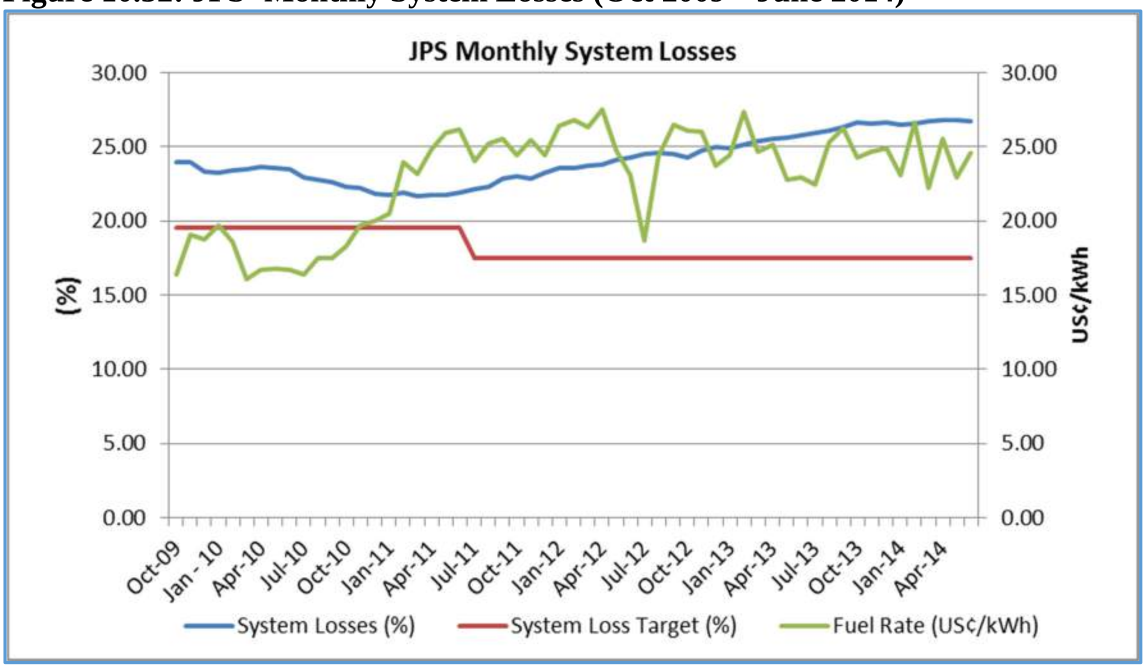
The current situation with System losses is very critical, with broad implications which cannot be addressed by merely pursuing mediocre approaches, and having expectations of shifting pass-through targets to dampen possible adverse financial effects that may emanate from the exacerbating System losses situation. On a practical level, the reversal and ultimately, the reduction in System losses requires the execution of a robust and properly coordinated programme enhanced by innovation and persistence. Notwithstanding these considerations, JPS has reported that it had, over the years, utilized significant resources and implemented the full gamut of loss-reduction initiatives to deal with the problem. Nevertheless, since May 2011, month after month, the increasing losses situation has prevailed without any apparent indication or impression of the impact of these loss reduction efforts.

10.3.4.1 Comparing Movement in Monthly Average System Losses and Fuel Rate

In its tariff application, JPS argued that fuel now represents approximately 70% of the total cost of electricity and, due to the high cost of energy and the generally challenging economic conditions in Jamaica, the company has seen increased incidences of the theft of electricity.

The cost of fuel used for generating electricity each month translates to a fuel rate which impacts all categories of consumers. In an attempt to substantiate the scenario described by JPS, the OUR examined the movement in the monthly average System losses relative to the monthly fuel rate for the period October 2009 to June 2014. The movement in monthly System losses relative to fuel rate over the stated period is illustrated in Figure 10.32 below.

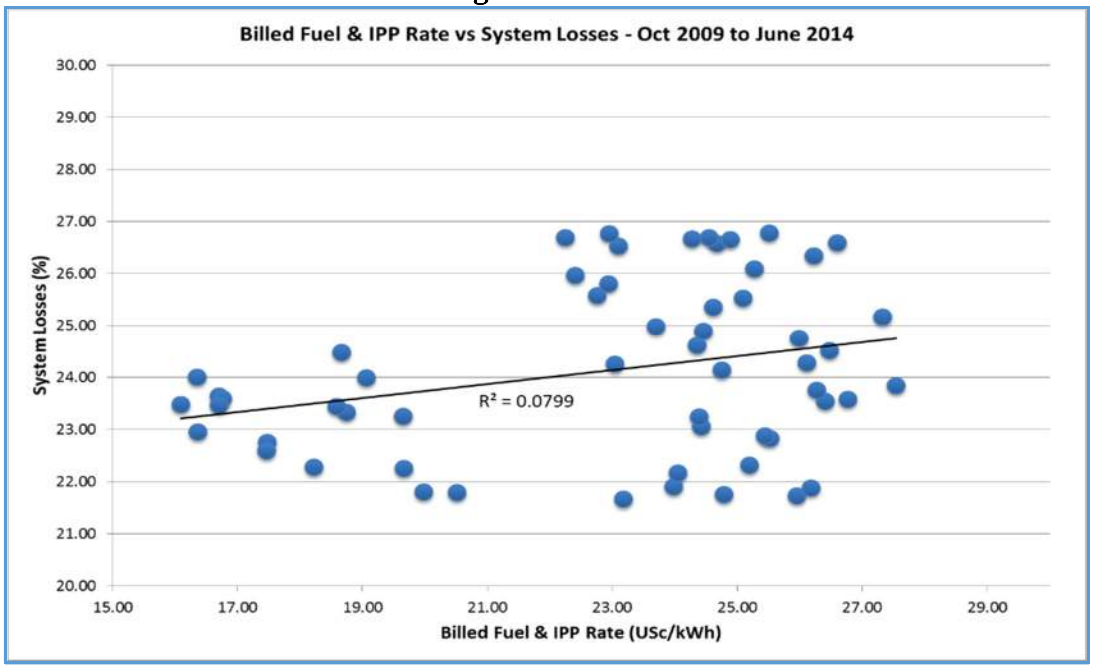
Figure 10.32: JPS' Monthly System Losses (Oct 2009 – June 2014)



Based on the relative movement and profiles exhibited by the monthly System losses and the monthly Fuel & IPP charge over the period October 2009 to June 2014, it does not appear that the two parameters are highly correlated as postulated by JPS.

The correlation between the monthly System losses and monthly Fuel & IPP charge is illustrated in Figure 10.33 below.

Figure 10.33: Illustration of Correlation between Monthly System Losses and Fuel & IPP Charge



The plot indicates that there is a relatively weak correlation between the two parameters.

Although the two variables do not appear to be strongly correlated, there may be an element of causation involved. High fuel rates tend to push up retail electricity rates which could in turn impact affordability.

10.3.5 Fuel Cost Recovery Adjustment (FCRA)

10.3.5.1 Background

In the 2013 Annual Tariff Adjustment Determination Notice, the Office approved an amount for fuel cost recovery relief to JPS on the grounds that the company would be willing to commit to a credible path for pursuing loss reduction.

In that regard, the Office took note of JPS' commitments in its proposed loss reduction plan submitted as part of the Annual Tariff Adjustment submission. The commitments include:

1. The investment of US$2.0M over the next eighteen (18)-month period on technical loss reduction with the objective of reducing losses by 0.6% or 9.6 GWh;

2. The installation of13,000 RAMI solutions during the next eighteen (18)-month period;

3. The installation of 3,800 CAMI solutions during the next eighteen (18)-month period;

4. The replacement of 12,000 Nansen type meters for the period 2013-2014 at a cost of US$480k;

5. The investment of US$34.6M over the next eighteen (18) months in an effort to control commercial losses, to yield loss reduction of approximately 2%;

6. A pre-paid service option for which a full pilot project is scheduled to commence in the fourth quarter of 2013 subject to regulatory approval.

In consideration of JPS' commitments, the Office approved an FCRA facility in the amount of US$20M. This represented approximately twelve (12) months' expenditure to support the activities that JPS committed to. To this end, equal amounts of US$1.67M were applied to the monthly fuel rate and passed through to JPS' customers over a twelve (12)-month recovery period. The application of the FCRA for the full twelve (12)-month period was contingent on the following conditions:

1. JPS honouring its commitment to inject additional capital into the company

2. JPS being bounded by its commitments set out in its System loss reduction plan

3. That on or before July 12, 2013 JPS shall submit to the Office a comprehensive budget and timetable for the eighteen (18)-month System loss reduction plan. The budget was required to show quarterly milestones with the first quarter commencing July 01, 2013 and must include but not be limited to:

    a. Expected date(s) and amount(s) of capital injection which should be at least US$40M;
    b. The amounts and the locations of the RAMI, CAMI to be installed and the Nansen meters to be replaced; and
    c. Projected capital expenditure.

4. On or before the 15th of the month immediately following the end of each quarter, JPS shall submit a quarterly progress report to the OUR. The first report was due on October 15, 2013 and shall include but not be limited to:

    a. Profiles of system losses in areas before metering infrastructure installations and subsequent monthly profiles;
    b. New customer additions in areas where meters have been installed;

5. JPS expediting the return of the existing Maggotty 6 MW hydro power plant which was removed from service to facilitate construction of the new plant; and

6. The commissioning of the new 6.37 MW hydro power plant (Maggotty Hydro Phase II) by month ending November 2013.

In the 2013 Annual Tariff Adjustment Determination Notice, the OUR also indicated that it reserved the right to suspend the FCRA should JPS fail to honour any of its obligations/commitments. The Office further stated that it was cognizant that its regulatory remit did not extend to prescribing JPS' management decisions regarding its dividend policy. However, given the assistance through the FCRA to alleviate the company's financial situation, the OUR expected that the board of management and equity holders going forward, would adopt a dividend policy that was reflective of the difficult times being faced.

The OUR expressed concern that notwithstanding the efforts and regulatory support to tackle System losses and in particular non-technical losses, the results continue to trend in the upward direction with the consequential negative impact on fuel costs and its recovery. In the 2009 Tariff Review, the OUR approved significant funding to JPS' proposed loss reduction initiatives and within months leading up to the 2014 Tariff Review, JPS again requested support to reduce the adverse impact on the recovery of its fuel cost. This culminated in the OUR's approval of the FCRA.

10.3.5.2 FCRA Requirements - Progress Reports

To date, JPS has submitted to the OUR four (4) quarterly progress reports on the progress of the loss reduction activities JPS committed to at the 2013 Annual Tariff Adjustment date.

As part of the requirements under the FCRA, JPS was required to invest US$44.38M to reduce System losses over a period of eighteen (18) months starting from the 2013 Annual Tariff Adjustment date. JPS was expected to inject capital in the amount of US$24.39M to complement the US$20M FCRA allowed by the OUR. A summary the loss reduction plan and projected capital expenditure is shown in Table 10.35 below.

Table 10.35: Summary of JPS' Loss Reduction Plan and Projected Capital Expenditure - (Q3 - 2013 to Q4 - 2014) Connected to the FCRA

		Costs																				
Loss Category		Q3, 2013			Q4, 2013			Q1, 2014			Q2, 2014			Q3, 2014			Q4, 2014			Total		
	Activities	Capital	O&M	Total	Capital	O&M	Total	Capital	O&M	Total	Capital	O&M	Total	Capital	O&M	Total	Capital	O&M	Total	Capital	O&M	Total
Technical Energy Loss	Initiatives	-	0.03	0.03	0.38	0.08	0.46	-	0.11	0.11	0.38	0.11	0.49	0.38	0.09	0.46	0.38	0.07	0.44	1.50	0.50	2.00
	Impact Assessment	-	-	-	-	-	-	-	-	-	-	0.01	0.01	-	0.23	0.23	-	0.03	0.03	-	0.27	0.27
Non-Technical Energy Loss	AMI	-	-	-	6.34	-	6.34	-	-	-	2.16	-	2.16	3.93	-	3.93	3.93	-	3.93	16.35	-	16.35
	Technological & Process Support Solution	0.12	-	0.12	0.76	-	0.76	1.68	-	1.68	0.11	-	0.11	1.12	-	1.12	1.02	-	1.02	4.81	-	4.81
	Initiatives	0.24	1.04	1.28	0.24	1.04	1.28	0.24	1.04	1.28	0.24	1.04	1.28	0.24	1.04	1.28	0.53	1.03	1.56	1.73	6.22	7.95
	Social Intervention	-	-	-	-	-	-	-	0.50	0.50	-	0.50	0.50	-	6.00	6.00		6.00	6.00	-	13.00	13.00
Total US$ 'Million		**0.36**	**1.07**	**1.43**	**7.71**	**1.12**	**8.83**	**1.92**	**1.65**	**3.58**	**2.88**	**1.66**	**4.54**	**5.66**	**7.35**	**13.02**	**5.86**	**7.13**	**12.99**	**24.39**	**19.99**	**44.38**

Source: JPS FCRA Compliance Report Jul 12, 2013

JPS' reported loss reduction activities related to the FCRA for Q3, 2013 are summarised in Table 10.36 below.

Table 10.36: JPS' Q3, 2013 Loss Reduction Activities linked to the FCRA

Loss Reduction Initiatives	Total Investment US$M	Total Quantity	Planned Completion	Q3, 2013 Results Quantity Planned	Q3, 2013 Results Quantity Actual	Q3, 2013 Results Cost (US$'000) Planned	Q3, 2013 Results Cost (US$'000) Actual	Comments
3. Technical Loss								
3.0 Power Factor Correction	0.3	47	2014 Q4	5	8	32	38	
4. Non-Technical Loss								
4.0 JPS & MLG Joint Street Light Audit	0.05	97,000	Q3, 2014	19,400	22,926	10	12	40.7 YTD but 11.82 for Q3
4.1 Annual meter /site Audits (RT50)	0.3	148	Q4, 2014	24	30	49	50	
Annual meter /site Audits (RT40)	0.6	1,698	Q4, 2014	283	289	100	100	
Audits - Rate 10 and 20 customers	3.27	112,500	Q4, 2014	18,750	25,307	545	647	
4.2 Meter Change Initiative	1.44	24,000	Q4, 2014	4,000	6,012	240	184	Labour cost outstanding
4.3 Sub-feeder Metering/Reclosers	1.05	114	Q4, 2014	13	16	120	167	
5. Other Non-Technical Solutions								
5.0 Strike Force Operation	2	120,000	Q4, 2014	20,000	56,587	333	330	
5.1 Energy Limiting Initiative - RELI	0.29		Q4, 2014					
Total	9.3			62,475	111,175	1,429	1,527	
Source: JPS QUARTERLY FCRA PROGRESS REPORT October 15, 2013								

JPS' reported loss reduction activities related to the FCRA for Q4, 2013 are summarised in Table 10.37 below.

Table 10.37: JPS' Q4, 2013 Loss Reduction Activities linked to the FCRA

Fourth Quarter Compliance Progress Report, 2013:								
Loss Reduction Initiatives	**Investment US$'000**	**Total Quantity**	**Planned Completion**	**Q4, 2013 Results Quantity Planned**	**Q4, 2013 Results Quantity Actual**	**Q4, 2013 Results Cost US$'000 Planned**	**Q4, 2013 Results Cost US$'000 Actual**	**Comments**
Technical Loss								
Installation of Bulk bank Capacitors (0.1%)	1,500	4	2014 Q4	1	2	375	63	Banks to be commissioned
Power Factor Correction (0.3%)	300	47	2014 Q4	5	6	32	38	
Feeder Phase Balancing (0.1%)	200	40	2014 Q4	10	0	50	0	
Non -Technical Loss								
JPS & MLG Joint Street Light Audit	50	97,000	Q3, 2014	19,400	-	10	0	Project Completed in Q3 2013
Annual meter /site Audits (RT50)	300	148	Q4, 2014	24	25	49	51	
Annual meter /site Audits (RT40)	600	1,698	Q4, 2014	283	340	100	120	
Meter Change Initiative	1,440	24,000	Q4, 2014	4,000	7,186	240	259	
CAMI Meter Installation	4,820	3,800	Q4, 2014	800	880	1,015	115	In many instances unused meters from
RAMI - Unmetered consumers	8,870	10,000		6,000	7,609	5,322	6,211	previous installations were used
Audits - Rate 10 and 20 customers	3,270	112,500	Q4, 2014	18,750	25,670	545	746	
Technological & Process Support Solutions								
Prepaid Application Management Systems	289	1,000	Q4, 2013	1,000		289		
Sub – feeder metering/Reclosers	1,050	114	Q4, 2014	51	46	470	453	
Other Non -Technical Solutions								
Strike Force Operation (removal of throw - ups)	2,000	120,000	Q4, 2014	20,000	36,221	333	604	
Energy Limiting Initiative - RELI	294		Q4, 2014		6		7	
Total	**44,379**					**8,829**	**8,673**	
Source: JPS QUARTERLY FCRA PROGRESS REPORT JANUARY 15, 2014								

JPS' reported loss reduction activities related to the FCRA for Q1, 2014 are summarised in Table 10.38 below.

Table 10.38: JPS' Q1, 2014 Loss Reduction Activities linked to the FCRA

First Quarter Compliance Progress Report, 2014:								
Loss Reduction Initiatives	Investment - US$'000	Total Quantity	Planned Completion	Q1, 2014 Results				Comments
				Quantity		Cost US$'000		
				Planned	Actual	Planned	Actual	
Technical Loss								
Power Factor Correction (0.3%)	300	47	2014 Q4	10		64	8.1	
Feeder Phase Balancing (0.1%)	200	40	2014 Q4	10		50		
Non-Technical Loss								
JPS & MLG Joint Street Light Audit	50	97,000	Q3, 2014	19,400	-	-	-	Project Completed in Q3 2013
Annual meter /site Audits (RT50)	300	148	Q4, 2014	25	48	51	98	
Annual meter /site Audits (RT40)	600	1,698	Q4, 2014	283	541	100	162	
Meter Change Initiative	1,440	24,000	Q4, 2014	4,000	14,104 up to Q1 2014	240	4	Total 0f 14,104 done for the first three (3) quarters, which is 2104 more than planned. Programme to continue in Q2.
Audits - Rate 10 and 20 customers	3,270	112,500	Q4, 2014	18,750	30,531	545	567	
Technological & Process Support Solutions								
Mobile Field Force Management System	1,572		Q1, 2014			1,572	1324.34	
Sub-feeder metering/Reclosers	1,050	114	Q4, 2014	12		111	46.1	
Other Non-Technical Solutions								
Strike Force Operation (removal of throw-ups)	2,000	120,000	Q4, 2014	20,000	39,142	333	301	
Energy Limiting Initiative - RELI	294		Q4, 2014					
Community Renewal/Customer Education	500					125		
Security	1,500					375		
Total	**44,379**					**3,076**		
Source: JPS QUARTERLY FCRA PROGRESS REPORT								

As shown, no loss reduction activity for technical losses was undertaken during Q1, 2014; however, capital in the amount of US$8,100 was expended.

JPS' reported loss reduction activities related to the FCRA for Q2, 2014 are summarised in Table 10.39 below.

Table 10.39: JPS' Q2, 2014 Loss Reduction Activities linked to the FCRA

Loss Reduction Initiatives	Investment US$M	Total Quantity	Planned Completion	Q2, 2014 Results				Comments
				Quantity		Cost US$'000		
				Planned	Actual	Planned	Actual	
Technical Loss								
Installation of Bulk Bank Capacitors (0.1%)	1.5	4	2014 Q4	1	1	375	126.93	Commissioned June 21, 2014
Power Factor Correction (0.3%)	0.3	47	2014 Q4	10	27	64	140.35	P.F. Correction > 0.95% for over 50% Feeders
Feeder Phase Balancing (0.1%)	0.2	40	2014 Q4	10	5	50	0	
Non-Technical Loss								
JPS & MLG Joint Street Light Audit	0.05	97,000	Q3, 2014	19,400		10	0	Project completed in Q3, 2013
Annual meter /site Audits (RT50)	0.3	148	Q4, 2014	25	26	51	0	
Annual meter /site Audits (RT40)	0.6	1,698	Q4, 2014	283	321	100	0	
Meter Change Initiative	1.44	24,000	Q4, 2014	4,000	-	240	0	Total of 14,104 done for the first three quarters, which was 2104 above planned. The cost effectiveness of the program was reviewed in Q2 to determine the way forward.
CAAMI Meter Installation	4.82	3,800	Q4, 2014	1,000	0	1,268	153.01	1,000 CAAMI meters have been procured and awaiting the Bureau of Standard Jamaica (BSJ) type approval tests
Smart Meter Solution (RAMI) - Rate 10 customers	2.66	3,000	Q3, 2014	1,000	613	887	89.15	
Audits - Rate 10 and 20 customers	3.27	112,500	Q4, 2014	18,750	23,288	545	91.81	Represent total costs associated with **all** audits & Investigation of customer accounts.
Technological & Process Support Solutions								
Sub-feeder metering/Reclosers	1.05	114	Q4, 2014	12	-	111	8.34	
Other Non-Technical Solutions						-	0	
Strike Force Operation (removal of throw-ups)	2	120,000	Q4, 2014	20,000	44,409	333	123.2	
Energy Limiting Initiative - RELI	0.29		Q4, 2014		-	-	0	The Energy Limiting Initiative commenced and discontinued in May 2014 based the OUR's directive to cease and desist.
Social Intervention								
Community Renewal/Customer Education	0.5		Q4,2014			125	0	JPS plans to commence pilot in 6 communities July 15, 2014
Security	1.5		Q4,2014			375	0	
TOTAL	**20.48**					**4,534**	**640.98**	
2nd Quarter Compliance Progress Report, 2014. This table outlines activities for which 2nd Quarter milestones were projected. See appendix Table for initiatives and the corresponding milestones								

While JPS has provided updates on some of its loss reduction initiatives and activities connected to the FCRA for four (4) consecutive quarters ending July 2014, the company was not definitive in quantifying the impact of the capital expended for the respective activities on System losses. Further, there was no analysis done by JPS in relation to the initial loss reduction projections and the actual reduction achieved.

Due to the impending Tariff Determination, the FCRA was extended by the OUR beyond the approved 12-month period, which expired at the end of June 2014. However, given the apparent ineffectiveness of the reported FCRA-related loss reduction initiatives and activities and their negligible impact on System losses, the facility will be completely discontinued. This decision will be communicated to JPS by way of written notification by the Office.

10.3.6 Electricity Efficiency Improvement Fund (EEIF)

As part of the 2009 Determination Notice, the OUR determined that a charge of 0.4 US¢/kWh be included in the tariff for a special System losses fund to be used specifically to implement Advanced Metering Infrastructure (AMI) and other anti-theft technology.

It was projected that the fund would accrue at a rate of approximately US$13M annually over the five (5)-year price-cap period. The rules of the Fund were to be determined by the OUR in consultation with JPS. The withdrawals from the Fund must be in relation to System loss projects that are approved by the OUR.

The Fund was designated the Electricity Efficiency Improvement Fund ("the EEIF") with the primary objective of providing a financial mechanism through which loss reduction strategies could be effectively deployed and losses systematically reduced through the implementation of AMI and other agreed loss reduction technologies.

A review of the use of the EEIF and the impact of the related projects executed by JPS revealed that the expected outcomes were not fully realized. While there is evidence of the implementation of a number of AMI projects, the level of AMI implementation and the commensurate impact on System losses that were envisioned in 2009 have not been achieved by JPS. This raises questions as to the effectiveness of the utilization of the EEIF over the price-cap period.

Notably, it was brought to the OUR's attention in 2013 that over 600 RAMI systems were installed in a community that was not characterized as a 'Red Zone'. The AMI solutions were primarily identified to deal with energy losses in 'red zones' and other problematic areas served by JPS. However, as indicated, these systems were being implemented in middle income communities and new developments where access to JPS' network is legitimate. At the same time, the company complains that unauthorized un-metered consumers are severely impacting its operations.

Although it is apparent that the Fund was not used effectively in addressing System losses during the previous price cap period, the Office believes that the EEIF could be more efficiently deployed to address the broad issue of System efficiency. The Fund now has an expanded scope to support a wider range of efficiency improvement projects (Refer to Chapter 6, Section 6.7.3).

10.4 JPS' Proposal for System Losses Target

JPS, at pages 329-332 of the JPS Tariff Submission, sets out its System losses proposal as follows:

"JPS believes that for the company to remain viable the basis for setting the System losses target must be changed. For any incentive mechanism to work it must be fair (i.e. grounded in some reality), practical and objectively determined. JPS strongly believes that using historical averages is a fair basis for setting the losses target and proposes that the Losses target be based on the last 3 years actual Losses with a stretch target of 2 percent. JPS has added a stretch target of 2% on the basis that in addition to JPS' best effort of the Government, OUR and other key stakeholders will work in partnership to ensure that the appropriate supporting legislation and social intervention programmes are implemented in a timely and effective manner. If this support is not implemented it should be appreciated that this stretch target will unlikely to be met. To avoid severe financial penalties which would impact the viability of the business and therefore its own ability to fund the loss reduction activities themselves and maintain a reliable power service for the country, there should also be a cap on the fuel penalty or gain of US$1M (or 1.5% of the cost of fuel) per month. This would result in an upper limit of US$12M in fuel penalties which would provide enough incentive to the company to fight system losses without putting it at risk of being completely wiped out. It should be noted that US$12M represents more than 20% of the target ROE of the Company.

This proposal is consistent with losses incentive mechanisms used in a number of jurisdictions. Table 13-10 below, retrieved from the KEMA Losses study, shows the number of countries with similar penalty reward mechanisms setting their losses targets based on historical performance. JPS was the only jurisdiction that had their target subjectively set by the regulator…

As noted by KEMA, JPS was the only country on the list where sales risks are also present. The countries that do in principle have sales risks did so due to non-technical losses but these are very low in these countries and thus immaterial. In cases such as Oman and Jordan the regulator has made separate arrangements within the price control formula to correct for not meeting the losses reduction targets.

The proposed losses target for 2014-2018 is outlined in Table13.11 below:

Table 13-11: JPS Proposed System Losses Target

	Actual (%)	Forecast (%)				
	2013	2014	2015	2016	2017	2018
System Losses - 3 Yr Rolling Average	23.34	24.95	25.98	26.22	25.63	24.88
Stretch Target		2	2	2	2	2
Proposed System Losses Target		22.95	23.98	24.22	23.63	22.88

The forecasts were calculated from 3-year rolling averages of the system losses based on the impact of the proposed initiatives detailed in the Table 13-6 of the current chapter. A summary of the calculations is provided below:

Table 13-12 JPS System Losses based on a 3-yr Rolling Average

	Actual (%)				Forecast (%)				
	2010	2011	2012	2013	2014	2015	2016	2017	2018
Losses - Beginning of the Year	23.32	21.80	23.24	24.97	26.64	26.34	25.69	24.86	24.08
Impact of Proposed Initiatives					0.30	0.65	0.83	0.78	0.86
Losses - End of the Year	21.80	23.24	24.97	26.64	26.34	25.69	24.86	24.08	23.22
System Losses - 3 Yr. Rolling Average	**23.30**	**23.1**	**22.79**	**23.34**	**24.95**	**25.98**	**26.22**	**25.63**	**24.88**

Though the energy loss reduction programs, initiatives and investments over the next 5 years are aimed at realizing an energy loss recovery equivalent to 7.17% (in terms of the reduction in the quantum of Losses as measured in GWh, the impact on the total system losses will be 3.1 percentage points. This reflects our expectation in terms of sales growth as reflected in our demand forecast... If the sales growth outturn is stronger than is anticipated then overall System losses would be expected to be lower than shown above.

JPS experience over the past decade and based on a recent study clearly demonstrate a very strong correlation between electricity theft, and the socio-economic and political conditions within which we operate. Hence, the following was concluded:

- *90% of the variability in the NTL [Non-Technical Losses] are explained by socio-economic variables.*
- *NTL depend positively on the poverty level, on the payment capabilities of the population and the degree of violence present in the environment.*
- *For each 1% increase in the proportion of the population that lives in conditions of poverty, the NTL level increases by 0.63%.*
- *The result confirms the importance of the social dimension on the performance of the electric utilities.*

The forecast reflects the fact that this task cannot be performed by JPS alone, but requires the joint efforts of the Regulator, GOJ, customers and other stakeholders. The stretch target implies that there will be full support from the GOJ in addition to JPS best effort to get the target indicated."

10.5 Regulatory Treatment of JPS' Technical Energy Losses

10.5.1 Technical Loss – Review and Analysis

JPS categorized technical losses into four groups as follows:

- Technical losses in the transmission system - JPS determined the amount of transmission system technical losses based on measurements of Net Generation Meters, Feeder Meters, and energy measured as delivered to customers who are supplied directly from the transmission system. The reported loss on the transmission system is currently 2.6%.

- Technical losses in distribution feeder lines - JPS used SynerGEE to calculate kW losses in peak load condition and then converted the peak kW losses to kWh energy losses by applying a system loss factor. The reported loss on the distribution feeder lines is currently 1.8%.

- Technical losses in distribution transformers - The method utilized to determine the energy losses from distribution transformers is based on the manufacturer's power loss specification for each transformer size, along with JPS' operating parameters of the year. The reported loss on the distribution transformers is currently 1.3%.

- Technical losses in low voltage networks - JPS estimated low voltage network losses in three portions: secondary line losses, service drop losses, and meter coil losses. The reported loss on the low voltage networks is currently 2.9%.

According to JPS, a comparison of its technical losses with that of other electric utilities with similar size networks and market structure in countries of similar size to Jamaica indicated that their technical losses were both better and worse than that of JPS'. As noted by JPS, the exercise was used to benchmark an optimal level for each of the four technical loss categories. The findings of JPS' benchmark comparison are summarized in Table 10.51 below.

Table 10.51: JPS' Benchmark comparison of Technical Losses

Electric Utility Location	Technical Loss (%)	Remarks
Pacific Region	6.5 - 8	Max load – 300 MW
Suriname	8	Max load – 200 MW
Nigeria	10	
CARILEC	8.36	JPS TL excluded

JPS' long-term proposal for achieving the optimal level of technical losses is shown in Table 10.52 below.

Table 10.52: JPS' Proposed Technical Losses Initiatives

JPS' Proposed Technical Losses Initiatives					
	Existing Loss (%)	Optimal Loss (%)	Investment US$(M)	Years	Loss Reduction Activities
Power System	2.6	2.4	1.8	5	Installation of Substation Capacitor Banks (0.2%)
Primary Distribution	1.8	1.0	85/0.8/0.2	15/5/5	VSP (0.3%)/VAR Management; (0.3)/ Phase balancing (0.2%)
Pole and Pad Mounted Transformers	1.3	1.3	0	0	Low Loss Transformers
Secondary and Services	2.9	2.7		5	Secondary Rehabilitation
Total	**8.6**	**7.4**		Years	Loss Reduction Activities

10.5.2 JPS' Proposed Technical Loss Reduction Programmes

Unlike non-technical energy losses, the technical energy losses generally can be positively identified, quantified and measured. This is an important feature that can enable the utility to develop practical and economical solutions for dealing with and ultimately bringing the systematic reduction of this type of losses to optimal levels.

In this regard, JPS indicated that it intends to continue its efforts to identify areas of the T&D network through its system planning, engineering designs and operations for further technical energy loss reductions. The company also indicated that for the period 2014-2018 it will be committing almost US$90M in capital expenditure to combat system losses. The details of specific loss reduction activities, programme costs and expected impact are provided in Table 10.53 below.

Regarding the implementation of the proposed System loss reduction programmes, JPS has requested that the EEIF which is embedded in the current tariffs be retained to provide partial funding to the initiatives, especially the Community Renewal Programme.

The 2014-2019 loss reduction programme indicated that the expected reduction in technical losses in 2014 is 0.18% with a capital requirement of US$0.85M. Going forward, the projected reduction for 2015 is 0.23% with capital requirement of US$3.1M.

Based on the proposed programme, the expected reduction in technical losses over the five (5)-year period is 0.9%. This projection reflects a 10% reduction in technical losses over the period 2014-2018, which would reduce technical losses to 7.7%. Based on the data presented by JPS, even if this impact is achieved, the level of technical losses will still not converge to the optimal loss level of 7.4% of net generation indicated by JPS in Table 10.52 above.

Table 10.53: Breakdown of JPS' 2014-2018 Loss Reduction Programme

JPS 5 Year Loss Reduction Program Breakdown

		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

10.5.3 OUR's Position

10.5.3.1 OUR's Perspective on Technical Losses

For a System loss incentive mechanism to be effective, the utility must be able to control the losses on its network to a large extent. As mentioned earlier, the level of losses on a utility's network is driven by a number of factors and the utility's ability to control them, as well as the associated costs. This is very crucial in determining the scope for the incentive mechanism to reduce losses, both technical and non-technical.

In reviewing JPS' technical losses, the OUR considered a number of factors influencing these losses including the following:

From a technical standpoint, technical losses can be broken down into two (2) categories; fixed technical losses (FTL) and variable technical losses (VTL). Fixed technical losses or iron losses occur mainly in the transformer cores and do not vary according to current. Variable technical losses, often referred to as copper losses, occur mainly in lines and cables, but also in the copper parts of transformers and vary with the amount of electricity that is transmitted through the equipment.

Fixed Technical Losses

These losses take the form of heat and noise and occur as long as a transformer is energised. About 25% to 33% of technical losses on electricity distribution networks are usually fixed. Fixed losses on a network can be influenced in the ways set out below:

<u>Quality of Transformer Core Material</u>
The level of fixed losses in a transformer is largely dependent on the quantity and quality of the raw material in the core. Transformers with more expensive core materials, such as special steel or amorphous iron cores, incur lower losses. This implies that there is a direct trade-off between capital expenditure and cost of losses. Therefore, the utility's initiative of using low loss distribution transformers requires the assessment of the expected benefits and the related costs.

<u>Transformation Levels</u>
Fixed losses can also be reduced by eliminating transformation levels. Transmission projects in other countries have shown that removal of voltage levels such 33 kV, 66 kV and 69 kV on a large proportion of the network, leaving a direct 132/11 or 138/13.8 kV transformation, has reduced the amount of transformation necessary to distribute electricity from the grid supply point (GSP) to the customers. Although, there may be some offsetting increase in variable losses on the 11 kV or 13.8 kV network, these would be clearly outweighed by the reductions.

Variable Technical Losses

Variable technical losses vary with the amount of electricity distributed and are, more precisely, proportional to the square of the current. Consequently, a 1% increase in current leads to an increase in losses of more than 1%. Between 67% and 75% of technical losses on distribution networks are usually variable. Some of the factors influencing variable technical losses are described below:

<u>Utilization Capacity</u>
Due to the proportionality between losses and the square of the current, the level of losses on a network will be affected by the utilisation of its capacity. By increasing the cross-sectional area of lines and cables for a given load, losses will fall. This implies that there is a direct trade-off between cost of losses and cost of capital expenditure. It has been suggested in the electric utility environment that optimal average utilisation rate on a distribution network that considers the cost of losses in its design could be as low as 30%.

<u>Higher Voltage Levels</u>
At higher voltages a lower current is required to distribute the same amount of electricity. Moving to higher distribution voltages will reduce losses on the network. The upgrade and standardization of distribution voltage level of 6.6 kV to 13.8 kV or 24 kV will result in a reduction in technical losses.

<u>Shorter and more Direct Lines</u>
Apart from capacity and voltage levels, the configuration of the network may have an effect on losses in terms of the length of the wires. As the customer base develops independently of the network, the resulting configuration of a network that has been constructed for over fifty (50) years will most likely not be optimal. Such a situation may require the reconfiguration of the network which could provide some scope for reducing technical losses.

<u>Demand Management</u>
Because variable technical losses increase proportionally to the current, distributing an additional 1 MWh in peak times will result in a greater increase in losses than 1 MWh in off-peak periods. This suggests that the utility can structure its tariffs so it encourages its large customers to smooth demand so the peaks on the distribution network can be reduced and technical losses will fall.

<u>Balancing Three-phase Loads</u>
Utilities sometimes act to balance loads on three-phase networks. If this is done periodically throughout a network, technical losses can be significantly reduced. Phase balancing can be done relatively easily on overhead networks and consequently offers considerable scope for cost-effective loss reduction.

Reduction in energy loss on the T&D system can be economically achieved by the proposed technical loss initiatives and having due consideration to the factors influencing technical losses outlined above.

Other Factors Influencing Technical Losses

Reduction in technical losses can also be realised by, among other things, the following:

<u>Distributed Resources</u>
The addition of distributed resources such as qualifying facilities (net billing) and other generation facilities to the distribution system will result in bi-directional power flows in the network and reduction in technical losses due to their relative proximity to load centres.

<u>Optimal Power Flow</u>
The execution of optimal power flow across the network could result in the optimization of operating costs and technical losses.

10.5.4 Projections for Technical Losses

A review of JPS' reported technical losses revealed that these losses have moved downwards to a level that appears to be fairly consistent with the existing System configuration and operations. Although the reported improvements in these losses may not be the result of any major loss reduction activity undertaken by JPS but may be largely due to alterations in the approach used to measure certain elements of this type of losses.

It is interesting to note that in JPS' 2009 Tariff Submission, it projected that technical losses would be reduced from 9.9% to 8.5% of net generation by June 2014. Noticeably, in its 2014 tariff application, JPS reported that its technical losses decreased to 8.6%.

At the 2013 Annual Tariff Adjustment, JPS proposed a number of initiatives for the reduction of technical losses which were linked to the FCRA. The impact of these loss reduction initiatives were quantified by JPS with the projection that by the end of Quarter 4, 2014, technical losses would be reduced by 0.27% of net generation (Refer to Table 10.35 above for details). The four (4) quarterly progress reports on these loss reduction activities submitted to the OUR by JPS have not provided any indication on the impact of the programmes on technical losses so far.

As previously mentioned, in the JPS' Tariff Submission, JPS indicated that the projected impact for technical losses in 2014 is 0.18% of net generation (Refer to Table 10.53 above) which is inconsistent with its projections shown in Table 10.35 above.

Despite these inconsistencies, based on the proposed loss reduction programmes and the proposed level of expenditure, the Office is of the view that optimal technical losses level of 7.4% projected by JPS is reasonable and representative, and can be achieved within the 2015-2019 price cap period. Essentially, technical losses represent an economic loss for the country; therefore its optimal level should be pursued by JPS.

With respect to the System losses target, it should be emphasized that technical losses comprise losses associated with JPS' T&D operations which are directly within JPS' control. Therefore, based on the existing loss level of 8.6% and JPS' projected reductions for 2014 and 2015, the Office is of the view that JPS' technical energy losses for the period January 2015 to May 2015 should at most be 8.4% of net generation. Overall, it is expected that technical losses will be reduced from 8.6% to JPS' proposed optimal level of 7.4% by 2019.

10.6 Treatment of JPS' Non-Technical Energy Losses

10.6.1 JPS' Position on Non-Technical Losses

With respect to non-technical losses, at section 13.3.2 of the JPS' Tariff Submission, JPS argued that:

- These losses are "*primarily due to a myriad of socio-economic challenges within the country. These situations and conditions include general macro-economic challenges impacting the affordability of electricity, governance, crime rate, unemployment, accessibility, etc.*

- *When a comparison is done with JPS' non-technical energy losses to other utilities, though it is discovered that the Company has a better performance level when compared to many utilities that exist in countries with similar socio-economic conditions, JPS commits a vast amount of its business resources to reducing losses. System losses especially jeopardize the viability of the business given that the existing regulated fuel tariff recognizes only 17.5% of the total system losses, which leaves JPS to absorb all the losses above this threshold – including those from theft. It is for this reason that JPS believes that the basis for setting the target must be fair and objective.*

- *In many countries, the percentage of System losses recognition by the energy tariff is dependent on the socio-economic structure of the country. A vivid example is the Dominican Republic, which has broadly similar socioeconomic conditions when compared to Jamaica.*

- *One difference is that in the Dominican Republic, the country's energy sector is unbundled and there are several generation companies (both Government and Private owned), one transmission company (Government owned) and three Distribution companies (both Government and Private owned). The distribution companies have system losses of 33% and higher. Though the loss figure sounds very high, it was agreed that to reduce losses substantially under the present socio-economic structure of the country, the companies would require extremely high investment during next 10 years but possibly with very little tangible return…*

- *In Brazil, where there are more than four (400) million inhabitants, they have sixty-three (63) distribution utilities in over fifty (50) main municipalities. The level of nontechnical losses varies greatly across these utilities, primarily dependent on the socio-economic conditions of each municipality. Accordingly, the regulator in Brazil has focussed on the* *socio-economic conditions in each municipality… as a means to deciding what level of system losses should be recovered through the tariffs.*

- *The major factors impacting Non-technical energy Loss are internal bleeds and electricity theft. Electricity theft primarily comes from socio-economic factors that are outside JPS control. Quantum (2013) looked at the socio- economic situation of Jamaica and how it affected system losses. To benchmark non-technical energy loss or electricity theft, electric utilities or countries with similar socio-economic conditions were considered. The objective of the study was to demonstrate that there is a strong relationship between non-technical losses (NTL) and the social conditions of the population living in the area supplied by JPS. To confirm the hypothesis that NTL are higher in those utilities operating in regions that have living conditions that are less favourable, data about utilities in Argentina, Bolivia, Brazil, Guatemala, El Salvador and the Dominican Republic corresponding to the years 2004 –2011 were used. These socio-economic conditions can be broken down by:*

    - *Demographic characteristics, violence, schooling, income, inequality, infrastructure, labour informality, temperature, market characteristics (% of residential customers) of the electric utility and electricity price.*

- *In looking at fifty-three (53) distribution companies, the model considered the NTL to low voltage index, poverty index, the average residential rate based on GDP per capita index and the violence index (murder rate per 100,000). The study (2013) has clearly demonstrated a very strong correlation between electricity theft, and the socio-economic and political conditions within which the utility operates. Hence, the following [were] concluded:*

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

10.6.2 Historical Look at JPS' Non-Technical Losses

There are some fundamental issues surrounding the non-technical loss components reported by JPS.

A breakdown of JPS' non-technical losses for specific points in time over the period 2004 to 2014 is shown in Table 10.61 below.

Table 10.61: JPS' Reported Non-Technical Losses Breakdown (2004-2014)

Non-Technical Losses Break-out							
Category	**2004**	**2006**	**2007**	**Dec 2008**	**Mar 2011**	**Dec 2012**	**Jan 2014**
Streetlight/Stoplight (R 60)						0.08	0.20
Large C&I (Rate 40&50)		1.3	1.3		0.25	0.16	1.19
Medium C&I (rate 20)							0.45
Small C&I (rate 20)		1.6	2.4		1.39	1.62	0.31
Residential (rate 10)		4.5	4.5		3.43	6.52	4.36
Sub-Total		**7.4**	**8.2**		**5.07**	**8.38**	**6.51**
Internal Bleeds/Unquantified		1.8			0.13	0.06	1.56
Un-metered Households		4.8	4.2		6.46	6.53	9.85
Total	**11.5**	**14.0**	**12.4**	**12.9**	**11.7**	**14.97**	**17.92**

The non-technical losses data provided in Table 10.61 above exhibits certain variations which suggest that there may be inconsistencies or inherent problems in the methodology used for the estimation of the System losses.

10.6.3 Examination of Methodology used for Estimating System Losses

A review of JPS' reported System losses data and methodology used by the company for estimating the relative contributions of each of the categories of losses does not provide a high degree of confidence in the reported figures.

The disaggregation of non-technical losses of 17.91% of total net generation as represented in JPS' January 2014 energy loss spectrum is shown in Table 10.62 below.

Table 10.62: Breakdown of JPS' Non-Technical Losses

Description/Category		No. of Customer	Bill Sales (MWh)	Energy Loss (MWh)	Loss (%)
Billed Customers	Streetlight/Stoplight/ Interchange (R60)	256	9637	684	0.20
	Large C&I (Rate 40&50)	1,874	112,768	4,072	1.19
	Medium C&I (Rate 20)	4,323	26,606	1,541	0.45
	Small C&I (Rate 20)	58,651	19,389	1,051	0.31
	Residential (Rate 10)	543,052	86,225	14,594	4.36
Sub-Total		608,156	254,625	22,941	6.51
Internal Bleeds/Unquantified					1.56
Un-metered Consumers		180,000		33,660	9.85
Total		**788,156**	**254,625**	**61,944**	**17.92**

JPS' reported losses for the 2004 and 2009 tariff reviews compared with that of 2014 are shown in Table 10.63 below.

Table 10.63: Proportions of Losses in JPS' 2004, 2009 & 2014 Tariff Application

Proportions of Loss Categories to Total System Losses						
	2004		2009		2014	
Category	**Actual**	**% of Total**	**Actual**	**% of Total**	**Actual**	**% of Total**
Technical	9.0	44%	10.0	44%	8.6	32.5%
Commercial	2.0	10%			8.07*	30.5%*
Theft	9.5	46%	12.9	56%	9.85/17.91	37%/67.5%
Total	20.5	100%	22.9	100%	26.52	100%

The comparison of the System losses shown in Tables 10.63 and 10.64 above provides a number of interesting indications. For example, total non-technical losses increased from 56% of total System losses in 2004 to 67.5% in 2014.

The approach of combining losses of metered customers and illegitimate consumers as a single category - "theft" - runs the risk of incorrectly representing the nature of the problem and distracting attention from an important aspect of lowering losses to a more acceptable and sustainable level. The aggregation of these losses to represent "theft" can also divert attention from implementing effective strategies for mitigating administrative losses and losses caused by inaccurate metering of customers' consumption.

With respect to the issue of control of non-technical losses, it should be emphasized that all categories of losses are within the control of JPS. However, it can be recognized that there are elements of the losses which stem from activities that may be more challenging to control.

10.7 Review of Non-Technical System Losses Target

10.7.1 Non-technical Losses due to Streetlights/Stoplights

According to JPS' January 2014 energy loss spectrum, the losses due to the streetlight/stoplight customer category were at 0.20%. The reported figure for December 2012 was 0.08%.

10.7.1.1 Report of the OUR's Streetlight Survey

On May 9-10, 2014 members of the OUR's technical team conducted a survey of the streetlights connected to JPS' distribution network to get a reasonable representation of the number of malfunctioning streetlights that are operating on 24-hour duty (i.e. are on during day time and night time hours) in certain areas. The survey was conducted on roads in residential areas, commercial areas and on major thoroughfares in the parishes of Kingston, St. Andrew, St. Catherine and St.

Thomas. The routes traversed and the pole locations of the malfunctioning streetlights detected were recorded by GPS.

Survey on May 9, 2014

Figure 10.71 below shows the route travelled on May 9, 2014 marked in red. Figure 10.72 below shows the route surveyed with white flags indicating the approximate location of streetlights found to be on during daylight hours.

Figure 10.71: General Overview of Route Surveyed on May 9, 2014

Figure 10.72: Route Surveyed on May 9, 2014 Showing Greater Detail

Streetlights found operating during daylight hours on May 9, 2014 are represented as flags in Figure 10.72 above and are listed in Table 10.71 below. Approximate locations as well as the specific location in terms of coordinates are shown. A significant portion of the streetlights in the sample were re-checked in the night hours to confirm that the lights were operating on 24-hour duty. The approximate length of the road travelled was 101km.

Table 10.71: Streetlights Found Operating on 24-hour Duty – May 9, 2014

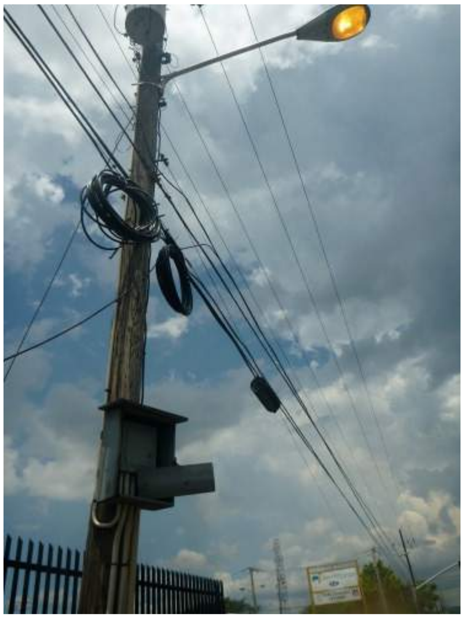
#	Pole Number	Approximate Location	GPS Coordinates	
			N	W
1	097871	West Kings House Road, Kingston	18° 1'16.10"	76°47'43.26"
2	not seen	Washington Boulevard, Kingston	18° 1'30.40"	76°49'24.23"
3	577182	W. Main Drive, Maverley, Kingston	18° 1'35.16"	76°49'25.74"
4	not seen	W. Main Drive, Maverley, Kingston	18° 1'35.05"	76°49'22.09"
5	515982	Hughenden Avenue, Kingston	18° 1'35.50"	76°49'20.03"
6	not seen	W. Main Drive, Maverley, Kingston	18° 1'35.36"	76°49'20.90"
7	not seen	Molynes Road, Kingston	18° 1'37.30"	76°49'21.54"
8	not seen	11 Maverley Avenue, Kingston	18° 1'41.02"	76°49'28.35"
9	not seen	Field Road/Maverley Avenue, Kgn.	18° 1'41.07"	76°49'26.25"
10	not seen	Kempton Avenue, Kingston	18° 1'39.45"	76°49'33.44"
11	not seen	Denver Crescent, Kingston	18° 1'41.10"	76°49'43.76"
12	577191	Denver Crescent, Kingston	18° 1'38.94"	76°49'48.15"
13	not seen	Elma Crescent/Fairfield Avenue, Kgn.	18° 1'34.98"	76°49'52.00"
14	not seen	Boulevard Supercenter - Taxi Stand	18° 1'32.57"	18° 1'32.57"
15	516319	Washington Blvd. - Dairy Ind/JPS	18° 1'31.41"	76°49'58.98"
16	not seen	Washington Boulevard	18° 1'33.85"	76°50'22.07"
17	048565	Whitney Drive, Kingston	18° 1'32.31"	76°50'23.63"
18	not seen	Weymouth Drive, Kingston	18° 1'4.05"	76°50'35.63"
19	not seen	Spanish Town Rd., Kingston	18° 1'14.46"	76°50'59.39"
20	not seen	Spanish Town Rd., Kingston	18° 1'23.91"	76°51'10.02"
21	not seen	Mandela Highway	18° 1'17.54"	76°52'47.07"
22	104064	Twickenham Park	17°59'47.79"	76°56'5.80"
23	not seen	Thompson Pen Road, St. Catherine	17°59'45.89"	76°56'48.93"
24	050478	Thompson Pen Road, St. Catherine	17°59'53.94"	76°56'54.42"
25	050492	Sellbourn Rd., St. Catherine	18° 0'9.93"	76°56'47.95"
26	088174	Clinton Dr., St. Catherine	18° 0'38.67"	76°57'3.35"
27	091808	Thompson Pen Rd., St. Catherine	18° 0'36.11"	76°57'3.20"
28	088074	Clinton Dr., St. Catherine	18° 0'47.13"	76°56'59.83"
29	020027	Thompson Pen Rd., St. Catherine	18° 1'37.88"	76°56'12.56"
30	not seen	Thompson Pen Rd., St. Catherine	18° 1'36.09"	76°56'14.43"
31	205686	Thompson Pen Rd., St. Catherine	18° 2'58.99"	76°56'22.31"
32	not seen	Thompson Pen Rd., St. Catherine	18° 3'40.91"	76°56'1.49"
33	228618	Thompson Pen Rd., St. Catherine	18° 4'5.08"	76°56'2.12"
34	504470	Thompson Pen Rd., St. Catherine	18° 4'19.31"	76°56'5.73"

#	Pole Number	Approximate Location	GPS Coordinates	
			N	W
35	not seen	Thompson Pen Rd., St. Catherine	18° 4'20.31"	76°56'6.44"
36	411591	Sligoville Rd., St. Catherine	18° 5'38.70"	76°57'49.36"
37	535785	Sligoville Rd., St. Catherine	18° 5'31.34"	76°59'6.52"
38	490067	Linstead Bypass, St. Catherine	18° 6'12.29"	77° 0'18.86"
39	not seen	Linstead Bypass, St. Catherine	18° 6'38.22"	77° 0'22.16"
40	not seen	Linstead Bypass, St. Catherine	18° 6'57.41"	77° 0'35.32"
41	157409	Church Road, Linstead, St. Catherine	18° 7'5.91"	77° 0'36.34"
42	146000	Church Road/Tulloch, St. Catherine	18° 7'0.27"	76°59'35.56"
43	145502	Knellis Housing Scheme, St. Catherine	18° 6'58.63"	76°59'40.20"
44	145501	Knellis Housing Scheme, St. Catherine	18° 6'55.43"	76°59'39.61"
45	not seen	Linstead Bypass, St. Catherine	18° 7'9.97"	77° 0'44.04"
46	217713	Linstead Bypass, St. Catherine	18° 8'24.32"	77° 1'23.02"
47	217655	Linstead Bypass, St. Catherine	18° 8'24.67"	77° 1'23.20"
48	199869	Linstead Bypass, St. Catherine	18° 8'29.91"	77° 1'28.22"
49	209113	Linstead Bypass -Roundabout, St. Catherine	18° 8'32.63"	77° 1'31.77"
50	209121	Linstead Bypass -Roundabout, St. Catherine	18° 8'32.63"	77° 1'32.20"
51	not seen-(opposite pole#020538)	Linstead Bypass–Bilton Ave, St. Catherine	18° 9'19.20"	77° 2'10.29"
52	028682	Ewarton Main Road, St. Catherine	18°10'35.65"	77° 5'10.33"
53	not seen	Ewarton Main Road – Newland Heights, St. Catherine	18°10'30.98"	77° 4'58.00"
54	not seen	Ewarton Main Road, St. Catherine	18°10'10.03"	77° 3'41.09"
55	not seen	Ewarton Main Road, St. Catherine	18° 9'27.34"	77° 2'19.56"
56	not seen	Vanity Fair, Linstead , St. Catherine	18° 8'42.56"	77° 2'3.65"
57	006804	Fletcher's Avenue, Linstead, St. Catherine	18° 8'29.16"	77° 1'57.24"
58	563001	Fletcher's Avenue, Linstead, St. Catherine	18° 8'28.97"	77° 1'52.09"
59	563143	Fletcher's Avenue, Linstead, St. Catherine	18° 8'28.30"	77° 1'50.44"
60	not seen	St. Helen's Church King Street, Linstead , St. Catherine	18° 8'2.07"	77° 1'51.01"
61	068077	King Street, Linstead, St. Catherine	18° 7'56.45"	77° 1'47.15"
62	208901	King Street, Linstead, St. Catherine	18° 7'48.82"	77° 1'38.14"
63	082326	King Street, Linstead, St. Catherine	18° 7'45.88"	77° 1'36.48"
64	011954	King Street, Linstead, St. Catherine	18° 7'33.50"	77° 1'24.10"
65	not seen	Bog Walk, St. Catherine	18° 5'58.40"	77° 0'22.13"
66	489849	Roundabout-Bog Walk, St. Catherine	18° 6'8.44"	77° 0'18.46"
67	not seen	Kent Village, Bog Walk Gorge, St. Catherine	18° 5'17.84"	76°59'39.36"
68	not seen	Flat Bridge, Bog Walk Gorge, St. Catherine	18° 3'41.65"	76°59'1.79"

As shown in the Table 10.71 above, sixty eight (68) streetlights were found to be malfunctioning and operating on 24-hour duty instead of the required 12 hours according to the applicable Determination Notice and JPS' Rate Schedule.

Sample of Streetlights Found Operating on 24-Hour Duty – May 9, 2014

Photo 1



Pole Number:	516319
Approx. Location:	Washington Blvd, Dairy Ind/JPS
Coordinates:	18° 1'31.41"N, 76°49'58.98"W

Photo 2

Pole Number:	050478
Approx. Location:	Thompson Pen Rd., St. Catherine
Coordinates:	17°59'53.94"N, 76°56'54.42"W

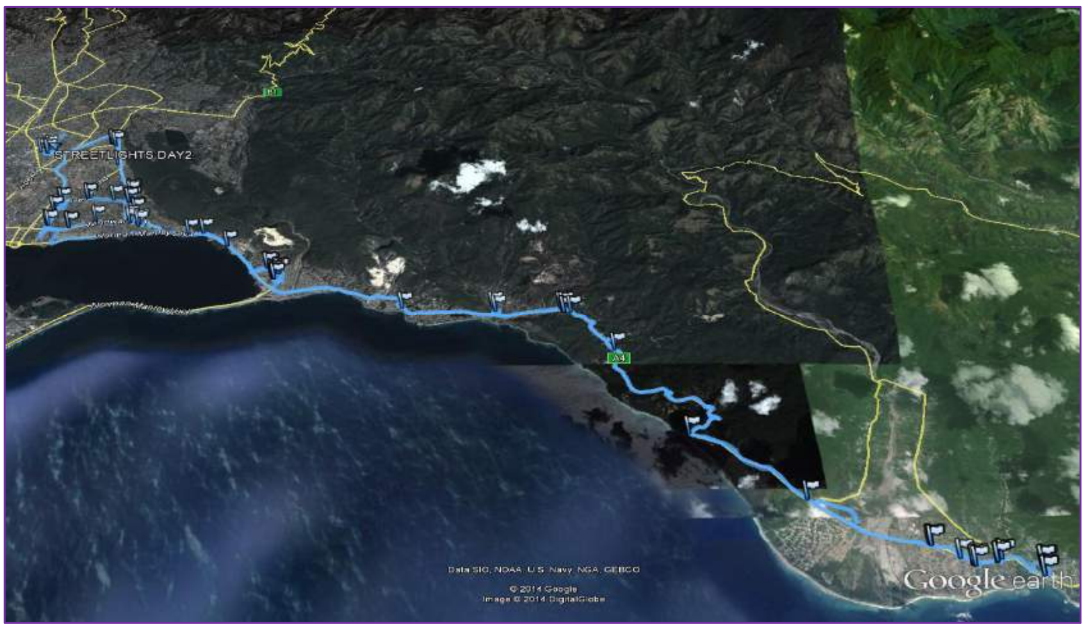
Surprisingly, one of the streetlights found operating on 24-hour cycle was located at the entrance to JPS' System Control Centre while two (2) were observed on the premises.

Survey on May 10, 2014

Figure 10.73 below shows the route travelled on May 10, 2014 marked in red. Figure 10.74 below shows the route surveyed with white flags indicating the approximate location of streetlights found to be on during daylight hours.

Figure 10.73: General Overview of Route Surveyed on May 10, 2014

Figure 10.74: Route Surveyed on May 10, 2014 Showing Greater Detail



Streetlights found operating during daylight hours on May 10, 2014 are represented as flags in Figure 10.74 above and are listed in Table 10.72 below. Approximate locations as well as the specific location in terms of coordinates are shown. A significant portion of the streetlights in the sample were re-checked in the night hours to confirm that the lights were operating on 24-hour duty. The approximate length of the road travelled was 61 km.

Table 10.72: Streetlights Found Operating on 24-hour Duty – May 10, 2014

#	Pole Number	Approximate Location	GPS Coordinates	
			N	W
1	not seen (next to pole#020889)	Oxford Road, Kingston	18° 0'5.41"	76°47'14.85"
2	051276	Norwood Avenue, Kingston	17°59'59.72"	76°47'14.32"
3	not seen	Norwood Avenue, Kingston	18° 0'0.11"	76°47'15.31"
4	051228 and 097450 (2 lamps)	Norwood Avenue, Kingston	18° 0'1.85"	76°47'21.63"
5	not seen	Mountain View Avenue, Kingston	18° 0'9.56"	76°46'11.71"
6	not seen	Arthur Wint Drive, Kingston	18° 0'13.27"	76°46'15.73"
7	not seen	Mountain View Avenue, Kingston	17°59'41.63"	76°46'2.61"
8	not seen	Jarrett Lane, Kingston	17°58'57.65"	76°45'39.02"
9	not seen	Jarrett Lane, Kingston	17°58'59.78"	76°45'38.88"
10	not seen	Norman Avenue, Kingston	17°58'48.15"	76°45'37.96"
11	not seen	Norman Avenue, Kingston	17°58'48.52"	76°45'38.32"
12	not seen	off Norman Avenue, Kingston	17°58'49.24"	76°45'35.99"
13	not seen	Lucas Rd., Kingston	17°58'34.51"	76°45'28.88"
14	not seen	Lucas Road, Kingston	17°58'33.41"	76°45'28.53"
15	not seen	Langston Road, Kingston	17°58'51.48"	76°45'52.62"
16	not seen	Langston Road, Kingston	17°58'54.55"	76°46'16.96"
17	037508	Heathfield Avenue, Kingston	17°58'47.97"	76°46'38.81"
18	not seen	Upper Elleston Road, Kgn	17°58'36.00"	76°46'42.49"
19	not seen	Pine Street, Kingston	17°58'17.58"	76°46'42.41"
20	not seen	Windward Road., Kingston	17°58'15.27"	76°46'22.48"
21	114571	Jackson Road, Kingston	17°58'23.46"	76°46'1.07"
22	not seen	Milford Road, Kingston	17°58'23.75"	76°45'31.08"
23	not seen	Milford Road, Kingston	17°58'20.30"	76°45'30.09"
24	not seen	Eastbourne Road, Kingston	17°58'19.00"	76°45'20.75"
25	not seen	Eastbourne Road, Kingston	17°58'16.33"	76°45'21.30"
26	not seen	Norman Manley Boulevard, Kgn.	17°58'5.84"	76°44'34.35"
27	not seen	Norman Manley Boulevard, Kgn.	17°58'5.70"	76°44'21.13"
28	079455	Norman Manley Boulevard, Kgn.	17°57'49.82"	76°43'56.48"
29	not seen	Coral Way, Harbour View	17°57'21.90"	76°43'17.66"
30	571390	Coral Way, Harbour View	17°57'22.19"	76°43'16.59"
31	not seen	Martello Drive, Harbour View	17°57'11.85"	76°43'11.85"
32	not seen	Dorado Drive, Harbour View	17°57'16.30"	76°43'7.81"
33	578101	Atoll Avenue, Harbour View	17°57'15.49"	76°43'5.87"
34	041078	Fort Nugent Drive, Harbour View	17°57'8.85"	76°43'9.53"
35	not seen	Bull Bay, St. Andrew	17°56'34.71"	76°41'19.10"
36	not seen	Cane River Falls, St. Andrew	17°56'34.87"	76°40'5.57"
37	551778	Cane River Falls, St. Andrew	17°56'30.98"	76°40'3.05"
38	not seen	11 Miles, Bull Bay, St. Andrew	17°56'33.73"	76°39'10.62"

#	Pole Number	Approximate Location	GPS Coordinates	
			N	W
39	not seen	11 Miles, Bull Bay, St. Andrew	17°56'28.87"	76°39'2.13"
40	not seen	11 Miles, Bull Bay, St. Andrew	17°55'46.94"	76°38'28.65"
41	049894	Grants Pen, St. Thomas	17°54'25.32"	76°37'37.98"
42	575025	Albion, St. Thomas	17°53'28.29"	76°36'21.54"
43	not seen	South Haven, St. Thomas	17°52'51.80"	76°35'5.13"
44	048609	South Haven, St. Thomas	17°52'38.87"	76°34'39.62"
45	026053	South Haven, St. Thomas	17°52'36.39"	76°34'39.64"
46	026103	Market Road, Yallahs, St. Thomas	17°52'37.25"	76°33'54.64"
47	not seen	Yallahs, St. Thomas	17°52'39.80"	76°34'24.35"
48	059566	Yallahs, St. Thomas	17°52'41.43"	76°34'21.05"
49	046740	South Haven, St. Thomas	17°52'41.94"	76°34'48.26"

As shown in the Table 10.72 above, forty nine (49) streetlights were found to be malfunctioning and operating on 24-hour duty instead of the required 12 hours according to the applicable Determination Notice and JPS' Rate Schedule.

Observation and Comments on the Streetlight Survey

Apart from the observed malfunctioning streetlights, the survey also provided an opportunity for the team to get a view of some of the electricity supply irregularities and an understanding of how some of the issues are being addressed by JPS.

The following were observed during the survey:

Based on interviews with residents and business personnel conducted during the survey, it was revealed that most of the streetlights have been operating on a 24-hour basis from between six (6) months to three (3) years. Interviewees imparted that repeated calls were made to JPS about the lights but JPS did not turn up.

It was observed that:

- Numerous streetlights were out of service - do not work in the nights.

- In certain communities where JPS failed to repair streetlights that do not work at nights, entities improvised by illegally installing their own makeshift street lamps on JPS' poles (refer to Figure 10.75 below). These installations appeared to operate on 24-hour duties as they were found turned on during the daylight hours. Some of these installations are located along community main roads and are therefore within the reach of JPS.

Figure 10.75: Makeshift Street Lamp On JPS Pole

- In cases where a customer is disconnected and JPS removed the meter and the service wires are not removed, entities utilised the existing infrastructure to illegally abstract electricity.

- Illegal connections were prevalent at JPS' poles where streetlights operate continuously. The illegal connections were frequently seen at the point of connection of the streetlights and JPS' secondary conductors. During the survey residents indicated that because JPS does not turn up to repair the streetlights and hardly patrol the areas, entities have capitalised by connecting freely to the System. Note that the areas being referred to are not classified as red zones. These conditions are within JPS' control.

- Some residents of a particular community on the main road to St. Thomas illegally connected several overhead wires with red insulation straight across the road. The conditions of the wires suggested that they may have been in place for a very long time.

- In certain prominent townships electricity was being openly extracted by small commercial operators – metered and unmetered. According to persons interviewed, JPS hardly visits some of the areas.

- In certain areas, segments of JPS' distribution system were found to be in a dilapidated state. There were several instances of excessive line sags, leaning wooden and concrete poles as well decayed pole bases.

Estimate of Energy Losses due to Malfunctioning Streetlights

JPS submitted the streetlight information shown in Table 10.73 below which summarizes the monthly energy consumption of currently installed streetlights, assuming night-time function only.

Table 10.73: Installed Streetlights with Corresponding Monthly Energy Usage

Bulbs		Total Count	Monthly Usage
Type	**Wattage (W)**		**kWh**
INC	150	7	384
MT	180	667	43,942
MV	140	350	17,934
MV	290	1,659	176,086
MV	440	9	1,449
HPS	95	5,505	191,409
HPS	137	60,633	3,040,260
HPS	193	20,289	1,433,174
HPS	300	6,651	730,280
HPS	465	501	85,265
Total		**96,271**	**5,720,184**

Being cognizance of the relatively limited data sample and margins of error and the applicable caveats, the streetlight data collected during the survey was extrapolated and used in conjunction with data provided in Table 10.73 above to derive a reasonable estimation of the energy consumed by the streetlights in the System that are operating on a 24-hour duty. The result of the analysis indicates that the percentage of streetlights that are operational during daylight hours is in the region of 12%. Based on the information given in Table 10.73 above, this translates to about 11,619 streetlights island-wide with an estimated daily consumption of 22.63 MWh or 8,262 MWh annually.

JPS' estimation of streetlight/stoplight/interchange losses shown above is 0.2% of net generation or 8,208 MWh per year. The OUR's estimation for streetlights alone is approximately 8,262 MWh. Despite the differential in values, the view of the Office is that non-technical energy loss due to streetlight is a visible problem that can be easily corrected by JPS.

Noticeably, the four (4) quarterly FCRA progress reports submitted to the OUR by JPS, show that between third quarter, 2013 and second quarter 2014, the company spent US$200,000 to conduct a joint streetlight audit along with the Ministry of Local Government and Community Development. This according to the reports was part of the company's loss reduction initiatives aimed at reducing technical losses. However, indications are that the audit was carried out primarily to ascertain the total number of streetlights in operation and the portion this functioning properly. Notwithstanding, based on the extent of the audit, the OUR is of the view that it should have provided the company an opportunity to identify specific sources of streetlight related losses as well as useful information to guide the formulation and deployment of an appropriate strategy to eliminate such losses.

Table 10.74: Losses due to Streetlight/Stoplight

Date	Category	No. of Customers	Energy Loss (MWh)	Loss (%)	Change (%)
Jan-2014	Streetlight/Stoplight	256	684	0.20	0.12
Dec-2012	Streetlight/Stoplight	251	292	0.08	0.08
Mar-2011	Streetlight/Stoplight	218		0.00	-

As shown in Table 10.74 above, reported losses for Streetlight/Stoplight in March 2011 were **0.0%** but have since then increased to 0.08% in 2012 and 0.20% in January 2014.

10.7.2 Non-Technical Losses due to Large C&I (Rate 40 & 50) Customers

At the beginning of 2014, losses attributable to large commercial and industrial (C&I) customers were reported at 1.19% of net generation by JPS, mirroring the 2006 and 2007 losses level of 1.3%. Reported losses for this Rate category in March 2011 and December 2012 were 0.25% and 0.16% respectively. However, the figure reported by JPS for January 2014 indicated a reversal of the reduction shown with a significant increase to 1.19%. Notably, in January 2014, JPS in its 2013 annual performance dataset reported that there were 1,874 customers in this Rate category whose consumption accounted for approximately 48% of annual electricity sales (1,532,170 MWh). According to JPS, most if not all, of its electricity supply to large C&I customers are equipped with AMIs that have anti-theft features and ICT platforms which allow JPS remote access to and control of these large accounts.

This capability immensely enhances JPS' capacity to monitor in real time the metered energy and power parameters of its large C&I customers' accounts including, among other things:

- kKW Hours (delivered and received);
- kVAr Hours (delivered and received);
- kVA Hours (delivered and received);
- Maximum Demand (kW and kVA) at 15-minute intervals; and
- Power Factor

Importantly, the AMI technology has the capability to accommodate the measurement of the metered parameters over intervals from 1 minute to 60 minutes, which provides JPS the latitude for extensive monitoring of its large C&I customers' accounts. Additionally, the advanced metering technology enables JPS to instantaneously detect electricity supply irregularities, such as:

- meter tampering;
- some types of meter by-pass; and
- supply connection errors and meter instrumentation connection errors caused by JPS' personnel.

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 physical/manual inspection and testing to ensure that energy loss or leakage in this customer category is minimized or kept at zero.

The importance of the large C&I (Rate 40 & 50) accounts is recognized under Schedule 2 of the Licence in terms of the frequency with which JPS is required to inspect and test the meters for these accounts compared to other customer classes.

The requirement for the frequency of testing Rate 40 & 50 customers' meters set out under Schedule 2 of the Licence is shown in Figure 10.76 below.

Figure 10.76: Frequency of Testing Rate 40 & 50 Customers' Meters as required by JPS' Licence

SCHEDULE 2

OVERALL STANDARDS

Code	Standard	Units	Targets June 2009–May 2014 (inclusive)
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 the relatively small number of JPS' Rate 40 & 50 accounts, the required meter testing should be easily achieved by the company.

Given JPS' capability to monitor its large C&I customers' accounts as well as its obligation to inspect and test these meters for accuracy, the OUR is of the view that the reported energy loss of 1.19% of net generation due to this customer category is avoidable.

Table 10.75: Losses due to Large C&I (Rate 40 & 50) Customers

Date	Category	No. of Customers	Energy Loss (MWh)	Loss (%)	Change (%)
Jan-2014	Large C&I (Rate 40 & 50)	1,874	4,072	1.19	1.03
Dec-2012	Large C&I (Rate 40 & 50)	1,870	561	0.16	-0.09
Mar-2011	Large C&I (Rate 40 & 50)	1,788		0.25	

As shown in Table 10.75 above, losses due to large C&I customers as at December 2012 was 0.16% and as at January 2014 was 1.19% representing a change of 1.03% of net generation. This loss level translates to the loss of 42,658,925 kWh per year, which is equivalent to the consumption of 22,935 residential customers based on an average monthly consumption of 155 kWh.

In general, energy sales of electric utility companies tend to be characterized by the Pareto Law. That is, a small number of large consumers' accounts for a significant portion of the utilities' revenue. It is therefore crucial for electric utilities to ensure full billing of, and full payment by 100 percent of its large consumers to ensure financial sustainability. Given the importance of large customers to the utility operations, the initial objective should be zero (0) non-technical losses related to electricity consumed by this customer category. Studies on non-technical losses in the power sector have shown that this has been achieved by many utilities in Latin America through a combination of good management practices and application of IT tools.

10.7.3 Non-Technical Losses due to Small and Medium C&I (Rate 20) Customers

According to JPS' January 2014 energy loss spectrum, the aggregate losses reported due to small and medium C&I customers was 0.76% representing 0.31% and 0.45% for small and large C&I customers respectively.

The total number of Rate 20 customers reported was 62,974 with 58,651 small C&I and 4,323 medium C&I customers respectively accounting for 9.3% and 0.7% of the total customer base.

Similar to large C&I customers, Rate 20 customers also accounted for a significant portion of JPS' annual sales. JPS' 2013 performance data showed that electricity sales to Rate 20 customers was 586,809 MWh. Notably, approximately 58% of Rate 20 sales is attributable to medium C&I (Rate 20).

For the medium C&I category, which has a small number of customers contributing to large sales volumes, a relatively small degree of losses can have a huge impact on sales. This implies that similar to large C&I accounts, these accounts require close monitoring by JPS. In the JPS' Tariff Submission, JPS had indicated that a large portion of these accounts have AMI meters installed to facilitate remote data access and continuous monitoring and control by the company. Also, due to the relatively high electricity usage of this category, it would be expected that JPS would persistently carry out periodic audits on these accounts to verify meter accuracy and check for irregularities. Given the importance of these accounts to JPS' revenue, the company should be focused on bringing these losses to zero.

Having regard to the above, the OUR is of the view that losses due to medium C&I (Rate 20) customers are readily under the control of JPS.

On the other hand, the situation with small C&I customers is somewhat different. For example, there are more accounts with less remote monitoring capabilities than the other C&I categories. While their aggregate impact on sales is noticeable, the OUR is of the view that it may be more difficult for the company to deal with this category of non-technical losses.

10.7.4 Non-technical Losses due to Residential (Rate 10) Customers

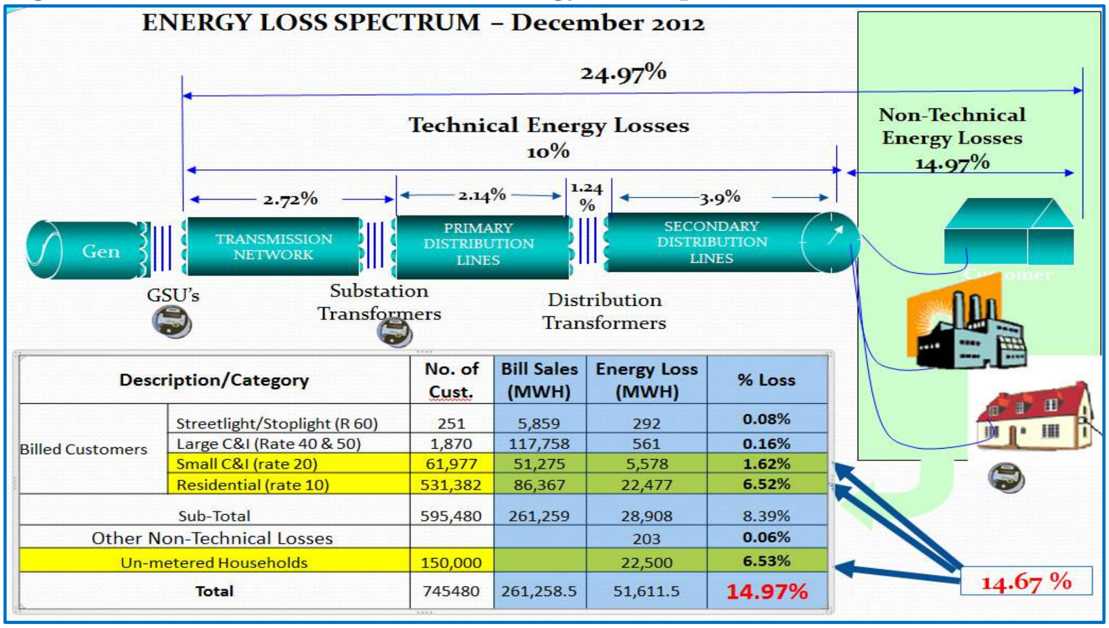
Based on JPS' January 2014 energy losses spectrum, losses due to residential customers were reported as 4.36% net generation or 15,594 MWh representing almost a 33.1% reduction in comparison to the losses reported in December 2012. The total number of customers was 543,052 accounting for 86,225 MWh or 37.8% of electricity sales.

Table 10.76: Losses due to Residential Customers

Date	Category	No of Customers	Energy Loss (MWh)	Loss (%)	Change (%)
Jan-2014	Residential (Rate 10)	543,052	15,594	4.36	- 2.16
Dec-2012	Residential (Rate 10)	531,382	22,477	6.52	3.09
Mar-2011	Residential (Rate 10)	512,568		3.43	-

According to JPS, it undertook major initiatives and programmes in 2013 to improve System losses.

Figure 10.77: JPS' December 2012 Energy Loss Spectrum



Description/Category		No. of Cust.	Bill Sales (MWH)	Energy Loss (MWH)	% Loss
Billed Customers	Streetlight/Stoplight (R 60)	251	5,859	292	0.08%
	Large C&I (Rate 40 & 50)	1,870	117,758	561	0.16%
	Small C&I (rate 20)	61,977	51,275	5,578	1.62%
	Residential (rate 10)	531,382	86,367	22,477	6.52%
Sub-Total		595,480	261,259	28,908	8.39%
Other Non-Technical Losses				203	0.06%
Un-metered Households		150,000		22,500	6.53%
Total		745480	261,258.5	51,611.5	14.97%

It can be deduced from JPS' energy loss spectrum for December 2012 shown in Figure 10.77 above and that for January 2014, that although the total non-technical losses increased from 14.97% to 17.91% of net generation, the losses due to residential customers decreased by 33.1% as shown in Table 10.76 above. This indicates that JPS achieved a reduction in losses due to residential customers of 2.16% of net generation in the thirteen (13)-month period between December 2012 and January 2014.

Having regard to the broad distribution of residential customers across the country, JPS' existing non-technical loss reduction programmes and their proposed programmes for 2014 and 2015, the Office is of the view that JPS could realize greater loss reduction outcomes for the residential customer category for the upcoming Annual Tariff Adjustment and over the entire price-cap period.

10.7.5 Non-Technical Losses due to Internal Bleeds/Un-quantified

Based on the JPS' January 2014 energy losses spectrum, internal bleeds/un-quantified losses were reported as 1.56%. This represents a self-inflicted problem which translates into a significant loss of energy relative to net generation with a consequential adverse impact on JPS' sales and revenues.

Internal bleeds stem from inefficiencies in JPS' internal operations. According to JPS, these losses are mainly due to the following:

- Monthly billing adjustments from exceptions due to human error, for example, meter reading, estimation errors, incorrect meter set-up, defective meters, etc.;

- Human error driven by current weaknesses in the Customer Information System (CIS) and process weaknesses. (According to JPS, its existing CIS is ten (10) years old and may have outlived its usefulness);
- Broken legacy business processes, leads to manual interventions; and
- High level of customization which limits flexibility to upgrade to future releases.

In its System losses presentations to the OUR, JPS indicated that, as part of its strategy to deal with its internal losses, it plans to replace the existing CIS with a modern system by August 2014.

10.7.6 Non-Technical Losses due to Unauthorized Un-metered Consumers

Based on JPS' January 2014 energy losses spectrum, losses due to unauthorized un-metered consumers were reported as 9.85% of net generation or 33,660 MWh.

In the spectrum, JPS has estimated that there are approximately 180,000 households in Jamaica with unauthorized electricity service connections up from the 150,000 estimated in December 2012. While the OUR understands that some of these activities may be related to socio-economic conditions in the country, it does not accept that the full range of this non-technical loss component is outside of the control of JPS. As previously stated, all types of losses are controllable; the issue is that some may be more difficult to control.

As the sole supplier of electricity in the country, JPS needs to tackle the problems that can severely impact its operations, rather than expect the customer base to constantly absorb the costs of these adverse effects. As mentioned earlier, addressing the issue of non-technical losses requires a clear and cogent strategy enhanced by innovation and persistence.

Table 10.77: JPS' Reported Losses due to Un-metered Consumers

Date	Category	No. of Consumers	Energy Loss (MWh)	Loss (%)	Change (%)
Jan-2014	Un-metered consumers	180,000	33,660	9.85	3.32
Dec-2012	Un-metered consumers	150,000	22,500	6.53	0.07
Mar-2011	Un-metered consumers	130,503	22,186	6.46	

As shown in Table 10.77 above, losses due to unauthorized un-metered consumers stood at 6.46% of net generation in March 2011 and 6.53% in December 2012. However, by January 2014 JPS reported that this figure skyrocketed to 9.85% resulting in an increased energy loss of 11,160 MWh or 3.32% of net generation.

This estimation of losses due to unauthorized un-metered consumers is questionable on the basis that no detailed and specific scientific/statistical measurement or model has been presented by JPS to substantiate it. By comparison to the March 2011 and December 2012 energy losses due to unauthorized un-metered consumers, the value for January 2014 appears to be extreme and unusual and could be considered inaccurate. The increase in the number of unauthorized un-metered consumers by approximately 49,500 over the period March 2011 to January 2014 at an average rate of 2,250 connections per month with 19,497 between March 2011 to December 2012 and 30,000 during the period December 2012 to January 2014 also raises concerns.

In contrast, according to JPS' annual performance data, only 36,350 customers over all categories were legitimately connected to the System for the same period, reflecting an average connection rate of 1,652 customers per month with 24,171 connected during the period March 2011 to December 2012 and 12,179 between December 2012 and January 2014.

The data indicates that the average number of customers legitimately connected to JPS' System each month for the period March 2011 to January 2014 is approximately 27% lower than that for the unauthorized un-metered customers. The data also indicates that over the thirteen (13)-month period, December 2012 to January 2014, the number of illegal un-metered consumers connected to the System was approximately 150% higher than those legitimately connected by JPS. This is an interesting result which raises concerns of:

- Whether there may be measurement bias in the System losses data;
- Whether JPS' loss reduction strategies are appropriately focussed; and
- Whether JPS' efforts to regularise illegally connected electricity consumers is sufficient and effective.

As previously indicated, the estimation of JPS' non-technical losses appears to have a low degree of confidence and there may be margins of error in the non-technical loss figure provided in JPS' energy loss spectrum due to the methods of estimation. This is also likely to be the case with JPS' estimation of losses associated with the un-authorized, un-metered consumers.

With respect to the relatively high reported losses due to un-metered consumers and the issue of confidence in the method of estimation, the OUR carried out its own analysis using JPS' 2013 performance data as a means of obtaining a reasonable estimate of the losses attributable to un-metered consumers referred to by JPS. The OUR assumed average monthly residential usage for the purpose of the calculations on the basis that the unauthorized un-metered electricity supply connections were predominantly related to households. The results are shown in Table 10.78 below.

Table 10.78: OUR's Estimation of Losses due to Unauthorized Un-metered Consumers

No. of Active Residential Customers	No. of un-metered Consumers	Annual Average Sales (KWh)	Average Annual Usage per Customer (kWh)	Annual Energy Losses (kWh)	Annual Net Gen (kWh)	Losses – (%) of Net Gen
501,771	180,000	986,350,792	1,965.7	353,832,303	4,141,643,178	8.5%

The results of the analysis show that losses due to un-metered consumers were estimated at 8.50% of net generation. This estimation is entirely based on data provided by JPS and does not necessarily represent the actual figure for this category of losses.

10.8 Funding of JPS' Proposed Loss Reduction Programmes

JPS has requested that the EEIF be embedded in the current tariffs be retained to provide partial funding for the initiatives, especially the Community Renewal Programme.

Specific details relating to the management and utilization of the EEIF are set out under Section 10.3.6.

As previously discussed, the projected level of AMI implementation and the commensurate impact on losses have not been achieved by JPS. This has raised issues regarding the application and utilization of the Fund.

Despite the concerns regarding the effective use of the Fund by JPS, the Office believes that the EEIF could be more efficiently deployed to address the broad issue of System efficiency. Accordingly, the Office's Determination on the EEIF is set out under Chapter 6, Section 6.7.3.

10.9 Discussion on JPS' Rationale for the Escalation in System Losses

10.9.1 JPS' Position on Non-Technical Losses

Against the background of the significant increase in non-technical losses over the period 2009 – 2014, the fundamental question that arises is - What are the factors that explain this development?
JPS has posited that the primary reason for these losses is the myriad of Jamaica's socio-economic challenges which include the general macro-economic challenges impacting the affordability of electricity, governance, crime rate, unemployment, accessibility, etc., and relied on a study conducted by Quantum in 2013 to support its position. See Section 10.1.8 above for the full details of JPS' arguments.

10.9.2 OUR's View on Non-Technical Losses

The OUR shares the view that the socio-economic conditions in a country may have an impact on the level of non-technical energy losses experienced by an electric utility. However, the argument proffered by JPS that non-technical losses depend positively on the degree of violence in the environment is questionable. In the present energy loss situation, a clear distinction must be drawn between causation and correlation. Correlation does not imply causation; a correlation between two variables does not necessarily imply that one causes the other. It is a logical fallacy to accept that two events happening together are taken to have a cause-and-effect relationship. In this context, it does not follow logically that more people will steal electricity in a country because the murder rate is increasing. It is possible that both system losses and violent crimes are explained in the same variable, poverty, and as such system losses and crime would naturally move in the same direction.

While an inference can be drawn that crime is correlated to electricity theft, the issue of causation is questionable. The assumption that correlation proves causation is a questionable cause.

Reference is made to Section 10.3.4 which indicates the OUR's position regarding the situation with System losses. In particular, the issue of the adoption of an appropriate strategy to deal with the losses has been a key area of concern.

The information available to the OUR do not indicate that the company has in place a specific and dedicated Loss Reduction unit which is a crucial element for ensuring the effective execution of its loss reduction initiatives. Notably, the responsibility for System losses resides with the Director, T&D Asset Management, and the various functions are discharged through the regional/district managers.

The OUR is not convinced that the present organizational structure provides sufficient focus on the execution of System losses strategies, especially, given the absence of a dedicated team to execute the designated programmes and initiatives. The OUR is also of the view that a well-planned programme designed for implementation over the five-year price-cap period should realize positive results.

10.9.3 Technological Solutions to Curtail System Losses

Over the past years, AMI, which provides remote metering, reading and monitoring of electricity consumption, has been extensively deployed by a number of electric utilities in developing countries including some in the Caribbean and Latin American region to deal with the issue of high non-technical losses. The experience in some of these countries indicates that the effectiveness of AMI to detect and discourage theft and other ways of unmetered consumption is enormous. Based on technological developments and economics associated with the adoption of AMI, the OUR is of the view that large-scale application of AMI which is appropriately managed can significantly contribute to sustainable utility operations and efficient performance of the power sector.

According to a "Background Paper for the World Bank Group Energy Sector Strategy" dated July 2009 and entitled *"Reducing Technical and Non-Technical Losses in the Power Sector"*, the application of AMI has the following positive impacts:

a) *"Watchdog" effect on users.* Users become aware that the utility can monitor consumption at its convenience. This allows the company fast detection of any abnormal consumption due to tampering or by-passing of a meter and enables the company to take corrective action. The result is consumer discipline. This has been shown to be extremely effective with all categories of large and medium consumers having a history of stealing electricity. AMI can be implemented at very low costs both for medium- and low-voltage consumers, using mobile phone networks, power line communication, or other means of remote communication between the meter located at the customer's premises and the company's office where the reading is received and processed. These measures can significantly increase the revenues of utilities with high non-technical losses.

b) *Enhancement of the company's corporate governance and anti-corruption efforts.* Instances of theft by large consumers usually involve collusion between them and meter readers. Corruption is also likely to occur in operations of service disconnection related to unpaid bills. Implementation of AMI eliminates those field operations (meter reading and service disconnection) and makes information on consumption transparently available to the users and managers in the company, greatly enhancing governance and reducing corruption.

c) *Implementation of pre-paid consumption.* Pre-paid consumption is generally a very good commercial option for low-income consumers. AMI enables replication in the power sector of the tremendous success of pre-paid consumption in the mobile phone industry. Implementation of AMI, together with a commercial management system (CMS), makes pre-paid consumption of electricity possible. Credit bought by consumer is loaded in his account in the CMS; many options are available for purchase and loading, including use of mobile phones. The company can easily implement operational procedures allowing the customer to have access to the remaining credit, receive alert messages from the company when the credit is about to expire, buy new credit, receive disconnection message, etc. The company can apply remote disconnection and reconnection included in the AMI devices used for low-voltage consumers in cases of credit expiration and non-renewal in the same way pre-paid mobile phones work. The AMI approach for pre-paid consumption has several significant advantages compared to the classic pre-paid card meters widely used in South Africa and other countries. Two very important ones are (1) significantly lower hardware costs, and (2) permanent monitoring of consumption allowed by AMI, which is not possible with the classic card meter. With a card meter, the company has no information on real-time consumption while the user has credit and the cardholder can by-pass the meter without being detected, unless field inspections are performed. AMI pre-paid consumption has been implemented in Brazil by the company AMPLA, an affiliate of the Enersis group.

d) *Elimination of losses in non-manageable areas.* AMI is a key component of the approach called medium-voltage distribution (MVD), used for construction and operation of electricity networks used to supply consumers located in areas where access of the service company is constrained due to safety or other reasons.

e) *Demand side management* to maximize efficiency in electricity supply and consumption. Permanent AMI (in general applied to medium and large consumers in all categories including residential, both in developed and developing countries) through smart grids allows optimization of electricity consumption by informing users on real-time prices, start and end of peak periods, accumulated consumption, alerts, etc. Recent experience, both in developed and developing countries, shows that medium and large consumers are responsive to clear and timely information on pricing options.

In the case of JPS, the company has implemented RAMI projects in a number of communities in the country with positive results. For example, the Old Harbour Bay project which JPS reported was cut-over in September 2010. The usage trend for the project up to December 2012 is shown in Figure 10.91.

Figure 10.91: Usage trend of Old Harbour Bay RAMI Project up to December 2012

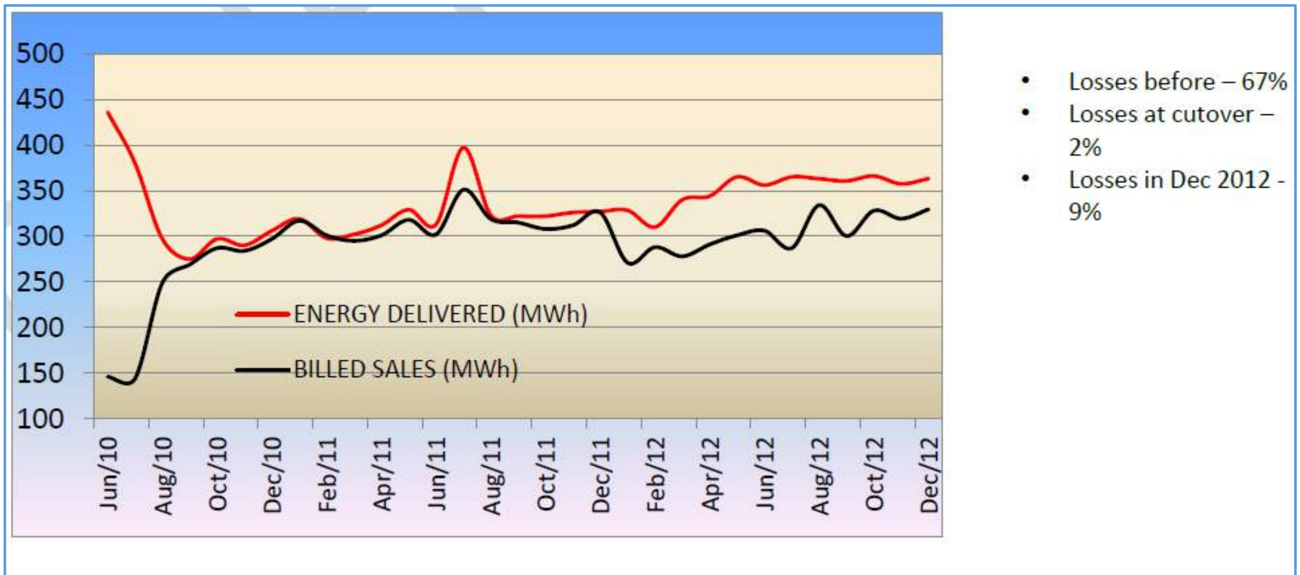


Fig 6. Old Harbor Bay (Cut-over Sept 2010)

As reported by JPS, RAMI deployments in the Spanish Town area have also delivered impressive results, reducing energy losses on secondary circuits in some of these areas from over 85% to 2%.

While the referenced RAMI projects have significantly reduced energy losses in those communities, the overall impact on System losses appears to be minimal due to the limited deployment of AMI by the company. In essence, the results of these initiatives are quite encouraging and suggest that with the appropriate management strategy and loss reduction plan, JPS should be able to achieve and sustain significant reduction in non-technical losses in the present socio-economic environment with large-scale deployment of AMI.

10.10 Determination on System Losses

In arriving at its determination regarding the System losses target to be applied in the FCAM, the Office took the following into account:

1. Prior to 2001, System losses were trending downwards and were approaching 16%. The System losses target was set at 15.8% at the time of privatization, up from just over 13%.

2. Between 2001 and 2004, System losses increased from 16.4% to 19.1%, while sales growth was in the region of 4% to 5%.

3. In 2004, the application of System losses was adjusted to exclude non-fuel costs.

4. Between 2004 and 2009 losses increased from 19.1% to 24%, while electricity sales increased by over 8%.

5. In its 2009 Tariff Submissions, JPS proposed that the losses target be increased to 20.5% in 2009 and decrease steadily over the five-year price-cap period to 16.3% in June 2014. This was based on their expectation that they could achieve actual losses of 18.3% by 2014 and could accommodate a stretch factor of 2%, resulting in the target of 16.3%. JPS indicated that to achieve this they would invest US$45 Million over the period.

6. The Office in its 2009 Determination Notice approved an increase in the System losses target from 15.8% to 19.5% and then decreased to 17.5% at the 2011 Annual Tariff and reviewed annually thereafter. The OUR also approved an additional amount in the base tariff of US$13 Million per year to fund the loss reduction programmes which would have enabled JPS to achieve the stated target.

7. In the 2011/12 Annual Tariff Adjustment, JPS proposed a System losses target of 19.5%, which was higher than the 18.5% the company had committed to in 2009. However, consistent with its 2009 Determination Notice, the OUR approved a target of 17.5%.

8. In the 2012/13 Annual Tariff Adjustment, JPS proposed a losses target of 18.5%, again deviating from the 17.7% commitment of 2009. The OUR however, maintained the target at 17.5% for this period.

9. At the 2013/14 Annual Tariff Adjustment, JPS proposed a full pass-through of system losses, which had continued to increase to over 26%. In effect, JPS was at the time proposing that, rather than legitimate customers paying the originally proposed 16.9%, they would now be required to bear the full System loss burden at 26% and increasing. The Office, in its 2013 Annual Tariff Adjustment Determination Notice, maintained the target of 17.5% rather than applying the 16.9% proposed by JPS in 2009. Additionally, the Office approved a Fuel Cost Recovery Adjustment (FCRA) of US$20M and directed that these funds be used to supplement the EEIF and other investments in addressing additional loss reduction initiatives.

10. In the JPS' Tariff Submission, JPS proposed a System losses target of 22.95% for 2014, 23.98% for 2015, 24.22% for 2016, 23.63% for 2017 and 22.88% for 2018, based on a three-year rolling average for System losses plus a 2% stretch factor.

Having regard to the inconsistences in JPS' reported System losses, the Office also took into account a reasonable range for each category of losses that it believes is achievable during the 2014-2019 price-cap period. These are set out below as follows:

<u>Technical Losses</u>

Technical losses should range from 8.4% - 7.7%.

Streetlights/Stoplights:
Losses due to streetlight/stoplight should be in the zero range.

Large C & I (Rate 40&50) Customers:
Losses due to Rate 40&50 customers should be in the zero range.

Medium C & I (Rate 20) Customers:
Losses due to medium C&I customers should be in the zero range.

Small C & I (Rate 20) Customers:
Losses due to small C&I should range from 0.16% - 0.0%

Residential (Rate 10):
Losses due to residential customers should range from 2.14% - 0.0%

Internal Bleeds/Unquantified:
Losses due to small C & I should be in the zero range.

Un-metered Consumers:
Losses due to small C & I should range from 8.5% - 6.5%

Aggregately, the range of losses for the various categories would result in a range for the System losses target of 14.2% - 19.2%.

Based on the above and earlier discussions regarding the specific components of JPS' reported current energy loss spectrum, the Office determines as follows:

DETERMINATION 35

Technical Losses

- **The indicative technical losses ceiling for the period January 2015 – May 2019 shall be 8.4%.**

- **The value of the technical losses for each month shall be reported in the monthly Fuel Rate Calculation submission.**

- **The Technical losses will be reviewed by the Office at each Annual Tariff Adjustment during the price-cap period.**

Non-Technical Losses

- **JPS' non-technical loss target ceiling for the period January 2015 – May 2019 shall be 10.8%.**

- **The non-technical losses will be reviewed by the Office at each Annual Tariff Adjustment during the price-cap period.**

- **The value of the non-technical losses for each month shall be reported in the monthly Fuel Rate Calculation submission.**

- **The aggregate System losses target ceiling for the price-cap period January 2015 – May 2019 shall be 19.20%.**

10.11 Community Renewal Programme

According to JPS, the Community Renewal Programme is one in which JPS, NWC, and Government agencies will come together to improve services to low-income communities island-wide, in an integrated way that emphasizes community responsibility and payment as the quid pro quo for service upliftment. JPS stated that Jamaica needs to move beyond an 'enforcement' approach to the problem of service theft and non-payment, to one which emphasizes reciprocity.

10.11.1 The Problem

JPS stated that the problem of electricity and water theft in low-income communities is endangering the financial health of Jamaican utilities. JPS says it is losing about US$75M in revenue from theft, and NWC is losing about US$49M.

JPS argued in the JPS' Tariff Submission that the problem of electricity theft is related to the issue of social exclusion. Low-income communities where people steal electricity and water often lack basic services, secure land tenure, and a voice in the development of the country. These communities are said to be suffering from inadequate water and sanitation services, and poor local roads, and paths. Many residents in these communities do not have titles to their land, even if generations of their family have lived there. Some entire communities have been established illegally, often on land owned by the Government. These informal settlements often fester a spirit of corruption and deceit as these poor inhabitants are 'forced' to do whatever they deem necessary in order to survive in very difficult economic conditions.

According to JPS, whilst problems are different in each community, low-income communities can reasonably be grouped into the following three types:

- Rural villages;
- Squatter settlements; and
- Inner-city areas.

From an electricity service perspective, these communities have key features in common:

- Almost everyone receives electricity from JPS' network;
- In many communities, almost no one is paying for electricity; and
- JPS' traditional approaches to controlling unauthorized connections are not working.

The traditional approaches involve removing unauthorized connections, and arresting persons.

JPS stated that when the company removes 'throw-ups' (wires) residents quickly reattach to distribution lines to illegally tap into the electricity network. JPS claimed that the company's repeated and increasing attempts at enforcement have not been effective at reducing electricity theft. JPS said that in 2013, the company lost an estimated US$11.1M from enforcement efforts, slightly less than the US$11.5M it lost in 2012.

10.11.2 The Proposed Solution

JPS proposed that it will partner with NWC, the Housing Authority of Jamaica (HAJ) and other Government agencies to offer a comprehensive Community Upliftment Programme. Residents in low-income communities would be offered improved roads and footpaths, land title regularization, and access to micro credit, as well as reliable electricity and water supply. In return for these services, residents would need to agree to pay for electricity and water service. To establish mutual trust, the proposal is that benefits must be provided step-by-step, emphasizing reciprocity and establishing mutual trust between community members and the program. Utilities, the Government, and donors are expected to collaborate in organizing and funding this programme. The utility companies are expecting to see a financial return on their investments in this programme through getting some revenue for services which they currently provide without any revenue. Donors and the Government should fund the non-utility aspects of the programme, which aligns well with their priorities.

JPS stated that utilities in other countries, and other sectors in Jamaica, have found ways to work more closely with communities to increase payment for service and three clear lessons have emerged from those experiences:

1. Involve communities in service design and management;
2. Tailor tariffs, financing, and collection mechanisms to community needs; and
3. Offer additional services that the utility is in a unique position to provide.

10.11.2.1 Offer Lower Tariffs

JPS proffered that sometimes, utilities can benefit by charging low-income communities less than the full cost of providing service. The company stated that charging lower tariffs can increase collection rates and overall revenues from these communities. For utilities, this is better than not collecting any money at all, and tariffs can be raised gradually to cover the full cost of providing the service. It also allows communities to establish a habit of paying utility bills, which they will continue as tariffs rise. JPS said that this makes good economic sense as long as the tariffs charged exceed the marginal cost of providing the service (i.e. MR > MC) even if the tariff does not recover the full cost of service.

10.11.2.2 Offer Additional Services that the Utility is in a Unique Position to Provide

JPS stated that people in low-income areas have service needs that differ from the needs of the middle class consumers. Utilities that respond to these needs have been rewarded with high payment rates. Types of services that have worked to increase payments include financial services, security of land ownership, and livelihood training.

JPS said that the company could fund some services for communities, especially micro-loans, and school improvement projects, out of the tariff revenue from that community. This would directly link payment for electricity with benefits to the community. Communities with good payment records would receive extra benefits (typically calculated on a commission basis), providing a further incentive for community members to pay for electricity.

10.11.2.3 Security of land ownership

JPS stated that many low-income people with unauthorized connections lack secure titles to their land. Persons living in rural areas often have a legitimate ownership based on traditional occupation, but lack a formal title. Squatters on government land have no title, but in established communities their de facto ownership is recognized by the GOJ. The GOJ regularizes ownership or offers plots of land or houses elsewhere in exchange for releasing the occupied land, through the HAJ.

10.11.2.4 Livelihood Training

In the poorest communities, utilities have offered livelihood training as a type of corporate social responsibility. In Delhi, India, Tata Power Delhi Distribution (TPDDL) offers free vocational training, education support, and medical facilities to its customers. Additionally, TPDDL employs community members for metering and bill collection. Similarly, NWC in Rocky Gully employed community members, which increased local support for the project and community members' skills. JPS is proposing to partner with the established GOJ vocational training centers to offer jobs and skills training to members of the communities which it is targeting to regularize.

10.11.2.5 Impact of the Service

As discussed above, JPS stated that the provision of additional services will increase the likelihood of payment in three ways:

1. Consumers are more likely to sign up for regularization of utility connections, since they want to access the other services. These are services that they typically cannot get in any way other than through regularizing their utility connections.

2. Customers are more likely to keep paying, since they want to retain access to the services. For instance, TPDDL cites the desire of very low-income families in Delhi to retain life insurance coverage as a key reason they remain current on their bills.

3. Increased earning power and access to credit makes it easier for customers to pay.

With livelihood skills, customers can earn more money. With insurance, tragedies such as the death of the income earner in the family do not necessarily mean a default in payment. With access to credit and banking services, customers can manage fluctuations in income and expenditure while remaining current with their bills. Finally, secure title provides a method to offer security, increases access to credit, and provides the opportunity to recover against the property in the event of serious default.

10.11.2.6 Strategies for Community Renewal

JPS proposed that it would partner with NWC and the Ministry of Transport, Works, and Housing to launch a programme that phases in community services in exchange for a commitment from the community to pay for the power and water services they receive. This programme would be piloted in squatter settlements and eventually rolled out to rural communities and inner-city communities. The programme would be funded by the GOJ, JPS, NWC, and the donor community. Given the multi-dimensional nature of the project, it is likely that the donor community would be a major source of funding and JPS has confirmed this in initial discussions with the Social Development Commission (SDC) and World Bank.

10.11.3 The Programme

The programme is proposed to be designed to offer infrastructure improvements and other benefits to communities. Infrastructure improvements would include:

1. Reliable access to water, sanitation, and electricity (including house wiring);
2. Fixing local roads and footpaths; and
3. Wireless broadband access (if there is demand).

Additional benefits would depend on community needs, and would be decided in consultation with the community. Some examples of additional benefits that have proven successful in encouraging payment in the past include:

1. Land title regularization;
2. Housing improvements or resettlement options for squatters;
3. Provision of utility bills to be used for credit checks and access to finance;
4. Skills and job training;
5. Employment for community members (job placement and apprenticeship programs); and
6. Option to purchase life insurance.

10.11.4 Payment

JPS stated that the programme would offer improved payment options. First, it would offer transitional “community upliftment tariffs.” These tariffs would be discounted and gradually increased as service levels increase and customers’ ability to pay increases. Additionally, there would not be any initial connection charge. Instead, customers would be able to pay for the cost of connection in instalments, added on to their monthly bills. Customers that cannot make payments will not be disconnected automatically. Instead, they will be offered credit arrangements with interest. Alternatively, prepaid metering system can be provided as a means of helping persons to manage their budget more efficiently and to “pay as they go” avoiding large monthly bills at the end of each month which they did not properly budget to address.

10.11.5 Community Involvement

The community would be consulted to determine its priorities for the upliftment plan. This will ensure that the community agrees to the services it will receive and understands that the programme will only be sustainable if the whole community participates and pays. A representative from each community would be selected as a liaison between the community and the relevant GOJ agency working alongside JPS and the NWC. This representative would help to canvas the needs of the community, respond in person to service problems, and provide other support, such as advice to customers on how to limit consumption levels. There will also be other opportunities for community responsibility, such as contracting out management of the billing and collections to a community-based organization.

10.11.6 Implementation Process

JPS indicated that the first step of the programme will need to be taken by the team of JPS, NWC, and the GOJ. The exact scope of works and initial project sites for the first year of the program could be finalized within ninety (90) days. The existing EEIF funds would be used to fund these projects after the project cost is developed for the first year and approved by the OUR. Utility rates initially would be discounted but would gradually increase as benefits to the community increase. JPS estimates the graduation period to be five (5) years but the success of each project would be reviewed annually and modifications sought from the OUR each year.

Service providers and community members would establish mutual trust and gradually work together to improve services and cost recovery. If payments were to stop at any point, community meetings would be organized to create social pressure to pay. If non-payment continued, any additional upgrades would cease and non-payers would be aggressively pursued. If, after project implementation, losses in such communities exceeded accepted standards then community-based load-shedding could be utilized through Recloser Energy Limiting Initiative (RELI) as a general strategy towards ensuring overall compliance and limiting the impact of losses to all other JPS customers. Load shedding during certain hours of the day would ensure the community still had access to electricity during certain agreed critical hours of the day but not provide that community with access twenty four (24) hours per day based on their unacceptably high level of energy losses. An appropriate schedule and scale would be communicated and agreed with the OUR prior to implementation. This could in fact be communicated to the community as a means of ensuring overall compliance and ensuring they understand clearly the consequence for non-compliance.

The communities that benefited from the programme and the improvements that they received would be publicized to create demand for the program throughout the country. However, JPS stated that the company is confident that with the World Bank funding and additional services that would likely be provided (credit support, life insurance, access to education, etc.) to such customers that the community renewal project would likely be a huge success.

10.11.7 Funding

JPS stated that this is a large-scale programme, and multiple sources of funding will be needed as follows:

10.11.7.1 GOJ

All improvements related to land, housing, roads, paths need to be funded by the GOJ. There are existing budgets that can be used to fund the project initially, but a longer-term commitment to the project will be required.

10.11.7.2 JPS

JPS proposed that it would pay for all the parts related to electricity infrastructure, financing the cost for house-wiring and for project organization. JPS and the NWC would jointly contribute towards the social intervention costs which are designed to ensure the sustainability of the programme. This would include contributions towards the cost for jobs and skills training, customer education and security and law enforcement. JPS stated that the programme should be able to prove its financial viability within twelve (12) months. It is expected that by this time it should be clear that communities engaged in the programme are paying for service they earlier took without paying. From this, it will be possible to validate ROI calculations and JPS is proposing to encourage that this analysis be conducted annually by a relevant GOJ agency (such as the Statistical Institute of Jamaica (STATIN)).

JPS proposed that it would reinvest a portion of the electricity revenue generated from communities with good payment records back into the community. It would do so by providing extra benefits, such as school electrification and micro-finance, or other programmes that community members want, such as, access to life insurance benefits. This will provide further encouragement for community members to pay for electricity, because it directly links electricity payment with benefits.

10.11.7.3 NWC

NWC will need to pay for everything related to water, and contribute to the costs of running the programme and like JPS, make a contribution towards social intervention costs. This program will also be financially positive for the NWC. NWC is on a drive to expand and improve services, and to reduce Non-Revenue Water (NRW), meaning that the programme will fit very well with the priorities of the GOJ.

10.11.7.4 Donors

JPS stated that if donor relations are well-handled, substantial concessional loans and grants will be coming from multilaterals such as IADB, CIDA, DFID, the EU, and others to support social intervention and community renewal. These funds should be managed by the GOJ Unit to ensure proper monitoring and reporting is maintained to the donor's satisfaction. JPS further mentioned that there are numerous existing programs today that are managed by Jamaica Social Investment Fund (JSIF) and the SDC.

10.11.8 Review of JPS' Proposal

10.11.8.1 The Community Renewal Initiative

The OUR is of the view that the proposed Community Renewal Programme as presented by JPS and summarized above is at an infancy stage. The following are some observations:

- There is no indication as to which entity is playing the leading role in this initiative.
- JPS has not demonstrated that it has properly assessed the risks that are involved in the implementation of such a project.
- The scope of the project is unclear and also how this would relate to each of the participating entity.
- There is no indication that a signed framework agreement between the parties is in place.
- There is no indication that JPS has prepared a cost-benefit analysis, although notably:
    - It is stated that JPS pays for all the parts related to electricity infrastructure, financing the cost for house-wiring and for project organization. JPS and the NWC would jointly contribute towards the social intervention costs which are designed to ensure the sustainability of the program and there was no indication of the extent of JPS' financial obligations in this regard.
    - There is no indication of what the overall project costs will be, the projected number of people/households to benefit, projected revenue to JPS and NWC.
- The proposed implementation strategy to disconnect by load-shedding is of concern to the OUR. Among other reasons, paying customers of JPS will suffer the inconvenience of this action.

JPS stated that, *"Service providers and community members would establish mutual trust and gradually work together to improve services and cost recovery. If payments were to stop at any point, community meetings would be organized to create social pressure to pay. If non-payment continued, any additional upgrades would cease and non-payers would be aggressively pursued. If, after project implementation, losses in such communities exceeded expected standards then community based load-shedding could be utilized through our [JPS] Recloser Energy Limiting Initiative (RELI) as a general strategy towards ensuring overall compliance and limiting the impact of losses to all other JPS customers."*

In its submission, JPS stated that the company would be funding a subsidized billing programme to help persons who are currently illegal consumers of electricity transition to legitimate paying customers. In this regard, JPS recommended the continuation of the EEIF programme for the purpose for funding this and other new initiatives aimed at reducing system losses. JPS did not present a plan to show the impact and projected reduction in non-technical losses over time which this initiative is expected to yield.

10.11.9 Community Renewal Programme Tariff

JPS stated in its proposal that through the Community Renewal Programme, communities currently not paying for electricity would be invited to connect to the system under promotional conditions, paying just for Long Run Marginal Cost. This would be a temporary programme aimed at recovering non-technical losses.

JPS proposed a "community upliftment tariff" structure as follows:

- No Network Access Charge (NAC): applicable whether there is consumption. It covers the customer service marginal costs.

- Energy charge: A charge that is paid for every kWh of consumption and it covers capacity marginal cost. 0.07USD/kWh

- The proposed rate is only applicable for the first 200 kWh/month. Any higher consumption amount would be charged at the normal rate.

These tariffs would be transitional and JPS stated that they would be discounted and gradually increased as service levels increase and customers' ability to pay increases. Additionally, there would not be any initial connection charge. Instead, customers would be able to pay for the cost of connection in instalments, which would be added on to their monthly bills.

10.11.10 OUR's Position

The Office may consider the implementation of a specified rate to encourage non-paying customers in high-loss areas who have affordability challenges to become legitimized. However, the initial transitional rate of $4.34/kWh proposed by JPS is NOT APPROVED. JPS claims this is a transitional tariff which has been discounted and will gradually be increased as service levels increase and customers' ability to pay increases. However, the Office's position is that the composition, operation and application of the programme have not been sufficiently defined to allow it to prescribe a specific rate.

DETERMINATION 36

The Office DETERMINES that the Community Renewal Initial transitional rate of $4.34/kWh proposed by JPS is NOT APPROVED

Notwithstanding, the Office may consider a prescribed rate after a complete proposal has been submitted.

Chapter 11: Other Fees

11.1 Interest on Accounts Receivables for Commercial Customers

JPS stated that currently, primarily on account of a mix of customers in all rate classes, bills are being paid well after the due date; on average, accounts receivable is collected over a fifty two (52)-day period. The late payment, JPS proffered, is evidenced in approximately 20,000 to 30,000 disconnections per month. JPS asserted that there is also a group of customers in the essential services (primarily GOJ accounts) which it cannot disconnect for late payment and as a result the company has seen an average outstanding balance well above the norm. JPS stated that approximately thirty percent (30%) of commercial customers pay their bills within the prescribed due date. According to JPS' data, GOJ receivables including NWC and other public sector agencies account for just under a third of total receivables and on average these customers are settling their bills in the 120-day time frame. Other industrial customers tend to pay within periods in excess of thirty (30) days.

Consequently, JPS argued that the company is suffering significant interest costs on the additional working capital requirement to fund the business. The company further posited that it has been incurring significant FX losses on the outstanding balances due from those customers as it is required to settle its own liabilities to Petrojam in foreign exchange at the rate of exchange that obtains at the date of settlement. JPS also noted that since the company has no interest rate clause in its standard offer contract, the interest paid on additional funding required to maintain operations while these receivables remain outstanding is absorbed by the company.

JPS proposed that a rate of interest on outstanding debt of 15% per annum for commercial customers be charged. As at December 2013 (the test year), the average cost of JPS debt stood at 8.07%. JPS argued that by setting the rate at this level, the 7% increment over and above the 8% average cost of debt, will act as a proxy for FX recovery. This is required since customers are settling their bills in J$ but JPS in turn requires this money to settle its US$ obligations, whereby 85% relates to Fuel (from Petrojam) and payment to the IPPs. The 7% portion of the interest rate charge is proposed to be used at the end of each financial year as an offset to the FX loss recovery (i.e. the proposed annual 'true-up').

The rate of devaluation of the Jamaican dollar experienced in 2013 was 14.3% and JPS claimed that this resulted in a US$21M FX loss for the year. The company stated that it is seeking to recover US$14M in the revenue requirement to adjust for a normal year's expectation and considers it reasonable that the rate of interest to be charged on commercial customer bills be set at such a level that would ensure recovery of the approximate FX loss that the company would suffer during the period the receivable remains outstanding.

Further, JPS proposed that commercial customers should be given a three (3)-day grace period during which no interest would apply to the outstanding balance. The grace period would commence the day following the due date on the customer's bill and would terminate on day three (3) following the due date. Interest accrual would therefore commence on the first day following the due date on the customer's bill but would be waived where the customer pays within three (3) days of the due date.

JPS argued that with this proposal, it is seeking to better manage its trade receivables. JPS argued that the company is suffering FX losses mainly due to customers who are settling their bills late and in J$ while it requires this money to settle its US$ obligations. JPS indicated that 85% of its payment obligations relate to Fuel (from Petrojam) and payment to the IPPs and that the rate of devaluation of the Jamaican dollar between the invoice date and the settlement date of these obligations is significant.

11.1.1 Review of JPS' Proposal

In examining the company's test year audited financial report, it revealed that of the US$179.3M in trade receivables, an amount totalling US$83.6M (47%) is past due, that is, payment remains uncollected by the company beyond thirty (30) days of the due date on the customers' bills. See Table 11.11 below for details.

Table 11.11: The Aging of Trade Receivables (as at the reporting date)

	2013		**2012**	
	Gross receivable	**Gross impairment**	**Gross receivable**	**Gross impairment**
	$'000	$'000	$'000	$'000
Neither past due nor impaired:				
Due 0-30 days	95,700		102,052	
Pass due and not impaired:				
Past due 31-60 days	11,478		12,933	
Past due 61-90 days	7,691		8,717	
More than 90 days	26,005		34,475	
	140,874	**-**	**158,177**	
Past due and impaired:				
More than 90 days	38,428	38,428	36,788	36,788
Trade accounts receivable	**179,302**	**38,428**	**194,965**	**36,788**

As it relates to payments under the PPAs to the IPPs, JPS is required within fourteen (14) days after the last day of each month to prepare and deliver to each IPP, a statement reflecting all amounts payable to each party by the other party in dollars pursuant to the agreements. All prices, charges and amounts expressed in those PPAs are in United States dollars. However, JPS may make payments to the IPP in equivalent Jamaican dollars by applying the invoice exchange rate. This means that JPS has an option for payment in Jamaican dollars converted from United States dollars at the invoice date. It is submitted therefore that JPS is in fact able to manage its foreign exchange exposure in respect of the payments to IPPs, by making payment in Jamaican dollars but at the exchange rate obtaining on the invoiced date, in which event, there would be no FX exposure between invoice date and settlement date as JPS is now claiming.

With respect to payments to Petrojam, one such recent related agreement - "Fuel Agreement 31 July 2014" indicates that … "*Payment shall be designated in US dollars but may be payable in Jamaica dollars, which shall be calculated at the rate of exchange (spot market weighted average selling rate as published by Bank of Jamaica) prevailing on the date of payment. However, Buyer retains the option to pay monies due in United States Dollars. Where invoices are settled in United States Dollars, Seller shall remit to Buyer as a financing incentive a sum equivalent to 1% of the CIF value.*"

It is submitted that JPS would have negotiated this agreement - which was awarded on a competitive basis, fully cognizant of the possibility of a foreign exchange exposure. Having not made sufficient contingencies to address that concern, the Office is of the view that it is not now appropriate to pass this on the consumers by way of an interest charge.

As more of a general observation, the Office wishes to underscore that JPS is already compensated for interest on receivables by virtue of the fact that these are included as part of its working capital on which it earns a return.

The Office has therefore determined that no interest shall be applied to receivables for commercial customers. JPS' application in respect of the approval of a 15% charge on such receivables is therefore denied.

DETERMINATION 37

JPS' request to charge interest on commercial customers' accounts is DENIED.

Chapter 12: Decommissioning

12.1 Description

At the time of the JPS' Tariff Submission, JPS had executed a PPA with Energy World International (EWI) to construct a new 381 MW generation facility (EWI Plant), which was scheduled to begin commercial operation in 2016. It was envisioned by JPS that when the EWI Plant begins commercial operation in 2016, it would be necessary to retire the existing Old Harbour Power Plant (Old Harbour) the same year, and potentially Hunts Bay Unit B6 (Hunts Bay) in 2017. The EWI Plant would necessitate the retirement of Old Harbour (292 MW) with the Hunts Bay (89 MW) remaining in operation to facilitate load growth. However, JPS stated that the current load forecast showed little to no growth in the near term. As a consequence, the EWI Plant, when commissioned, would have displaced the existing resources, both the Old Harbour units and the Hunts Bay facility. It would become necessary then for JPS to prepare a decommissioning and closure cost report for submission to the NEPA. JPS therefore saw it fitting, to include these costs in the JPS' Tariff Submission.

Additionally, for Hunts Bay, JPS looked at two options:

1. Closure of the unit in accordance with the OUR's requirement; and
2. Repowering of the unit by converting the fuel source to LNG.

JPS' proposal is for the detailed planning process for decommissioning of its plants once a PPA was signed and financial closure was reached for the new generation expansion.

12.2 OUR's Response

JPS' plant retirement plans were premised on the successful commissioning of the EWI Plant. The development of the EWI Plant was aborted prior to the conclusion of the rate review. However, there is still an imperative for a substantial quantity of new base-load generation and it is understood that this is being pursued by the GOJ. The OUR accepts that significant addition of new base-load generation capacity to the grid will necessitate the retirement of JPS' aged and inefficient base-load plants which may have costs implications.

If such generation capacity is committed to be added to the System within the price-cap period, an interim review of the rates may be required to take into account the cost impact of the new generation capacity and the treatment of costs associated with the retirement of the existing plants.

In the event that such generation capacity development is initiated, the Office, in consultation with JPS, will decide on an appropriate framework for addressing any possible request for rate adjustment.

SECTION II: - Stakeholders' Submissions on the JPS' Tariff Submission/Guaranteed and Overall Standards/Demand Projections

Chapter 13: Consumer Issues and Quality-of-Service Standards

In keeping with its statutory mandate to protect the interest of utility consumers, the OUR conducted public consultations as part of its tariff review process. The consultations are designed to provide an opportunity for discourse about the tariff application among all stakeholders. Seven public meetings were held across the island in the following parishes: Kinston & St. Andrew, St. Catherine, Manchester, St. Ann, St. James, Westmoreland and Portland. Prior to hosting the public meetings, JPS' Tariff Submission as well as a summary of the application were posted on the OUR's website. Also, media advertisements, flyers, town criers, and direct texting were some of the measures employed to sensitize the public to the rate application.

Additionally, JPS was afforded the opportunity to comment on the proposed changes to both the Guaranteed and Overall Standards. The feedback from the consultations as well as the extensive comments submitted by JPS has been taken into consideration in arriving at the Office's determinations.

13.1 Summary of Stakeholders' Concerns on the Tariff Application

13.1.1 Inability to Afford Increased Rates

Customers, both at the meetings and in the written submissions received, expressed the view that JPS' request for a tariff increase is unreasonable, given the current economic conditions. They lamented that the cost of the service is already high; therefore to request an increase, when most persons' salaries have remained unchanged for a number of years, is unconscionable. Additionally, they pointed out that any increase in the rates may result in an increased number of persons resorting to stealing.

Customers further suggested that JPS should include more energy from renewable sources as this will result in cost savings which will ultimately reduce the cost of providing electricity.

13.1.2 Proposed Changes to Rate Structure

JPS proposed to charge a lower rate for its customers with the highest usage (Rates 40 and 50 customers) as an incentive for them to remain on the grid. Residential customers were therefore interested in knowing and expressed concerns regarding the impact on their rates should these large customers ultimately leave the grid.

13.1.3 Electricity Theft

The issue of electricity theft also resonated as customers vehemently expressed the view that it is unreasonable for the company to request that they continue to bear the burden for stolen electricity. They implored the company to find ways to reduce and eliminate electricity theft. In their view, a reduction in electricity theft will result in a reduction in costs to the company and this could eventually be passed on to legitimate customers.

13.1.4 Late Payment Fee/Early Payment Initiative

Customers expressed the view that it is unreasonable for JPS to apply this charge when the main reason for late payments of bills might be affordability. They also took issue with the application of General Consumption Tax (GCT) to this charge.

13.1.5 Residential Advanced Metering Infrastructure (RAMI) System

Customers complained about a myriad of issues regarding the operations of the RAMI system. One of the issues most complained about relate to the frequent and prolonged interruptions in their electricity supply, which, in some instances last for several days. This disruption causes severe inconvenience to not only residential but commercial customers as well.

Customers also complained about receiving estimated bills for protracted periods and that they are not provided with the Customer Display Unit (CDU) upon installation of service with which to monitor their consumption. Some customers have reported that the CDUs they have received are inoperable. Additionally, customers reported that while they have entered into contracts with JPS, they are yet to be connected as the company has advised that there are no available boxes to which they can be connected.

13.1.6 Service Reliability

Customers, particularly in Mandeville – Manchester and St. Ann, complained about the frequency with which they experienced daily fluctuations in their power supply. They made allegations that this has resulted in damage to their equipment.

13.1.7 The Guaranteed Standards Scheme

Consumer concerns regarding quality of service are dealt with through the Guaranteed Standards Scheme (the GS Scheme). The GS Scheme for JPS was established in 2002 to ensure that the company meets minimum service levels to its customers. Prior to 2009, the standards were reviewed every five (5) years, to coincide with the rate review. However, based on requests received from customers for more frequent reviews, the OUR in its 2009 Determination Notice implemented mid-tariff reviews.

Presently, there are a total of eighteen (18) standards (seen in Table 13.11 below) which measure service delivery in the areas of: Access to Service, Investigation of Customer Complaints, Billing, Metering, Disconnection and Reconnection of Service.

Table 13.11: JPS' Guaranteed Standards 2012–2014

Code	Focus	Description	Performance Measure
EGS 1(a)	Access	Connection to Supply - New Installations	New service Installations within five (5) working days after establishment of contract
EGS 1(b)	Access	Connection to Supply - Simple Connections	Connections within four (4) working days after establishment of contract where supply and meter are already on premises
EGS 2(a)	Access	Complex Connection to supply	Between 30m and 100m of existing distribution line (i) estimate within ten (10) working days (ii) connection within thirty (30) working days after payment
EGS 2(b)	Access	Complex Connection to supply	Between 101m and 250m of existing distribution line (i) estimate within fifteen (15) working days (ii) connection within forty (40) working days after payment
EGS 3	Response to Emergency	Response to Emergency	Response to Emergency calls within five (5) hours – emergencies defined as broken wires, broken poles, fires
EGS 4	First Bill	Issue of First bill	Produce and dispatch first bill within forty (40) working days after service connection
EGS 5(a)	Complaints/ Queries	Acknowledgements	Acknowledge written queries within five (5) working days
EGS 5(b)	Complaints/ Queries	Investigations	Complete investigation within thirty (30) working days
EGS 5(c)	Complaints/ Queries	Investigations involving 3rd party	Complete investigation within sixty (60) working days if 3rd party involved
EGS 6	Reconnection	Reconnection after Payments of Overdue amounts	Reconnection within twenty-four (24) hours of payment of overdue amount and reconnection fee **Attracts automatic compensation**
EGS 7	Estimated Bills	Frequency of Meter reading	Should NOT be more than two (2) consecutive estimated bills (where company has access to meter).
EGS 8	Estimation of Consumption	Method of estimating consumption	An estimated bill should be based on the average of the last three (3) actual readings
EGS 9	Meter Replacement	Timeliness of Meter Replacement	Maximum of twenty (20) working days to replace meter after detection of fault which is not due to tampering by the customer **Attracts automatic compensation**
EGS 10	Billing Adjustments	Timeliness of adjustment to customer's account	Where necessary, customer must be billed for adjustment within three (3) months of identification of error, or subsequent to replacement of faulty meter

Code	Focus	Description	Performance Measure
EGS11	Disconnection	Wrongful Disconnection	Where the company disconnects a supply that has no overdue amount or is currently under investigation by the OUR or the company and only the disputed amount is in arrears. **Attracts automatic compensation**
EGS12	Reconnection	Reconnection after Wrongful disconnection	The company must restore a supply it wrongfully disconnects within five (5) hours. **Attracts automatic compensation**
EGS13	Meter	Meter change	JPS must ensure that a note is left at the premises and or utilize its text messaging service indicating the meter change including date of the change and meter readings at the time of change, reason for change and serial number of new meter
EGS14	Compensation	Making compensatory payments	Accounts should be credited within thirty (30) working days of verification of breach

13.1.8 Breaches of the Guaranteed Standards – JPS' Compliance Report

The review of the quarterly reports submitted by JPS on its performance on the Guaranteed Standards indicated that on average the company breached 12,000 standards on a quarterly basis, which attracted potential compensation of over $30,000,000. However, as a result of the low number of claims submitted, the actual amount paid out by JPS on average per quarter amounted to $1,200,000, of which approximately 85% is as a result of the compensation being automatically applied to customers' accounts.

13.1.8.1 OUR's Review

Since the implementation of the GS Scheme, the level of customer participation required to make it effective has been dismal.

In the first quarter of 2014, the OUR's National Consumer Survey confirmed the low level of participation by JPS' customers in the GS Scheme. The results of the consumer survey indicated that the level of customer awareness of the Guaranteed Standards was at 34%. Public education activities by the OUR will therefore have to be intensified around the Guaranteed Standards programme to increase the awareness level of customers.

Chapter 14: Guaranteed and Overall Standards

14.1 Summary of JPS' Proposals to Guaranteed and Overall Standards

The following represents JPS' proposed changes to the Guaranteed Standards Scheme.

14.1.1 Existing Standards

GS 1(a) and 1(b): Connection to Supply – New & Simple

- JPS proposed that EGS1 (a) and EGS1 (b) be combined into a single standard with a minimum performance standard of five (5) days to complete any new or simple connections.

EGS2 – Connections to Supply – Complex

- JPS proposed that under circumstances peculiar to a customer's location or requirement where connection within the standard may not be practicable, the company and the customer should be allowed the latitude to determine a mutually agreed schedule for connection by a specified date. In those instances, JPS would be liable to pay compensation if the connection is not completed by the agreed date.

EGS3 – Response to Emergency

- This standard be removed from the Guaranteed Standards and be included as an Overall Standard.

EGS 5a, b, c - Complaint Queries

- JPS proposed that EGS5 a, b & c be united into one standard to require that customer written queries are to be acknowledged, investigated and a response provided to the customer in thirty (30) days. Where a clearly identified 3rd party is involved the allowed time is sixty (60) days.

EGS7 – Frequency of Estimates

- The company proposed that it be allowed to return to the standard of billing customers on an actual reading in alternate months with bills based on estimates (based on the last three (3) actual readings) in the intervening months.

EGS10 – Billing Adjustments

- JPS recommended that the billing exception threshold be revised upward from the current levels of 30% for residential customers and 60% for commercial customers.

EGS13 – Meter Change

- JPS proposed that the method of informing customers of a meter change be expanded to include email notification in addition to the physical card currently used and text messages already allowed.

EGS14 – Compensation

- JPS recommended that the current performance standard be revised to compensation being paid (credited to customer accounts) within thirty-five (35) days or by the subsequent billing period after verification of the breach.

14.1.2 Compensation Mechanism

In light of its proposal to replace the customer charge with a network access charge, JPS proposed that the compensation for Rate 20 customers be $3,405.6 and $24,768 for Rates 40 and 50 customers.

In relation to the compensation mechanism, JPS proposed that:

1. Only an additional four (4) standards be converted to automatic in the 2014 rate review;
2. JPS and OUR review the performance against the standards at the inter-regulatory standards review due in 2016 to determine what, if any additional steps, are needed to increase the effectiveness of the standards; and
3. It will increase ex-gratia payments currently made to customers on non-automatic standards and report on these compensatory payments in its quarterly reports for consideration in the 2016 standards review.

14.1.3 Postponement of Additional and Automatic Standard

JPS reported that it will be conducting a major upgrade of its Customer Information System (CIS) which was scheduled to be completed in August 2014. The company claimed that the CIS is the heart of its operations and the primary system used to manage and report on the Guaranteed Standards. JPS therefore requested that the commencement date for any additional automatic standards for the new tariff period be delayed to June 2015 due to the challenges that are likely to occur with the system upgrade.

14.1.4 List of Exemptions and Exceptions

JPS proposed that a list of exemptions and exceptions be developed that will outline the circumstances under which the Guaranteed Standards will not be applicable or suspended.

14.1.5 OUR's Response – List of Exceptions and Exemptions

Whilst the Office is mindful that there may be circumstances that would warrant the suspension of the Guaranteed Standards, it is of the view that these circumstances should be restricted to those that are outside of the company's control and must be specific to individual standards. Accordingly, the Office will, in collaboration with JPS, develop a list of exceptions/exemptions to the standards within the first three (3) months of the effective date of this Determination Notice.

DETERMINATION 38

The Office has DETERMINED that a reasonable exceptions list will be developed in collaboration with JPS within three (3) months of the effective date of this Determination Notice.

14.2 OUR's Review of Existing Guaranteed Standards

In conducting this review, the Office has taken account of recommendations from JPS to amend some standards over the price cap period and submissions made during the stakeholders' consultation. These standards are amended as follows:

14.2.1 Review of EGS 1(a) and EGS 1(b)

14.2.1.1 Description and Performance Measure

EGS 1(a) and EGS 1(b)

- Description: Connection to Supply – New & Simple
- Performance Measure: JPS must complete new and simple connections within five (5) working days.

14.2.1.2 Office's Comments and Determination

The Office accepts JPS' proposal to combine EGS 1(a) and EGS 1(b) into one standard which requires that the company completes new and simple connections within five (5) working days. The Office has also noted the concerns of new customers, who are to be connected to the RAMI system, which include the delay in being connected as well as not being provided with the Customer Display Unit (CDU) in a timely manner. The Office is therefore including new service connections to the RAMI system in EGS 1, which is in conformity with JPS' stated 'Policy & Procedures Documentation: Residential Advanced Metering Infrastructure (RAMI)' that governs the operations of the RAMI system.

Additionally, the Office reminds JPS that where a meter is being transferred to effect a new supply, the company must conduct the relevant meter checks to ensure that same is working within the tolerances of commercial accuracy.

The Office determines that failure to complete new and simple connections within the specified five (5) working days will constitute an additional breach that will attract daily compensation. The additional compensation will be prorated on an hourly basis after the established time has elapsed. Therefore, after the initial five (5) working days have passed, JPS will pay an additional $1/24^{th}$ of the compensatory amount hourly, up to a maximum of eight (8) original breach periods.

14.2.2 Review of EGS 2(a) and EGS 2(b)

14.2.2.1 Description and Performance Measure

EGS 2(a)

- Description: Connection to Supply – Complex (between 30 and 100m of existing distribution line).

- Performance Measure: Estimate within ten (10) working days; connection within thirty (30) working days after payment.

EGS 2(b)

- Description: Connection to Supply – Complex (between 101 and 250m of existing distribution line).

- Performance Measure: Estimate within fifteen (15) working days; Connection within forty (40) working days after payment.

14.2.2.2 Office's Comment and Determination

JPS stated that it has no objection to the current standard being the default. However, the company has requested that in circumstances peculiar to a customer's location or requirement where connection within the standard may not be practicable, the company and the customer should be allowed the latitude to determine a mutually agreed schedule for connection by a specified date. In those instances, JPS would be liable to pay compensation if the connection is not completed by the agreed date which should be given in writing.

The Office has reviewed JPS' proposed change to EGS 2(a) and EGS 2(b) and is of the view that incorporating the change would lend ambiguity to the standard in respect to the completion timeline. It is the view of the Office that this ambiguity will make it increasingly challenging to collect data and report on its performance against this standard.

Furthermore, the Office has recognized that particularly in the last two (2) years, there has been a significant reduction in requests for this type of service. The Office is of the view that the downward trend - from 109 construction requests in 2009 to nine in 2014 - is likely to continue, suggesting that the company should be able to satisfy the requests received within the stipulated timeline.

The Office will therefore not incorporate JPS' proposal and maintain the existing standard. Additionally, where JPS fails to complete complex connections within the specified timelines (which should be given in writing), this will constitute an additional breach that will attract daily compensation. The additional compensation will be prorated on an hourly basis after the established time has elapsed. Therefore, after the respective thirty (30) and forty (40) working days have passed, JPS will pay an additional 1/24th of the compensatory amount hourly, up to a maximum of the eight original breach periods.

14.2.3 Review of EGS 3

14.2.3.1 Description and Performance Measure

EGS 3

- Description: Response to Emergency (localized situations such as broken wires, broken poles, fire, etc.)

- Performance Measure: Respond to emergency within five (5) hours.

14.2.3.2 Office's Comment and Determination

The Office has considered JPS' proposal to remove EGS3 from the GS Scheme and place it on the list of Overall Standards. The Office is however of the view that the emergency situations identified can have an adverse effect on the affected customers and should be treated with great urgency. It is also the Office's view that compensation should be paid when JPS does not respond within the specified timeline to an emergency situation.

The Office will therefore maintain this Standard under the GS Scheme with compensation being applicable to the affected customer/premises.

14.2.4 Review of EGS 4

14.2.4.1 Description and Performance Measure

EGS 4

- Description: Issue of First Bill

- Performance Measure: Produce and dispatch bill within forty (40) working days after service connection.

14.2.4.2 Office's Comments and Determination

JPS did not propose a change to this Standard. The Office has nevertheless reviewed it and has concluded that it will maintain this Standard as currently exists. However, the Office is of the view that customers should be provided with a bill based on an actual meter reading at the earliest possible time, as this will provide them with an opportunity to assess whether any anomalies exist at the premises that may require remedial action. Accordingly, the Office is also of the view that a bill based on actual meter reading must be produced and dispatched within the first two (2) billing periods for new connections.

14.2.5 Review of EGS 5(a), (b), (c)

14.2.5.1 Description and Performance Measure

EGS 5(a)

- Description: Acknowledgement
- Performance Measure: Acknowledge written queries within five (5) working days

EGS 5(b)

- Description: Investigations
- Performance Measure: Complete investigations within thirty (30) working days

EGS 5(c)

- Description: Investigations involving 3rd party
- Performance Measure: Complete investigations within sixty (60) working days if 3rd party involved

14.2.5.2 Office's Comment and Determination

With reference to JPS' proposed change to incorporate all three Standards into one, the Office is of the view that it is important to maintain the separation between acknowledgments of customers' written complaints from the investigation process. The Office views acknowledgement of customers' complaint as an important indicator to the customer that the correspondence has been received and will receive attention.

The Office also takes this opportunity to point out that investigation of customer complaints is not restricted by the medium through which the complaint was received. There is a breach of the

Standard if JPS does not complete an investigation of a customer's complaint within the specified time.

The Office however accepts JPS' proposal to incorporate EGS 5(b) and EGS 5(c) into one standard. The amended Standard will therefore be:

> *EGS 5(b): Investigations - Complete investigations and respond to customer within thirty (30) working days. Where investigation involves a 3rd party, same is to be completed within sixty (60) working days.*

14.2.6 Review of EGS 6

14.2.6.1 Description and Performance Measure

<u>EGS 6</u>

- Description: Reconnection After Payment of Overdue Amounts
- Performance Measure: Reconnection within twenty-four (24) hours of payment of overdue amounts.

14.2.6.2 Office's Comment and Determination

JPS did not propose a change to this Standard. The Office has nevertheless reviewed it and has concluded that it will maintain the reconnection timeline as currently exists. However, where a supply is not restored within the specified twenty-four (24)-hour period, each subsequent hour constitutes an additional breach which will attract compensation. The additional compensation will be prorated on an hourly basis after the established time has elapsed. Therefore, after the initial twenty-four (24)-hour period has passed, JPS will pay an additional $1/24^{th}$ of the compensatory amount hourly, up to the maximum eight (8) original breach periods.

14.2.7 Review of EGS 7

14.2.7.1 Description and Performance Measure

<u>EGS 7</u>

- Description: Frequency of Meter Reading
- Performance Measure: Should not be more than two (2) consecutive estimated bills where the company has access to the meter.

14.2.7.2 Office's Comment and Determination

The Office has noted JPS' proposal to revert to reading meters every other month (bi-monthly). The company stated that the request is in an effort to: (1) place itself in a position to develop and offer alternative billing solutions, such as budget billing, to its customers and, (2) pass on the cost savings from bi-monthly reading to its customers. The company also highlighted the significant number of potential penalties for breaches of this Standard, even with the average number of breaches being less than 2% over the review period.

The Office has considered the points raised by JPS in support of this request but has to balance these against the potential impact that reverting to bi-monthly readings will have on customers. Customers continue to express a lack of confidence in the accuracy of the bills produced by the company, in spite of JPS reporting that approximately 98% of bills are based on meter readings. While fewer readings are the international trend, the Office is of the view that in light of the high cost of electricity, customers will likely have more confidence in the accuracy of bills based on monthly actual readings. Additionally, customer feedback has indicated that more respondents preferred to receive bills based on monthly meter readings than those who wanted bi-monthly readings.

The Office has also noted in its deliberations that the impact of reverting to bi-monthly readings will not only affect the Guaranteed Standards but other policies that relate to meter readings such as the Back Billing Policy since the timelines for the specific clauses are predicated on the frequency of meter reading. It has also not escaped the Office's notice that in the high System loss environment in which JPS operates, it would be expected that more frequent meter readings should assist the company in the surveillance of its network.

The Office has therefore concluded that the benefits of monthly meter readings outweigh its cost at this time. As such, the Office will maintain the Standard as it currently exists.

The Office reminds JPS that an additional breach is committed for each third consecutive estimate that is produced and sent to the customer. Therefore, any consecutive estimate subsequent to the initial three constitutes an additional breach for which compensation is applicable. For clarity, every fourth, fifth, sixth, etc. consecutive estimate sent, constitutes a breach of the Guaranteed Standards.

14.2.8 Review of EGS 8

14.2.8.1 Description and Performance Measure

EGS 8

- Description: Method of Estimating Consumption
- Performance Measure: An estimated bill should be based on the average of the last three (3) actual readings – First six (6) bills of new accounts excepted.

14.2.8.2 Office’s Comment and Determination

JPS did not propose a change to this Standard. The Office has nevertheless reviewed it and has concluded that it will maintain this Standard as it currently exists.

14.2.9 Review of EGS 9

14.2.9.1 Description and Performance Measure

EGS9

- Description: Timeliness of Meter Replacement

- Performance Measure: maximum of twenty (20) working days to replace meter after detection of fault

14.2.9.2 Office’s Comment and Determination

JPS did not propose a change to this Standard. The Office has nevertheless reviewed it and has concluded that it will maintain this Standard as it currently exists.

14.2.10 Review of EGS 10

14.2.10.1 Description and Performance Measure

EGS10

- Description: Timeliness of Adjustment to Customer’s account

- Performance Measure: Where it becomes necessary, customer must be billed for adjustment within three (3) months of identification of error.

14.2.10.2 Office’s Comment and Determination

The Office notes JPS’ proposal to increase the billing exceptions threshold, from the current +/- 30% for residential and +/- 60% for commercial customers, to which this Standard is aligned. The company reported that on a monthly basis the current threshold generates a significant number of exceptions which when investigated, approximately 80% are verified to be accurate.

While the Office recognizes the concerns regarding the exceptions threshold, this issue will have to be addressed outside of this current Review. This Standard specifically relates to the timeliness within which adjustments are posted to customers’ account, which the Office will maintain as it currently exists.

14.2.11 Review of EGS 11

Description and Performance Measure

EGS 11

- Description: Wrongful Disconnection
- Performance Measure: Where the company disconnects an account which currently has no overdue amount or is currently under investigation by the OUR or JPS.

14.2.11.1 Office's Comment and Determination

JPS did not propose a change to this Standard. The Office has nevertheless reviewed it and has concluded that it will maintain this Standard as it currently exists with a clarification on its applicability. This Standard will include accounts that are disconnected for non-payment of the Late Payment Fee when an investigation is being conducted by JPS or the OUR.

14.2.12 Review of EGS 12

14.2.12.1 Description and Performance Measure

EGS12

- Description: Reconnection after Wrongful Disconnection
- Performance Measure: The company must restore a supply if wrongfully disconnected within five (5) hours.

14.2.12.2 Office's Comments and Determinations

JPS did not propose a change to this Standard. The Office has nevertheless reviewed it and has concluded that it will maintain the reconnection timeline as it currently exists. However, the Office also determines that every additional hour that passes without service being restored constitutes an additional breach which will attract hourly compensation. The additional compensation will be prorated on an hourly basis after the established time has elapsed. Therefore, after the initial five (5)-hour period has passed, JPS will pay an additional 1/5th of the compensatory amount hourly, up to the maximum eight (8) original breach periods.

Additional Matters Relating to Disconnection/Reconnection

The Office has noted JPS' request to impose a penalty on those customers who illegally reconnect without paying the requisite reconnection fee. The Office advises that in order for any such consideration to be made, it needs to be satisfied that JPS has a documented procedure in place that outlines the steps that are taken when effecting a reconnection exercise. This is critical in eliminating any ambiguity as to how the company, or its agents, conduct these exercises.

In addition, the Office is aware that JPS has disconnected electricity supply where the applicable grace period has not expired. On these occasions, the Office determines that the customer ought not to be billed the reconnection fee and is to be reconnected within twenty-four (24) hours of the disconnection.

14.2.13 Review of EGS 13

14.2.13.1 Description and Performance Measure

ESG 13

- Description: Meter Change
- Performance Measure: JPS must ensure that customers are notified of the change of meter. Notification must include date of the change, the meter readings at the time of change, reason for change and the serial number of the new meter.

14.2.13.2 Office's Comments and Determination

The Office notes JPS' recommendation to include email as an alternative method of notifying customers of the meter change. Having carefully considered all the scenarios relating to the methods used to notify customers, it is the view of the Office that this decision be left to JPS' discretion. However, JPS will need to include in its quarterly report to the Office, information on the number of meters changed for the reporting period.

This standard will therefore be amended as follows: *JPS must notify customers of a meter change within one (1) billing period of the change. The notification must include: the date of the change, the meter reading at the time of change, reason for change and the serial number of the new meter.*

14.2.14 Review of EGS 14

14.2.14.1 Description and Performance Measure

EGS 14

- Description: Compensation

- Performance Measure: Accounts should be credited within thirty (30) working days of breach

14.2.14.2 Office's Comment and Determination

Having considered the matter, the Office has determined that this Standard will be modified to reduce the period for paying compensation from thirty (30) working days to one (1) billing period in order to align the payment of compensation with the first billing period following the breach. The Office further notes that this Standard is applicable to all other breaches. For clarity, where there is a breach of any other standard and the relevant compensation is not paid within one (1) billing period, this also constitutes a breach of EGS 14 for which additional compensation is payable.

14.3 Implementation of a New Standard

In an effort to ensure that the Guaranteed Standards adequately address all relevant quality of service issues, the Office deems it necessary to introduce one (1) new Standard. The new Standard was developed based on complaints received from affected customers over the review period and at the public consultations. The new standard is:

14.3.1 Transitioning Existing Customers to RAMI System

With the implementation of the RAMI system during the 2009 - 2014 tariff period, the OUR's Consumer Affairs Unit received several complaints about the system. One issue relates to the delay in transitioning existing customers unto the RAMI system. As a result of this delay, customers experienced disruptions in their service as they are disconnected from the existing system and are not connected to the RAMI system in a timely manner, having satisfied all the company's requirements. Accordingly, this Standard is being implemented to incentivize JPS to conduct the transitioning process in a more timely and seamless manner.

The Office is of the view that all new connection applications must be treated in the same way as non-RAMI residents application in accordance with JPS' Terms & Conditions of Supply and as per the policies and procedures set out in JPS' Policy and Procedures Documentation RAMI (December 2010).

The Standard will be defined as follows:

Where all requirements have been satisfied on the part of the company and the customer, service to existing JPS customers must not be disrupted for more than three (3) hours to facilitate transition to the RAMI system.

In arriving at this decision, the Office has given consideration to the fact that the arrangements should be concluded on both JPS' and the customer's side of the network before the existing supply is disconnected, in which event, the exercise is simply one of effecting the switch-over.

14.3.2 Additional Matters Relating to Transitioning to RAMI System

The OUR is of the view that any additional cost to transfer a customer from a regular supply to RAMI should be borne by JPS as the customer has no choice in the type of installation to which he/she is connected by JPS. Furthermore, if a customer had previously undertaken the cost to have his/her premises certified by the GEI and JPS subsequently made the decision to change this customer to the RAMI system, the customer should not be required to undertake any further costs to facilitate JPS' decision. The cost for any additional work should be borne by JPS.

14.4 Compensation Mechanism

14.4.1 Implementation of Automatic Compensation

The Office has determined that in keeping with Condition 17 of the Licence, it will move towards automatic compensation for breaches of all Guaranteed Standards. While the Office has noted JPS' arguments against this decision, it reminds the company that making compensatory payments for breaches is merely one aspect of the incentive scheme. The other aspect serves to encourage the company to deliver quality service to its customers in every instance.

Furthermore, while the compensation mechanism which also includes the submission of customer claims has been the general practice, where the scheme exists, the Office has noted that at least one other utility regulator, within the region, is also on track to make the compensation for all Guaranteed Standards automatic. In its 2013 publication on the performance of the Trinidad and Tobago Electricity Commission (for the 2012 period), the Regulated Industries Commission (RIC) signalled its intention to make automatic at the upcoming review, the one remaining standard for which customers currently have to submit a claim.

Additionally, the Office is cognizant that the general practice to maintain a claim and automatic compensation mechanism, has been in an attempt to keep customers engaged in the process. However, JPS data on the administration of the Guaranteed Standards indicates that this approach has not been sufficiently effective. In this regard, the Office is of the view that it is prudent and reasonable to place greater weight on the company responsibility to deliver acceptable quality of service to its customers on a consistent basis. It is therefore the Office's view that making all compensations automatic will serve to incentivize JPS to achieve the objective of delivering consistently high quality service.

In making its decision to allow automatic compensation for breach of all the Guaranteed Standards, the Office took into consideration the fact that JPS is in the process of implementing an upgrade to its Customer Information System (CIS), which the company has advised will pose significant challenges to effecting the necessary system changes to facilitate immediate full automatic compensation. Accordingly, the implementation of all automatic compensation mechanisms will be carried out on a phased basis, with the first phase taking effect June 1, 2015. Accordingly, as at June 1, 2015, the number of standards that will attract automatic compensation will increase to eight (8).

The following four Guaranteed Standards will attract automatic compensation at the first phase:

- EGS 1: Connection to Supply – New and Simple Connections
- EGS 8: Estimation of Consumption
- EGS 10: Billing Adjustments
- EGS 14: Compensation

At the second phase, which shall take effect on January 1, 2016, the following four (4) standards will attract automatic compensation, thereby bringing the total automatic compensation standards to twelve (12).

Guaranteed Standards that will attract automatic compensation at the second phase:

- EGS 2a: Connection to supply - within 30 and 100 meters of the existing distribution line
- EGS 2b: Connection to Supply - within 101 and 250 meters of the existing distribution line
- EGS 4: First bill
- EGS 15: Transitioning Existing Customers to RAMI System

The final stage shall take effect on June 1, 2016 at which time all Guaranteed Standards shall attract automatic compensation.

At the 2017 Annual Tariff Adjustment, a comprehensive analysis of the effectiveness of the GS Scheme will be conducted by the OUR in collaboration with JPS.

The approved schedule that shall be applied by JPS for automatic compensation for breach of the Guaranteed Standard is summarized in Table 14.11.

Table 14.11: Approved Schedule for implementation of Automatic Compensation for the EGS

Code	Focus	Description	Performance Measure
EGS 1	Access	Connection to Supply - New & Simple Installations	New service installations within five (5) working days after establishment of contract, including connection to RAMI system. **Automatic Compensation as of June 1, 2015.**

Code	Focus	Description	Performance Measure
EGS 2(a)	Access	Complex Connection to supply	From 30m to 100m of existing distribution line: (i) estimate within ten (10) working days; (ii) connection within thirty (30) working days after payment. **Automatic Compensation as of January 1, 2016.**
EGS 2(b)	Access	Complex Connection to supply	From 101m to 250m of existing distribution line: (i) estimate within fifteen (15) working days; (ii) connection within forty (40) working days after payment. **Automatic Compensation as of January 1, 2016.**
EGS 3	Response to Emergency	Response to Emergency	Response to Emergency calls within five (5) hours – emergencies defined as: broken wires, broken poles, fires. **Automatic Compensation as of June 1, 2016.**
EGS 4	First Bill	Issue of First bill	Produce and dispatch first bill within forty (40) working days after service connection. **Automatic Compensation as of January 1, 2016.**
EGS 5(a)	Complaints/ Queries	Acknowledgements	Acknowledge written queries within five (5) working days. **Automatic Compensation as of June 1, 2016.**
EGS 5(b)	Complaints/ Queries	Investigations	Complete investigations and respond to customer within thirty (30) working days. Where investigations involve a 3rd party, same is to be completed within sixty (60) working days. **Automatic Compensation as of June 1, 2016.**

Code	Focus	Description	Performance Measure
EGS 6	Reconnection	Reconnection after Payments of Overdue amounts	Reconnection within twenty-four (24) hours of payment of overdue amount and reconnection fee. **Automatic Compensation**
EGS 7	Estimated Bills	Frequency of Meter reading	Should NOT be more than two (2) consecutive estimated bills (where company has access to meter). **Automatic Compensation as of June 1, 2016.**
EGS 8	Estimation of Consumption	Method of estimating consumption	An estimated bill should be based on the average of the last three (3) actual readings **Automatic Compensation as of June 1, 2015.**
EGS 9	Meter Replacement	Timeliness of Meter Replacement	Maximum of twenty (20) working days to replace meter after detection of fault which is not due to tampering by the customer. **Automatic Compensation**
EGS 10	Billing Adjustments	Timeliness of adjustment to customer's account	Where it becomes necessary, customer must be billed for adjustment within three (3) months of identification of error, or subsequent to replacement of faulty meter. **Automatic Compensation as of June 1, 2015.**
EGS 11	Disconnection	Wrongful Disconnection	Where the company disconnects a supply that has no overdue amount or is currently under investigation by the OUR or the company and only the disputed amount is in arrears. **Automatic & Special Compensation**
EGS12	Reconnection	Reconnection after Wrongful disconnection	The company must restore a supply it wrongfully disconnects within five (5) hours. **Automatic & Special Compensation**

Code	Focus	Description	Performance Measure
EGS13	Meter	Meter change	JPS must notify customers of a meter change within one (1) billing period of the change. The notification must include: the date of the change, the meter readings at the time of change, reason for change and serial number of new meter. **Automatic Compensation as of January 1, 2016.**
EGS 14	Compensation	Making compensatory payments	Accounts should be credited within one (1) billing period of verification of breach. **Automatic Compensation as of June 1, 2015.**
ESG 15	Service Disruption	Transitioning Existing Customers to RAMI System	Where all requirements have been satisfied on the part of the company and the customer, service to existing JPS customers must not be disrupted for more than three (3) hours to facilitate transition to the RAMI system. **Automatic Compensation as of January 1, 2016.**

14.4.2 Additional Changes to the Compensation Mechanism

In addition to its decision for all standards to attract automatic compensation, the Office is of the view that further changes to the mechanism is needed to further incentivize the company to continue to improve on its performance, thereby reducing the instances of inconvenience to the customer.

The Office notes and commends JPS for the efforts made to reduce the number of breaches committed by 25% during this review period when compared with the 2004-2009 period. This reduction has resulted in the company attaining a performance average of approximately 90%. However, despite this performance improvement, the evidence from customer complaints/appeals submitted to the Office is that there are still a number of instances in which breaches are not being addressed within the established timeline. Furthermore, in some instances the breach may continue for a prolonged period whereas compensation is only payable up to six (6) periods of the breach occurring. The Office is of the view that every effort must be made to reduce the inconvenience to the customer and hereby determines the following, which is deemed to serve as an incentive to remedy breaches within the shortest time:

14.4.2.1 Cap Period for Breaches

Resulting from the OUR's review of the Guaranteed Standards, the Office **DETERMINES** that the period in which compensation for a breach will be applicable shall be increased from six (6) to eight (8) periods. For clarity, where a breach is committed and is not remedied within the established timeline, then the compensation shall be payable for up to eight periods of the breach occurring.

DETERMINATION 39

Breaches of the Guaranteed Standards by JPS shall attract compensatory payments up to eight (8) periods.

14.4.2.2 Increased Breach Periods and Compensation for EGS 1, EGS 2(a) & 2(b), EGS 6 and EGS 12

Four Guaranteed Standards have been identified for shortened periods of breaches after the established time has elapsed. The selected standards focus on the critical areas of access and connectivity to supply which can result in increased inconvenience to the customer should there be any undue delay in remedying such a breach. Accordingly, the Office **DETERMINES** as follows:

DETERMINATION 40

Additional compensation will apply to these Standards as follows:

- **EGS 1: additional compensation will be prorated on an hourly basis after the established period has elapsed. Therefore, after the initial five (5) working days have passed, JPS will pay an additional 1/24th of the compensatory amount hourly, up to the maximum eight original breach periods.**

- **EGS 2(a) & 2(b): additional compensation will be prorated on an hourly basis after the established period has elapsed. Therefore, after the respective thirty (30) and forty (40) working days have passed, JPS will pay an additional 1/24th of the compensatory amount hourly up to the maximum eight original breach periods.**

- **EGS 6: additional compensation will be prorated on an hourly basis after the established time has elapsed. Therefore, after the initial twenty four (24)-hour period has passed, JPS will pay an additional 1/24th of the compensatory amount hourly, up to the maximum eight original breach periods.**

- **EGS 12: additional compensation will be prorated on an hourly basis after the established time has elapsed. Therefore, after the initial five (5)-hour period has passed, JPS will pay an additional 1/5th of the compensatory amount, up to the maximum eight periods.**

Notably, the practice to reduce the breach periods for some standards is not unique to Jamaica, as similar provisions are included in the Guaranteed Standards for Barbados Light & Power Company Ltd. (BL&P) and for the electricity providers in the UK as determined by Ofgem, the regulator. In these jurisdictions, specific standards incur additional hourly breaches for which compensation is applicable.

DETERMINATION 41

The Office further determines that these additional changes to the Guaranteed Standards set forth in Determination 39 shall take effect on January 7, 2015.

The Office has also noted JPS' proposal for compensation for a breach of the Guaranteed Standard to be set at $3,405.60 for Rate 20 customers and $24,768 for Rates 40 and 50 customers. However, JPS has provided no basis on which these proposed rates were determined. Accordingly, the Office **DETERMINES** as follows:

DETERMINATION 42

The Office will retain its methodology for computing compensation as follows:

General Compensation – this does not include compensation for wrongful disconnection

- **Residential Customers – a breach of a standard will result in compensation equal to the reconnection fee**

- **Commercial Customers – a breach of the standard will remain at four (4) times the customer charge**

Compensation for Wrongful Disconnection (Special Compensation)

- **Compensation for wrongful disconnection will remain at two (2) times the reconnection fee for residential customers and five (5) times the network access/customer charge for commercial customers.**

- **Reconnection after wrongful disconnection (when breached) will remain at two (2) times the reconnection fee for residential customers and five (5) times the network access/customer charge for commercial customers.**

14.5 Review of the Guaranteed Standards

The Office will maintain its mid-tariff review of the GS Scheme which will examine:

- whether new standards need to be introduced
- whether existing performance measures need to be modified
- measures to improve on the effectiveness of the GS Scheme

14.6 Reporting Requirements

The Office requires that JPS submits quarterly performance reports on its compliance with each Guaranteed Standard. The report should include an appendix which provides details on the number of breaches attracting automatic compensation, the affected accounts and the credits applied. The performance report must be delivered within ten (10) working days after the reporting period.

14.7 Additional Quality of Service Issues

The Office has identified the following additional quality of service issues that will be addressed through the development of new policy directives as well as to review and revise existing protocols and procedures:

14.8 Service Level Agreement

During the review period, October 2009 to December 2013, concerns were expressed by the OUR to JPS about the timeliness with which requested information is provided to OUR regarding its investigation of customers' appeals. A review conducted by the OUR indicates that only 63% of the information requested by the OUR was received within the agreed period.

In an effort to encourage JPS to improve its responsiveness to requests for information, the OUR established a Service Level Agreement (SLA), which was signed on June 25, 2014. The SLA outlines the requirements for both parties along with the specified timelines within which requested information is to be provided.

14.9 Prepaid Metering System

JPS has proposed to introduce a Pre-paid Metering System. The Office has noted however that provisions for such a system are not included in its existing Terms and Conditions of Service. JPS is therefore required, prior to its general introduction, to submit to the Office the Terms and Conditions of Service that will govern the operations of its Pre-paid Metering System.

Additionally, in anticipation of the introduction of this service and in an effort to ensure that customers who opt to migrate to JPS' Pre-paid Metering System continue to receive quality of service at an acceptable level, the Office has **DETERMINED** the following Guaranteed Standards for this service:

DETERMINATION 43

JPS' Pre-paid Metering Guaranteed Standards

Code	Focus	Description	Performance Measure
EPMS 1	**Service Connection**	**Transitioning Existing Customers to Pre-paid Metering System**	**Transition to the pre-paid metering service must be completed within fifteen (15) days of establishment of contract.**
EPMS 2	**Service Disruption**	**Transitioning Existing Customers to Pre-paid Metering System**	**Except where there is the need for the premises to be re-certified by the GEI, there should be no disruption in customer's service.**

14.10 Policies and Procedures for Review

The Office has noted that billing-related issues, which stand at 54% of customers' complaints was the main cause for JPS' customer-related contact with the OUR. The Office will therefore be conducting reviews on the following policies and procedures to ensure that they adequately address the following concerns raised:

14.10.1 RAMI System

Given expressed concerns about the RAMI system, the Office will in consultation with JPS and within the first three (3) months of the effective date of this Determination Notice, conduct a review of the existing protocol. This review will seek to ensure that customers connected to the system are provided with the same quality of service as non-RAMI customers.

14.10.2 Electricity Meter Testing Protocol

In keeping with the provisions of the existing policy, a revision of the Electricity Meter Testing Protocol will be conducted within the first six (6) months of the date of this Determination Notice. This review will ensure that the Bureau of Standards Jamaica will continue to be the relevant authority to conduct independent tests on JPS' meters.

14.10.3 Guidelines for the Conduct of Meter Inspections and Audits

The Office has noted the increase in the number of complaints that were received during the review period relating to incidents of illegal abstraction of electricity, specifically through meter gear change and by-pass. The Office will therefore within the first six (6) months of the effective date of this Determination Notice conduct a review of the procedure that governs the activities of JPS in its investigations of these matters.

14.11 JPS' Overall Standards 2014 – 2019

The Overall Standards remain unchanged for the tariff period 2014-2019.

Code	Standard	Units	July 2014 – May 2019
EOS 1	No less than 48 hours prior notice of planned outages	Percentage of planned outages for which at least forty-eight hours advance notice is provided	100%
EOS 2	Percentage of line faults repaired within a specified period of that fault being reported	Urban – 48 hrs Rural - 96 Hrs	100% 100%
EOS 3	System Average Interruption Frequency Index (SAIFI)	Frequency of interruptions in service	To be set annually
EOS 4	System Average Interruption Duration Index (SAIDI)	Duration of interruption in service	To be set annually
EOS 5	Customer Average Interruption Duration Index (CAIDI)	Average time to restore service to average customer per sustained interruption	To be set annually
EOS 6	Frequency of meter reading	Percentage of meters read within time specified in the Licensee's billing cycle	99%
EOS 7(a)	Frequency of meter testing	Percentage of rates 40 and 50 meters tested for accuracy annually	50%

Code	Standard	Units	July 2014 – May 2019
EOS 7(b)	Frequency of meter testing	Percentage of other rate categories of customers meters tested for accuracy annually	7.50%
EOS 8	Billing Punctuality	98% of all bills to be mailed within specified time after meter is read	5 working days
EOS 9	Restoration of service after unplanned (forced) outages on the distribution system	Percentage of customer's supplies to be restored within 24 hours of forced outage in Rural and Urban areas	98%
EOS 10	Responsiveness of call centre representatives	Percentage of calls answered within 20 seconds	90%
EOS 11	Effectiveness of call centre representatives	Percentage of complaints resolved at first point of contact	To be set
EOS 12	Effectiveness of street lighting repairs	Percentage of all street lighting complaints resolved within 14 days	99%

Chapter 15: Demand Projections

15.1 Introduction

The sales demand projection is developed to determine the billing determinant for the tariff review period 2014 - 2019. This billing determinant is used to calculate the average base rate of electricity based on the determined Revenue Requirements. This average base rate is determined by dividing the determined revenue requirement by the billing determinant. The billing determinant is derived and is determined from the Sales Demand Forecast.

This section outlines the OUR's approach for developing the Sales Demand projections that incorporates the regulatory period 2014 - 2019. It describes the approach and assumptions used to build the model.

15.2 Modelling Approach

15.2.1 JPS' Approach

JPS posited that the first step in forecasting JPS' sales of electricity was building a baseline model that projects sales based on the assumption that historic trends will be continued in the future. JPS further posited that the baseline sales derived from the historical trend analysis is adjusted for variations in sales in each rate class due to regulatory, managerial, or technological changes that are expected would change the historical trend. In particular, JPS modelled the impact of efforts to promote energy efficiency and reduce consumption of electricity. JPS also considered the impact of the planned introduction of natural gas in JPS' energy generation mix on electricity sales. Furthermore, JPS also analyzed the impact of recently introduced OUR initiatives such as Net Billing and the Wheeling schedule.

15.2.2 OUR's Approach

The OUR holds the view that the modelling approach used by JPS is very similar to the approach outlined herein. The assumptions regarding the forecast model are, however, different for the most part.

The methodology used to derive the OUR demand forecast sought to define electricity consumption as a function of the growth in the average number of customers and growth in the level of average usage per customer. These are defined as a function of socio-economic and electric system variables with different models developed for each rate class according to their particular nature and usage pattern. Historical socio-economic data that are postulated as relevant sales demand drivers were analyzed using trend analysis as well as Econometric modelling technique by applying the statistical package - EVIEWS Software, which is known to provide robust regression and time series estimates.

A base sales demand projection is derived and measured against the impact for regulatory, technological and actual/potential system changes. Specifically, the OUR assessed the impact of the recently introduced Net Billing Programme, Non-Technical Losses initiative and the impending Wheeling implementation and estimated the adjustments to the base forecast for the years covering the tariff period 2104 - 2019.

The econometric relationships employed by the OUR internalize the influence among other variables, price, income, population, household size and policy effects while the adjustment factors considered provide an accounting plane for aggregating the impact, if any, these externalities would have on the base sales.

15.2.2.1 Factors/Parameters acting as the Drivers behind Customer and Energy Demand.

In seeking to derive the demand forecast, an econometric model is developed to estimate electricity demand over time as driven by the increases in the average number of customers and average use per customer across each electricity rate class. The output for each class is then aggregated to determine total sales/demand for the electricity system. Notably, the model specification for each rate class is based on certain assumptions of both economic and non-economic explanatory variables included in each model. These assumptions are based on historic, *a priori*, as well as macro-economic expectations and projections.

An array of possible drivers of electricity demand is considered when deriving the demand forecast. These include several economic and demographic factors as well as electric system variables. The basis for incorporating these parameters is to ensure that the factors which have influenced customer numbers and average energy use (for each rate class) in the past and that are likely to affect demand in the future, are captured and their responsiveness measured. Any set of variables commensurate with each model are viable for testing and inclusion. However, only those with an historical, measurable and available time series are suited for use in each model specification.

15.2.2.2 Economic and Demographic Drivers

Economic drivers look at various economic indicators and activities which by way of theory and/or practice may potentially affect changes in rate class demand. These include variables such as gross domestic product (GDP), disposable income, interest rate, exchange rate, inflation, tourism arrivals and length of stay (hotel). The main driver often referred to tends to be GDP, however all determinants are modelled and specified (depending on the rate class being represented) for estimating average customer numbers and average energy use per customer.

Demographic drivers look at the nature and characteristics of the society in terms of the population (both mean and urban) and housing distribution as a measure of how energy demand is likely to be affected.

15.2.2.3 Electric System Drivers

Factors which affect the responsiveness of demand such as price and alternative electricity sources are assessed to determine their impact on changes in energy usage. The variables used included electricity prices for each rate class and LPG prices.

15.2.2.4 Residential Service Class (Rate 10)

The residential service class demand forecast is a projection based on the estimates and gross values from the models of both the average number of rate 10 customers and average usage per Rate 10 customer. For the former, the following variables were used as determinants:

1. Mean population
2. Household size

The determinants arise from the implication that the population is an indication of the total number of persons using electricity as its source of residential lighting. Meanwhile, the household size (average number of persons in each household) is indicative of the number of households that are JPS residential customers. Both explanatory variables were projected to have a potentially significant effect on changes in the average number of residential customers.

The average use per residential customer is given by the annual megawatt hour (MWh) of electricity consumption per Rate 10 customer. The determinants used for the average usage per customer model were:

1. Real per capita disposable income
2. Real Rate 10 electricity price ($/kwh)
3. Real LPG price (J$/litre)*

These determinants were selected based on economic theory which suggests that residential consumption pattern is a result of household choices, given disposable income and the price of a commodity demanded. The implication is that households will only demand and use the levels of a commodity that can be afforded given the price of the commodity and the price of substitute commodities (in this case liquid petroleum gas - LPG). **Real LPG price was however dropped from the model because of statistical insignificance.**

15.2.2.5 General Service Class (Rate 20)

The general service class consists of non-residential, small commercial/industrial businesses which demand under 25 kilovolt-amperes (kVA) of electricity. This class spans a diverse and heterogeneous set of businesses which range from service entities such as banks, hairdressing/ barber shops, small hotels and restaurants to non-profit and GOJ entities such as hospitals, schools and churches as well as general stores, which include pharmacies and gas stations.

The demand forecast for this rate class is also based on the estimates and gross values from the models of both the average number of Rate 20 customers and average usage per Rate 20 customers. The nature of this service class implies that several variables may possibly explain both components from which electricity demand is determined. To explain the average number of customers, the following variables were used:

1. Urban population*
2. Real GDP per capita
3. Net interest rate (loans)
4. Exchange rate

Economic theory implies that, *inter alia*, these variables should affect the level of establishment and growth in businesses overtime. The stipulated variables are believed to either facilitate or inhibit the local business environment and therefore their projections should help to explain changes in the number of general service customers. Of note, **urban population was dropped from the model because of statistical insignificance when included.**

The average use per general service rate class customer is given by the annual megawatt hour (MWh) consumption per Rate 20 customer. The explanatory variables are selected mainly given the premise that businesses are established and sustainable based on economic conditions.

Therefore the determinants for the average usage per Rate 20 customers included:

1. Urban population*
2. Real Rate 20 electricity price ($/kwh)
3. Average exchange rate*

For this model: urban population and average exchange rate were dropped because of statistical insignificance. Based on diagnostic testing once these variables were removed, a first order auto-regressive (AR) or moving average term was included in order to improve the goodness of fit of the model.

15.2.2.6 Large Commercial Class (Rate 40)

This service class consists of medium to large commercial and industrial customers with electricity demand of over 25 kilovolt-amperes (kVA). The number of Rate 40 customers has been influenced by class reclassification, particularly between this and the Rate 50 service class. As such both the projection and estimates of the changes in the average number and usage per customer are subject to errors which in the case of the latter have been corrected for using the econometric auto-regressive process at order one (1).

The determinants for the average number of rate 40 customers included:

1. Real GDP per capita*

2. Net interest rate (loans)
3. Average exchange rate
4. Average annual inflation rate*
5. Real per capita disposable income*

Real GDP per capita, average annual inflation rate and real per capita disposable income were dropped because of statistical insignificance. Based on diagnostic testing, once these variables were removed, a first order auto-regressive (AR) or moving average term was also included in order to improve the goodness of fit of the model.

The projected average usage per rate 40 customers was derived based on similar economic theory as that assumed in selecting the determinants of Rate 20 usages. The dependent variable was derived by dividing the total annual Rate 40 electricity sales by the average annual number of large commercial service class customers. Proposed independent variables including urban population were assessed but only the following were selected for a model determination:

1. Tourist stopover arrivals
2. Real Rate 40 electricity price ($/kwh)*
3. Average length of stay in hotels
4. Average exchange rate

Rate 40 electricity price was dropped because of statistical insignificance.

15.2.2.7 Large Industrial Class (Rate 50)

The large industrial service class represents large industrial customers as well as big hotels with demand of over 25 kilovolt-amperes (kVA). The Rate 50 demand forecast is projected based on a model specification which considers variables influencing the growth in number of customers and their average use. The determinants of the average number of Rate 50 customers also depended on economic conditions, which included:

1. Real GDP per capita
2. Net interest rate (loans)*
3. Average exchange rate

Of note, net interest rate was dropped because of statistical insignificance.

In terms of the average use per Rate 50 customers, the dependent variable was obtained by dividing the total annual Rate 50 electricity sales by the average annual number of large industrial class customers. Both urban population and the real price of electricity were selected as likely determinants which may predict electricity demand for the service class.

15.2.2.8 Street Lighting and Municipalities (Rate 60)

The demand forecast for the Rate 60 service class is based solely on average usage. Therefore, the projection was executed somewhat differently, whereby an overall sales model was developed with mean population, urban population and household size used as explanatory variables. However, **urban population and household size were dropped from the model because of statistical insignificance**.

1. **Comparison of driver relationships and their relevance for historical and forecasted demand**

Table 15.21 below shows the model output depicting the historical driver relationships for each rate class for the number of customers' model. The relevance of these variables as drivers for demand over the 1982-2013 period has been supported by econometric assessment of their explanatory power. Table 15.21 shows those economic and demographic variables with statistical significance at the 95% confidence level. In addition, Table 15.22 below shows the driver relationships established in the sales per customer models also at the 95% confidence level. Where statistical significance is found, the inference may therefore be drawn that each such variable is instrumental in explaining changes in energy demand and are indicators of possible relevance in forecasting future demand. Statistically, significant variables are therefore included in the model for forecasting demand, whilst those that were not statistically significant were excluded as explanatory factors for forecasting demand.

Table 15.21: Number of Customer Models

Explanatory	Rate 10	Rate 20	Rate 40	Rate 50	Rate 60
Mean population	3.4487	-	-	-	-
	0.0000*				
Household size	-0.8874	-	-	-	-
	0.0047*				
Real disposable		-	0.1990	-	-
per capita			0.2296		
Real electricity	-	-	-	-	-
LPG price	-	-	-	-	-
Urban population	-		-	-	-
Net interest rate	-	-0.2460	-0.2568	-	-
		0.0000*	0.0378*		
Exchange rate	-	0.2056	0.1696	0.4771	-
		0.0000*	0.0001*	0.0000*	
Real GDP per capita	-	1.1607	-	1.2966	-
		0.0000*	-	0.0496	
Inflation rate	-		-	-	-
Tourist stopover	-	-	-	-	-
Average length of	-	-	-	-	-
Constant	-36.8717	4.4630	4.5069	-3.1179	-
	0.0004*	0.0001*	0.0006*	0.2461	
AR(1)			0.6659 0.0001*		-

* denotes statistically significant probability values at the 95% confidence level

Table 15.22: Average Use (Sales) per Customer Models

Explanatory	Rate 10	Rate 20	Rate 40	Rate 50	Rate 60
Mean population	-	-	-	-	5.1456
					0.0000*
Household size	-	-	-	-	-
					-
Real disposable	0.3430	-	-	-	-
per capita	0.0000*				
Real electricity	-0.2490	-0.0878	0.1446	-0.1640	-
	0.0002*	0.0074*	0.0737	0.0435	
LPG price	-	-	-	-	-
Urban population	-	-	-	-1.3288	-
		-		0.0000*	-
Net interest rate	-	-	-	-	-
Exchange rate	-	-	-0.2444	-	-
			0.0001*		
Real GDP per	-	-	-	-	-
Inflation rate	-	-	-	-	-
Tourist stopover	-	-	0.8095	-	-
			0.0000*		
Average length of	-	-	0.8586	-	-
			0.0086		
Constant	-2.4514	2.3103	-6.1178	27.5013	-64.8679
	0.0000*	0.0000*	0.0031*	0.0000*	0.0000*
AR(1)		0.4595 0.0000*			

* denotes statistically significant probability values at the 95% confidence level

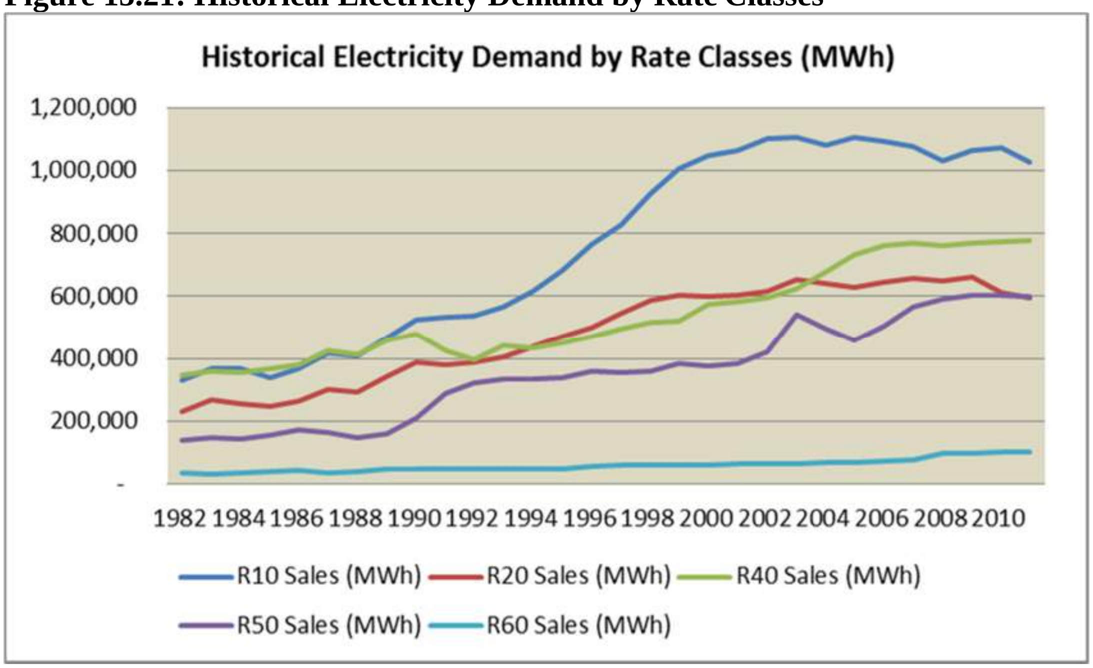
Having used the parameter elasticities to project demand over the 2014-2019 period, the contribution to base sales is depicted in Table 15.23 below.

Table 15.23: Contribution to Base Sales by Rate Class

Year	R10 Sales (MWh)	R20 Sales (MWh)	R40 Sales (MWh)	R50 Sales (MWh)	R60 Sales (MWh)	Base Sales (MWh)	Base Sales Growth Rate	Adjustment based on Externalities	Adjusted Base sales	Growth Rate
2008	1,032,182	650,424	759,739	590,569	96,973	3,129,887	-0.7%	-	3,129,887	-0.66%
2009	1,091,900	670,000	777,600	594,600	97,300	3,231,400	3.2%	-	3,231,400	3.24%
2010	1,107,000	664,600	745,700	602,200	102,200	3,221,700	-0.3%	-	3,221,700	-0.30%
2011	1,051,200	634,900	771,200	607,300	97,900	3,162,500	-1.8%	-	3,162,500	-1.84%
2012	1,025,100	600,501	765,000	609,200	99,100	3,098,901	-2.0%	-	3,098,901	-2.01%
2013	986,351	586,809	766,082	599,193	99,998	3,038,434	-2.0%	-	3,038,434	-1.95%
Average Sales									3,147,137	
2014	995,684	553,424	721,159	612,587	102,058	2,984,913	-1.8%	-	2,984,913	-1.76%
2015	1,013,187	568,949	724,259	611,769	104,035	3,022,198	1.9%	-	3,022,198	1.91%
2016	1,036,179	584,538	727,961	630,501	105,930	3,085,110	2.1%	-	3,085,110	2.06%
2017	1,056,740	606,301	732,232	647,980	107,745	3,150,999	2.1%	-	3,150,999	2.12%
2018	1,074,585	628,472	737,041	669,352	109,481	3,218,932	2.1%	-	3,218,932	2.14%
2019	1,110,725	652,400	742,361	692,133	111,139	3,308,758	2.8%	-	3,308,758	2.77%
Average Sales									3,128,485	

Over the 1982–2013 period, base sales were attributable mainly to the growth in residential and large industrial rate classes, which reflected compounded average annual growth rates of 4.01% and 5.19% respectively (see Figure 15.21 below).

Figure 15.21: Historical Electricity Demand by Rate Classes



The growth rate for actual energy sales for the 2009–2014 price cap period shows relative declines and the energy sales for the period averages 3,147 GWh. By comparison the projected average energy sales for the price cap period is 3,128.4 GWh (see Table 15.23 above).

2. **The factors expected to have significant impact on the various rate class demand projections.**

The explanatory variables in the specified models are based on certain assumptions and projections. Critical variables include, but are not limited to, real GDP, real per capita disposable income, population growth, real electricity price and the inflation rate (used to deflate nominal prices). Of particular note, is the change in economic and other circumstances which influence these (and other parameters) and their outlook going forward.

15.2.3 Economic price assumptions

The foregoing indicated that several economic and other variables were used to build models for electricity demand determination. By virtue of the econometric modelling techniques applied, the historical driver relationships have enabled the forecast results in Table 15.23 above.

The assumptions for Gross Domestic Product (GDP) were predicated on projections in the Vision 2030 Plan developed by the PIOJ. The Plan projected economic recovery after the economic decline in the 2008/2009 period is for GDP to stand at 3% by 2012 and stabilize at 5% through 2015 - 2030. However, the actual realized value in 2012 was -0.30% with a preliminary (not yet realized) estimate for 2013 of 0.2%. This had the effect of a downward pull in demand. The OUR assumed an average 1.5% growth in GDP over the 2014 - 2019 period and believes this assumption is consistent with the IMF programme being implemented.

Additionally, the OUR's forecast assumption is for the real average price of electricity to hold constant over the period 2014 – 2019 notwithstanding the delayed time schedule of new Generation technology options. The OUR is of the view that given the delicate balance between higher real average price of electricity and larger customers coming off the JPS grid, it is imperative that the nominal average price increases over the period do not exceed inflation. If this should occur then it is likely the start of a vicious cycle of continuous price increases and unsustainable revenues.

15.2.3.1 Forecasting the impact of new technologies and Policy Programmes/Initiatives

The forecasting process took into account effects of new technologies that may be in use over the 2014 – 2019 price cap regulatory period on the usage, efficiency, and losses of electricity sales.

JPS identified and the OUR concurred that there are four such factors:

- Addition of new technology generation capacity
- Net Billing Programme
- Wheeling Framework

- Non-Technical Losses

In order to assess the impact, classical techniques are not applicable here. A high degree of complex technical input into the decision process is required. Based on data available both objective and subjective methods are employed.

15.2.4 Addition of New technology - Generation Capacity

The OUR carried out analyses to determine the overall tariff impact[35] of the proposed 381 MW combined cycle natural gas-fired plant, and the 78 MW of renewable projects, taking into account overall costs of production including transmission expansion costs. The analyses provided tariff reduction impact and time schedule of tariff reduction based on the timing and cost characteristics of the projects added.

[36]<u>Scenario 1: 78 MW of renewable projects added in January 2016, no 381 MW project</u>

- The projected tariff in 2016 will be reduced by 0.33c/kWh or 0.97% due to the addition of the 78 MW of renewable projects.

[37]<u>Scenario 2: 381 MW CC plant operating capacity factor: 85%. Losses in 2017: 26.64%</u>

- The tariff is projected to be reduced from US35.34 c/kWh in 2013 to US28.30 c/kWh in 2017, a reduction of 19.9%.

[38]<u>Scenario 3: 381 MW natural gas fired combined cycle (CC) plant added in January 2017 and 78 MW of renewable projects added in January 2016,</u>

- <u>381 MW CC plant operating capacity factor: 85%. Losses in 2017: 22.5%</u>

  The tariff is projected to be reduced from US 35.34 c/kWh in 2013 to US 27.69 c/kWh in 2017, a reduction of 21.64%.

Of the three scenarios outlined above, only scenario 1 is expected to impact the base sales forecast for the regulatory period 2014 – 2019. This is so since new development with respect to the 381 MW CC Plant would have moved the time schedule for implementation and hence the time schedule of tariff reduction beyond the tariff review period.

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[35] OUR commissioned study - tariff impact of new 381 mw base load & 78 mw renewable generating plants, march 2014
[36] ibid
[37] ibid
[38] ibid

The tariff reduction impact of 0.97% due to the addition of the 78 MW of renewable projects at the end of 2016 is presented in Table 15.24 below. This is simulated by reducing the price variables in the econometric model by 0.97%. The result is as shown in Table 15.24 below.

Table 15.24: Impact of RE Projects on Base Sales

Year	Base Sales (MWh)	Base Sales Growth Rate	Adjustment based on Tariff reduction Impact of 0.97% from addition of 78 MW Renewables 2016	Adjusted Base sales	Growth Rate
2014	2,984,913	-1.8%	-	2,984,913	-1.76%
2015	3,022,198	1.9%	-	3,022,198	1.91%
2016	3,085,110	2.1%	-	3,085,110	2.06%
2017	3,150,999	2.1%	**2,140.1**	3,153,139	2.12%
2018	3,218,932	2.1%	**2,197.9**	3,221,129	2.14%
2019	3,308,758	2.8%	**2,302.3**	3,311,060	2.77%
				3,129,592	

15.2.5 Net Billing Program

Based on net billing data[39] available, applications received and programme profiles as of May 5, 2014 are as indicated in Table 15.25 below:

Table 15.25: Status Data on Net Billing Pilot Programme

i. Total Net Billing applications: 206
ii. Applicants commissioned and grid-tied: 52
iii. Percentage of applicants grid connected to date: 25%
iv. Ratio of residential to commercial applicants: Approx. 50% - 50%
v. Aggregate capacity of all applications: 3.5MW over the two years pilot
vi. Aggregate residential applicants capacity: 0.6MW over the two years pilot
vii. Aggregate commercial applicants capacity: 2.9MW over the two years pilot
viii. Aggregate connected applicants capacity: ≥ 1MW

If all the data represented in Table 15.25 for the Net Billing Pilot programme hold true for the forecast period, it could be assumed that the annual aggregate connected capacity of all applicants is 1.75 MW instead of the ≥ 1 MW implemented in the pilot programme over two years. The

[39] Net billing pilot programme report to OUR June 9, 2014

assumption is based on the view of the OUR that JPS needs to move more aggressively in the connection of applicants.

Table 15.26 below shows the annual potential energy Sales reduction from Net Billing.

Table15.26: Projected Energy Sales reduction from Net Billing

Year	Annual Capacity Uptake (MW)	Potential Energy Sales reduction from Solar Capacity Factor @ 19% (MWh)
2014	1.75	**2,912.7**
2015	3.50	**5,825.4**
2016	5.25	**8,738.1**
2017	7.00	**11,650.8**
2018	8.75	**14,563.5**
2019	10.50	**17,476.2**
Total	10.50	**61,166.7**

15.2.6 Wheeling and Non-Technical losses

There is much uncertainty as it relates to the final framework, timing of implementation and the potential impact on energy sales. This is so because JPS has successfully appealed the OUR's Determination and a decision is pending on the approach going forward. In the absence of objective data, the OUR finds it difficult to independently quantify a potential impact on energy sales, if any, for the regulatory period. In any case, any potential impact on the reduction of energy sales will be more than offset from the sales recovery from non-technical loss recovery initiatives and from the implementation of the Community Renewal Programme. In the absence of alternative data source available to objectively quantify the impact on energy sales from Wheeling and Non-Technical Losses initiatives, the OUR has therefore accepted JPS' proposed estimates as outlined in Tables 15.27 and 15.28 below.

Table 15.27: JPS' proposed impact on Sales from Wheeling and Non-Technical Losses Initiatives

Year	Loss of Energy Sales due to Wheeling (MWh)	Non-Technical losses recovery of energy sales (MWh)	Net recovery of Sales (MWh)
2014	-	43,000	43,000
2015	-	2,100	2,100
2016	-	-	-
2017	-	-	-
2018	-	-	-
2019	68,000	72,100	4,100
Total	**68,000**	**117,200**	**49,200**

Table 15.28: Overall Sales Forecast for Tariff period 2014 – 2019

Year	R10 Sales (MWh)	R20 Sales (MWh)	R40 Sales (MWh)	R50 Sales (MWh)	R60 Sales (MWh)	Base Sales (MWh)	Base Sales Growth Rate	Adjustments based on Externalities (new Technology, Net Billing, Wheeling, Losses Initives)	Adjusted Base sales (MWh)	Growth Rate
2008	1,032,182	650,424	759,739	590,569	96,973	3,129,887	-0.7%	-	3,129,887	-0.7%
2009	1,091,900	670,000	777,600	594,600	97,300	3,231,400	3.2%	-	3,231,400	3.2%
2010	1,107,000	664,600	745,700	602,200	102,200	3,221,700	-0.3%	-	3,221,700	-0.3%
2011	1,051,200	634,900	771,200	607,300	97,900	3,162,500	-1.8%	-	3,162,500	-1.8%
2012	1,025,100	600,501	765,000	609,200	99,100	3,098,901	-2.0%	-	3,098,901	-2.0%
2013	986,351	586,809	766,082	599,193	99,998	3,038,434	-2.0%	-	3,038,434	-2.0%
Average Sales									3,147,137	
2014	995,684	553,424	721,159	612,587	102,058	2,984,913	-1.8%	**40,087.3**	3,025,000	-1.8%
2015	1,013,187	568,949	724,259	611,769	104,035	3,022,198	1.9%	**(3,725.4)**	3,018,473	1.9%
2016	1,036,179	584,538	727,961	630,501	105,930	3,085,110	2.1%	**(8,738.1)**	3,076,372	2.1%
2017	1,056,740	606,301	732,232	647,980	107,745	3,150,999	2.1%	**(9,510.7)**	3,141,488	2.1%
2018	1,074,585	628,472	737,041	669,352	109,481	3,218,932	2.1%	**(12,365.6)**	3,206,566	2.1%
2019	1,110,725	652,400	742,361	692,133	111,139	3,308,758	2.8%	**(11,073.9)**	3,297,684	2.8%
Average Sales									**3,127,597**	

Based on the foregoing, the OUR's projected Billing Determinant for Tariff period 2014–2019 is 3,127,597 MWh.

Test Year Energy Sales

JPS proposed total energy sales of 2,967,417 MWh for the test year 2013. See Table 15.29 below for the details. JPS' proposal excludes energy sales for Caribbean Cement. The real demand for the test year is shown in Table 15.210 below. JPS also reduced the demand for street lighting by the amount of 28,312 MWh. The reduction is a result of inclusion of the average of the projected street lighting demand for 2014-2019 representing the planned LED replacement. See Table 15.211 below for JPS' projected street light demand.

The OUR approves the exclusion of the Caribbean Cement's energy sales of 89,886 MWh from the total energy sales as necessary as there is a long-standing contractual agreement with JPS and this very large customer. The representative revenue was also removed from the Revenue Requirement. The OUR does not approve JPS' use of the average demand for street lighting as the LED replacement schedule is not confirmed. Instead, the OUR will approve the test year unadjusted actual demand of 73,027 MWh for street lighting.

Table 15.29: JPS' Proposed Test Year Billing Determinants

Customer Class	Customers	Energy (MWh)	Demand kVA/Month		
			STD and On-Peak	Partial-Peak	Off-Peak
RT 10 LV Res. Service ≤ 100 kWh	222,531	118,508			
RT 10 LV Res. Service 101-500 kWh	301,954	710,037			
RT 10 LV Res. Service > 500 kWh	14,116	157,095			
RT 20 LV Gen. Service ≤ 100 kWh	24,842	11,145			
RT 20 LV Gen. Service 101-1000 kWh	28,235	135,779			
RT 20 LV Gen. Service 1001-7500 kWh	8,588	304,169			
RT 20 LV Gen. Service > 7500 kWh	992	201,647			
RT 60 LV Street Lighting	236	44,715			
RT 40 LV Power Service (Std)	1,601	645,804	187		
RT 40 LV Power Service (TOU)	121	121,303	24	28	26
RT 50 MV Power Service (Std)	104	411,322	95		
RT 50 MV Power Service (TOU	27	105,893	23	26	25
Total	**603,346**	**2,967,417**	**328**	**54**	**51**

Table 15.210: JPS' Proposed Test Year (2013) Real Demand

Customer Class	Customers	Energy (MWh)
RT 10 LV Res. Service ≤ 100 kWh	222,531	118,508
RT 10 LV Res. Service 101-500 kWh	301,954	710,037
RT 10 LV Res. Service > 500 kWh	14,116	157,095
RT 20 LV Gen. Service ≤ 100 kWh	24,842	11,145
RT 20 LV Gen. Service 101-1000 kWh	28,235	135,779
RT 20 LV Gen. Service 1001-7500 kWh	8,588	304,169
RT 20 LV Gen. Service > 7500 kWh	992	201,647
RT 60 LV Street Lighting	236	**73,027**
RT 40 LV Power Service (Std)	1,601	645,804
RT 40 LV Power Service (TOU)	121	121,303
RT 50 MV Power Service (Std)	104	411,322
RT 50 MV Power Service (TOU)	27	105,893
Caribbean Cement Company	1	**89,886**
Total	**603,347**	**3,085,615**

Table 15.211: Proposed Street Lighting Replacement with LED

Street Lighting	Test Year	2014	2015	2016	2017	2018	Average
Level of replacement		25%	50%	75%	100%	100%	
Projected demand (MWh)	73,027	62,916	52,804	42,692	32,580	32,580	44,715

Billing determinant of 3,256 GWh for the tariff period 2009-2014 included 55% of the difference between the test year sales and the possible sales if losses targets were met, was approved by the OUR in the 2009 Determination Notice. The actual sales targets were not achieved for the years within the review period. See Table 15.213 which shows the variance over the said period. JPS' proposed revenue requirement is predicated on test year costs and for these reasons the OUR will approve a test year billing demand determinant. Table 15.212 below shows the OUR's approved test year billing determinants.

Table 15.212: OUR's Approved Test Year Billing Determinants

OUR's Approved Billing Demand Determinant	
Test Year (2013) Sales (MWh)	**3,069,689**
Less Caribbean Cement Company (MWh)	89,886
Test Year Billing Demand (MWh)	**2,979,803**

Table 15.213: Energy Sales against OUR's Approved Billing Determinant 2009-2013

Year	2008	2009	2010	2011	2012	2013
Energy Sales (GWh)	**3179.3**	3187.2	3187.5	3216.0	3134.0	**3069.7**
OUR 2009 Determination (GWh)		3256.0	3256.0	3256.0	3256.0	3256.0
Variance (GWh)		**-68.8**	**-68.5**	**-40.0**	**-122.0**	**-186.3**

DETERMINATION 44

The Office DETERMINES that the test year energy demand is 2,979,803 MWh.

ANNEX A: Estimated Bill Impact of JPS' Request

Given the interest in showing the total average tariff variation, a fuel charge needs to be considered in the analysis. For OUR purposes, a fuel charge is added to current non-fuel rates (0.239 USD/kWh). This fuel charge is based on the same data used to determine the February 2014 fuel charge, but relies on JPS' proposed losses target of 21.5%, and excludes the FCRA component that was scheduled to end in June 2014. The resulting fuel charge is 0.2585 USD/kWh.

Bill Comparison for a Typical Rate 10 Consumer with consumption up to 100kWh
Usage 90 kW

Rate 10	Before			After				
Below 100kWh	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	**112.00**		112.00	112.00			
	Usage kWh	Rate		Usage kWh	Rate			
Energy 1st	90	6.98	628.20	90	**10.30**	927.36	299.16	47.62%
Energy Next	0	15.96	-	0	**24.53**	-	-	
N A C			387.00			**672.00**	285.00	73.64%
Sub Total			**1,015.20**			**1,599.36**	**584.16**	**57.54%**
F/E Adjust		0.101	102.29		0.000	-	- 102.29	
Fuel & IPP	90	28.828	2,594.52	90	**28.006**	2,520.55	- 73.97	-2.85%
Bill Total			**J$ 3,712.01**			**J$ 4,119.91**	**407.91**	**10.99%**

Bill Comparison for a Typical Rate 10 Consumer with consumption between 100kWh – 500kWh
Usage 200 kWh

Rate 10	Before			After				
100 - 500kWh	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	**112.00**		112.00	112.00			
	Usage kWh	Rate		Usage kWh	Rate			
Energy 1st	100	6.98	698.00	100	**10.30**	1,030.40	332.40	47.62%
Energy Next	100	15.96	1,596.00	100	**24.53**	2,452.80	856.80	53.68%
N A C			387.00			**1,344.00**	957.00	247.29%
Sub Total			**2,681.00**			**4,827.20**	**2,146.20**	**80.05%**
F/E Adjust		0.101	270.12		0.000	-	- 270.12	
Fuel & IPP	200	28.828	5,765.60	200	**28.006**	5,601.22	- 164.38	-2.85%
Bill Total			**J$ 8,716.72**			**J$ 10,428.42**	**1,711.70**	**19.64%**

Bill Comparison for a Typical Rate 10 Consumer with consumption above 500kWh Usage 600 kWh

Rate 10	Before			After				
Above 500kWh	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
	Usage kWh	Rate		Usage kWh	Rate			
Energy 1st	100	6.98	698.00	100	10.30	1,030.40	332.40	47.62%
Energy 2nd	500	15.96	7,980.00	400	24.53	9,811.20	1,831.20	61.59%
Energy 3rd			-	100	30.84	3,083.97	3,083.97	
N A C			387.00			2,016.00	1,629.00	420.93%
Sub Total			**9,065.00**			**15,941.57**	**6,876.57**	**75.86%**
F/E Adjust		0.101	913.34		0.000	-	- 913.34	
Fuel & IPP	600	28.828	17,296.80	600	28.006	16,803.67	- 493.13	-2.85%
Bill Total			**J$ 27,275.14**			**J$ 32,745.25**	**5,470.11**	**20.06%**

Bill Comparison for a Typical Rate 20 Consumer with consumption below 100kWh Usage 90 kWh

Rate 20	Before			After				
Below 100kWh	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
		.						
	Usage kWh	Rate		Usage kWh	Rate			
Energy	90	13.63	1,226.70	90	22.512	2,026.08	799.38	65.17%
N A C			851.40			1,008.00	156.60	18.39%
Sub Total			**2,078.10**			**3,034.08**	**955.98**	**46.00%**
F/E Adjust		0.101	209.38		0.000	-	- 209.38	
Fuel & IPP	90	28.828	2,594.52	90	28.006	2,520.55	- 73.97	-2.85%
Bill Sub-Total			**4,882.00**			**5,554.63**	**672.63**	**13.78%**
GCT @16.5%		0.165	805.53		0.165	916.51	110.98	13.78%
Bill Total			**J$ 5,687.53**			**J$ 6,471.15**	**783.62**	**13.78%**

Bill Comparison for a Typical Rate 20 Consumer with consumption between 100kWh & 1000kWh
Usage 1,000 kWh

Rate 20	Before			After				
100 - 1000kWh	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
		.						
	Usage kWh	Rate		Usage kWh	Rate			
Energy	1000	13.63	13,630.00	1000	21.84	21,836.64	8,206.64	60.21%
N A C			851.40			1,680.00	828.60	97.32%
Sub Total			**14,481.40**			**23,516.64**	**9,035.24**	**62.39%**
F/E Adjust		0.101	1,459.06		0.000	-	- 1,459.06	
Fuel & IPP	1000	28.828	28,828.00	1000	28.006	28,006.12	- 821.88	-2.85%
Bill Sub-Total			**44,768.46**			**51,522.76**	**6,754.30**	**15.09%**
GCT @16.5%		0.165	7,386.80		0.165	8,501.26	1,114.46	15.09%
Bill Total			**J$ 52,155.26**			**J$ 60,024.02**	**7,868.76**	**15.09%**

ANNEX A: Estimated Bill Impact of JPS' Request

Bill Comparison for a Typical Rate 20 Consumer with consumption between 1000kWh & 7500kWh
Usage 5,000 kWh

Rate 20	Before			After				
1000 - 7500kWh	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
		.						
	Usage kWh	Rate		Usage kWh	Rate			
Energy	5000	13.63	68,150.00	5000	21.18	105,907.70	37,757.70	55.40%
N A C			851.40			2,800.00	1,948.60	228.87%
Sub Total			**69,001.40**			**108,707.70**	**39,706.30**	**57.54%**
F/E Adjust		0.101	6,952.19		0.000	-	- 6,952.19	
Fuel & IPP	5000	28.828	144,140.00	5000	28.006	140,030.61	- 4,109.39	-2.85%
Bill Sub-Total			**220,093.59**			**248,738.32**	**28,644.72**	**13.01%**
GCT @16.5%		0.165	36,315.44		0.165	41,041.82	4,726.38	13.01%
Bill Total		**J$**	**256,409.04**		**J$**	**289,780.14**	**33,371.10**	**13.01%**

Bill Comparison for a Typical Rate 20 Consumer with consumption above 7,500kWh
Usage 8,000 kWh

Rate 20	Before			After				
Above 7500kWh	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
		.						
	Usage kWh	Rate		Usage kWh	Rate			
Energy	8000	13.63	109,040.00	8000	13.13	105,060.44	- 3,979.56	-3.65%
N A C			851.40			4,480.00	3,628.60	426.19%
Sub Total			**109,891.40**			**109,540.44**	**- 350.96**	**-0.32%**
F/E Adjust		0.101	11,072.04		0.000	-	- 11,072.04	
Fuel & IPP	8000	28.828	230,624.00	8000	28.006	224,048.98	- 6,575.02	-2.85%
Bill Sub-Total			**351,587.44**			**333,589.42**	**- 17,998.02**	**-5.12%**
GCT @16.5%		0.165	58,011.93		0.165	55,042.25	- 2,969.67	-5.12%
Bill Total		**J$**	**409,599.37**		**J$**	**388,631.68**	**- 20,967.69**	**-5.12%**

Bill Comparison for a Typical Rate 40 Consumer
Usage 35,000 kWh
Demand 100 kVA

Rate 40	Before			After				
Standard	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
	Usage	Rate (J$)		Usage	Rate (J$)			
Energy kWh	35000	3.89	136,150.00	35000	0.00	-	- 136,150.00	-100.00%
Demand kVA	100	1466.12	146,612.00	100	3192.00	319,200.00	172,588.00	
N A C			5,160.00			8,960.00	3,800.00	73.64%
Sub Total			**287,922.00**			**328,160.00**	**40,238.00**	**13.98%**
F/E Adjust		0.101	29,009.40		0.000	-	- 29,009.40	
Fuel & IPP	35000	27.675	968,625.00	35000	26.886	941,005.72	- 27,619.28	-2.85%
Bill Sub-Total			**1,285,556.40**			**1,269,165.72**	**- 16,390.68**	**-1.27%**
GCT @16.5%		0.165	212,116.81		0.165	209,412.34	- 2,704.46	-1.27%
Bill Total		**J$**	**1,497,673.21**		**J$**	**1,478,578.07**	**- 19,095.14**	**-1.27%**

ANNEX A: Estimated Bill Impact of JPS' Request

Bill Comparison for a Typical Rate 50 Customer (Standard)
Usage 500,000 kWh
Demand 1,500 kVA

Rate 50	Before			After				
Standard	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
	Usage	Rate (J$)		Usage	Rate (J$)			
Energy kWh	500000	3.69	1,845,000.00	500000	0	-	- 1,845,000.00	-100.00%
Demand kVA	1500	1319.52	1,979,280.00	1500	2842.37	4,263,561.25	2,284,281.25	115.41%
N A C			6,192.00			8,960.00	2,768.00	44.70%
Sub Total			**3,830,472.00**			**4,272,521.25**	**442,049.25**	**11.54%**
F/E Adjust		0.101	385,936.81		0.000	-	- 385,936.81	
Fuel & IPP	500000	27.675	13,837,500.00	500000	26.886	13,442,938.87	- 394,561.13	-2.85%
Bill Sub-Total			**18,053,908.81**			**17,715,460.13**	**- 338,448.68**	**-1.87%**
GCT @16.5%		0.165	2,978,894.95		0.165	2,923,050.92	- 55,844.03	-1.87%
Bill Total			**J$ 21,032,803.76**			**J$ 20,638,511.05**	**- 394,292.71**	**-1.87%**

Bill Comparison for a Typical Rate 50 Customer (TOU: On-Peak)
Usage 500,000 kWh
Demand 1,500 kVA

Rate 50	Before			After				
TOU (On-Peak)	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
	Usage	Rate (J$)		Usage	Rate (J$)			
Energy kWh	500000	3.69	1,845,000.00	500000	0	-	- 1,845,000.00	-100.00%
Demand kVA	1500	733.06	1,099,590.00	1500	1579.08	2,368,623.60	1,269,033.60	115.41%
N A C			6,192.00			8,960.00	2,768.00	44.70%
Sub Total			**2,950,782.00**			**2,377,583.60**	**- 573,198.40**	**-19.43%**
F/E Adjust		0.101	297,304.19		0.000	-	- 297,304.19	
Fuel & IPP	500000	32.599	16,299,500.00	500000	29.429	14,714,406.89	- 1,585,093.11	-9.72%
Bill Sub-Total			**19,547,586.19**			**17,091,990.49**	**- 2,455,595.70**	**-12.56%**
GCT @16.5%		0.165	3,225,351.72		0.165	2,820,178.43	- 405,173.29	-12.56%
Bill Total			**J$ 22,772,937.91**			**J$ 19,912,168.92**	**- 2,860,768.99**	**-12.56%**

ANNEX B: Estimated Bill Impact of Office's Determination

Given the interest in showing the total average tariff variation, a fuel charge needs to be considered in the analysis. For OUR purposes, a fuel charge is added to current non-fuel rates (0.239 USD/kWh). This fuel charge is based on the same data used to determine the February 2014 fuel charge, but relies on the OUR's revised losses target of 19.20%, the revised heat rate target which now utilizes a JPS thermal heat rate target of 12,010 kJ/kWh and excludes the FCRA component that was scheduled to end in June 2014. The resulting fuel charge is 0.2431 USD/kWh.

Bill Comparison for a Typical Rate 10 Consumer with consumption up to 100kWh
Usage 90 kWh

Rate 10	Before			After				
Below 100kWh	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy 1st	90	6.98	628.20	90	7.00	630.00	1.80	0.29%
Energy 2nd	0	15.96	-	0	18.07	-	-	
Customer Charge			387.00			390.00	3.00	0.78%
Sub Total			**1,015.20**			**1,020.00**	**4.80**	**0.47%**
EEIF				90	0.4886	**43.97**		
F/E Adjust		0.101	102.29		0.000	-		
Fuel & IPP	90	28.828	2,594.52	90	27.228	2,450.54		
Bill Total			**J$ 3,712.01**			**J$ 3,514.52**	**- 197.49**	**-5.32%**

Bill Comparison for a Typical Rate 10 Consumer with consumption between 100kWh – 500kWh
Usage 200 kWh

Rate 10	Before			After				
100 - 500kWh	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy 1st	100	6.98	698.00	100	7.00	700.00	2.00	0.29%
Energy 2nd	100	15.96	1,596.00	100	18.07	1,807.00	211.00	13.22%
Customer Charge			387.00			390.00	3.00	0.78%
Sub Total			**2,681.00**			**2,897.00**	**216.00**	**8.06%**
EEIF				200	0.4886	**97.72**		
F/E Adjust		0.101	270.12		0.000	-		
Fuel & IPP	200	28.828	5,765.60	200	27.228	5,445.65		
Bill Total			**J$ 8,716.72**			**J$ 8,440.37**	**- 276.36**	**-3.17%**

ANNEX B: Estimated Bill Impact of Office's Determination

Bill Comparison for a Typical Rate 10 Consumer with consumption above 500kWh
Usage 600 kWh

Rate 10	Before			After				
Above 500kWh	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy 1st	100	6.98	698.00	100	7.00	700.00	2.00	0.29%
Energy 2nd	500	15.96	7,980.00	500	18.07	9,035.00	1,055.00	13.22%
Energy 3rd						-	-	
Customer Charge			387.00			390.00	3.00	0.78%
Sub Total			**9,065.00**			**10,125.00**	**1,060.00**	**11.69%**
EEIF				600	0.4886	**293.16**		
F/E Adjust		0.101	913.34		0.000	-		
Fuel & IPP	600	28.828	17,296.80	600	27.228	16,336.94		
Bill Total			**J$ 27,275.14**			**J$ 26,755.10**	- **520.04**	**-1.91%**

Bill Comparison for a Typical Rate 20 Consumer with consumption below 100kWh
Usage 90 kWh

Rate 20	Before			After				
Below 100kWh	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	90	13.63	1,226.70	90	13.61	1,224.90	- 1.80	-0.15%
Customer Charge			851.40			820.00	- 31.40	-3.69%
Sub Total			**2,078.10**			**2,044.90**	- **33.20**	**-1.60%**
EEIF				90	0.4886	**43.97**		
F/E Adjust		0.101	209.38		0.000	-		
Fuel & IPP	90	28.828	2,594.52	90	27.228	2,450.54		
Bill Sub-Total			**4,882.00**			**4,539.42**	- **342.58**	**-7.02%**
GCT @16.5%		0.165	805.53		0.165	749.00		
Bill Total			**J$ 5,687.53**			**J$ 5,288.42**	- **399.11**	**-7.02%**

Bill Comparison for a Typical Rate 20 Consumer with consumption between 100kWh & 1000kWh
Usage 1,000 kWh

Rate 20	Before			After				
100 - 1000kWh	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	1000	13.63	13,630.00	1000	13.61	13,610.00	- 20.00	-0.15%
Customer Charge			851.40			820.00	- 31.40	-3.69%
Sub Total			**14,481.40**			**14,430.00**	- **51.40**	**-0.35%**
EEIF				1000	0.4886	**488.60**		
F/E Adjust		0.101	1,459.06		0.000	-	- 1,459.06	
Fuel & IPP	1000	28.828	28,828.00	1000	27.228	27,228.23	- 1,599.77	-5.55%
Bill Sub-Total			**44,768.46**			**42,146.83**	- **2,621.63**	**-5.86%**
GCT @16.5%		0.165	7,386.80		0.165	6,954.23	- 432.57	-5.86%
Bill Total			**J$ 52,155.26**			**J$ 49,101.06**	- **3,054.20**	**-5.86%**

ANNEX B: Estimated Bill Impact of Office's Determination

Bill Comparison for a Typical Rate 20 Consumer with consumption between 1000kWh & 7500kWh
Usage 5,000 kWh

Rate 20	Before			After				
1000 - 7500kWh	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
		.						
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	5000	13.63	68,150.00	5000	13.61	68,050.00	- 100.00	-0.15%
Customer Charge			851.40			820.00	- 31.40	-3.69%
Sub Total			**69,001.40**			**68,870.00**	- **131.40**	**-0.19%**
EEIF				5000	0.4886	**2,443.00**		
F/E Adjust		0.101	6,952.19		0.000	-	- 6,952.19	
Fuel & IPP	5000	28.828	144,140.00	5000	27.228	136,141.17	- 7,998.83	-5.55%
Bill Sub-Total			**220,093.59**			**207,454.17**	- **12,639.42**	**-5.74%**
GCT @16.5%		0.165	36,315.44		0.165	34,229.94	- 2,085.50	-5.74%
Bill Total			**J$ 256,409.04**			**J$ 241,684.11**	- **14,724.92**	**-5.74%**

Bill Comparison for a Typical Rate 20 Consumer with consumption above 7,500kWh
Usage 8,000 kWh

Rate 20	Before			After				
Above 7500kWh	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
		.						
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	8000	13.63	109,040.00	8000	13.61	108,880.00	- 160.00	-0.15%
Customer Charge			851.40			820.00	- 31.40	-3.69%
Sub Total			**109,891.40**			**109,700.00**	- **191.40**	**-0.17%**
EEIF				8000	0.4886	**3,908.80**		
F/E Adjust		0.101	11,072.04		0.000	-	- 11,072.04	
Fuel & IPP	8000	28.828	230,624.00	8000	27.228	217,825.88	- 12,798.12	-5.55%
Bill Sub-Total			**351,587.44**			**331,434.68**	- **20,152.76**	**-5.73%**
GCT @16.5%		0.165	58,011.93		0.165	54,686.72	- 3,325.21	-5.73%
Bill Total			**J$ 409,599.37**			**J$ 386,121.40**	- **23,477.96**	**-5.73%**

Bill Comparison for a Typical Rate 40 Consumer
Usage 35,000 kWh
Demand 100 kVA

Rate 40	Before			After				
Standard	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
	Usage	Rate (J$)		Usage	Rate (J$)			
Energy kWh	35000	3.89	136,150.00	35000	4.38	153,300.00	17,150.00	12.60%
Demand kVA	100	1466.12	146,612.00	100	1587.07	158,707.00	12,095.00	
Customer Charge			5,160.00			6,200.00	1,040.00	20.16%
Sub Total			**287,922.00**			**318,207.00**	**30,285.00**	**10.52%**
EEIF				35000	0.4886	**17,101.00**		
F/E Adjust		0.101	29,009.40		0.000	-	- 29,009.40	
Fuel & IPP	35000	27.675	968,625.00	35000	26.139	914,868.70	- 53,756.30	-5.55%
Bill Sub-Total			**1,285,556.40**			**1,250,176.70**	- **35,379.71**	**-2.75%**
GCT @16.5%		0.165	212,116.81		0.165	206,279.15	- 5,837.65	-2.75%
Bill Total			**J$ 1,497,673.21**			**J$ 1,456,455.85**	- **41,217.36**	**-2.75%**

ANNEX B: Estimated Bill Impact of Office's Determination

Bill Comparison for a Typical Rate 50 Customer (Standard)
Usage 500,000 kWh
Demand 1,500 kVA

Rate 50	Before			After				
Standard	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
	Usage	Rate (J$)		Usage	Rate (J$)			
Energy kWh	500000	3.69	1,845,000.00	500000	4.05	2,025,000.00	180,000.00	9.76%
Demand kVA	1500	1319.52	1,979,280.00	1500	1421.81	2,132,715.00	153,435.00	7.75%
Customer Charge			6,192.00			6,200.00	8.00	0.13%
Sub Total			**3,830,472.00**			**4,163,915.00**	**333,443.00**	**8.71%**
EEIF				500000	0.4886	**244,300.00**		
F/E Adjust		0.101	385,936.81		0.000	-	- 385,936.81	
Fuel & IPP	500000	27.675	13,837,500.00	500000	26.139	13,069,552.79	- 767,947.21	-5.55%
Bill Sub-Total			**18,053,908.81**			**17,477,767.79**	**- 576,141.01**	**-3.19%**
GCT @16.5%		0.165	2,978,894.95		0.165	2,883,831.69	- 95,063.27	-3.19%
Bill Total			**J$ 21,032,803.76**			**J$ 20,361,599.48**	**- 671,204.28**	**-3.19%**

Bill Comparison for a Typical Rate 50 Customer (TOU: On-Peak)
Usage 500,000 kWh
Demand 1,500 kVA

Rate 50	Before			After				
TOU (On-Peak)	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
	Usage	Rate (J$)		Usage	Rate (J$)			
Energy kWh	500000	3.69	1,845,000.00	500000	4.05	2,025,000.00	180,000.00	9.76%
Demand kVA	1500	733.06	1,099,590.00	1500	793.78	1,190,670.00	91,080.00	8.28%
Customer Charge			6,192.00			6,200.00	8.00	0.13%
Sub Total			**2,950,782.00**			**3,221,870.00**	**271,088.00**	**9.19%**
EEIF				500000	0.4886	**244,300.00**		
F/E Adjust		0.101	297,304.19		0.000	-	- 297,304.19	
Fuel & IPP	500000	32.599	16,299,500.00	500000	28.611	14,305,704.99	- 1,993,795.01	-12.23%
Bill Sub-Total			**19,547,586.19**			**17,771,874.99**	**- 1,775,711.20**	**-9.08%**
GCT @16.5%		0.165	3,225,351.72		0.165	2,932,359.37	- 292,992.35	-9.08%
Bill Total			**J$ 22,772,937.91**			**J$ 20,704,234.36**	**- 2,068,703.55**	**-9.08%**

ANNEX C: Summary of Estimated Bill Impacts

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	11.0%	**16.2%**
RT 10 LV Res. Service 100-500 kWh	200	n/a	17.4%	
RT 10 LV Res. Service > 500 kWh	600	n/a	20.1%	
RT 20 LV Gen. Service < 100 kWh	90	n/a	13.8%	**9.2%**
RT 20 LV Gen. Service 100-1000 kWh	1,000	n/a	15.1%	
RT 20 LV Gen. Service 1000-7500 kWh	5,000	n/a	13.0%	
RT 20 LV Gen. Service > 7500 kWh	8,000	n/a	**-5.1%**	
RT 40 LV Power Service (Std)	35,000	100	**-1.3%**	**-5.2%**
RT 50 MV Power Service (Std)	500,000	1,500	**-1.9%**	
RT 50 MV Power Service (TOU(on- peak))	500,000	1,500	**-12.6%**	
Efficiency Targets:	**System Losses Target**		**System Heat Rate Target**	
	21.50%		10,200 kJ/kWh	

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	**-5.3%**	**-3.5%**
RT 10 LV Res. Service 100-500 kWh	200	n/a	**-3.2%**	
RT 10 LV Res. Service > 500 kWh	600	n/a	**-1.9%**	
RT 20 LV Gen. Service < 100 kWh	90	n/a	**-7.0%**	**-5.9%**
RT 20 LV Gen. Service 100-1000 kWh	1,000	n/a	**-5.9%**	
RT 20 LV Gen. Service 1000-7500 kWh	5,000	n/a	**-5.7%**	
RT 20 LV Gen. Service > 7500 kWh	8,000	n/a	**-5.7%**	
RT 40 LV Power Service (Std)	35,000	100	**-2.8%**	**-5.0%**
RT 50 MV Power Service (Std)	500,000	1,500	**-3.2%**	
RT 50 MV Power Service (TOU(on- peak))	500,000	1,500	**-9.1%**	
Efficiency Targets:	**System Losses Target**		**JPS Thermal Heat Rate Target**	
	19.20%		12,010 kJ/kWh	

ANNEX D: Estimated Bill Impact of Office's Determination on November Bills

For OUR purposes, an estimated fuel rate is added to the Office determined non-fuel rates. October's billed fuel and IPP rate charged by JPS is 0.20721USD/kWh. The estimated fuel rate is based on the same data used to determine the October 2014 fuel charge, but relies on the OUR's revised losses target of 19.20%, the revised heat rate target which now utilizes a JPS thermal heat rate target of 12,010 kJ/kWh and excludes the FCRA component. The resulting fuel charge is 0.19522USD/kWh.

Customer Class	Overall Bill Impact of the OUR Approved Rates			
	Typical Usage (kWh)	Demand (kVA)	Total Bill Impact (%)	Average Change (%)
RT 10 LV Re. Service < 100 kWh	90	n/a	-0.59%	0.60%
RT 10 LV Res. Service 100-500 kWh	200	n/a	0.67%	
RT 10 LV Res. Service >500 kWh	600	n/a	1.72%	
RT 20 LV Gen. Service < 100 kWh	90	n/a	-3.40%	-3.32%
RT 20 LV Gen. Service 100-1000 kWh	1,000	n/a	-6.08%	
RT 20 LV Gen. Service 1000-7500 kWh	5,000	n/a	-1.91%	
RT 20 LV Gen. Service > 7500 kWh	8,000	n/a	-1.90%	
RT 40 LV Power Service (Std)	35,000	100	2.43%	1.99%
RT 50 MV Power Service (Std)	500,000	1,500	2.20%	
RT 50 MV Power Service (TOU(on-peak))	500,000	1,500	1.35%	
Efficiency Targets:	System Losses Target		JPS Thermal Heat Rate Target	
	19.20%		11,990 kJ/kWh	

Bill Comparison for a Typical Rate 10 Consumer with consumption up to 100kWh Usage 90 kWh

Rate 10	Before			After				
Below 100kWh	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy 1st	90	6.98	628.20	90	6.99	629.10	0.90	0.14%
Energy 2nd	0	15.96	-	0	17.91	-	-	
Customer Charge			387.00			399.55	12.55	3.24%
Sub Total			1,015.20			1,028.65	13.45	1.32%
EEIF				90	0.5638	50.74		
F/E Adjust		0.101	102.29		0.000	-		
Fuel & IPP	90	23.365	2,102.89	90	23.579	2,122.07		
Bill Total			J$ 3,220.37			J$ 3,201.46	(18.91)	-0.59%

Bill Comparison for a Typical Rate 10 Consumer with consumption between 100kWh – 500kWh
Usage 200 kWh

Rate 10	Before			After				
100 - 500kWh	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy 1st	100	6.98	698.00	100	6.99	699.00	1.00	0.14%
Energy 2nd	100	15.96	1,596.00	100	17.91	1,791.00	195.00	12.22%
Customer Charge			387.00			399.55	12.55	3.24%
Sub Total			**2,681.00**			**2,889.55**	**208.55**	**7.78%**
EEIF				200	0.5638	**112.76**		
F/E Adjust		0.101	270.12		0.000	-		
Fuel & IPP	200	23.365	4,673.08	200	23.365	4,673.08		
Bill Total			**J$ 7,624.20**			**J$ 7,675.39**	**51.19**	**0.67%**

Bill Comparison for a Typical Rate 10 Consumer with consumption above 500kWh
Usage 600 kWh

Rate 10	Before			After				
Above 500kWh	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy 1st	100	6.98	698.00	100	6.99	699.00	1.00	0.14%
Energy 2nd	500	15.96	7,980.00	500	17.91	8,955.00	975.00	12.22%
Energy 3rd						-	-	
Customer Charge			387.00			399.55	12.55	3.24%
Sub Total			**9,065.00**			**10,053.55**	**988.55**	**10.91%**
EEIF				600	0.5638	**338.28**		
F/E Adjust		0.101	913.34		0.000	-		
Fuel & IPP	600	23.365	14,019.24	600	23.365	14,019.24		
Bill Total			**J$ 23,997.57**			**J$ 24,411.07**	**413.49**	**1.72%**

Bill Comparison for a Typical Rate 20 Consumer with consumption below 100kWh
Usage 90 kWh

Rate 20	Before			After				
Below 100kWh	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
		.						
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	90	13.63	1,226.70	90	13.72	1,234.80	8.10	0.66%
Customer Charge			851.40			852.58	1.18	0.14%
Sub Total			**2,078.10**			**2,087.38**	**9.28**	**0.45%**
EEIF				90	0.5638	**50.74**		
F/E Adjust		0.101	209.38		0.000	-		
Fuel & IPP	90	23.365	2,102.89	90	23.365	2,102.89		
Bill Sub-Total			**4,390.36**			**4,241.01**	**(149.36)**	**-3.40%**
GCT @16.5%		0.165	724.41		0.165	699.77		
Bill Total			**J$ 5,114.77**			**J$ 4,940.77**	**(174.00)**	**-3.40%**

Bill Comparison for a Typical Rate 20 Consumer with consumption between 100kWh & 1000kWh

Usage 1,000 kWh

Rate 20	Before			After					
100 - 1000kWh	2013 Rates J$			2014 Rates J$			Change		
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate			J$	%
	98.89	112.00		112.00	112.00				
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)				
Energy	1000	13.63	13,630.00	1000	13.52	13,520.00	-	110.00	-0.81%
Customer Charge			851.40			820.00	-	31.40	-3.69%
Sub Total			**14,481.40**			**14,340.00**	**-**	**141.40**	**-0.98%**
EEIF				1000	0.5638	**563.80**			
F/E Adjust		0.101	1,459.06		0.000	-	-	1,459.06	
Fuel & IPP	1000	23.365	23,365.39	1000	22.013	22,013.38	-	1,352.02	-5.79%
Bill Sub-Total			**39,305.86**			**36,917.18**	**-**	**2,388.68**	**-6.08%**
GCT @16.5%		0.165	6,485.47		0.165	6,091.33	-	394.13	-6.08%
Bill Total			**J$ 45,791.32**			**J$ 43,008.51**	**-**	**2,782.81**	**-6.08%**

Bill Comparison for a Typical Rate 20 Consumer with consumption between 1000kWh & 7500kWh

Usage 5,000 kWh

Rate 20	Before			After				
1000 - 7500kWh	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
		.						
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	5000	13.63	68,150.00	5000	13.72	68,600.00	450.00	0.66%
Customer Charge			851.40			852.58	1.18	0.14%
Sub Total			**69,001.40**			**69,452.58**	**451.18**	**0.65%**
EEIF				5000	0.5638	**2,819.00**		
F/E Adjust		0.101	6,952.19		0.000	-	(6,952.19)	
Fuel & IPP	5000	23.365	116,826.97	5000	23.365	116,826.97	-	0.00%
Bill Sub-Total			**192,780.56**			**189,098.55**	**(3,682.01)**	**-1.91%**
GCT @16.5%		0.165	31,808.79		0.165	31,201.26	(607.53)	-1.91%
Bill Total			**J$ 224,589.35**			**J$ 220,299.81**	**(4,289.54)**	**-1.91%**

Bill Comparison for a Typical Rate 20 Consumer with consumption above 7,500kWh
Usage 8,000 kWh

Rate 20	Before			After				
Above 7500kWh	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
		.						
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	8000	13.63	109,040.00	8000	13.72	109,760.00	720.00	0.66%
Customer Charge			851.40			852.58	1.18	0.14%
Sub Total			**109,891.40**			**110,612.58**	**721.18**	**0.66%**
EEIF				8000	0.5638	**4,510.40**		
F/E Adjust		0.101	11,072.04		0.000	-	(11,072.04)	
Fuel & IPP	8000	23.365	186,923.15	8000	23.365	186,923.15	-	0.00%
Bill Sub-Total			**307,886.59**			**302,046.13**	**(5,840.46)**	**-1.90%**
GCT @16.5%		0.165	50,801.29		0.165	49,837.61	(963.68)	-1.90%
Bill Total			**J$ 358,687.87**			**J$ 351,883.74**	**(6,804.13)**	**-1.90%**

Bill Comparison for a Typical Rate 40 Consumer
Usage 35,000 kWh
Demand 100 kVA

Rate 40	Before			After				
Standard	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
	Usage	Rate (J$)		Usage	Rate (J$)			
Energy kWh	35000	3.89	136,150.00	35000	4.34	151,900.00	15,750.00	11.57%
Demand kVA	100	1466.12	146,612.00	100	1585.70	158,570.00	11,958.00	
Customer Charge			5,160.00			6,330.38	1,170.38	22.68%
Sub Total			**287,922.00**			**316,800.38**	**28,878.38**	**10.03%**
EEIF				35000	0.5638	**19,733.00**		
F/E Adjust		0.101	29,009.40		0.000	-	(29,009.40)	
Fuel & IPP	35000	22.431	785,077.21	35000	22.635	792,238.05	7,160.83	0.91%
Bill Sub-Total			**1,102,008.62**			**1,128,771.43**	**26,762.81**	**2.43%**
GCT @16.5%		0.165	181,831.42		0.165	186,247.29	4,415.86	2.43%
Bill Total			**J$ 1,283,840.04**			**J$ 1,315,018.71**	**31,178.67**	**2.43%**

Bill Comparison for a Typical Rate 50 Customer (Standard)

Usage 500,000 kWh

Demand 1,500 kVA

Rate 50	Before			After				
Standard	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
	Usage	Rate (J$)		Usage	Rate (J$)			
Energy kWh	500000	3.69	1,845,000.00	500000	4.05	2,025,000.00	180,000.00	9.76%
Demand kVA	1500	1319.52	1,979,280.00	1500	1426.90	2,140,350.00	161,070.00	8.14%
Customer Charge			6,192.00			6,330.38	138.38	2.23%
Sub Total			**3,830,472.00**			**4,171,680.38**	**341,208.38**	**8.91%**
EEIF				500000	0.5638	**281,900.00**		
F/E Adjust		0.101	385,936.81		0.000	-	(385,936.81)	
Fuel & IPP	500000	22.431	11,215,388.78	500000	22.635	11,317,686.38	102,297.60	0.91%
Bill Sub-Total			**15,431,797.59**			**15,771,266.76**	**339,469.17**	**2.20%**
GCT @16.5%		0.165	2,546,246.60		0.165	2,602,259.02	56,012.41	2.20%
Bill Total			**J$ 17,978,044.19**			**J$ 18,373,525.77**	**395,481.58**	**2.20%**

Bill Comparison for a Typical Rate 50 Customer (TOU: On-Peak)

Usage 500,000 kWh

Demand 1,500 kVA

Rate 50	Before			After				
TOU (On-Peak)	2013 Rates J$			2014 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	98.89	112.00		112.00	112.00			
	Usage	Rate (J$)		Usage	Rate (J$)			
Energy kWh	500000	3.69	1,845,000.00	500000	4.05	2,025,000.00	180,000.00	9.76%
Demand kVA	1500	733.06	1,099,590.00	1500	789.06	1,183,590.00	84,000.00	7.64%
Customer Charge			6,192.00			6,330.38	138.38	2.23%
Sub Total			**2,950,782.00**			**3,214,920.38**	**264,138.38**	**8.95%**
EEIF				500000	0.5638	**281,900.00**		
F/E Adjust		0.101	297,304.19		0.000	-	(297,304.19)	
Fuel & IPP	500000	30.412	15,206,181.36	500000	30.412	15,206,181.36	-	0.00%
Bill Sub-Total			**18,454,267.55**			**18,703,001.74**	**248,734.19**	**1.35%**
GCT @16.5%		0.165	3,044,954.15		0.165	3,085,995.29	41,041.14	1.35%
Bill Total			**J$ 21,499,221.70**			**J$ 21,788,997.03**	**289,775.33**	**1.35%**

ANNEX E: Submissions/Responses to JPS' Application

Stakeholder Groups

- Fair Trading Commission
- Jamaica Chamber of Commerce
- Jamaica Workers Union
- Ministry of Local Government and Community Development
- Jamaica Institutions of Engineers
- Romain Stewart: Scientific Researcher and Engineering Lecturer
- Consumer Advisory Committee on Utilities (CACU)

Fair Trading Commission

FTC Comments on JPS 2014-2019 Rate Case Submission

Prepared by:
Kevin Harriott, Ph.D. (economics)
FAIR TRADING COMMISSION

April 29, 2014

Background

This opinion is being provided as FTC's contribution to the Office of Utilities Regulation's (OUR's) stakeholder group consultation exercise, as per letter dated March 26, 2014 from Mr. Gordon Brown, Public Affairs Coordinator of OUR to Mr. David Miller, Executive Director of the Fair Trading Commission (FTC). These comments are offered with reference to a document entitled "JPS 2014-2019 Rate Case Submission: Summary Report" issued by the OUR on April 11, 2014. In reviewing the document, our comments are limited to identifying proposals which are likely to influence the incentives for the JPS to operate efficiently, given the regulatory environment in which it operates.

- Proposed Revenue Cap

JPS proposes to replace the current Price Cap regime with a Revenue Cap regime.

1. **A pure revenue cap regime is likely to lessen the incentives for JPS to establish an efficient tariff structure, relative to the incentives to do so under a pure price cap regime.**

Justification:

A revenue cap provides adequate incentives for a profit-maximizing utility company such as the JPS to reduce the total cost of production, since total revenue is guaranteed. A utility company operating under revenue cap, rather than a price cap, can reduce production levels without reducing revenue flows. The company will choose to reduce production costs by (i) satisfying the current demand using more cost-effective production techniques while maintaining the same level of production; and/or (ii) reducing the quantity of electricity demanded below current levels, hence reducing the output volume required to produce to satisfy demand.

Under a revenue cap, the utility company would suppress demand for electricity by simply setting a tariff structure that deviates from efficient levels. In contrast, it would be considerably more costly for the company to improve the productive efficiency of its plants as this would require replacing its stock of inefficient generating machinery (turbines). Accordingly, it is likely that a revenue cap regime provides the

JPS with adequate incentives to set a tariff structure designed to reduce the volume of electricity demanded by its customers. The proposed rate changes are consistent with the view that the tariff structure deviates from efficient pricing principles (for more details on this issue see our comments on proposed rate changes).[1]

- Proposed Rate Changes

The JPS proposes to (i) increase its residential tariff (Rate 10) by 21% on average; (ii) increase its general service tariff (Rate 20) by 15% on average; and (iii) reduce its commercial and industrial tariff (Rate 40 and Rate 50) by 1.5% on average.

2. **The proposed rate change is likely to deviate from accepted rules of efficient pricing, relative to existing structure.**

Justification
It is recognized in regulatory economics that an efficient pricing structure of a monopolist would charge a higher price mark-up for customers whose demand are less sensitive to price changes ('less elastic demand') and charge a lower price mark-up on customers whose demand are more sensitive to price changes ('more elastic demand').[2] The proposed rate changes will increase the price of electricity paid by residential customers, relative to the price paid by commercial and industrial customers. The FTC is unaware of any attempts to measure the elasticity of demand for the different class of customers. We note, however, that studies conducted in other jurisdictions conclude that in the short run, residential customers exert a more elastic demand for electricity compared to commercial customers.[3] If these measures hold true for Jamaica, then under the proposed rate structure JPS would charge a higher mark-up to consumers with the more elastic demand and relatively lower mark-up to consumers with less elastic demand; in violation of an accepted rule for efficiently pricing on the part of a monopolist.

- Proposed Wholesale Tariff

The JPS proposes to introduce a wholesale rate designed to encourage its largest customers to remain entirely on the grid.

3. **The proposal to encourage large customers to remain on the grid is internally inconsistent with the JPS proposal to replace the price cap regime with a revenue cap regime.**

Justification:

[1] For a more detailed discussion on efficient pricing in a monopoly market, see Frontier Economics, 2009. Theory of Efficient Pricing of Electricity Transmission Services: A report prepared for the New Zealand Electricity Commission. Available at www.ea.gov (last accessed: April 29, 2014)
[2] This is referred to as Ramsey rule for efficient pricing (in natural monopoly markets).
[3] See Bernstein, M.A. and J. Griffin, 2006. Regional Differences in Price Elasticity of Demand. Available at http://www.nrel.gov/docs/fy06osti/39512.pdf (last accessed April 29, 2014).

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For reasons explained above, a revenue cap provides adequate incentives for any utility company to discourage demand as a reduction in demand will increase profits by reducing production costs without any reduction in revenue.

- Three year Rate Review Request

The JPS proposes that the rate review period be reduced from five years to three years.

4. **The FTC does not support the proposal to reduce the review period to three years as it would likely frustrate the ability of the regulator (OUR) to monitor and evaluate the behavior of the utility company.**

Justification:
One of the inherent problems overseeing any regulated industry is the information asymmetry problem which exists between the regulator and the regulated entity. Typically, the regulated entity has superior information about, say, the costs of providing the service. Reducing this asymmetry is one of the crucial reasons for establishing a review period since it allows the regulator to acquire critical information while key variables, such as price, are stabilized. Reducing the review period is likely to reduce the quality of the information that the regulator has at its disposal when reviewing the rates, hence exacerbating the information asymmetries. In practice, the rate review period is typically between 4 and 6 years and we know of no compelling reason for the JPS review period to be established outside of this range.[4]

- Proposed Non-fuel Rate Schedule
  Comments reserved

- Proposed Tariff Design
  Comments reserved

- Proposed FX Adjustment Factor
  Comments reserved

- Foreign Exchange Losses
  Comments reserved

- Interest on Accounts Receivables for Commercial Customers
  Comments reserved

- Community Renewal Programme
  Comments reserved

[4] See page 3 of Jamison, Mark A. Regulation: Price Cap and Revenue Cap. Available for download at http://warrington.ufl.edu/centers/purc/purcdocs/papers/0527_jamison_regulation_price_cap.pdf (last accessed: April 28, 2014)

- <u>Prepaid Metering</u>
  Comments reserved

- <u>Proposed System Losses & Heat Rate Targets</u>
  Comments reserved

- <u>Quality of Service Standards</u>
  Comments reserved

Jamaica Chamber of Commerce

The Jamaica Chamber of Commerce

Suite 13-15, UDC Office Centre Building • 12 Ocean Boulevard, Kingston • Tel: (876) 922-0150–1; 922-4857
Fax: (876) 924-9056 • Email- info@jamaicachamber.org.jm • Website: www.jamaicachamber.org.jm

OUR 30/4/14

JCC RESPONSE TO JPS RATE INCREASE REQUEST

1. Proposed Non-fuel Rate Schedule in JMD

The requested rate increases will be used to maintain or better JPS performance. Have all the performance guarantees set by the OUR been met? This should determine the level of increase.
We support the differential rates, and the special rate designed to keep the large consumers on the system.
How much of the spinning reserve is on line and is that now included in the proposed rate request?
An independent study could be of assistance in determining the rates.

2. Proposed Revenue Cap

The report shows conclusively that the PBRM has caused JPS to become more efficient. Why should it therefore be changed?

3. Proposed Tariff Design

We support a tariff structure that allocates costs according to a usage profile

4. Proposed Wholesale Tariff

We support the wholesale tariff in principle, as an inducement to keep the bigger users online. An independent study is suggested.

1

Jamaica Workers Union

JAMAICA WORKERS UNION
78 SLIPE ROAD, KINGSTON 5. PHONE: 754-2955 FAX: 754-8483
E-mail: jamaicaworkersunion@yahoo.com

April 14, 2014

Honourable Phillip Paulwell
Minister of Science, Technology, Energy and Mining
Ministry of Science. Technology, Energy and Mining
PCJ Building
36 Trafalgar Road
Kingston 10

Dear Minister Paulwell,

Re: Proposed Hike in Electricity Rates

We note with grave concern the proposed increase in electricity rates proposed by the Jamaica Public Service (JPS) and currently being considered by the Office of Utility Regulation (OUR). We wish to make it pointedly clear that we are absolutely opposed to any increase in electricity rates at this point in time.

Our position stems primarily from the fact that Public Sector workers are currently bound by an agreed wage freeze and in furtherance, that the working class would find it virtually impossible to absorb same at this time.

We are of the view that the primary focus of the JPS should be to improve efficiency and also focus on the reduction of electricity theft.

It must be noted that there is already restiveness among public sector workers regarding this matter and which has the potential to escalate into industrial action.

We therefore urge that this issue be carefully considered with a sense of empathy.

With Best Regards.

Yours truly,

Clifton Brown
PRESIDENT

C. Mr. Ray Howell, General Secretary (Actg.), Jamaica Confederation of Trade Unions

Clifton Brown: President * Lascell Spence: 1st Vice President * Keith Lowe: 2nd Vice President
* Leonie Sterling-Williams: 3rd Vice President * Lorraine Brown: General Secretary

Ministry of Local Government and Community Development

OFFICE OF UTILITIES REGULATION
MAY 3 0 2014

MINISTRY OF LOCAL GOVERNMENT AND COMMUNITY DEVELOPMENT

85 HAGLEY PARK ROAD, KINGSTON 10, JAMAICA
Telephone: (876) 754-0992-9; 754-1010; 754-1041; 754-1005
Email: permanentsecretaryoffice@mlge.gov.jm.
Web site: www.localgovjamaica.gov.jm

May 27, 2014

Mr Albert Gordon
Director General
Office of Utilities Regulation
36 Trafalgar Road
Kingston 10

2014/05/30

Dear Mr Gordon:

Re: MLGCD review of the Tariff Application 2014-2019 submitted by JPS

The Ministry of Local Government and Community Development (MLGCD), as you are aware, has responsibility for the Local Authorities and by extension the liability for streetlight electricity charges. The application by the JPS for a tariff to cover the period 2014 – 2019 is therefore of critical importance to us, particularly the aspects related to streetlighting designated Rate 60.

Having reviewed the tariff application, a presentation containing our findings and recommendations was discussed at the OUR yesterday, Monday, May 26, 2014. A copy of the presentation is attached to this correspondence for reference. A summary of our findings are as follows:

1. Multiple jurisdictions worldwide are replacing their current streetlights with LED lights. Given the difference in costs of LED lights it is recommended that the tariff include rates for LED lights.
2. The JPS has indicated that they are not in a position to replace the existing inefficient lights. The GOJ has decided to replace the existing lamps with LEDs.
3. Given the basis for the computation of the tariff, the current value of streetlights per JPS records should be clearly stated in their application.
4. The capital and maintenance costs expended on streetlights should be clearly stated.
5. The age of the lamps, average life and method of depreciation should be clearly stated.
6. The revised streetlight tariff should include rates for customer owned and maintained lamps.
7. The Energy Charge for customer owned and maintained lamps should be reduced by removing the cost of maintenance and capital cost of replacement.
8. The non-replacement of inefficient streetlights is now costing the GOJ-MLGCD an avoidable recurrent expense of approximately J$1.7Billion/year.
9. The tariff should recognise that streetlight management systems now allow for flexible streetlight operation including dimming with significant additional energy saving.

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May 27, 2014

Mr Albert Gordon
Director General
Office of Utilities Regulation

Re: MLGCD review of the Tariff Application 2014-2019 submitted by JPS

The high cost of streetlighting has been, as you are aware, an area of focus recently. There have been multiple references to the subject in the Parliament prior to and during the 2014 budget debate. The monthly cost of approximately J$260 million coupled with the arrears of J$2.7 billion are an excessive drain on the Property Taxes collected and is unsustainable. This also deprives Jamaican citizens of other services which could and should be provided via their Property Taxes.

The streetlighting service is currently provided by JPS. The high cost of electricity supply to streetlights of approximately J$40.00 per KWH will rise even further, by an estimated 15%, based on the current JPS tariff application to the OUR. This high cost is compounded by the inefficient streetlight fittings currently being deployed by the JPS.

Cabinet has given approval for the identification and implementation of more efficient and cost-effective streetlighting systems. These include the replacement of the current streetlight fittings with more efficient LED lamps, the management of the entire system to minimise energy consumption, and the amendment of the streetlight tariff to reflect the new and evolving streetlighting technologies and modes of operation.

In pursuit of the above, the MLGCD intends to embrace every opportunity to be apprised of the most current streetlighting systems and technologies which are commercially available, and to incorporate these into, and inform our retrofit program.

It is anticipated that the perspectives of the MLGCD will be integral to the process of the finalisation of a tariff which will make provision for the evolution of the streetlighting systems and be in harmony with international best practice. The MLGCD remains available to provide any further clarification which the OUR may require.

Sincerely

Dione Jennings (Mrs)
Permanent Secretary (Actg.)

Copy: Hon. Noel Arscott, Minister of Local Government & Community Development
Hon. Peter Bunting, Minister of Science, Technology Energy and Mining
Mrs. Hillary Alexander, Permanent Secretary – Ministry of Science, Technology Energy and Mining

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MINISTRY OF LOCAL GOVERNMENT AND COMMUNITY DEVELOPMENT

PERSPECTIVES ON THE JPS TARIFF APPLICATION 2014-1019

WITH SPECIFIC REFERENCE TO STREETLIGHTING

GENERAL OBSERVATIONS

1. The tariff is up for review in 2014 as per the JPS application dated April 7. 2014.
2. It is based on the premise that JPS collects enough revenue to recoup its expenses and make an agreed margin.
3. In the tariff 2009-2014 under Rate 60 the Energy Charge is the component unique to Streetlights and Traffic lights and is one common fee of J$15 /KWH.
4. The listing of multiple fittings with different Energy Charges in the tariff can be misleading as all have the same cost per KWH.
5. The total current cost of electricity supply to streetlights is approximately J$40/KWH.
6. Cost for similar service in the USA is US$0.20 including maintenance and US$0.14 excluding maintenance by the utility..
7. There is no incentive for efficient streetlighting.
8. There is an implicit incentive for inefficient streetlighting when JPS makes a markup on gross operating costs.
9. There is no evidence in the streetlight tariff application or determination that issues unique to streetlights were considered.
10. Utilities in other jurisdictions have streetlight tariffs for both utility owned and non-utility owned lamps. The difference in maintenance costs is explicitly stated in the tariff.
11. The current tariff for streetlights has not had fundamental review since the OUR Determination Notice dated September 18, 2009. It assumes that a small set of luminaries (HPS 70, 100, 125, 250, 400 and some MV) operate for 12 hours per day at full power. A fixed charge per KWH is therefore applied to consumption.

TARIFF ISSUES GENERAL

1. There is no available data in the body of the tariff application regarding the capital expenditure on streetlights.
2. There is no available data in the tariff application on the maintenance expended by JPS on streetlights.
3. The cost of inefficient streetlights is passed through to the GOJ-MLGCD.
4. Maintaining the high revenue stream from streetlights is seen by JPS as a means of maintaining their profit margin.
5. The non-replacement of inefficient streetlights by JPS is counter to the GOJ energy policy.
6. The non-replacement of inefficient streetlights is now costing the GOJ-MLGCD an avoidable recurrent expense of approximately J$1.7Billion/year.

•

Review of JPS Rate Application 2014-2019

1. JPS is aware of the GOJ plan to have the current streetlights replaced with LED fittings.
2. The tariff is based on a "revenue cap" in contrast to a tariff cap as in the previous 2009-2014 tariff. In effect it guarantees the JPS a rate of return on assets.
3. There is no detailed breakdown of how the streetlight rates are determined.
4. There is no differential rate for streetlights owned and operated by JPS versus customer owned streetlights.
5. There are no details regarding the cost of streetlight retrofits, maintenance or asset value.
6. There is one "Energy Charge" for streetlights which is assumed to include the current HPV , MV and Incandescent lamps.
7. There is no provision for the retrofit to LED streetlights with their significantly longer life, increased reliability.
8. The application proposes a 45% increase in the "Energy Charge" which is projected to increase the overall bill by 15%

RECOMMENDATIONS

1. The current value of streetlights per JPS records needs to be clearly stated.
2. The capital and maintenance costs expended on streetlights needs to be clearly stated.
3. The age of the lamps, average life and method of depreciation needs to be clearly stated.
4. The revised streetlight tariff should include rates for customer owned and maintained lamps
5. The Energy Charge for customer maintained lamps should be reduced by removing the cost of maintenance.
6. The tariff for the new system will be based on KWH consumption reported by the system.
7. The JPS Tariff Application 2014-2019 proposes a 45% increase in the Rate 60 Streetlighting Energy Charge moving from US$0.145 to US$0.21 /KWH.
8. This is estimated by JPS to increase the overall Streetlight Bill by 15%.

Factors Impacting the Tariff by Replacement with LEDs Owned by GOJ

1. Elimination of any capital recovery charge in the Energy Charge.
2. Elimination of maintenance charges in the Energy Charge. (GOJ will engage private maintenance)
3. Reduction on Technical Losses by elimination of electro-magnetic ballasts used in current lamps. These generally have a lower power factor than LED lamps.
4. Incorporation of a factor to reflect the "Off-Peak" nature of the streetlight load
5. Incorporation of a factor to reflect the predictability of the streetlight load.
6. Incorporation of a factor to reflect the future smart management of streetlights facilitating managed load shedding if required.

RATES PROPOSED BY JPS INCLUDING STREEETLIGHT RATE60

Tariff Design (Non-fuel)

Table 8-29: Non-fuel Final Rate Schedule in USD

	Network Access Charge USD/Month	Energy Charge USD/kWh	Demand Charge USD/kVA			Standby Rate (USD/kVA)		
			STD and On-Peak	Partial-Peak	Off-Peak	STD and On-Peak	Partial-Peak	Off-Peak
RT 10 Prepaid Rate		0.22						
RT 10 Community Renewal Program	0.00	0.07						
RT 10 LV Res. Service < 100 kWh	6.00	0.09						
RT 10 LV Res. Service 100-500 kWh	12.00	0.22						
RT 10 LV Res. Service > 500 kWh	18.00	0.28						
RT 10 LV Res. Service - Net Billing	18.00	0.00	70.00					
RT 20 LV Gen. Service < 100 kWh	9.00	0.20						
RT 20 LV Gen. Service 100-1000 kWh	15.00	0.19						
RT 20 LV Gen. Service 1000-7500 kWh	25.00	0.19						
RT 20 LV Gen. Service > 7500 kWh	40.00	0.12						
RT 20 LV Gen. Service - Net Billing	25.00	0.00	80.00					
RT 60 LV Street Lighting	40.00	0.21						
RT 40 (Std)< 1 MVA	80.00	0.00	28.50					
RT 40 (Std)- From 1 MVA to 2 MVA	80.00	0.00	27.65					
RT 40 (Std)- From 2 MVA to 3 MVA	80.00	0.00	26.79					
RT 40 (Std)- From 3 MVA to 4 MVA	80.00	0.00	25.94					
RT 40 (Std)> 4 MVA	80.00	0.00	25.08					
RT 40 (Std) - Net Billing	80.00	0.00	28.00					
RT 40 (Std) - Wheeling	80.00	0.00	14.54			13.10		
RT 40 (TOU)< 1 MVA	80.00	0.00	16.05	12.54	1.21			
RT 40 (TOU)- From 1 MVA to 2 MVA	80.00	0.00	15.56	12.16	1.17			
RT 40 (TOU)- From 2 MVA to 3 MVA	80.00	0.00	15.08	11.79	1.14			
RT 40 (TOU)- From 3 MVA to 4 MVA	80.00	0.00	14.60	11.41	1.10			
RT 40 (TOU)> 4 MVA	80.00	0.00	14.12	11.04	1.06			
RT 40 (TOU) - Wheeling	80.00	0.00	8.19	6.40	0.62	7.86	6.14	0.59
RT 50 (Std)< 1 MVA	80.00	0.00	26.18					
RT 50 (Std)- From 1 MVA to 2 MVA	80.00	0.00	25.38					
RT 50 (Std)- From 2 MVA to 3 MVA	80.00	0.00	24.59					
RT 50 (Std)- From 3 MVA to 4 MVA	80.00	0.00	23.81					
RT 50 (Std)> 4 MVA	80.00	0.00	23.02					
RT 50 (Std) - Net Billing	80.00	0.00	27.00					
RT 50 (Std) - Wheeling	80.00	0.00	13.35			12.03		
RT 50 (TOU)< 1 MVA	80.00	0.00	14.54	11.34	1.16			
RT 50 (TOU)- From 1 MVA to 2 MVA	80.00	0.00	14.10	11.00	1.13			
RT 50 (TOU)- From 2 MVA to 3 MVA	80.00	0.00	13.66	10.66	1.09			
RT 50 (TOU)- From 3 MVA to 4 MVA	80.00	0.00	13.23	10.32	1.06			
RT 50 (TOU)> 4 MVA	80.00	0.00	12.79	9.98	1.02			
RT 50 (TOU) - Wheeling	80.00	0.00	7.42	5.78	0.59	7.12	5.55	0.57

JPS STREEETLIGHT ASSUMPTIONS

17.3.2.1 Street lighting (R60)

The assumptions for projecting the number of customers and total consumption of streetlights are based on our historic trend analysis. Table 17-7 summarizes our key assumptions for projecting sales in rate class R60.

Table 17-7: Model Assumptions for Street Lighting (R60)

Variable	Model Assumptions
Number of customers	
	Number of customers grows in line with historic trend (compound annual growth rate from 2004 to 2012)
Total consumption	
Urban population	Total consumption grows at the same rate as urban population
Reduction in total consumption	
Energy efficiency measures by customers	We assume that streetlights will start to be replaced by LEDs in 2017. We assume that it will take about ten years until all streetlights are replaced with LEDs. The total consumption reduction through LEDs is expected to be 40 percent.

[130] IMF, World Economic Outlook Database 2013, April 2013.

The historic trend analysis showed that total electricity consumption of electricity by streetlights is driven by urban population growth. We do not expect any streetlight additions from the Government's highway expansion project during the regulatory period. We thus assume that total consumption will grow from 2014 to 2019 at the same rate as the urban population. For the urban population, we assume that it will continue to grow at its historic trend from 2014 to 2019. We thus used the compound annual growth rate of population growth from 2001 to 2011 to project urban population growth.

PROPOSED STREEETLIGHT RATE60

Class	Typical Customer's Billing Determinants and Billing				
	Customer	Energy (kWh/month)	Current Billing (USD/month)	Proposed Rate Billing (USD/month)	Variation (%)
RT 60 LV Street Lighting	1	15,800	6,098	7,022	15%

Class	Current Rate Billing (JMD/month)	Proposed Rate Billing (JMD/month)	Variation (%)
RT 60 LV Street Lighting	683,034	786,441	15%

Base exchange rate of JMD112:USD1

8.4.3.4 Large Commercial Customers—RT40 and RT50

Regular Tariff

Definition and proposed charges for non-fuel costs recovery

The Power Service Low Voltage category keeps the current tariff structure. These classes comprise users with a very wide range of energy and demand consumption. Because the surplus in these categories is based on the analysis of the average customer, implementing the NAC as a fixed charge per customer is inappropriate, mainly because of the influence of customers whose consumption is far below the class average. So, the second best solution is to state a charge expressed in terms of contracted capacity ($/kVA/month). At the same time, and based on the results obtained from the load characterisation study, the load profiles of these customers contribute positively to JPS' total system load profile. This indicates that the signal price by time-of-use block facing these customers is satisfactory. In an attempt to minimise the possible changes to the existing tariff structure for these classes, the portion of the NAC that cannot remain as fixed charge is allocated in the demand charge ($/kVA) or is energised, to become part of the energy charge ($/kWh) to equalise charges between RT40 and RT50, and between the Standard and TOU options:

- NAC: applicable whether there is consumption and irrespective of consumption. It covers the customer service marginal costs and a portion of the Revenue Gap.
- Energy charge: This charge is paid for every kWh of consumption and it covers capacity marginal cost and a portion of non-fuel costs that are part of the revenue gap.
- Demand charge
  - Standard Option:
    1. One demand charge applicable on each kVA billing demand
    2. Billing demand: The kilovolt-ampere (kVA) Billing Demand for each month shall be the maximum demand for that month, or 80% of the maximum demand during the five-month period immediately preceding the month for which the bill is rendered, whichever is higher, but not less than 25 kilovolt-amperes.
  - TOU Option:
    1. One demand charge applicable on each kVA billing demand per hour block.

45% CHANGE IN ENERGY CHARGE 2014 vs 2009

Base exchange rate of JMD112:USD1

The General Service category has on average an increase of *9%*.

8.4.3.3 Street Lights and Traffic Lights— RT60

Definition and proposed charges for non-fuel costs recovery

The Street Lighting category tariff structure remains the same:

- NAC: applicable whether there is consumption. It covers the customer service marginal costs and a portion of the Revenue Gap.
- **Energy charge:** This charge is paid for every kWh of consumption and it covers capacity marginal cost and a portion of non-fuel costs that are part of the revenue gap.

Rate schedule

According to the proposed tariff design, the non-fuel rate schedule and its comparison with the adjusted current rate schedule is as follows:

Table 8-18: RT60 Rate Schedule

Class	Proposed Rates		Current Rates		Variation %	
	Network Access Charge (USD/Cust./ month)	Energy Charge (USD/kWh)	Customer Charge (USD/Cust./ month)	Energy Charge (USD/kWh)	NAC vs Customer Charge	Energy Charge
RT 60 LV Street Lighting	40.000	0.210	22.892	0.145	75%	45%

Billing impact

The proposed rates, when applied to the average street lighting customer, yield the monthly bill presented in the table below. A comparison with the adjusted actual rates in force is also shown.

Given the interest in showing the total average tariff variation, a fuel charge needs to be considered in the analysis. For our purposes, a fuel charge is added to current non-fuel rates (0.239 USD/kWh). This fuel charge is based on the same data used to determine the February 2014 fuel charge, but relies on the proposed losses target of 21.5%, and excludes the FCRA component that will end in June 2014. The resulting fuel charge is 0.232 USD/kWh.

JPS ESTIMATES STREETLIGHT BILLS TO INCREASE BY 15%

Class	Typical Customer's Billing Determinants and Billing				
	Customer	Energy (kWh/month)	Current Billing (USD/month)	Proposed Rate Billing (USD/month)	Variation (%)
RT 60 LV Street Lighting	1	15,800	6,098	7,022	15%

Class	Current Rate Billing (JMD/month)	Proposed Rate Billing (JMD/month)	Variation (%)
RT 60 LV Street Lighting	683,014	786,441	15%

Base exchange rate of JMD112:USD1

JPS STREEETLIGHT ASSUMPTIONS

17.3.2.1 Street lighting (R60)

The assumptions for projecting the number of customers and total consumption of streetlights are based on our historic trend analysis. Table 17-7 summarizes our key assumptions for projecting sales in rate class R60.

Table 17-7: Model Assumptions for Street Lighting (R60)

Variable	Model Assumptions
Number of customers	
	Number of customers grows in line with historic trend (compound annual growth rate from 2004 to 2012)
Total consumption	
Urban population	Total consumption grows at the same rate as urban population
Reduction in total consumption	
Energy efficiency measures by customers	We assume that streetlights will start to be replaced by LEDs in 2017. We assume that it will take about ten years until all streetlights are replaced with LEDs. The total consumption reduction through LEDs is expected to be 40 percent.

The historic trend analysis showed that total electricity consumption of electricity by streetlights is driven by urban population growth. We do not expect any streetlight additions from the Government's highway expansion project during the regulatory period. We thus assume that total consumption will grow from 2014 to 2019 at the same rate as the urban population. For the urban population, we assume that it will continue to grow at its historic trend from 2014 to 2019. We thus used the compound annual growth rate of population growth from 2001 to 2011 to project urban population growth.

JPS ANTICIPATION OF STREEETLIGHT CONVERSION TO LED

The Power (Self) Wheeling initiative was introduced in a 2013 OUR Determination Notice and will be implemented in 2014. It is expected to enable large commercial and industrial customers, rate classes R40 and R50, to self-supply electricity using off-site generation. Only one customer has made a formal application to JPS for a power wheeling license however, customer surveys conducted by JPS in 2013 indicates that several large customers are interested in either self-generation or power wheeling, but are awaiting the development of Wholesale tariffs for large industrial customers and a better understanding of timing of the proposed Energy World International's (EWI) 381MW LNG base-load project before finalizing their resource decisions. A delay or failure of the EWI 381MW LNG project could cause a significant risk to JPS' electricity sales as these large industrial customers fully appreciate that the fuel cost now represents more than 75% of their total energy cost. Further, the uncertainty with the development and timing of the EWI project and the addition of 78 to 115 MW of renewables not only makes fulfilling the timelines of the national energy policy challenging, and makes managing resources and financial planning difficult for JPS.

The energy landscape has also transformed given the proliferation of projects to create the supporting infrastructure for the development of an Energy Services Company (ESCO) Industry in Jamaica. According to the Government, the ESCO industry has the potential to create new businesses, generate new jobs, and deliver savings in energy consumption and cost, and climate change mitigation through reduced carbon emissions. Currently, there are over forty companies in Jamaica that can be identified as ESCOs which are providing a wide range of energy services including auditing, energy management and sales and servicing of energy efficiency and renewable energy equipment. In addition, the government has announced a raft of initiatives that it is planning to implement to reduce energy consumption in the public sector, for example, it has received USD$20 million dollar from the Inter-American Development Bank (IDB) to implement energy conservation opportunities in public sector buildings and we now understand that local government is resolved to convert all of its streetlights to energy efficient LED lights in the near future. Additionally, the National Water Commission (NWC) has also received separate financing from the IDB to optimize the efficiency of its water distribution system and to improve its energy efficiency. These two entities are in fact JPS' two largest customers under the existing tariff regime and their conservation efforts will significantly impact the sales outlook for the future.

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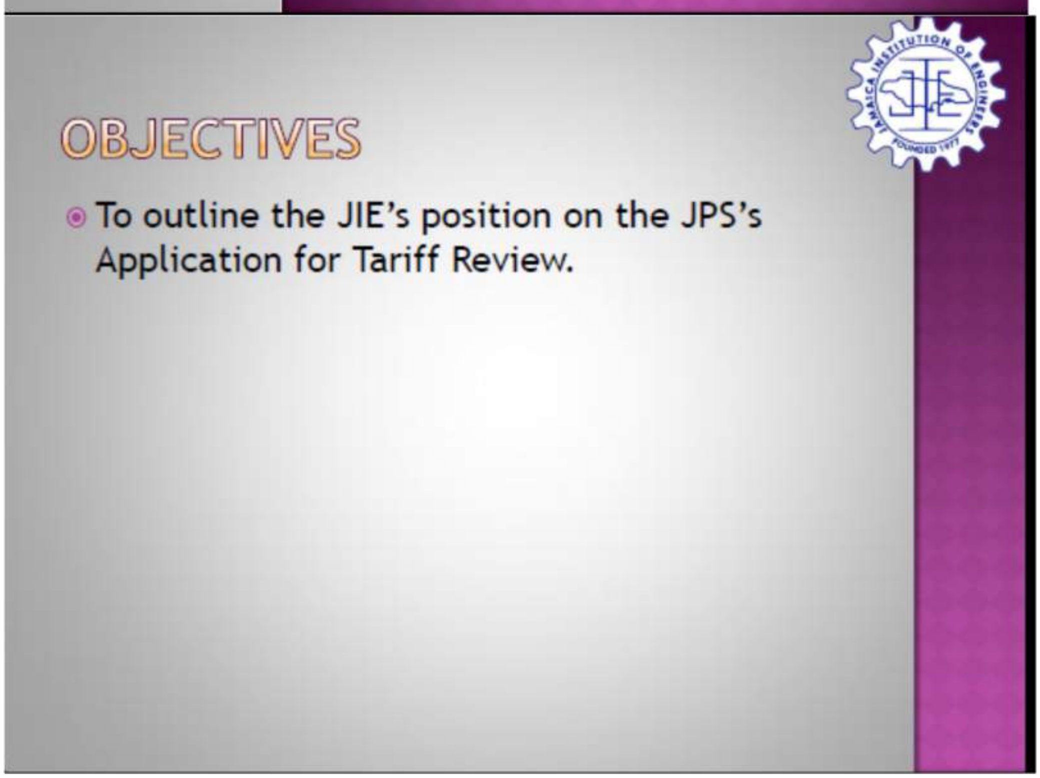
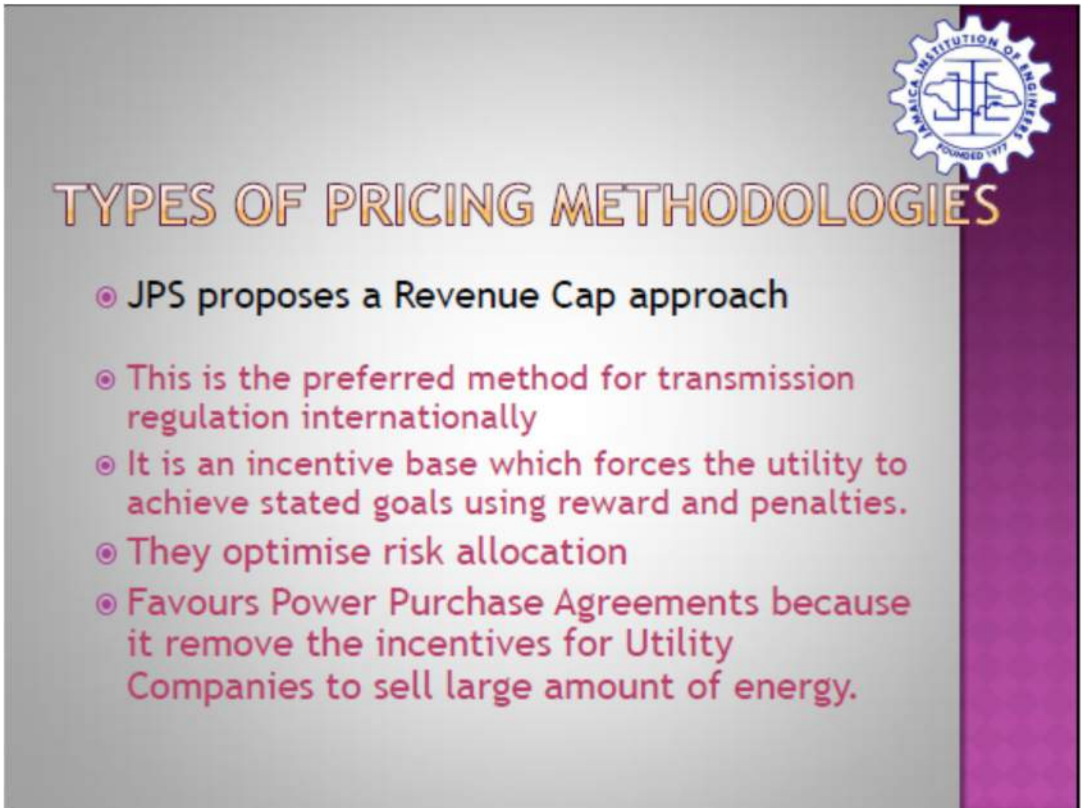
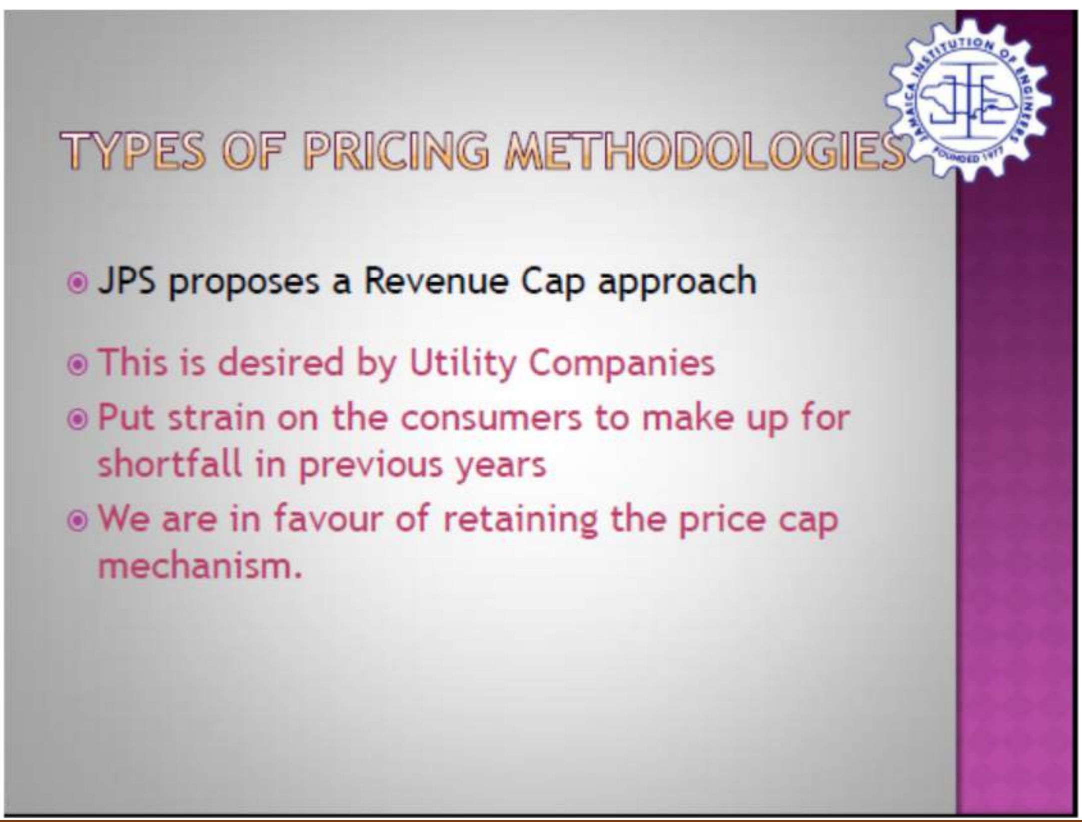
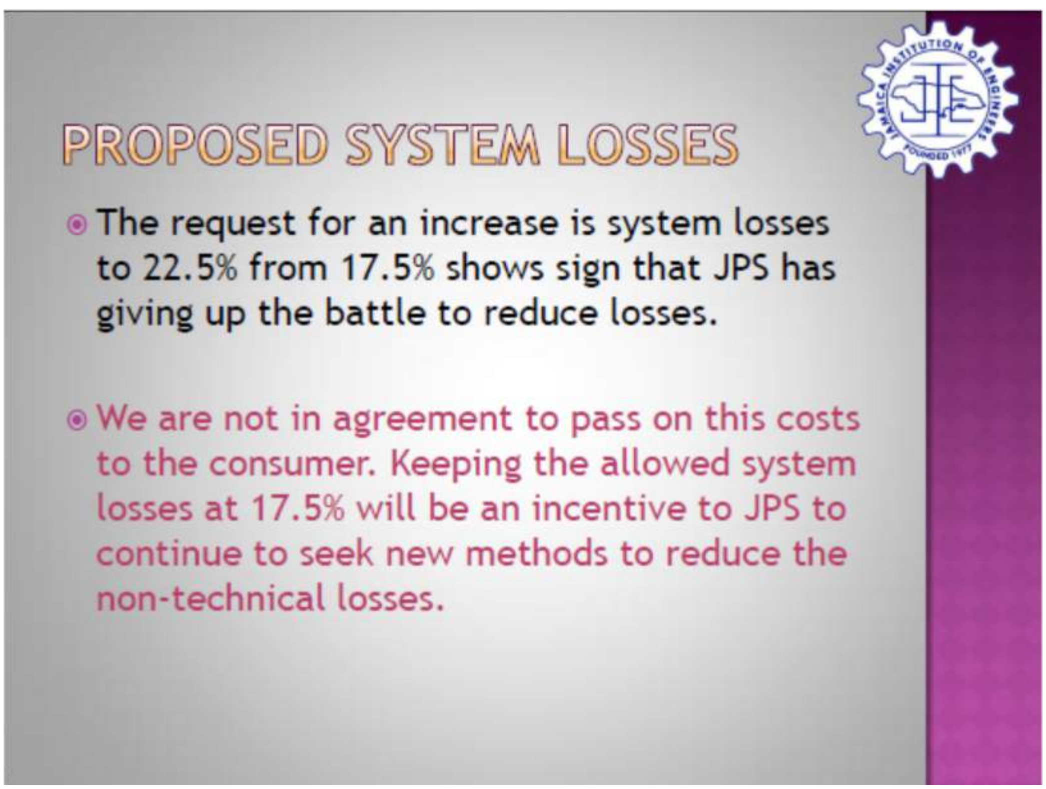
Jamaica Institutions of Engineers



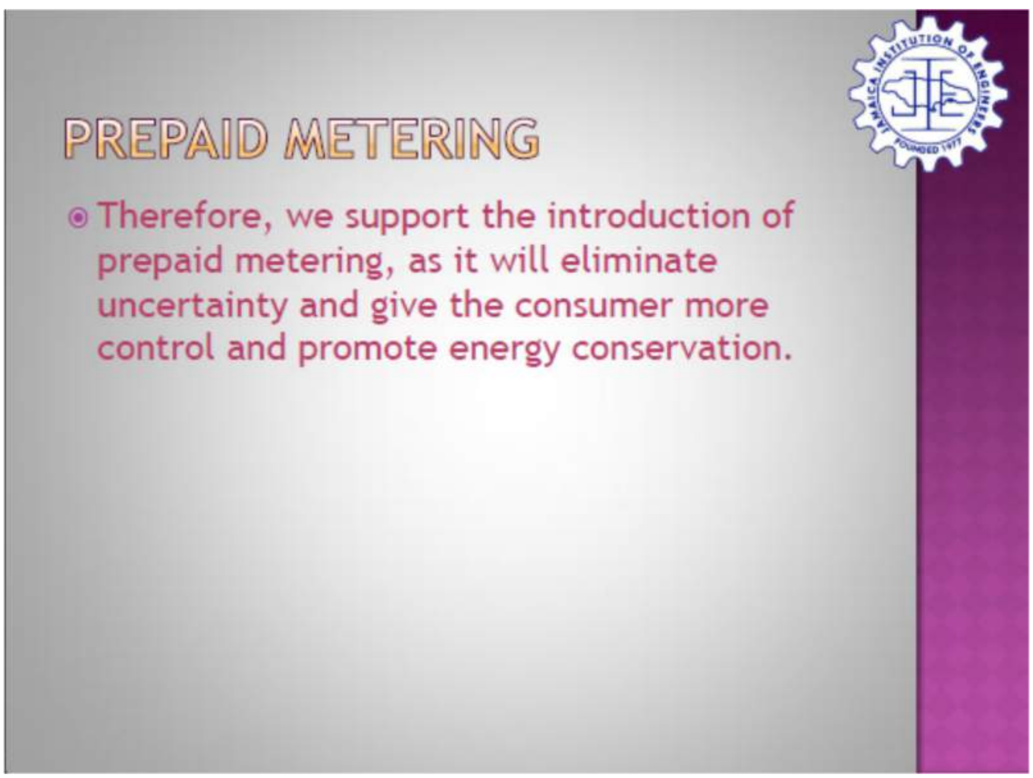

TYPES OF PRICING METHODOLOGIES
JPS proposes a Revenue Cap approach
This is the preferred method for transmission regulation internationally
It is an incentive base which forces the utility to achieve stated goals using reward and penalties.
They optimise risk allocation
Favours Power Purchase Agreements because it remove the incentives for Utility Companies to sell large amount of energy.

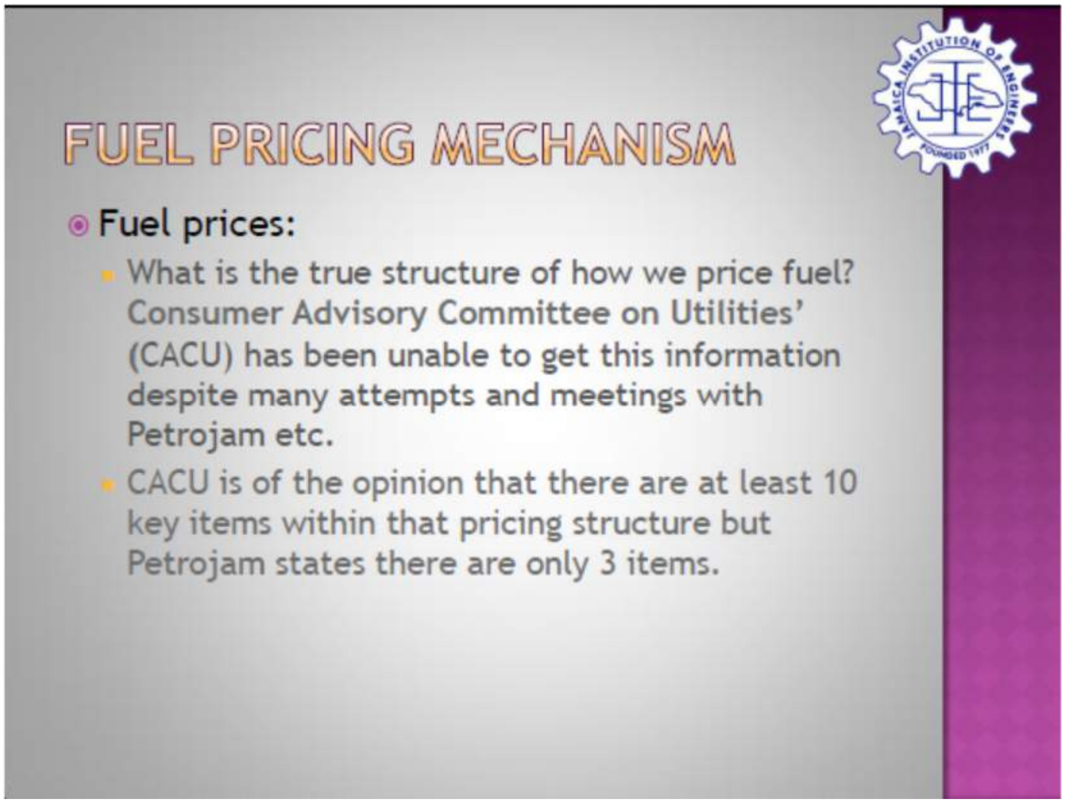

TYPES OF PRICING METHODOLOGIES
JPS proposes a Revenue Cap approach
This is desired by Utility Companies
Put strain on the consumers to make up for shortfall in previous years
We are in favour of retaining the price cap mechanism.

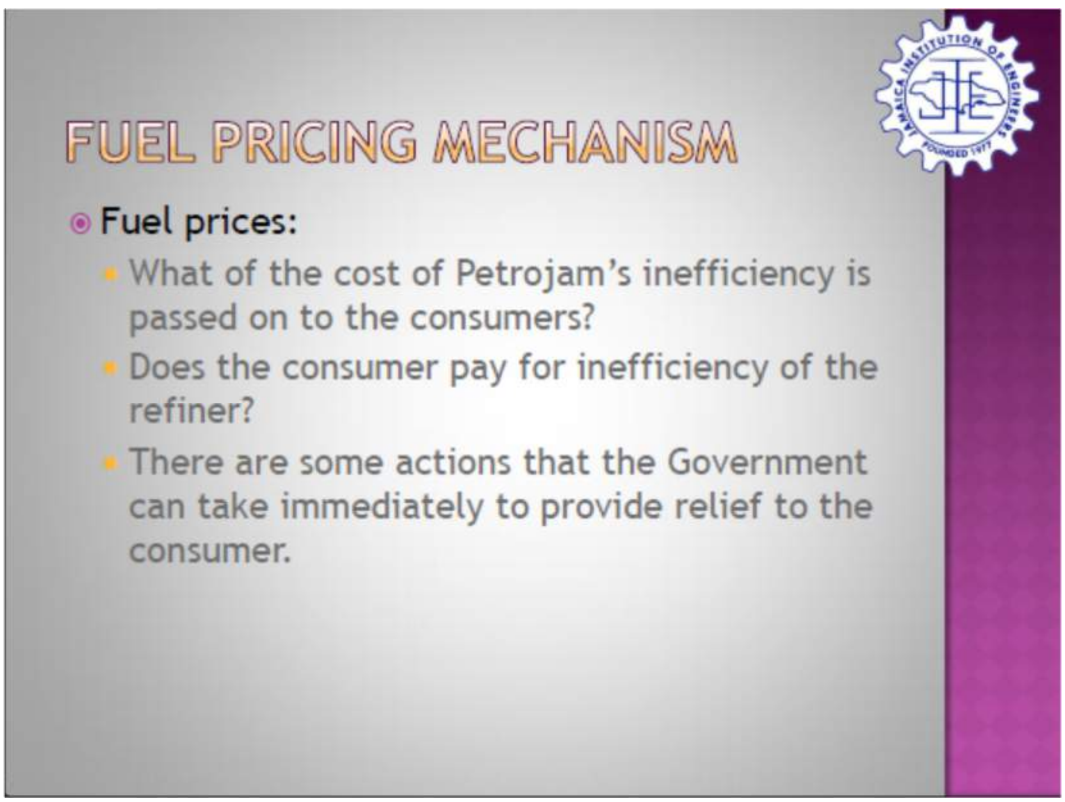

PROPOSED WHOLESALE TARIFF
This will allow JPS to respond to market changes within a short period of time as technology is changing rapidly. This is within the context of price cap (i.e. rates will be less than the full cost of providing service). This will encourage larger customers to remain on the grid and hence reducing the upward pressure of prices on the remaining customers.
We are in favour of Wholesale Tariff.

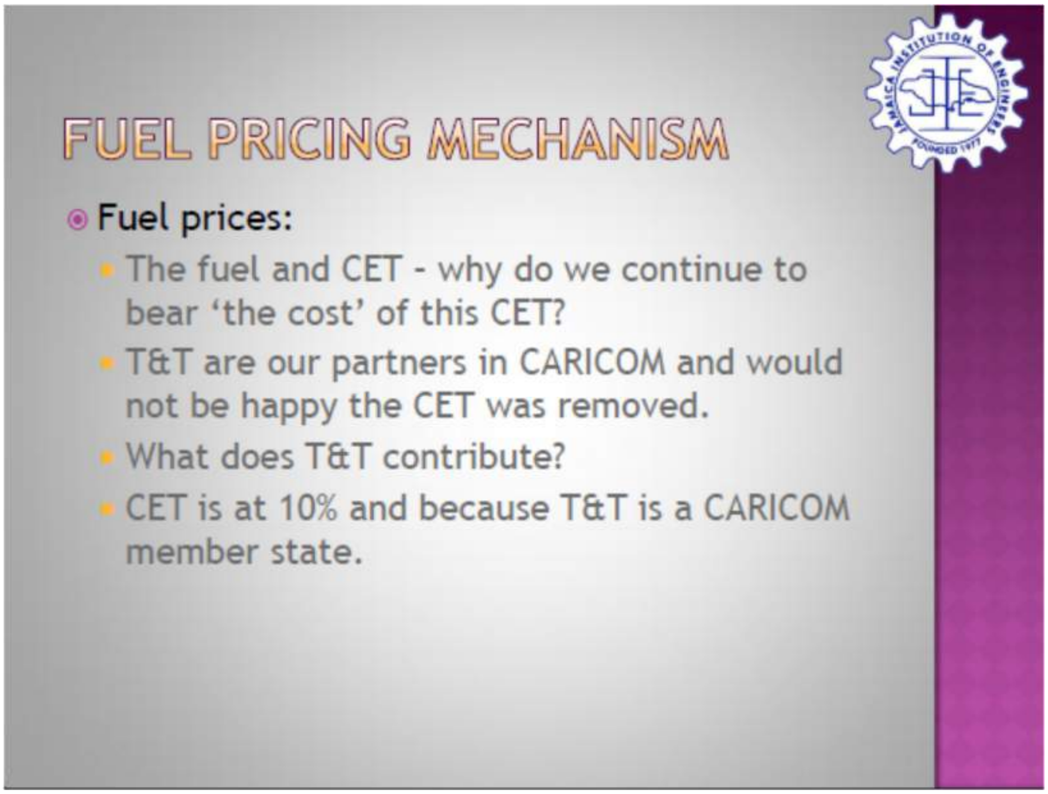

PROPOSED SYSTEM LOSSES
The request for an increase is system losses to 22.5% from 17.5% shows sign that JPS has giving up the battle to reduce losses.
We are not in agreement to pass on this costs to the consumer. Keeping the allowed system losses at 17.5% will be an incentive to JPS to continue to seek new methods to reduce the non-technical losses.


PREPAID METERING
Currently, postpaid metering take away all control from the consumer.
They have no idea of their daily, or weekly consumption. They don't know how much electricity their appliances use or able to identify where in homes or business facilities they are wasting electricity or how much the bill might go up during different seasons.
The utility company sends you a bill at the end of the month with very few details.


PREPAID METERING
Therefore, we support the introduction of prepaid metering, as it will eliminate uncertainty and give the consumer more control and promote energy conservation.


FUEL PRICING MECHANISM
Fuel prices:
What is the true structure of how we price fuel? Consumer Advisory Committee on Utilities' (CACU) has been unable to get this information despite many attempts and meetings with Petrojam etc.
CACU is of the opinion that there are at least 10 key items within that pricing structure but Petrojam states there are only 3 items.


FUEL PRICING MECHANISM
Fuel prices:
What of the cost of Petrojam's inefficiency is passed on to the consumers?
Does the consumer pay for inefficiency of the refiner?
There are some actions that the Government can take immediately to provide relief to the consumer.


FUEL PRICING MECHANISM
Fuel prices:
The fuel and CET - why do we continue to bear 'the cost' of this CET?
T&T are our partners in CARICOM and would not be happy the CET was removed.
What does T&T contribute?
CET is at 10% and because T&T is a CARICOM member state.


GUARANTEED STANDARD
Reported compensatory pay-outs relating to these breaches was approximately $480,000 out of a potential compensatory pay-out of approximately $32 million.
Seventy-eight percent (78%) of the total pay-out was by way of automatic compensation.
Low level of claims has not acted as an effective driver of efficient performance.


GUARANTEED STANDARD
Guaranteed Standards Scheme that aims to improve the efficiency of service delivery of the JPS, is not achieving the intended objective.
Compensation mechanism is not assisting OUR in achieving its legislated mandate to undertake such measures as it considers necessary or desirable to protect the interests of consumers.


GUARANTEED STANDARD
Review of the automatic and claimable compensation system with an aim to foster greater compliance with the Guaranteed Standards Scheme by JPS.
OUR could consider levying a penalty on the JPS for breaches.


THANK YOU
"As we continue to work to create a modern, efficient, diversified and environmentally sustainable energy sector…"
JAMAICA INSTITUTION OF ENGINEERS
FOUNDED 1977

Romain Stewart: Scientific Researcher and Engineering Lecturer

Inefficiency, Unreliability & Imprudence
A Submission on the
Jamaica Public Service Company Limited

Tariff Application 2014-2019
'Going for Growth'
By:
Romain G. Stewart B.Sc. Mech. Eng., B.Sc. Psych., P.G. Dip. Ed & Tr
April 26, 2014
Montego Bay, JAMAICA 2

April 26, 2014

The following constitutes a formal submission on the Jamaica Public Service Company (JPSCo) Limited and their 2014-2019 Tariff Application, 'Going for Growth' to the Office of Utilities Regulation (OUR). The arguments used against the Tariff Application are scientific.

Broad Topic: Performance and Tariff Applications

Narrow Topic: Efficiency, Reliability and Prudence at the JPSCo

Thesis Statement: The JPSCo's tariff application for the 2014-2019 period is undeserving of any positive response from the OUR due to a lack of performance as evidenced by JPSCo's inefficiencies, unreliable delivery of electric service and their lack of prudence.

It is an immutable law in business that words are words, explanations are explanations, promises are promises – but only performance is reality." Harold Green (as cited by Taddeo, 2003, p. 159). Performance is defined by the Webster's Integrated Dictionary and Thesaurus 2006 as "a carrying out (of something); … manner of, or success in, working." (p. 677). The same dictionary defines efficiency as "power to produce the result intended; the ratio of the energy output of a machine, etc., to the energy input…" (p. 302). Some of the synonyms for reliable are: certain, dependable, stable, unfailing. (Ibid). Prudent on the other hand has synonyms like: circumspect, far-sighted, frugal, judicious, sparing, thrifty and well-advised. (Ibid). The JPSCo's tariff application for the 2014-2019 period is undeserving of any positive response from the OUR due to a lack of performance as evidenced by JPSCo's inefficiencies, unreliable delivery of electric service and their lack of prudence.

Inefficiency

The high heat rates of JPSCo owned thermal power generators and plants are the first indicator of a poor performance. JPSCo seems to have a tendency to want to hide behind a compound system heat rate (HR) that includes the low HR's of the Independent Power Producers (IPP's). JPSCo is to be examined on its own merit and not be allowed to obfuscate their higher HR's with the lower HR's provided by the IPP's. Since the last tariff application in 2009 a major milestone has been achieved in Mechanical Engineering. In May 2011 in Bavaria, Germany, the Irsching 4 Combined Cycle Plant from Siemens Energy broke the thermodynamic efficiency ceiling of 60% when it returned an overall thermal efficiency of more than 60.75% when running at 578 MegaWatts (MW). (Neville, 2011). This means that under optimal conditions, the Irsching 4 wastes just under 40 units of fuel for every 100 units supplied to it. This efficiency has a matching HR of 6,000 kJ/kWh. Like Usain Bolt's 100m run in 9.58s, the Irsching 4 holds the current world record performance for lowest recorded HR and highest overall thermal efficiency of more than 60.75 percent.

How does the JPSCo match up to the world's best heat engine power plant in Germany? In 2013, GT#7 at the Bogue Power Station returned a HR of 19,139 kJ/kWh (JPSCo, 2014). This high HR makes GT#7 the most inefficient heat engine generator in Jamaica for 2013 to supply the national grid. Its HR was more than three times the world's best and its overall thermal efficiency was less than one third of the Irsching 4 plant. For every 100 units of fuel sent into GT#7, it wasted more than 80 units. Arguments provided at the OUR Consultation in Montego Bay in defense of the gas guzzling that GT#7 carries out every time it is used were that it is not used for base loads and used instead to address peak loading etc. When the steam section ST14 was off-line for 4 months in 2013, was GT#7 used as part of the replacement capacity? Given its outrageous HR, GT#7 should be retired and its capacity replaced with a more efficient machine that is at same time environmentally friendly. It was Dan Theoc, Chief Financial Officer of JPSCo, who said at the April 23, 2014 public consultation in Montego Bay that Trinidad can afford to run inefficient generators for they have oil. As we (Jamaica) have none, the GT#7 ought not to be used.

JPSCo's Old Harbour Plant had an average plant-wide HR of 13,133 kJ/kWh in 2013. (JPSCo, 2014). This HR is more than twice the world's best and gives an overall thermal efficiency of 27.4 percent. This means that on average, the Old Harbour plant in 2013 wasted more than 70% of the fuel dispatched to its heat engines. According to Dan Theoc, JPSCo via its Old Harbour Plant performance in 2013 behaved as if Jamaica had large, established reserves of oil at that time.

Although the B6 unit at JPSCo's Hunt's Bay Power Plant is used to carry base load, the B6 unit itself is not efficient. For according to the JPSCo (2014) a 2013 HR of 12,774 kJ/kWh was attained for the B6 unit and a 2013 plant-wide HR of 13,268 kJ/kWh was obtained at Hunt's Bay. This plant-wide HR like that of Old Harbour is again more than double the world's best. Why is only Old Harbour being replaced? Both Old Harbour and Hunt's Bay should be replaced in parallel or simultaneously for we are not Trinidad, Lybia or Nigeria, that is, we do not have established oil reserves.

The Jamaica Private Power Company (JPPC) is an IPP. According to the JPSCo (2014) JPPC returned a HR of 8,081 kJ/kWh for 2013. JPPC supplied the national grid at the lowest HR for 2013. They were some 2000 kJ/kWh above the world's best and they did it with Bunker C Fuel Oil #6. This shatters the myth that JPSCo's principal problem is fuel. Yes, fuel diversification is a good thing especially when one has no oil. However, JPSCo's principal problem is one of an aged fleet of heat engines. If JPSCo were right and the fuel were to hold the first blame, then JPPC could not have returned such a low average HR in 2013 using Bunker C.

The Heat Rate Box Plot on p. 264 of the JPSCo 2014-2019 Tariff Application tells a story. Between 2009 and 2013, there has been only a marginal downward movement of the upper whisker indicating that the largest HR is still active in the system HR. JPSCo is the owner of the largest HR on the system. The bottom whisker has moved considerably lower over the period, especially in 2012. The JPSCo themselves attrribute the movement on the bottom whisker in 2012 to the West Kingston Power Plant (WKPP), an IPP (JPSCo, 2014, p. 264). One can really appreciate the IPP's and how they move the bottom whisker. One cannot appreciate JPSCo's inertia on the box plot with their slight movement down of the top whisker position. JPSCo needs to do much more to drive this whisker down. In each of the years from 2009 to 2013 excepting 2010, JPSCo seemingly succeeded in dragging the mean HR above the median HR towards the higher JPSCo HR. Although every IPP in 2013 excepting Jamalco had an average HR in the 8000 kJ/kWh region, the lowest system average HR for 2013 was 9,398 kJ/kWh. Again, the JPSCo is responsible for this elevated minimum system HR. The IPP's tame the high HR of JPSCo.

Everybody knows that the fuel and IPP charge covers most of the JPSCo bill sent to customers. However, the non-fuel tariff is becoming more comparable to the fuel and IPP charge for at least the sub 100 kWh per month user. In November 2008, I used 94 kWh (actual reading) over 29 days. The bill came up to JA$1,640.64 of which JA$1,243.24 was the fuel and IPP charge representing 75.8% of the total bill. The remaining 24.2% was the non-fuel tariff including the Ivan recovery charge. Here, the non-fuel tariff to fuel and IPP tariff ratio would be one to three. In February 2014, I used 95 kWh (actual reading) over 28 days. Excluding the early payment incentive, the bill came up to JA$3,240.32 of which JA$2,365.31 was the fuel and IPP charge representing 67.8% of the total bill. The remaining 32.2% was the non-fuel tariff. Here the non-fuel tariff to fuel and IPP tariff ratio increased to one to two. With these increased ratios coupled with a 90% increase in fuel and IPP tariff between November 2008 and February 2014 the non-fuel tariff has increased by 183% for the sub 100 kWh per month user over the period. JPSCo should not be allowed to head for a 1:1 ratio between the non-fuel tariff and the fuel and IPP charge, as with their gas guzzlers, the latter charge is much too onerous on its customers.

The JPSCo has been terribly inefficient when compared to the world record Irsching 4 Plant. JPSCo's inefficiency must not be hidden by the IPP's efficiency. JPSCo's non-fuel tariffs have been on the rise and are now more comparable to the fuel and IPP charges at least for the sub 100 kWh / month user. The only heat engine assets that the JPSCo could label as efficient are the Rockfort Plant and the Combined Cycle at Bogue. No other heat engine at Bogue and no other Plant of the JPSCo is worthy of the label efficient.

Efficient Frontier Analysis and the X-Factor Study

JPSCo uses three models here to prove that they are efficient on the non-fuel side of their business. The three models should work together to give a complete picture. Unfortunately for the JPSCo, two of the models can be used to discredit the Efficient Frontier Anaylsis (EFA). The Productivity Benchmarking shown on p. 17 of the JPS Tariff Application 2014-2019 Annex shows how powerful a factor GWh sold is in labour productivity. When GWh sold was substituted for 1000's of customers JPSCo's second place position turned into 5th place and the initial last position holder, the Hawaiian Electric Company overtook the JPSCo to hold forth place. This demonstrates how the inclusion of a variable can paint a different picture. I am not arguing that log MWh sold should be included in the econometric model. MWh sold can affect total expenditure (the dependent variable) both positively as in the case of oil costs and negatively as in the case of increased labour productivity which could mean lower labour costs. What I am saying is that other variables that were absent from the econometric model may make the model invalid. What was done in the Data Envelopment Analysis sets the stage for a claim of invalidity of the econometric model.

In the Data Envelopment Analysis on pp 28- 29 of the Annex it was stated that "Because it was not simple to account for variation in time, business structure, and operating environment (as we did using the EFA technique), we restricted our model to the year 2011, and to the subset of Caribbean utilities…" (JPSCo Annex, p. 29). If Business structure and operating environments can be so confounding, then the econometric model selected, must address them. I take it that DDistOnly covers business structure and this variable is in the selected econometric model. However, D Caribbean and DNZ which I take as operating environment variables were not covered in the selected model (model 1.9). On the face of it, model 1.9 is not valid for it neglects the effects of the operating environments of New Zealand and the Caribbean. If these were included perhaps a drastic change like onto when the GWh sold was included in the labour productivity benchmarking on p. 17 the JPSCo Tariff Application 2014-2019 Annex. Also half of the independent variables (excluding the dummies) in model 1.9 had weak beta coefficients very close to zero. These variables were customer density and energy density. Of what worth is the selected econometric model 1.9? Perhaps two models should have been used just as how two productivity benchmarks were used.

I also see that the frontier was drawn at the 75th percentile. What ever happened to the 99th percentile? Why was not, as is the custom, the leading most efficient power company not chosen as the true efficient frontier? Is it because the JPSCo would then find themselves on the left, inefficient side of the log-linear graph? Is the 75th percentile frontier and the restriction of the data envelopment analysis to the Caribbean only ploys to make the JPSCo look good? Am I to believe that T&TEC did not place in the top 10 of the data envelopment analysis? Or was T&TEC ruled out in the confound of business structure? In Trinidad none of the T&D assets were divested and this may affect business structure. I am only hypothesizing, but I would still like some conclusions.

The case cannot be made that the JPSCo is efficient. By their own admission their chosen econometric model 1.9 excludes confounds named in the data envelopment analysis and we saw how the inclusion of a variable such as GWh sold changes labour productivity drastically for JPSCo. The inclusion and exclusion of certain independent variables are important considerations when modeling. More care should have been taken over which independent variables were excluded from the econometric model.

Unreliable

The second indicator of JPSCo's poor performance is its low reliability in electric service as well as in some of the guaranteed standards. Low reliability of a service that is inefficient and hence expensive for customers is a double negative. The Regulated Industries Commission (RIC) of

Trinidad and Tobago (T&T) (2005) "compares the performance of the Trinidad and Tobago Electricity Commission (T&TEC) – against international best practice in order to analyze its present level of performance and determine the need for improvement where necessary." (p. 1). Does the OUR hold the JPSCo up to this international, best practice level of scrutiny? If not, why not? What is the sense of the JPSCo feeling good over a reduction in SAIFI or SAIDI when such reductions leave them terribly far from the standards used by the RIC? RIC published a best practice developed country System Average Interruption Duration Index (SAIDI) of 120 minutes or 2 hours (2005). RIC (2005) listed a best practice developed country System Average Interruption Frequency Index (SAIFI) of 1.2. These best practice SAIFI and SAIDI together give a mean time between failures (MTBF) of 304 days. This means that on average, each customer should experience one blackout once every 304 days in an ideal developed country. JPSCo is no where near this standard. By their own reporting of their SAIDI of 22 hours for 2013 and SAIFI of 17.65 for 2013, one obtains a MTBF of 20.6 days. This means that in 2013, each JPSCo customer experienced a blackout in power supply from the JPSCo once every 20.6 days, when the best practice standard is the much longer once every 304 days. By no stretch of the standard, could the JPSCo be considered to be reliable.

My own personal experience tells of how I worry over the very computer I am typing this document on. I have a desktop. I have no unlimited power supply back up. I have experienced quite a few blackouts whilst using my desktop and work is lost. How much work is lost or how much double work has to be done when JPSCo fails? How many manufacturing plants lose man-hours? I live near the Stewart's Appliance Traders Limited (ATL) in Montego Bay. They have a standby generator. It comes on when JPSCo fails. It comes on quite a few times. If I were to get the log for the operation of that generator, would it show that it energizes once every 20.6 days?

As the SAIFI and SAIDI are average values, I would like the JPSCo to report a range. I say this because the MTBF of 20.6 days seems too long to represent my experience. Perhaps the JPSCo could do a SAIFI and SAIDI measurement for each parish so that a range could be stated along with the average value for Jamaica.

My experience as a JPSCo customer includes switching off equipment and lights when I see JPSCo going into a brown out. When I say brown out I mean that the lights start to go dim. PowerGen in T&T had an installed capacity of 1178 MW and had a 15 year power purchase agreement (PPA) with T&TEC whereby they were to supply 819 MW of supply and 100 MW of spinning reserve. (RIC, 2005). How much spinning reserve does the OUR now set for the JPSCo to have on the grid? Is this amount published by the OUR? Is it enough to ward off spikes in demand? In 2006 it was reported that "the convention has been that you operate with a margin which will allow you to continue to supply if you lose the largest unit that's on the system." Paul Morgan (as cited by Dunkley). This is really prudent redundancy. Is the JPSCo still at the 30 MW spinning reserve level? If the spinning reserve is currently still too small, could the IPP's be asked to supply it since their heat engines are more efficient than the majority of those belonging to the JPSCo?

Every time there is a rain cloud near where I live in Bogue (near the Bogue Power Plant) I can count on a blackout. Lightning seems to strike the same place more than twice and the JPSCo seemingly does nothing to arrest it. Anytime I see a rain cloud, I have to make sure that I am not on my desktop. The Outage Management System of 2013 lightning mitigation programme is needed for Bogue Village.

The failure of ST14 at the Bogue Power Plant in June 2013 is a cause for concern. This is so because it supplies the base load and it was out for some 4 months. As the combined cycle at Bogue is the only fit heat engine at the Bogue Power Plant, when it or any part of it fails, gas-guzzlers will likely have to fill in the gap. The projected average HR from the Bogue Plant for each year from 2009 - 2013 was 9,146 kJ/kWh (JPSCo, 2009). Every year from 2009-2013, the combined cycle returned a HR greater than the predicted 9,146 kJ/kWh. Due to the failure of ST14, the average HR from the Bogue Power Plant for 2013 was the highest over the 2009-2013 period and had a value of 10,491 kJ/kWh. The reverse is true of the JPSCo Rockfort Plant. In every year, Rockfort returned an HR below those predicted in 2009 by JPSCo. What are the maintenance practices at Rockfort and are they different from those used on the Combined Cycle at Bogue?

The monthly actual readings of meters is reliable and as such should be maintained until smart meters that can send information to a remote JPSCo site are installed by the JPSCo. Is it possible to have meter readers note which streetlights are running all day as they pass them to read meters?

The 2013 KPMG Depreciation Study on p. 89 of the current JPSCo application puts the meter life at 15 years when the current life estimate is 30 years. Are some of the JPSCo meters past their useful life and hence operating without calibration? Is this why when customers upgrade to the electronic meters they see a jump in their bills? Why are calibration stickers with a calibration expiry not used to label JPSCo meters? Does the JPSCo reliably maintain the calibration on their meters?

With respect to guaranteed standards, the percentage of calls answered within 20 seconds is well below the target. The percentage of streetlight repair is horrendous, it is 25.5% year to date, when it should be at 99 percent. The JPSCo, when held to the best practice developed world standard of reliability, has been shown to come up woefully short.

One blackout every 304 days is a distant dream for Jamaicans. JPSCo should be evaluated up against international best practices like T&TEC and not the previous periods' performance excepting where the previous period's performance was better than the international best practice. JPSCo should adopt SAIDI and SAIFI measures for each parish so that range values can qualify these mean statistics. The question as to whether JPSCo is meeting the conventional value for spinning reserve is still unanswered. Streetlight surveilance and maintenance, meter calibration maintenance and the maintenance practices surrounding the Combined Cycle at Bogue are areas worthy of further investigation.

Imprudence

There is a serious case that could be made on the JPSCo regarding imprudence and their Self Insurance Fund (SIF). There is an insufficient amount of money in the SIF, yet JPSCo wants to put less in it per year. Instead of setting aside US$7.5 million per year to going into the SIF less taxes which can be reclaimed in the event of a hurricane, the JPSCo wants to set aside only US$3 million per year for the SIF less taxes. (JPSCo, 2014). As at December 31, 2013, the SIF stood at US$21.6

million. (JPSCo, 2014). The JPSCo is unable to get conventional insurance for their transmission and distribution (T&D) assets as they are exposed to too much hurricane and earthquake risks. The net book value of the T&D asset of the JPSCo is US$362 million. The SIF has to be used to restore the T&D asset after a natural disaster.

Though hurricane Ivan was a category 4 storm, the closest its eye came to Jamaica was 30 km south of Portland Point, Clarendon. JPSCo, however put in a Z-Factor claim for JA$1.46 billion in March 2005 when the Jamaican dollar was approximately JA$60 to US$1. This was the equivalent of US$23.7 million. If, God forbid, another Ivan were to brush pass Jamaica as it did in 2004, JPSCo may only just have enough money in the SIF to restore the T&D asset. What if, again God forbid, a hurricane like unto Gilbert of 1988 whose eye entered at Morant Point and left at Negril Point should make landfall this year? Would the JPSCo have enough money in the SIF to restore the T&D asset? If not, to whom would the JPSCo turn to in order to get money? When JPSCo does not save enough in their SIF, they surreptitiously point the finger of responsibility on the JPSCo customer. Are we the JPSCo's Automated Teller Machine (ATM)? Were the private owners of the JPSCo prudent in purchasing a T&D system in a hurricane zone? Is the T&D system not better managed by the government? Has the JPSCo ever thought of burying some of the T&D assets?

Another instance of imprudence whether by the JPSCo, the Government of Jamaica (GOJ) or both, is the fact that the combined cycle at Bogue has been installed since 2002 or 2003 and over 10 years have passed and natural gas has not been supplied to it. The U. S. Energy Information Administration (2014) indicates that the export price of liquefied natural gas (LNG) in December 2003 was US$4.51 per 1000 cubic feet. In December 2013 the price was US$12.69 per 1000 cubic feet. This represents a 181% increase in the export price over the period. It is likely true, that where ever in the world JPSCo could have found LNG in 2003, it would be cheaper then, than it is now to sign an LNG contract with a supplier. Why did JPSCo wait until 2008? Why did the GOJ have to give the JPSCo a guarantee in order to proceed? Had JPSCo been in the LNG market, when the GOJ could not source the LNG for the Old Harbour replacement plant that JPSCo won the contract to install maybe the JPSCo would not have been so flat footed.

JPSCo now complains that they cannot now replace their own fleet at will. Everything now is by competitive bidding. Paredes (2004) stated that the OUR and the GOJ in 2001 agreed that a part of the JPSCo license would include the following clause: "During the first three years, the JPS would have the exclusive right to add new generating capacity and could do so without competitive bids." (p. 218). The first 3 years of the license ran from 2001 to April 2004. JPSCo took some advantage of this 3 year period and had installed a 120 MW combined cycle plant at the Bogue Power Station. They however, could have installed more capacity in the first three years of their license. This lack of exhausting this opportunity must now necessarily be a regret of the JPSCo who now has to compete when installing new generating capacity.

JPSCo customers were looking forward to reductions in their light bills due to JPSCo's efficacious measures in theft reduction. Alas, this is yet to come to fruition. The Electricity Efficiency Improvement Fund (EEIF) has not been used efficaciously. Results of anti-theft initiatives have been ephemeral and fleeting. I believe that the JPSCo should be punished for failing to lessen the theft from their T&D system. It is their asset and they are responsible for the non-technical losses.

The criminal versatility and resilience of the thieves on the T&D network was severely underestimated by the JPSCo. In 2009, total system losses stood at 24% but in 2013 this rose to 25.9 percent. Non-technical losses accounted for 67% of the 25.9 percent. Most of the non-technical losses are due to theft. US$53.99 million was spent on the CAPEX loss prevention programme between 2009 and 2013. (JPSCo, 2014) What have we to show for this? JPSCo is not prudently finding solutions to their theft problems. Their paying customers cannot continue to pay for those who steal electricity. One wonders if it was prudent of the JPSCo to purchase the T&D system in the first place give the challenge of theft, threat of hurricanes and earthquakes. The abhorrent excuse given by the JPSCo for taking up the Ivan charge was that this was the practice elsewhere where power companies could not get insurance. Is this abhorrent excuse also being applied to theft – for if JPSCo cannot get the thieves off of their system is the JPSCo saying that its paying customers should continue to pay for the thieves? Once upon a time, JPSCo used to talk about the uptown thief? Have such thieves now been eradicated uptown?

The judicious use of money is also in question with the 5% wage adjustment at the JPSCo. An auditor found a surplus of US$4.52 million in the pension fund for JPSCo workers. This amount could serve to pay 1.7 years of the 5% wage adjustment. Instead it was allocated to employee benefits. Why is this? General and Central government workers salaries are frozen and only go up in small increments of approximately 2 percent per annum. I am asking that the JPSCo use the surplus from the pension to go towards supplying the first 1.7 years of the wage increase.

The discrepancies in the life time estimates from KPMG should be only considered for the meters and the streetlights. This would reduce the depreciation charge from 8 million to 1.4 million. When juxtaposed with General Plant Equipment, priority seems to favour streetlights and meters.

JPSCo's prudence is in question. Their SIF is not sufficiently funded yet they want to reduce the inflows into the fund thereby pointing their fingers to the pockets of their customers in the event of a category 3 storm like that of hurricane Gilbert 1988. Given the JPSCo's poor management of non-technical loss reduction, low SIF and poor reliability one wonders why the JPSCo bothered to acquire 80% of the T&D asset in the first place and why they are currently in court contesting the Supreme Court ruling by Justice Sykes on July 30, 2012. Greater caution as to how money is deployed may be needed at the JPSCo as evidenced by a missing priority listing in the KPMG depreciation study and the pension surplus.

Conclusion

It has been shown in this paper that the JPSCo is inefficient and that they have not proven by the econometric model presented that they are efficient in their non-fuel side of their business. JPSCo is also terribly unreliable when the blackouts on their system are compared to best practice developed world standards. JPSCo needs to be more prudent in the SIF and possibly other matters like seizing and exhausting opportunities and effective theft reduction. The JPSCo does not deserve a non-fuel tariff rate increase at this time.

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Consumer Advisory Committee on Utilities (CACU)

CONSUMER ADVISORY COMMITTEE ON UTILITIES
c/o The OUR, P.O. Box 593, 36 Trafalgar Road, Kingston 10, Jamaica W.I.
Tel: (876) 968-6053-4 Fax: (876) 929-3635 Mobile: (876) 322-9301
E-mail: cacu2@our.org.jm

June 10, 2014

Mr. Albert Gordon
Director General
Office of Utilities Regulation (OUR)
3rd Floor, P.C.J. Resource Centre
36 Trafalgar Road
Kingston 10, Jamaica.

Dear Mr. Gordon,

Re: CACU Comments on the JPS' Tariff Review Application – 2014/19

The Consumer Advisory Committee on Utilities (CACU) appreciates the opportunity to participate in the subject tariff review process and in that regard, is pleased to submit comments in response to the application submitted by the Jamaica Public Service Co. Ltd. dated April 11, 2014.

The CACU continues to be of the view that the energy/electricity sector is in need of policy and regulatory modernization, revamping and reshaping with clearly defined roles and responsibilities for all stakeholders in the development of an efficient and affordable industry. That being said, the following comments refer specifically to the regulator's tariff review of the JPS' Tariff Review Application for the period covering 2014-2019.

Tariff Rebalancing and Proposed Rate Changes

JPS has proposed rates that would result in average tariff increases of 21% for residential consumers and 15% for small commercial customers with demand less than 7,500 kWh per month. Larger customers would benefit from reduced tariffs. The rationale given by JPS for this tariff rebalancing which would mean large increases for smaller customers is that this approach is necessary to keep large customers on the grid and that if these large customers leave the grid consumers will bear even more costs than the proposed increases.

The CACU notes that this proposal reflects the inordinate and unacceptable delays in installing new efficient generating plant to replace the old inefficient generators on which we now depend. The delay in getting new generation into the system is imposing a tremendous cost. Larger customers have greater ability to escape the costs of this inefficient generation by generating their own electricity. The tariff rebalancing approach proposed by JPS seeks to transfer the cost of this inefficiency to the smaller customers who are least able to defect from the grid. Had the Government of Jamaica (GOJ), the OUR and JPS acted to ensure that new efficient generation plant was available in a timely manner there would not now need to be any need to propose such large increases for small electricity consumers. All the above-named parties share blame in failing to ensure that new generation plant was installed in a timely fashion.

The CACU notes that there is merit in the argument that small consumers will suffer if there is significant defection of large consumers from the grid. Therefore we reluctantly accept that there has to be some rebalancing of rates in favour of the larger consumers. However, we do not believe that the levels of increase proposed for residential and small commercial customers are practical and sustainable. In particular we think JPS is significantly underestimating the capacity of residential and small commercial consumers to themselves defect from the grid. The smallest consumers, who are already under economic strain, could very well respond to a large increase in tariffs by joining the ranks of those stealing electricity. JPS' own analyses over the years have demonstrated strong correlation between electricity rates and losses. Other residential and small commercial consumers are likely to respond to significant increases by moving to self generating from renewable sources. JPS has sought to do economic analyses of the best alternative options (BAO) available to customers and these analyses suggest that even with large proposed increases the BAO for small customers would still be more expensive than the proposed rates. However, small consumers are not going to analyze the situation in this way. If they feel sufficiently disgruntled with high prices from JPS they will move to self generation from solar and wind even if dispassionate economic analysis suggests this is a more expensive option for them. The CACU therefore advises that the risk of grid defection by smaller consumers should not be underestimated. We recommend that the increases to residential and small commercial customers should be significantly less than the 21% and 15% proposed by JPS, even while we accept that there should be some rebalancing in favour of larger consumers.

Wheeling and Self-Generation

We detect from the tariff proposal that JPS is especially fearful that wheeling will provide the avenue for many of their large customers to shift to being self-generators. The CACU does not believe that customers moving to wheeling should necessarily be disadvantageous to JPS. Wheeling customers still have to pay JPS for use of the transmission and distribution grid. By installing new generation plant wheeling customers relieve the grid of the expense of having to install equivalent capacity. A significant push to wheeling could in fact mitigate the penalties being imposed on customers by the delays in getting new generation on the grid by allowing the earlier retirement of some of the oldest and most inefficient units. **What is important is to ensure that the applicable wheeling tariffs cover the full costs imposed by those who undertake wheeling and to ensure that those who remain as JPS customers do not subsidize those who choose to wheel. This must also apply to those who choose to self-generate while using JPS as a backup. Remaining customers must not subsidize such self-generators.**

Against the background of the above, the CACU is extremely concerned that smaller demand charges are proposed for wheelers and self-generators who use back-up service from JPS than for regular customers of JPS. JPS still has to provide capacity to serve these customers even if this capacity is used for only a minute fraction of the time. Normal customers must not pay to ensure standby capacity is available to wheelers and self-generators. Wheelers and self-generators must bear the full cost of any standby capacity they require. The CACU is of the view that the standby demand charges for wheelers and self-generators should be at least equal to the charges for regular customers and we believe there would even be justification for these charges to be larger than those applicable to regular customers.

All self-generators must take out their plants for maintenance at some point. It is either that they ensure that they have adequate reserve capacity or they resort to using JPS as a standby service. The CACU is of the view that if true costs are reflected in the standby rates then the incentive for large customers to resort to wheeling and self-generation will be much reduced. We are insistent that regular customers must not subsidize those who choose to wheel or self-generate.

Tariff Design & Restructuring

The CACU is supportive of the proposal to impose a three-tiered rate class structure for residential consumers and a four-tiered rate structure for small commercial consumers. We accept the argument that the tiered structures help to keep electricity affordable for marginal and vulnerable customers.

We also support the introduction of the tiered network access charge which will help to better aligning the tariff to JPS' large fixed cost structure, while giving consumers some incentive to pursue energy efficiency measures. However, we note that for the tiered structure to truly incentivize energy efficiency the bands may have to be narrowed. For example there is one residential band from 100 kWh to 500 kWh. No matter what energy efficiency measures a customer using 300 or 400 kWh undertakes it is highly unlikely that that customer will be able to drop down to the lower band of 100 kWH. Therefore in such instances the network access charge would do little to incentivize energy efficiency.

Wholesale Tariff

The CACU supports the proposal for a wholesale tariff aimed at keeping the largest customers on the grid.

Revenue Cap

One of the key proposals in the JPS Tariff Application is to shift from a price cap to a revenue cap approach. There may be merit in some of the arguments that JPS has put forth in support of a revenue cap approach such as the possibility that this approach better incentivizes the utility to support energy efficiency and distributed generation initiatives. However, the CACU does not support a shift to revenue cap approach at this time. JPS has proposed a raft of measures, including tariff rebalancing and restructuring, shortened tariff review period and shifting to a revenue cap, which would have the effect of decreasing risk to the utility in the upcoming tariff review period, but which also shifts significant risks and costs to JPS' customers – particularly those in the residential and small commercial categories.

The CACU does not believe it is fair for these electricity consumers to have so many risk shifting initiatives thrown at them simultaneously. We also note that JPS is somewhat disingenuous when it argues that a revenue cap approach reflects a sharing of risk between the utility and the customers. In a situation of declining sales growth, which JPS obviously expects for the upcoming review period, it is the customer who would bear all the risk under a revenue cap approach.

The CACU supports to some extent some of the measures that would decrease risk to JPS, such as a shortened review period, but we do not support a change to a revenue cap at this time on the basis that there are already several other initiatives that increase risk and costs to consumers. A revenue cap approach may be considered in future tariff applications when there has been sufficient time to weigh the pros and cons of such an approach.

Three Year Rate Review Request

The CACU supports JPS' proposal that the determination for the current rate review be for three years only instead of the normal five years. The significant uncertainty regarding the installation of new efficient generators makes it virtually impossible to plan for a five year period. This uncertainty has increased since JPS submitted their tariff application as moves have now been taken to revoke the licence issued to EWI, whereas the assumption at the time of submission was that EWI would provide electricity from new plant beginning in 2016.

As we note above the imposition of a shorter review period significantly reduces any demand risk to JPS and lessens the need to consider a revenue cap approach at this time.

Return on Equity

JPS' requested return on equity (ROE) of 19.8% for the 2014 – 2019 tariff period does not appear unreasonable in the context of typical returns demanded by other companies doing business in Jamaica. The CACU also notes that JPS' historical ROEs have generally been far below expectations. We therefore understand JPS' desire to achieve a more reasonable ROE. However, we believe that we have to take account of the current situation and that JPS' customers should not be expected to bear the brunt of moving from a very low ROE to a high ROE in one step. We support the idea that JPS's ROE should be gradually increased, maybe approaching the proposed 19.8% in year 5 of the 2014-2019 tariff period.

We note JPS' desire to move from the traditional bond spread approach to synthetic spread approach in calculating the country risk premium for the purpose of establishing the applicable ROE. We are concerned that there should be consistency in calculation methods and that established approaches should not be changed merely because a different approach is more in JPS' favour at this point in time.

Depreciation

The CACU believes that the depreciation changes proposed by KPMG are reasonable and acceptable.

FX Losses and Fuel Penalties

The CACU believes that there are real and significant penalties imposed on JPS because the calculation methods and time lags inherent in the way these matters are dealt with. We support revised approaches that will lessen the penalties on JPS arising from FX Losses and the treatment of fuel costs.

High Dividend Payments

We are concerned that JPS made high dividend payouts in the early part of the last tariff review period. These dividend payouts were particularly high in 2010 and 2011 even though the company was experiencing sharply declining profit margins in these years. It is likely that the company had to borrow in order to facilitate these dividend payouts. The CACU does not support any move by JPS to pay out dividends in excess of profits and recommends that the OUR takes steps to avoid this practice in future.

Dividend payments were significantly lower in the last two years of the period, but this is likely only because JPS financial covenants with their lenders prevented higher payouts.

Decommissioning Costs

JPS proposed approach to decommissioning of the Old Harbour and Hunts Bay B6 plants seems to be overly elaborate and expensive. The CACU is not aware of such an extensive decommissioning approach being taken for any previous industrial facility in Jamaica nor of any need to actually dismantle and remove the plant. Even at JPS Hunts Bay there are units which have long been retired which remain in place up to now. We accept that the practices of the past may not be best practice today, but we caution against consumers being burdened with the costs of an overly elaborate and decommissioning exercise.

We suspect that with the presence of a thriving scrap metal industry in Jamaica there are entities that would be quite willing to entertain a deal where they take responsibility for dismantling the plant as long as they get all the scrap. Such an approach would mean no cash outlay for dismantling of the retired plants.

We also note that both sites, Old Harbour and Hunts Bay, will remain attractive sites for future power plants. They are likely to remain in use as power plant sites as opposed to be transferred to any other use. In fact possession of these sites will give JPS a significant advantage in future power tenders and consumers should not be paying for the cleanup of sites that JPS will use to its advantage in the future.

System Heat Rate

With the expected delay in bringing new generation on to the system, JPS' recommendation for the current system heat rate target to remain in place is understandable. However, the CACU believes that every effort must be made to deliver electricity to customers in the most efficient manner, even while relying on old and inefficient generating plant. Since the commission of the West Kingston Power Partners facility, JPS has achieved system heat rates of less than 10,000 kJ/kWh. The system heat rate is likely to improve with the addition of more renewable capacity in 2015. Against this background the CACU recommends that the target system heat rate be reduced from 10,200 kJ/kWh to 10,000 kJ/kWh.

Procurement of Generation Capacity

The current debacle surrounding the procurement of new baseload generation capacity provides ample evidence that the existing procurement methods are not serving consumers well. In particular CACU takes note of the long drawn out process to procure approximately 360 MW of new capacity, the bulk of which (292 MW) is simply to **replace** old JPS capacity.

We believe that the evidence of the last few years clearly shows that the licence provision that bars JPS from replacing or repowering its own capacity without going to competitive tender has not served consumers well. For the benefit of consumers we recommend that the relevant provisions in the JPS licence be amended to allow JPS to replace or repower its existing capacity, subject to normal regulatory oversight that costs are prudently incurred. We recommend that competitive tender be reserved only for provision of capacity to meet **incremental** demand.

Consumers are paying an extremely high price for the repeated bungling of the public procurement process to obtain new baseload capacity. As noted above it is largely the failure in install this new capacity on a timely basis that is leading JPS to recommend rate increases of 21% and 15% for residential and small commercial customers. All consumers would be much better served if JPS is mandated and obliged to maintain an efficient core generating capacity.

PROPOSED COMMUNITY RENEWAL PROGRAM

The proposed program is a bold and innovative yet timely initiative, seeking to take a holistic approach to tackling commercial losses a.k.a. electricity theft. The success of the program will depend on the level of commitment of all utility partners and stakeholders including the Government of Jamaica (GOJ). The Government must make reducing electricity theft a priority and put in place practical and necessary policies, programs etc. to support the programme.

- ✓ Available funding for the program is a key concern. There was no indication of the estimated cost of such a program and the level of funding required from each partner, in particular the funding to be provided by the GOJ, given the current economic conditions. Where does JPS foresee the available source of funding from the Government to implement the proposed infrastructure improvements and organizational requirements such as establishing a Unit and the employment of staff? What is the level of funding anticipated from partners and other stakeholders and for what period (such as the life of the program)?

- ✓ Other key partners which the JPS may consider include the Ministry of Local Government & Community Development (MLGCD), the Rural Electrification Programme (REP), the Social Development Commission (SDC) and the political directorate – Members of Parliament. The proposed program would best be implemented by the MLGCD, the Social Development Commission (SDC) and JPS' and NWC's loss reduction teams. Additionally, the Ministry of Labour and Social Security may also be a key partner since specifically all partners and stakeholders could explore collaboration with the Ministry's *Programme of Advancement Through Health and Education* (PATH) Programme as many persons who live in these low-income communities may also be beneficiaries under the PATH programme. It could be explored as to how having legitimate electricity connection could be incorporated in this social program. Finally, collaboration could be explored with the Land Administration & Management Program (LAMP) in terms of land title regularization.

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- ✓ In terms of Community Involvement, how will the proposed liaisons be selected? Would these persons be employed/contracted to the Programme Unit to be established to lead the program? How is it proposed to garner acceptance by the community of such liaison officers? Consideration should be given to whether this liaison role could be incorporated in the functions of Councillors. Further details are required as to how billing and collections will be handled in the urban renewal process. These details would have to be clearly thought out and designed and should incorporate workable solutions proposed through the Special Committee on Electricity Theft, chaired by Minister Julian Robinson. The CACU's proposal to tackle electricity theft is being submitted to the Special Committee and will be shared with the Regulator and the Company for consideration.

- ✓ There is CACU support for the principle behind rolling out the plan in squatter settlements. However, for the pilot to be successful, plans for community renewal in these areas must be aligned with whatever plans the Government may have for the regularization of squatter settlements.

JPS Guaranteed and Overall Standards – 2014-2019

General Comments:

Guaranteed standards reflect the pre-determined levels of specific services for each customer as well as the prescribed penalty payments when the Company fails to meet those standards. Research of various regional and extra-regional jurisdictions suggests that while there has been a mix of methodologies and approaches with regards to automatic payments and/or claims, a common feature is the application of fewer numbers of guaranteed standards when compared to the Jamaican standards. The CACU's considered view is that there should be a reduction in the number of guaranteed standards, to allow for better management and more efficient monitoring by the regulatory authorities. The recommended methodology is to merge those standards with similar focus and transfer one standard to the overall standards category.

We see the need to fairly consider and in fact establish exceptions and exemptions to the Guaranteed Standards for which automatic payments are not obligatory however, we believe that in adopting any exception/exemption, the rules must provide clarity for both the consumer and the utility and not be subject to interpretation.

Overall standards set service levels for the more universal areas of service which affect customers in general and for which the Company is not obligated to make compensation directly to the customer except that the Company's performance on these standards can and do affect its revenue under the Q-Factor programme. For the present overall standards, the CACU suggests that the current standards remain in place and also include the transferred guaranteed standard regarding Response to Emergency. These standards as with others should seek to encourage and engender a high quality of service ethos by the company for all customers of the company. The company must ensure that the relevant technology is applied to achieve efficiencies throughout the business and especially in the way they communicate with and provide the service to their public.

Guaranteed Standard

The CACU recommends that the Guaranteed Standards be revamped to reflect a total of six (6) standards, the respective performance measures and the compensatory and claim mechanisms for each standard. While the available technology should be utilized to provide timely compensation payments to customers, the Committee is of the view that a few standards should not attract automatic compensation given the nature of the standards and the fact that they will allow for important customer-company service engagement in the process.
The following table provides an outline of the recommended guaranteed standards with the associated type of compensation and claim to be applied to each guaranteed standard:

Schedule of Guaranteed Standards 2014-2019 - recommended

Code	Focus	Description	Performance Measure
EGS I(a)	Access	Connection to supply: a) New Installations and	a) New service Installations within five (5) working days after establishment of contract and **AUTOMATIC COMPENSATION**
		b) Simple Connections	b) Connections within four (4) working days after establishment of contract where supply and meter are already on premises. **AUTOMATIC COMPENSATION**
EGS 1(b)	Access	Complex connection to supply	Between 30m and 100m of existing distribution line: (i) Estimate within ten (10) working days. (ii) Connection within thirty (30) working days after payment. **AUTOMATIC COMPENSATION**
			Between 101m and 250m of the existing distribution line: (i) Estimate within fifteen (15) working days. (ii) Connection within forty (40) working days after payment. **AUTOMATIC COMPENSATION**
EGS 2	Billing	Issuance of First Bill	Produce and dispatch first bill **by e-mail /text /post** within forty (40) working days after service connections **AUTOMATIC COMPENSATION**
		Estimated Bills/Frequency of meter reading	No more than TWO (2) consecutive estimated bills (where the company has access to the meter).**+**
		Estimation of Consumption / Method of estimating consumption	An estimated bill should be based on the average of the last three (3) actual readings.
		Billing adjustments / Timeliness of adjustment to customer's account	Customer must be billed for adjustment within three (3) months of identification of error or subsequent to replacement of faulty meter. **AUTOMATIC COMPENSATION**
EGS 3	Complaints / Queries	Acknowledgements / Investigations including those involving a 3rd party	Acknowledge, investigate and respond to the customer within thirty (30) days. In the case of a clearly identified third party, the matter should be acknowledged, investigated and responded to **by e-mail or post** within sixty (60) days. **AUTOMATIC COMPENSATION**
EGS 4	Reconnection	Reconnection after payments of overdue amounts	Reconnection should be made within twenty-four (24) hours of payment of overdue amount and reconnection fee. **AUTOMATIC COMPENSATION**
		• Disconnection – Wrongful disconnection	Where the company disconnects a supply that has no overdue amount or is being investigated by the OUR or the JPS and only the disputed amount is in arrears. **AUTOMATIC COMPENSATION**

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		• Reconnection – after wrongful disconnection	The company must restore a supply it wrongfully disconnects within five (5) hours. **AUTOMATIC COMPENSATION**
EGS 5	Meter Replacement	Timeliness of Meter Replacement	Maximum of twenty (20) working days to replace meter after detection of fault which is not due to tampering by the customer. **AUTOMATIC COMPENSATION**
		Meter change	JPS must ensure that a note is left at the premises and/or utilize its e-mail and/or text messaging service indicating the meter change, the date of the change, the meter readings at the time of change, reason for the change and the serial number of the new meter.
EGS 6	Compensation	Making compensatory payments	Accounts should be credited within thirty (30) working days of verification of breach or by the subsequent billing period, whichever is earlier. **AUTOMATIC COMPENSATION**

General Compensation: Residential Customers – Equal to the reconnection fee
Commercial Customers – Four (4) times the applicable service charge

- **Special Compensation:** Residential Customers – Two (2) times the applicable reconnection fee
Commercial Customers – Five (5) times the customer charge

+ We are of the view that this standard should remain as is. For customers who opt for budget billing, there could be an exception to this standard and the same for customers with prepaid meters and other payment options.

Exceptions and Exemptions – Proposed Modifications

The CACU accepts the proposed exemptions with the following amendments/clarifications:

✓ Severe weather - must be predefined by the OUR and the JPS.

✓ Industrial action – we are not in agreement with this exception. JPS is determined to be an essential service and should be fully familiar with the industrial relations climate within which it operates in Jamaica. We are of the view that the company must put contingency plans in place to ensure little or no disruption in service for such matters.

✓ Belief on the part of JPS that the information provided is of a frivolous or vexatious nature – this can only be considered when there is a clear and pre-defined outline of information which is "frivolous and vexatious".

✓ We do not agree with this exception as the fact that a customer may have an outstanding/overdue amount should not absolve the JPS from meeting the standards.

Overall Standards

As mentioned earlier, the CACU recommends that the current standards remain in place and that there should be an addition to the Overall Standards – **Response to Emergency** – as outlined in the following table:

Code	Standard	Units	Target
EOS 13	Response to Emergency	Response to emergency calls within five (5) hours for those incidents caused by the Company's actions and those triggered by third parties. Events deemed to be threats to public safety should be the elevated to the highest priority level.	100%

We are also of the view that the O.U.R. should make a decision on the sample meter testing methodology so that the meter testing protocol may be finalized to coincide with the 2014-2019 tariff review determination.

The CACU trusts that the aforementioned comments will be useful in your deliberations and should you require clarification and/or amplification on any or all of the remarks please feel free to request same. We look forward to continuing the collaborative relationship with the O.U.R. on behalf of all consumers of regulated utilities.

Kind regards.

Yours truly,
CONSUMER ADVISORY COMMITTEE ON UTILITIES

Yasmin M. Chong

Yasmin M. Chong (Ms)
Chairman

c.c. Mr. Maurice Charvis – Deputy Director General, O.U.R.
Mr. Hopeton Heron – Deputy Director General, O.U.R.
Mrs. Yvonne Nicholson – Director, Consumer and Public Affairs, O.U.R.

Online, Facebook and Newspaper Responses to JPS 2014-2019 Application

From: Kga Hill
Sent: Friday, April 11, 2014 9:50 PM
Are the percentage increases accurate and the 3 year review with anticipated further increases as well? It seems the consumer is expected to make the several financiers even more well compensated with little or no upgrading of investment in generation and T&D. Does GOJ get a return on its 19.9% stake?

From: Claudette Peart
Sent: Monday, April 14, 2014 3:59 PM
I want to draw your attention to the following before you consider granting an increase to JPS Co. I have seen where JPS Co has disconnected light and took out the meter at 12 Service Path, Glendale Housing Scheme and still yet that home has light every night and is not just light also water.
What they are doing about it? Is full time they do some night work and caught all the thieves in that area.
I preferred to be anonymous but I need my mail to be included in the conversation.
Thanks very much.

From: Gibbie Gibson
Sent: Monday, April 14, 2014 7:09 PM
JPS Co. knows who they should be focusing on. The people whose bill(s) I'm paying. Stressing people who are already burdened by rising prices, devaluing Jamaican Dollar (which is affecting necessary things I now cannot buy) will only set more people to steal electricity. Imagine law abiding, tax paying citizens, most barely outside minimum wage and in the public sector struggling even more? Likkle more from this we can't find fare or REALLY can't find petrol for our cars! We haffi go park it and walk!

From: Carol Logan
Sent: Tuesday, April 15, 2014 4:35 PM
Have a problem with captioned subject, as I have not had a salary adjustment in more than 3 years. It is difficult to keep up with current bill, but I try. At this time a 21% adjustment would be more than hazardous to my health. In my household there are 2 adults and a 3 year old. No one at home in the days

From: Facebook responses **David Gordon**
Sent: 16 April, 2014 08:28
Why hold any consultation?
OUR just going knock off a few percentage points n grant the increase. From parliament straight down to the man that sweeps the street just token gestures.....

From: Olivia Reece
Sent: Wednesday, April 16, 2014 9:33 AM
Subject: Residential Rate Increase

Good Morning Sirs,
I am writing to register my disapproval with the rate increase for residential customers requested by the Jamaica Public Service Company. I presently occupy a two bedroom home and is being charged between $6500 - $7500 monthly although no one is at home between the hours of 7:30 am – 7:00 pm. This amount is already too high and with a rate increase of 21% this will even be higher. Furthermore in light of the harsh economic circumstances and heavy tax burden carried by the working class, of which I am apart, I cannot afford to pay anymore. Moreover we as people are being asked to make a sacrifice in order to help the country out of the economic crises that we are in by taking wage freezes among other things, so how can we be asked by the JPS of which the government is apart of to pay more when we are not earning more. As a patriotic Jamaican I believe it is time the government and corporations of this country take all the people into consideration before making decision that will have an adverse effect on us.

From: Simone White
Sent: Wednesday, April 16, 2014 10:12 AM
Subject: Increase in residential rate
This is highly ridiculous that J.P.S would want to ask for a rate increase to residential customers, when is the last time anybody get a salary increase, every week you go to the supermarket the prices of the food items goes up, not everybody goes to the supermarket, some ppl go to the wholesale because they think the wholesales are cheaper. I have 3 children, myself and husband is in my household, the present electricity bills is between $8000-12,000(3bulb in use ,1 fridge,1 tv in use ,microwave use now and then because we provide a cook meal every day for the kids, clothes iron once a week, wash once a week in the machine) my food bill is $30,000 per mth , water $4000, cable $2500, internet $2500, the children age 15,9,4 have to attend school daily, it's obvious that this government have not a clue if they give JPS an increase, they are forcing us to take our qualifications to other countries, THINK BEFOR YOU ACT PPL ARE GOING TO SUFFER BITERLY !!!!
Best Regards,
Simone P.White-Golding

RoJe SteWart
The only way Jamaican people will be willing to accept this proposal is, if JPS Co.
Firstly, remove the IPP charges for the bills
Secondly, go on a drive to remove the inefficiency and delay in connecting person/customers whose premises have been certified and has to be waiting months for connection.
Finally, spend the money necessary to reduce system losses and down time for grid.

From: T Fraser
Sent: Thursday, April 17, 2014 9:41 AM
Subject: Public Consultation for JPS Tariff Review 2014-2019
Good day:
In fairness to JPS, the reliability of the service has been fairly good. However, the problem is that JPS tries to recoup its losses from illegal connections from those who are regularized. That cannot be so. JPS needs to take very drastic measures against persons and communities who continue to

flout the law and steal electricity. As was recently mentioned in a news article, the CEO was considering to simply not providing electricity in those areas at all. I agree. I don't believe a flat fee is the way to go for those communities either, unless that flat rate has a limit attached to it.
My view therefore is that JPS should NOT be granted such a drastic increase or any increase at this time to a nation already suffering so many burdens but rather must now take the drastic decisions to manage those persons and communities who are consistently delinquent. Those of us who are paying on time and in full every month should not be penalized for others' slackness.
Regards

'Stupid idea of the year' award to Minister Paulwell
Tuesday, April 15, 2014
So, Mr. Phillip Paulwell, the Minister of Energy, wants to reward the people who steal electricity — a criminal act — with a monthly flat rate of approximately $2,000.
The idea, he told the Standing Finance Committee meeting last week, is to have these people develop the practice of paying for the service until 2016 when, according to him, new capacity will come on stream. At that time, he added, those people will be called upon to pay the real cost.
That, no doubt, takes the 'Stupid idea of the year' award, because we can see no reason for persons who now steal electricity, and who are obviously getting away with it, to suddenly develop a conscience and pay.
What Minister Paulwell is encouraging here is a further entrenchment of the sense of entitlement that has been promoted by politicians for too long in this country.
Minister Paulwell should tell us what he, the Government and JPS would do if all law-abiding customers decide to start stealing electricity.

From: Wayne Martin
Sent: Thursday, April 17, 2014 1:12 PM
Subject: JPS, increases are not the only way
Dear Sir/Madam,
My name is Wayne Martin, and is a resident of Portmore. I have written this mail to add my voice to the cry of my fellow Jamaicans who are felling the hardship that is being cased on us; I am feeling really feeling it.
After doing all the necessaries to lower my usage of electricity for the past 5 years, I am yet to see my monthly charges reduced. I have changed all my bulbs from incandescent bulbs to energy saving bulbs, I have not used my AC unit, it is shut off from the breaker. I have rewired my house, and have upgraded by house from 110 to 220, I plug out electrical items when not being used, I have done it all; my monthly charges hover between 11K-14K.
I understand the business decisions that JPS has to make, but I believe that we cannot increase our way out of our financial troubles. The Jamaican people are taxed, taxed, and taxed beyond measure, so this increase would just be another tax. I believe that what JPS is experiencing is a falloff in revenues from residential customers. The theft of electricity may be a contributory factor, but based on JPS's loss reduction expenditure table, they spent approximately 7% of the total cost to reduce losses over the 5 year period 2009- 20013, see below:

	JPS Expenditure							
	2009	**2010**	**2011**	**2012**		**2013**		**AVG %**
Maintenance	8,337	8,530	14,126	14,660		14,538	12,038	
Trans & Distri	15,425	15,089	20,778	14,938		16,110	16,468	
Routine Ass. Replacement	14,809	13,557	17,928	13,586		15,778	15,132	
	38,571	**37,176**	**52,832**	**43,184**		**46,426**	**218,189**	
	18%	17%	24%	20%		21%		20%
System Improvement	**393**	**1,150**	**2,251**	**1,032**		**332**	**5,158**	
	8%	22%	44%	20%		6%		20%
Protection & Control	**223**	**381**	**599**	**320**		**0**	**1,523**	
	4%	7%	12%	6%		0%		6%
System Expansion	**13890**	**20584**	**16389**	**15492**		**28318**	**94,673**	
	15%	22%	17%	16%		30%		20%
Loss Reduction	**6759**	**13384**	**16994**	**10596**		**6258**	**53,991**	
	7%	14%	18%	11%		7%		11%

So losses due to theft would also reduce based on their chart from the Tariff Application Report. What this is telling me, is that they are also experiencing lower usage from residential customers, as people are using more alternative (solar, windmill, etc..), and is conserving more. People have also opted to use solar lights for outdoors at nights.

In an economy where people are being squeezed financially, what would possess JPS to believe that they would have benefitted in the long run from such an increase, especially in light of that fact that residential people are being asked to pay 19% more, plus the 15% in the goods and services that are purchased from businesses. The increased cost would become a part of the total cost of production, that businesses would pass on to the same residential customers; a virtual 34% increase. This is saying to the residential customers, that they should gravitate to alternative sources and conserve more.

I believe that in a monopoly situation, that there can be less attention paid to spend, because the spend can be passed on to customers as costs. Especially in situations where there is a guaranteed % return on investment. This type of quarantee, allows companies to automatically increase rates when the targets are not met. Is this the path being pursued by JPS at this time? Why is it, that based on the JPS expense table, that there was a significant increase in expenditure for 2011? I cannot remember a major disaster that year. I am thinking that there could be other spend being passed on the customers that may be outside regular operational cost. What is there to prevent this from happening if it haven't started yet, or inversely, stop it.

I believe that this is not a smart move for JPS, and that they should find ways of reducing costs through proper spend management initiatives, reduce obsolete inventory and non-performing asset costs, manage capex and opex spend more prudently, by improving their procurement policies and practices, and the negotiation of longer supplier payment terms to manage cash outflows. When revenues have fallen off target, you then find creative ways of reducing costs, not pressure your customers, by trying to squeeze 10$ out of $5.

People can take so much and no more. These increases will not matter much if people begin to explore and embark on other sources of electricity. If a man gets a loan and solar his house, the savings from the reduction in JPS bill will pay for it in the long run. JPS should think about that when they ask for these ridiculous increases from a suffering nation.
Regards
Wayne Martin
JPS Customer

From: Shanna Thompson
Sent: Sunday, April 27, 2014 9:37 PM

Good evening Sir/Madam:
Thank you for serving the Jamaican public in such a grand way throughout all these years. I am a valued customer of Jamaica Public Service and I am current with my payments. Thank you for providing this shortened tariff proposal that I read. On perusal of the summary of the 2014-2019 Tariff review submission, I reconsidered the point of view that I had of accepting no increase at all. I am of the firm belief that it would be unrealistic of the Jamaica Public Service (JPS) to impose any tariff without due consideration of the economic status of the commercial and residential customers. On that ground, I would like to enlighten the OUR that we as Jamaicans are presently under a wage freeze and we have received no new increase for at least one year. In my own situation, the reclassification that was tabled from 2009 has come into effect since last year and only afforded me a meager 10% increase. This I must say may reflect the general change in income of the few workers who have received an increase at all. With that thought in mind, I cannot afford more than this 10% increase in my utility bill at this time.
Another matter that I am concerned about is the proposed revenue cap. The fact that the customers would have to pay more when they use less is incredibly unethical. We, as customers, are continually asked to conserve on our usage of energy. How then can we be rewarded, when our demand declines, with a rate increase? The fixed costs of JPS can be reduced and nowhere in this document is there a mention of reducing costs or reduced costs being passed on to the customer. I think that the Price Cap should remain in place unless there is a better proposal.
Thirdly I want to comment on proposal to review the FX Adjustment factor: the FX adjustment factor for me has been adjusted every month without fail. The FX adjustment should not be adjusted any further than it already is. Let it remain where it is.
I think that if the EWI is cooperative with the contract due in 2017 and the power plants retired, there will be a cost associated initially as an investment this may be passed on to the customer but it should be divided to a payout time of ten years and only if the profit gained from this investment is also passed on to the customer . This is due to the fact that the JPS would already be gaining from this IPP investment and will start realizing the benefit after approximately five years. These power systems which are to be closed down were in use for much longer than ten years. If another player, that is, energy provider comes to the market during those ten years it should be offered to them for sale if they so desire.
I must say I absolutely love the idea of prepaid metering and I suggest they offer this as an option to not just the problem areas but to all residential customers. In closing, I would like to say any

proposal must be to the mutual benefit of both consumer and provider and this would facilitate a great relationship between both.

Yours Truly,

Shanna Thompson

"A positive attitude attracts a positive response"

From: N Forrester
Sent: Monday, April 28, 2014 7:52 PM
Subject: Payment of Light bill to third party agents

Dear OUR Consumer Service Representative,

I note the 'approved' practice of the Jamaica Public Service (JPS) to debit one's account for late payment, and credit it whenever there is an on-time payment. In other word, if I pay my bill late, I have to pay JPS $250 + 16.5% GCT, and if I pay on-time I receive $250. Now, I have been paying my bill using TeleScotia for many years, and did so on-time every single payment. I always paid my bill on the due date that JPS says the bill is due. I don't check to see if the payment date falls on Sunday, Monday, Tuesday, etc. I just pay based on their instruction.

To my dismay I saw a late payment amount on my bill for April 2014, which suggests to me that I paid my March bill late. I actually did the transaction on Sunday March 2014. I contacted both Scotia Bank and JPS, and what I am being told is not good enough. Scotiabank is telling me that because I paid the bill on the weekend (Sunday, March 30, 2014) the system updates it as my doing the payment on Monday. This information is sent to JPS thus they charge me a late fee. JPS is telling me that the information they received from Scotiabank is that I paid on Monday, March 31, 2014.

The problem I have is that the date my bill was actually paid was not recorded as such - not by Scotiabank and not by JPS. So then, why is JPS telling me that my bill is due on a weekend, particularly a Sunday when they know that the third party information is not going to be accurate. The system does not update on the weekend until the next business day, which I was unaware of.

I am suggesting that JPS be instructed not to have due date falls on a weekend especially the Sunday because their third party interest information will not or is not being updated immediately. As a result, a customer will be charged late fee because of that 'grey area'. I'm being charged $250 + tax for that 'grey area' I did pay my bill on March 30, 2014 as JPS advised but because the bank's system was not updated until the following day, the information that goes to JPS says I paid on Monday, March 31, 2014, which in fact is not so.

I'm not feeling good about this because there must be some consideration for people like myself who like to stick to the rule of law --- you stay pay this time, I pay this time. And this is mostly so because of when the funds can become available. I would really like a refund of this money. Following the rule, I have paid in fully my April bill with the late fee amount included. Luckily I have the money available for this date - April 28.

I would hate to know that I'm being cheated out of my money by this grey area, which leaves the impression that I honoured my bill late. I didn't! Kindly use your good office to help me resolve this issue. My meter number is xxxxx.

Sincerely,

N.Forrester-

From: Martell Fennell
Sent: Wednesday, April 30, 2014 8:57 PM
Dear Sirs,
Thanks for a chance to make an input re JPS tariff application; here is my suggestion.
Many persons find it difficult to meet JPS payment deadline.
Persons such as pensioners and others get their income cheque sometimes after the JPS due date so they cannot avoid the $250 late fees. I am suggesting that the customer be allowed to choose a date from a range of dates e.g 25 - 31 of each month as was once offered by JPS sometime around the late 1990s, It is only fair that the customer should have some say into a contract between two parties especially where a penalty is being charged for not sticking to a payment date in which you had no input.
Regards

From: ROSEMARIE ROBINSON
Sent: Wednesday, April 30, 2014 4:01 PM
Subject: JPS - Bringing My Views to Light
My view is that JPS should not get an increase at this time. It is very unfair as there is no way that JPS is operating at a loss as our light bill increase almost every month to cover their excess operational expenses.
How can we be expected to pay any more for such high electricity with our salaries at the same figure for a number of years? If they are granted a 19%-21% increase, the only thing most of us can do is to hand over our pay cheque to them at the end of the month.
JPS need to go and find the persons who are stealing the electricity and stop pressuring the persons who are trying very hard to pay their bills. It is not that we have it but we try to live up to our obligations. Even though we try to conserve, JPS is always sending a high bill which is very depressing. They are just like the government who pressure you with PAYE and then still tax you and will not go after those who are not willing to pay.
OUR remember you are here to help us and not help the utility companies to hold us hostage.

From: roger
Sent: 06 May, 2014 10:53
Subject: JPS tariff review submission
Below are my contributions:
Roger Chang
Merit order dispatch remove from JPS to somewhere else, perhaps OUR, but ideally not. OUR
Too corrupt towards JPS
Demand charge
Change from 6 months to less; say 3 or even 1 or 2 months
Should be a tiered charge (smaller rate for smaller users) say 3 tiered
Voltage, frequency, PF (power factor)
Must put in place penalties for over/under voltage/frequency and 'bad' PF
Increase 'life line' subsidy from 100kwh/month to say 150kwh/month or more
Remove clause that allows JPS to offer special discount - or put limits on discount period to no more than say 6 months (or 1 year)

- this impacts jps's bottom line profitability (P/L). This therefore is unregulated and should not be allowed. Rate payers will ultimately have to pay without any oversight or regulation - also makes 3rd party generators (like PV or co-gen) a disadvantage to make a good business case. Suggest net-metering as a part of solution to anti-theft program could limit to say 100kwh/month (a small PV system) gets them formally on the grid, and pay very little monthly we are already subsidizing 0 to 100kwh/month
Decrease deposit amount from 3 months to say 2 months (or less) calculate upgrade deposit from jps discretionary (avg over previous 12 months) to previous 3 months usage add interest on deposit (market rate)
Payment for all breaches of guaranteed standards should be automatic

From: roger chang
Sent: 08 May, 2014 13:30
Another JPS tariff review submission:
Condition 16: codes of practice
This condition has no deadline. A deadline must be set for the various codes of practice and adhered.
Roger

From: roger
Sent: 08 May, 2014 09:17
Subject: Re: Media release
Certain JPS customers (including JPS staff members) pay a 'discounted' rate on their bill. This unregulated benefit must stop. It is not fair, it is only available at the discretion of the JPS.
All rate payers have to pay for this, but all cannot benefit.
Regards
Roger

From: Lionel Whittingham]
Sent: Tuesday, May 13, 2014 5:58 PM
Please Note: base on follow-up to our recent Breakfast meeting held by your Office on the 29th April, 2014 @ the Knutsford Court Hotel, dealing with Energy issues and matters with various Stakeholders, by then on behalf of the Jamaica Lobbyist Action Enterprise (J.L.E.A.) situated @ 2 Kirk Avenue, Kingston C.S.O. JA. W.I.
As I speak to suggested solutions in terms of Policy Directions the JPS Co. could be looking at, in the of sense of a Residential and Commercial Flat-Rate in light of users in certain Geographic and Demographic Areas, Zones, Inner-Cities, Red or Garrison Districts where by your Company supply Electricity, but most cases unable to collect for such usages, we are to further propose for serious consideration to collect rather than disconnect, whereby we are willing to play such mediating role in bringing some these so-called users ramping up many breaches these are as follow as listed below;
1) Big Yard Meter Setting where-by users can be collect from in central format authorizing a collector to make payment when due per month, based on their Residential-Layout.

2) Big Stick Commercial Meter Setting where-by users can be collect from in these Market and Commercial Districts where-by Vendors, Higglers and informal Traders being allow to get on the to system where ever it fall.
3) The creation of a JPS Swipe-Card for quicker Bill Payment, where by persons in these informal setting can pay their bills more easy, rather than the total formal setting using Mobile- Collectors.
4) Community-Scanners who research in on what equipment within these informal settings.
We further ask for an urgent meeting to discuss the way forward, on these proposed solutions, so as to bring about amicable settlement, to these informal areas and zones.

JPS goes after $10-b annual return
Electricity distributor seeks up to 93% rate hike
Wednesday, April 16, 2014
JAMAICA Public Service Company (JPS) is hoping to clear US$94-million ($10.3 billion) profit a year should its proposed rate hike be approved.
The light and power company applied to the Office of Utilities Regulations (OUR) for a raft of changes to its non-fuel tariff (the rate that recovers cost associated with transmitting and distributing electricity rather than generating it).
Residential customers will see the monthly charge for network access (which up to now has been called the customer charge) increase by a range of 70 per cent to 420 per cent, depending on usage, if JPS gets its way.
What's more, the monopoly electricity distributor hopes to raise the non-fuel or energy charge to households by a range of 48 per cent to 93 per cent, moving from the lower end of the range to the higher end, the more electricity is used.
For commercial customers the rate for which JPS has applied, decreases with higher usage, supposedly to promote greater use of electricity for business purposes.
On the other hand, the utility proposes a 65 per cent increase for the smallest commercial users, while enterprises can't realise a decrease in the overall rate until they have consumed some 140,000 kilowatt-hours (kWh).
Indeed, the utility devised creative ways of encouraging more efficient consumption, such as recommending to the regulator that it altogether remove the non-fuel rate charged to large industrial customers.
That would see JPS give up just under $5 billion in revenue, which it would earn back from proposed increases to the demand charge that are applied to bills of consumers with heavy-duty electric machinery.
When factoring in the fuel charge, the rate hikes might not seem so daunting.
JPS figures that using a fuel rate of 23 US cents per kWh, the residential tariff increases, on average, by 22 per cent. Most commercial customers or 98 per cent of them would see an average increase of 16 per cent, using the same math.
Of course, the proposed non-fuel tariff rates coupled with the fuel rates would put the cost of electricity at 45 US cents per kWh for the average household and 43 US cents per kWh for the overwhelming majority of commercial customers.
In its latest five-year tariff review application, JPS rationalised that it accumulated net profit of US$96 million, or an average of US$24 million a year, from 2010 to 2013.

"The target profit for JPS, allowed (not guaranteed) through the revenue requirement, has never been achieved, representing an allowed return on equity (ROE) of 16 per cent that was approved in 2009, which should have resulted in a net profit of approximately US$43 million per annum", said JPS of its profit performance over the tariff period that recently ended.

High system losses over the period factored heavily in its shortfall.

The utility company estimated that it was not allowed to recover US$111 million in fuel costs due to penalties from 2009 to 2013.

"The magnitude of the penalty varies with the price of oil and the risk exposure was amplified with the spike in the price of oil over the past two years," said the light and distribution company. "At the end of 2013 losses, technical (8.6 per cent) and non-technical (largely theft --18.04 per cent), stood at a total of 26.64 per cent"

Unfair Criticism of Paulwell

Published: Thursday | April 17, 2014

I think it is an unfair criticism being levelled against Minister Paulwell in regard to his proposal to allow persons who steal electricity to pay a flat rate for a period of time and then bring them up to standards.

Yes, I admit, it is not the best proposal, and those of us who have to pay between $5,000 and $10,000 monthly have all rights to react strongly against such proposal, but then again, we have to think about a number of things.

1. Those who pay for electricity have to foot the cost for those who don't.
2. When those who steal electricity start paying a flat rate, there is less pressure on our pockets.
3. To pay a flat rate might be seen as a signal of entitlement, but I say it is a humanitarian approach to solving the issues plaguing us.
4. Those of us who are middle-class sometimes forget how harsh those in the lower strata of society have to live under the tough economic conditions which plague our society.

JPS's CEO Kelly Tomblin has said that other measures to bring in those who steal electricity to the table of paying for electricity has been exhausted. She further said that there is only one remaining measure, the most draconian of all, and that is to shut off electricity in troubled communities.

We certainly cannot afford to move in this direction, so while EWI has been granted a licence to add more energy to the national power grid to bring down the cost of electricity, let's remember that as a society we have a humanitarian approach to make as a government, especially towards the most vulnerable in our society.

Jevon Minto

Questions For OUR

Published: Friday | April 25, 2014

In light of the current Jamaica Public Service Company (JPS) tariff review being undertaken by the Office of Utilities Regulation (OUR), there are some pertinent regulatory questions which the Young Entrepreneurs' Association (YEA) would like to publicly pose to the OUR:

1. Being that JPS has an exclusive licence for the distribution of electricity, and being that the JPS is also an electricity generator, does the JPS have a power purchase agreement (PPA) with itself?
2. If the answer is yes and the JPS does have a PPA with itself, are the selling prices, efficiency rates, and operational efficiency requirements within the same bands as those embedded in the PPAs between the JPS and independent power producers (IPPs)?.

3. If a PPA does not exist between the JPS and itself, why is this not the case? And are there steps currently being taken to have one implemented? And by what process, and what considerations, will this PPA be instituted?
4. Does the regulation still exist by which the electricity generated by the JPS has first option of being fed into the grid, regardless of the rate at which it is produced compared to that of IPPs? If this regulation still exists, does the OUR not consider this to be inefficient and ineffective, and what steps are being taken to have this regulation repealed?
5. Being that the JPS has an exclusive licence on electricity distribution, and also acts as a generator of electricity, does the OUR not see an inherent conflict of interest with this arrangement?
6. Are there any considerations being given to the liberalisation of the grid to allow for other entrants to the market to also have a right to electricity distribution?
7. Are there any considerations to instructing JPS to break up its operations into a distributions company separate and apart from its production operations? This would be to ensure that the conflict of interest is eliminated, regulatory considerations for electricity distribution could be undertaken separate from generation considerations, and the production arm of the JPS would be subject to the said rules and regulations as those applied to IPPs.

We would welcome the OUR's considered answers to these questions.

ANDRAE BLAIR
Public Policy & Advocacy Committee Chair,
Young Entrepreneurs Association of Jamaica

Appendix A: GOJ 10-year US$ Bond Yield, US 10-year Treasury Rates and Jamaica CRP for the period 31st January 2007 to 31st December 2013

Dates	GOJ 10yr US$ Bond Yield (%)	US 10yr Treasury (%)	CRP (%)	Dates	GOJ 10yr US$ Bond Yield (%)	US 10yr Treasury (%)	CRP (%)
1/31/2007	6.63	4.87	1.76	1/31/2011	7.51	3.35	4.16
2/28/2007	6.62	4.55	2.07	2/28/2011	7.61	3.42	4.19
3/30/2007	6.51	4.64	1.87	3/31/2011	7.50	3.47	4.03
4/27/2007	6.74	4.68	2.06	4/29/2011	7.28	3.29	3.99
5/31/2007	6.77	4.87	1.90	5/31/2011	6.97	3.06	3.91
6/29/2007	7.00	5.09	1.91	6/30/2011	6.93	3.18	3.75
7/31/2007	7.09	4.84	2.25	7/29/2011	6.99	2.97	4.02
8/31/2007	7.04	4.54	2.50	8/31/2011	7.44	2.30	5.14
9/28/2007	6.79	4.53	2.26	9/30/2011	7.74	1.98	5.76
10/31/2007	6.75	4.41	2.34	10/31/2011	7.49	2.15	5.34
11/29/2007	6.65	3.99	2.66	11/30/2011	7.51	2.01	5.50
12/31/2007	6.57	4.05	2.52	12/31/2011	7.72	1.98	5.74
1/31/2008	6.75	3.64	3.11	1/31/2012	6.35	1.97	4.38
2/29/2008	6.76	3.61	3.15	2/29/2012	6.39	1.97	4.42
3/31/2008	6.89	3.45	3.44	3/31/2012	6.03	2.17	3.86
4/30/2008	6.80	3.80	3.00	4/30/2012	6.09	1.95	4.14
5/30/2008	6.74	4.03	2.71	5/31/2012	6.24	1.80	4.44
6/30/2008	7.43	3.98	3.45	6/30/2012	6.38	1.62	4.76
7/31/2008	7.23	4.04	3.19	7/31/2012	6.00	1.53	4.47
8/29/2008	7.28	3.77	3.51	8/31/2012	5.70	1.68	4.02
9/30/2008	7.79	3.62	4.17	9/30/2012	6.07	1.72	4.35
10/31/2008	10.40	3.89	6.51	10/31/2012	6.02	1.75	4.27
11/28/2008	11.13	2.98	8.15	11/30/2012	6.16	1.65	4.51
12/29/2008	11.32	2.11	9.21	12/31/2012	6.05	1.72	4.33
1/27/2009	11.47	2.62	8.85	1/31/2013	8.16	1.91	6.25
2/26/2009	11.31	2.98	8.33	2/29/2013	8.14	1.98	6.16
3/31/2009	11.91	2.72	9.19	3/31/2013	8.03	1.96	6.07
4/30/2009	11.90	3.14	8.76	4/30/2013	7.83	1.76	6.07
5/20/2009	10.80	3.22	7.58	5/31/2013	7.83	1.93	5.90
6/30/2009	10.03	3.49	6.54	6/30/2013	8.03	2.30	5.73
7/31/2009	9.62	3.57	6.05	7/31/2013	8.19	2.58	5.61
8/31/2009	10.39	3.44	6.95	8/31/2013	8.23	2.74	5.49
9/30/2009	9.51	3.32	6.19	9/30/2013	8.26	2.81	5.45
10/30/2009	10.41	3.44	6.97	10/31/2013	8.40	2.62	5.78
11/30/2009	11.68	3.23	8.45	11/30/2013	8.50	2.72	5.78
12/31/2009	11.43	3.83	7.60	12/31/2013	8.48	2.90	5.58
1/29/2010	10.32	3.67	6.65				
2/26/2010	9.50	3.62	5.88				
3/31/2010	7.54	3.83	3.71				
4/30/2010	7.23	3.74	3.49				
5/28/2010	8.18	3.32	4.86				
6/30/2010	7.54	2.97	4.57				
7/30/2010	7.22	2.92	4.30				
8/31/2010	7.71	2.48	5.23				
9/30/2010	7.78	1.87	5.48				
10/29/2010	7.45	2.61	4.84				
11/30/2010	7.56	2.76	4.80				
12/31/2010	7.56	3.39	4.17				
				Averages	**7.90**	**3.06**	**4.84**

Appendix B: List of Power Companies Included in Estimating Equity Beta (β_e)

Argentina	Capex S.A. (BASE: CAPX) Central Puerto S.A. (BASE: CEPU2) Pampa Energia SA (BASE: PAMP) Compania de Transporte de Energia Electrica en Alta Tension Transener (BASE:TRAN) Edenor SA (BASE: EDN)
Australia	Hot Rock Limited (ASX: HRL) Pacific Energy Ltd. (ASX: PEA) Envestra Limited (ASX: ENV) ERM Power Limited (ASX: EPW) Petratherm Ltd. (ASX: PTR) Wasabi Energy Limited (ASX: WAS) Torrens Energy Limited (ASX: TEY) KUTh Energy Limited. (ASX: KEN) Energy World Corp. Ltd. (ASX: EWC) Geodynamics Limited (ASX: GDY) Redbank Energy Limited (ASX: AEJ) K2 Energy Limited (ASX: KTE)
Austria	EVN AG (WBAG: EVN) VERBUND AG (WBAG: VER)
Bangladesh	Power Grid Company of Bangladesh Ltd (DSE: POWERGRID) Dhaka Electric Supply Company Limited (DSE: DESCO) Summit Power Limited (DSE: SUMITPOWER) Khulna Power Company Ltd. (DSE: KPCL)
Belgium	Elia System Operator SA (ENXTBR: ELI) Thenergo (ENXTBR: THEB)
Brazil	Eletrobras Participacoes SA (BOVESPA: LIPR3) CEMAR - Cia Energetica do Maranhao (SOMA: ENMA3B) AES Elpa S.A. (BOVESPA: AELP3) Redentor Energia SA (BOVESPA: RDTR3) AFLUENTE GERA‚ÌO DE ENERGIA ELƒTRICA SA (BOVESPA: AFLU3) EDP - Energias do Brasil S.A. (BOVESPA: ENBR3) Tractebel Energia S.A. (BOVESPA: TBLE3) CPFL Energia S.A. (BOVESPA: CPFE3) Equatorial Energia S.A. (BOVESPA: EQTL3)

AES Tiet S.A. (BOVESPA: GETI3)
Light SA (BOVESPA: LIGT3)
MPX Energia SA (BOVESPA: MPXE3)
Companhia Estadual de Distribui ‹o de Energia ElŽtrica - CEEE-D (BOVESPA: EEEL3)
Ampla Energia e Servi os S/A (BOVESPA: CBEE3)
GTD Participa ›es, SA (SOMA: GTDP3B)
Companhia Estadual de Distribui ‹o de Energia ElŽtrica (BOVESPA: CEED3)

Canada
Capital Power Corporation (TSX: CPX)
HTC Purenergy Inc. (TSXV: HTC)
Northland Power Inc. (TSX: NPI)
Maxim Power Corp. (TSX: MXG)
Emera Inc. (TSX: EMA)
TransAlta Corp. (TSX: TA)
Fortis Inc. (TSX: FTS)
Sea Breeze Power Corp. (TSXV: SBX)
Changfeng Energy Inc. (TSXV: CFY)
Algonquin Power & Utilities Corp. (TSX: AQN)
Boralex Inc. (TSX: BLX)
Run of River Power Inc. (TSXV: ROR)
Alterra Power Corp. (TSX: AXY)
Alter NRG Corp. (TSX: NRG)

Cayman Islands Caribbean Utilities Co. Ltd. (OTCPK: CUPU.F)

Channel Islands Jersey Electricity plc (LSE: JEL)

Chile
CGE DISTRIBUCIîN S.A. (SNSE: CGEDISTRO)
Empresa Electrica De Antofagasta S.A (SNSE: ELECDA)
Empresa Electrica de Magallanes S.A. (SNSE: EDELMAG)
Minera Valparaiso S.A. (SNSE: MINERA)
Compa–'a General de Electricidad S.A. (SNSE: CGE)
Empresa Electrica Pehuenche S.A. (SNSE: PEHUENCHE)
Colbun S.A. (SNSE: COLBUN)
Chilectra S.A. (SNSE: CHILECTRA)
Gasco S.A. (SNSE: GASCO)
Empresa Electrica Pilmaiquen S.A. (SNSE: PILMAIQUEN)
Empresa Nacional de Electricidad S.A. (SNSE: ENDESA)
Enersis S.A. (SNSE: ENERSIS)
E-CL S.A. (SNSE: ECL)
AES Gener S.A. (SNSE: AESGENER)

China Guangdong Electric Power Development Co. Ltd. (SZSE: 200539)

Xinjiang TianfuThermoelectric Co.,Ltd (SHSE:600509)
China Yangtze Power Co. Ltd. (SHSE: 600900)
Shanghai Electric Power Company Limited (SHSE: 600021)
Zhejiang Fuchunjiang Environmental Thermoelectric Inc (SZSE: 002479)
Guodian Changyuan Electric Power Co. Ltd. (SZSE: 000966)
Fujian Mindong Electric Power Co. Ltd. (SZSE: 000993)
Shenzhen Energy Group Co., Ltd. (SZSE: 000027)
Huadian Energy Company Limited (SHSE: 900937)
Datang Huayin Electric Power Co., Ltd (SHSE: 600744)
GD Power Development Co., Ltd (SHSE: 600795)
China Tian Lun Gas Holdings Limited (SEHK: 1600)
Sichuan Chuantou Energy Co Ltd (SHSE: 600674)
Jilin Power Share Co.,Ltd. (SZSE:000875)
Guangdong Meiyan Jixiang Hydropower Co., Ltd. (SHSE: 600868)
Chongqing Fuling Electric Power Industrial Co.,Ltd. (SHSE:600452)
Shenergy Company Limited (SHSE: 600642)
Jiangsu Wujiang China Eastern Silk Market Co., Ltd. (SZSE: 000301)
Shenzhen Nanshan Power Co., Ltd. (SZSE: 200037)
Jiangxi Ganneng Co., Ltd. (SZSE: 000899)
Sichuan Mingxing Electric Power Co., Ltd. (SHSE: 600101)
Inner Mongolia MengDian HuaNeng Thermal Power Corporation Limited (SHSE: 600863)
Shenyang Jinshan Energy Co., Ltd. (SHSE: 600396)
Shanxi Zhangze Electric Power Co.,Ltd. (SZSE:000767)
Guangxi Guiguan Electric Power Co., Ltd. (SHSE: 600236)
Shanghai DaZhong Public Utilities (Group) Co.,Ltd (SHSE:600635)
Guangdong Baolihua New Energy Stock Co Ltd (SZSE: 000690)
Guangdong Shaoneng Group Co., Ltd. (SZSE: 000601)
Sichuan Guangan AAA Public Co., Ltd. (SHSE: 600979)
Henan Yuneng Holding Co.,Ltd. (SZSE:001896)
Chongqing Jiulong Electric Power Co. Ltd. (SHSE: 600292)
Huaneng Power International, Inc. (SEHK: 902)
Sichuan Xichang Electric Power Company Ltd. (SHSE: 600505)
Beijing Jingneng Thermal Power Co., Ltd. (SHSE: 600578)
Guangxi Guidong Electric Power Co. Ltd. (SHSE: 600310)
ENN Energy Holdings Limited (SEHK: 2688)
Hunan Fazhan Industrial Co., Ltd. (SZSE: 000722)
Anhui Province Wenergy Company Limited (SZSE: 000543)
Leshan Electric Power Co., Ltd. (SHSE: 600644)
Yunnan Wenshan Electric Power Co.,Ltd. (SHSE:600995)
China Longyuan Power Group Corporation Limited (SEHK: 916)
Amber Energy Limited (SEHK: 90)
Huadian Power International Corporation Limited (SEHK: 1071)
Sino Gas International Holdings, Inc. (OTCPK: SGAS)

Appendix B: List of Power Companies Included in Estimating Equity Beta (βe)

Colombia

Isagen S.a. E.s.p. (BVC: ISAGEN)
Celsia SA ESP (BVC: CELSIA)
Interconexi—n ElŽctrica S.A. E.S.P. (BVC: ISA)
Empresa de Energia de Bogot‡ S.A. ESP (BVC: EEB)

Czech Republic

CEZ, a.s. (SEP: CEZ)
BGS Energy Plus a.s. (WSE: BGS)

Finland

Fortum Oyj (HLSE: FUM1V)

France

Electricite de Strasbourg SA (ENXTPA: ELEC)
Aerowatt (ENXTPA: ALWAT)
Velcan Energy SA (ENXTPA: ALVEL)
L'Air Liquide SA (ENXTPA: AI)
Rubis (ENXTPA: RUI)
Electricite de France SA (ENXTPA: EDF)
Sechilienne-Sidec (ENXTPA: SECH)
THEOLIA S.A. (ENXTPA: TEO)

Germany

SŠchsische & Oldenburgische Agrar Aktiengesellschaft (DB: BUF)
EnBW Energie Baden-Wuerttemberg AG (DB: EBK)
DTB - Deutsche Biogas AG (DB: DB9)
Energiekontor AG (DB: EKT)
Lechwerke AG (DB: LEC)
SAG Solarstrom AG (DB: SAG)
Kofler Energies Power AG. (DB: R7U)
PNE Wind AG (XTRA: PNE3)
Biogas Nord AG (XTRA: BG8)
Conergy AG (XTRA: CGY)
The Linde Group (DB: LIN)

Greece

Terna Energy SA (ATSE: TENERGY)
Public Power Corporation S.A. (ATSE: PPC)

Hong Kong

CLP Holdings Ltd. (SEHK: 2)
Zhongyu Gas Holdings Ltd. (SEHK: 3633)
Power Assets Holdings Limited (SEHK: 6)
The Hong Kong and China Gas Company Limited (SEHK: 3)
Yingde Gases Group Co Ltd. (SEHK: 2168)
Towngas China Company Limited (SEHK: 1083)
China Power International Development Ltd. (SEHK: 2380)
China Gas Holdings Limited (SEHK: 384)
China Oil and Gas Group Limited (SEHK: 603)

Appendix B: List of Power Companies Included in Estimating Equity Beta (βe)

Hungary Budapesti Elektromos Mžvek Rt. (BUSE: ELMU)
North Hungarian Electricity Supply plc (BUSE: EMASZ)
PannErgy Plc (BUSE: PANNERGY)

India Mytrah Energy Limited (AIM: MYT)
SJVN Limited (NSEI: 533206)
NHPC Ltd. (BSE: 533098)
GAIL (India) Limited (BSE: 532155)
Veer Energy & Infrastructure Ltd (BSE: 503657)
DPSC Limited (NSEI: DPSCLTD)
NTPC Ltd. (BSE: 532555)
Indraprastha Gas Limited (BSE: 532514)
Power Grid Corporation of India Limited (BSE: 532898)
CESC Limited (BSE: 500084)
BOC India Ltd. (BSE: 523457)
OPG Power Ventures PLC (AIM: OPG)
Gujarat Gas Co. Ltd. (BSE: 523477)
Suryachakra Power Corporation Limited (BSE: 532874)
Adani Power Limited (BSE: 533096)
Sun Techno Overseas Ltd. (BSE: 531752)
Gujarat State Petronet Limited (BSE: 532702)
The Tata Power Company Limited (BSE: 500400)
Torrent Power Limited (BSE: 532779)
Gujarat Industries Power Co. Ltd. (BSE: 517300)
Neyveli Lignite Corporation Limited (BSE: 513683)
Indiabulls Power Limited (BSE: 533122)
Orient Green Power Company Limited (NSEI: GREENPOWER)
PTC India Limited (BSE: 532524)
Entegra Ltd (BSE: 532287)
JSW Energy Limited (BSE: 533148)
Jaiprakash Power Ventures Limited (BSE: 532627)
Aegis Logistics Limited (BSE: 500003)
Energy Development Co. Ltd. (BSE: 532219)
Bhagawati Gas Ltd (BSE: 500051)
Reliance Power Limited (BSE: 532939)
GVK Power & Infrastructure Limited (BSE: 532708)
Reliance Infrastructure Ltd (BSE: 500390)
BF Utilities Ltd. (BSE: 532430)

Indonesia PT Leyand International Tbk (JKSE: LAPD)
PT Perusahaan Gas Negara (Persero) TBK (JKSE: PGAS)

Isle of Man Greenko Group PLC (AIM: GKO)

Appendix B: List of Power Companies Included in Estimating Equity Beta (βe)

Israel	Maxima Air Separation Center Ltd. (TASE: MAXM)
Italy	Sol SpA (BIT: SOL) Ascopiave S.p.A. (BIT: ASC) Snam S.p.A. (BIT: SRG) TERNA - Rete Elettrica Nazionale Societˆ per Azioni (BIT: TRN) Kinexia SpA (BIT: KNX) Acsm-Agam S.p.A. (BIT: ACS) TerniEnergia SpA (BIT: TER) ErgyCapital S.p.A. (BIT: ECA) K.R.Energy S.p.A. (BIT: KRE) Enel SpA (BIT: ENEL)
Ivory Coast	Compagnie Ivoirienne d'ElectricitŽ (BRVM: CIEC)
Japan	Electric Power Development Co. Ltd. (TSE:9513) The Kansai Electric Power Company, Incorporated (TSE:9503) CLEX Co.,Ltd. (JASDAQ:7568) Hokuriku Electric Power Company (TSE:9505) Shikoku Electric Power Co. Inc. (TSE:9507) The Chugoku Electric Power Co.,Inc. (TSE:9504 Hokkaido Electric Power Co. Inc. (TSE:9509) Chubu Electric Power Company, Incorporated (TSE:9502) The Okinawa Electric Power Company, Incorporated (TSE:9511) Tohoku Electric Power Co. Inc. (TSE:9506) HIROSHIMA GAS Co.,Ltd. (TSE:9535) Kyushu Electric Power Company, Incorporated (TSE:9508) Toell Co Ltd (JASDAQ: 3361) Air Water Inc. (TSE:4088) Tokyo Electric Power Company, Incorporated (TSE:9501) Taiyo Nippon Sanso Corporation (TSE:4091) Toho Acetylene Co. Ltd. (TSE:4093)
Jordan	Irbid District Electricity Co. Ltd. (ASE:IREL) Jordan Electric Power Company Limited (ASE:JOEP)
Kenya	The Kenya Power and Lighting Company Limited Carbacid Investments Ltd.
Latvia	JSC Latvijas Gaze (RISE: GZE1R)
Lithuania	Lietuvos Dujos AB (NSEL: LDJ1L)

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Malaysia	Tenaga Nasional Bhd (KLSE: TENAGA) Mega First Corp. Bhd (KLSE: MFCB) SIG Gases Berhad (KLSE: SIGGAS) Eden Inc. Berhad (KLSE: EDEN)
Mauritius	Omnicane Ltd. (MUSE: MTMD)
Morocco	Maghreb Oxyg ne S.A. (CBSE: MOX)
Netherlands	New Sources Energy NV (ENXTAM: NSE)
New Zealand	Horizon Energy Distribution Ltd. (NZSE: HED) TrustPower Limited (NZSE: TPW) Contact Energy Ltd. (NZSE: CEN) Infratil Limited (NZSE: IFT)
Norway	Hafslund ASA (OB: HNB)
Oman	Sohar Power Company SAOG (MSM: SHPS) United Power Company (SAOG) (MSM: UECS)
Pakistan	The Hub Power Company Limited (KASE: HUBC) Kohinoor Energy (KASE: KOHE) Sitara Energy Limited (KASE: SEL) Kot Addu Power Co. Ltd. (KASE: KAPCO) Southern Electric Power Company Limited (KASE: SEPCO) Japan Power Generation Limited (KASE: JPGL) Nishat Chunian Power Ltd. (KASE: NCPL) Kohinoor Power Company Ltd. (KASE: KOHP) Nishat Power Ltd. (KASE: NPL) Karachi Electric Supply Company Limited (KASE: KESC) Ghani Gases Limited (KASE: GGL)
Peru	Empresa De Distribucion Electrica De Lima Norte S.a.a. (BVL: EDELNOC1) Luz del Sur S.A.A. (BVL: LUSURC1) Edegel SAA (BVL: EDEGELC1) Hidrandina S.A. (BVL: HIDRA2C1)
Philippines	Salcon Power Corp. (PSE: SPC) Vivant Corporation (PSE: VVT) First Philippine Holdings Corporation (PSE: FPH) First Generation Corporation (PSE: FGEN) Alsons Consolidated Resources, Inc. (PSE: ACR) Aboitiz Power Corp. (PSE: AP)

	Energy Development Corporation (PSE: EDC) Manila Electric Co. (PSE: MER)
Poland	Elektrocieplownia Bedzin S.A. (WSE: BDZ) ENEA S.A. (WSE: ENA) PGE Polska Grupa Energetyczna Spolka Akcyjna (WSE: PGE) Polish Energy Partners Spolka Akcyjna (WSE: PEP) TESGAS Spolka Akcyjna (WSE: TSG) Tauron Polska Energia Spolka Akcyjna (WSE: TPE) Atlantis Energy SA (WSE: ATE) Fon Ecology SA (WSE: FNE) Centrozap S.A. (WSE: IDE) Grupa DUON Spolka Akcyjna (WSE: DUO)
Portugal	EDP-Energias de Portugal, S.A. (ENXTLS: EDP)
Romania	CNTEE Transelectrica S.A. (BVB: TEL)
Russia	Magadanenergo (MICEX: MAGE) Chelyabenergosbyt (MICEX: CLSB) Open joint-stock company Moscow United Electric Grid Company (MICEX: MSRS) Tomsk Distribution Company (MICEX: TORS) Volga Territorial Generation Company (MICEX: VTGK) Kuzbass Power and Electrification Open Joint-Stock Company (MICEX: KZBE) OAO Nizhny Novgorod Retail Company (MICEX: NNSB) Open Joint Stock Company Territorial Generating Company No 9 (MICEX: TGKI) Joint Stock Company Yakutskenergo (MICEX: YKEN) Open Joint Stock Company "Energosbyt Rostovenergo" (MICEX: RTSB) OAO Territorial Generation Company No. 6 (MICEX: TGKF) Krasnoyarsk HES (MICEX: KRSG) Open Joint Stock Company Interregional Distribution Grid Company of North-West (MICEX: MR OAO Ryazan Energy Retail Company (MICEX: RZSB) Open Joint-Stock Company Enel OGK-5 (MICEX: OGKE) Tambov Energy Retail Company (MICEX: TASB) Public Joint-Stock Company Territorial Generating Company #2 (MICEX: TGKB) Open Joint Stock Company Territorial Generating Company No5 (MICEX: TGKE) OJSC Territorial Generating Company No. 14 (MICEX: TGKN) Open Joint-Stock Company INTERS RAO UES (MICEX: IRAO) Open Joint-Stock Company E.ON Russia (MICEX: EONR) Open Joint-Stock Company RusHydro (MICEX: HYDR) JSC Lenenergo (MICEX: LSNG) Joint Stock Company Far-Eastern Energy Company (MICEX: DVEC)

Open Joint Stock Company of Power and Electrification Mosenergo (MICEX: MSNG)
Kuban Power Sale Company Open Joint-Stock Company (MICEX: KBSB)
Open Joint-Stock Company Interregional Distribution Grid Company of Volga (MICEX: MRKV)
Interregional Distribution Grid Company of Centre Joint-Stock Company (MICEX: MRKC)
Irkutsk Joint Stock Company of Energetics and Electrification (MICEX: IRGZ)
Open Joint-Stock Company Interregional Distributive Grid Company of Urals (MICEX: MRKU)
Interregional Distribution Grid Company of South Joint Stock Company (MICEX: MRKY)
JSC TGC-1 (MICEX: TGKA)
Mosenergosbyt Oao (MICEX: MSSB)
Interregional Distribution Grid Company of Siberia Joint Stock Company (MICEX: MRKS)
Open Joint Stock Company "Federal Grid Company of Unified Energy System" (MICEX: FEES)
Open joint-stock company The Second Generating Company of the Wholesale Power Market (MIC
Joint Stock Company Interregional Distribution Grid Companies Holding (MICEX: MRKH)

Saudi Arabia Saudi Electricity Company (SASE: 5110)

Singapore Asia Power Corporation Limited (SGX: A03)
YHM Group Limited (Catalist: 5QT)

South Africa Southern Electricity Company Ltd. (JSE: SLO)

South Korea YESCO Co., Ltd. (KOSE: A015360)
Samchully Co.,Ltd. (KOSE:A004690)
E1 Corporation (KOSE: A017940)
Kyungnam Energy Co., Ltd (KOSE: A008020)
Korea Electric Power Corp. (KOSE: A015760)
Daesung Energy Co., Ltd. (KOSE: A117580)
Korea Electric Power Industrial Development Co., Ltd (KOSE: A130660)
Daesung Holdings (KOSE: A016710)
OCI Materials Co., Ltd. (KOSE: A036490)

Spain EDP Renov‡veis (ENXTLS: EDPR)
Red ElŽctrica Corporaci—n S A. (CATS: REE)
Enag‡s, S.A. (CATS: ENG)
Endesa SA (CATS: ELE)

	Fersa Energias Renovables, S.A. (CATS: FRS) Iberdrola SA (CATS: IBE) Acciona SA (CATS: ANA)
Sri Lanka	Vallibel Power Erathna plc (COSE: VPEL.N0000) Hydro Power Free Lanka PLC (COSE: HPFL-N-0000)
Sweden	Vallentuna Elverk AB (OM: ELV) Opcon AB (OM: OPCO)
Switzerland	Centralschweizerische Kraftwerke AG (SWX: CKWN) Societˆ Elettrica Sopracenerina SA (SWX: SOPN) Energiedienst Holding AG (SWX: EDHN) Romande Energie Holding SA (SWX: HREN) Alpiq Holding AG (SWX: ALPH) Etrion Corporation (TSX: ETX)
Taiwan	Taiwan Cogeneration Corporation (TSEC: 8926) Ta-Yuan Cogeneration Company Ltd (GTSM: 8931)
Thailand	Sahacogen (Chonburi) Public Company Limited (SET: SCG) Electricity Generating Public Company Limited (SET: EGCO) Ratchaburi Electricity Generating Holding Public Company Limited (SET: RATCH) Glow Energy Public Company Limited (SET: GLOW) Solartron Public Company Limited (SET: SOLAR)
Turkey	Aygaz A.S. (IBSE: AYGAZ) Aksa Enerji †retim AS (IBSE: AKSEN) Ayen Enerji A.S. (IBSE: AYEN) Aksu Enerji ve Ticaret AS (IBSE: AKSUE) Zorlu Enerji Elektrik Uretim A.S. (IBSE: ZOREN) Akenerji Elektrik Uretim A.S. (IBSE: AKENR)
Ukraine	Centrenergo JSC (UKR: CEEN)
United Kingdom	Kalahari Greentech, Inc. (OTCPK: KHGT) SSE plc (LSE: SSE) Drax Group plc (LSE: DRX) Helius Energy plc (AIM: HEGY) IPSA Group PLC (AIM: IPSA) Andes Energia PLC (AIM: AEN) KSK Power Ventur PLC (LSE: KSK) Rurelec PLC (AIM: RUR)

Appendix B: List of Power Companies Included in Estimating Equity Beta (βe)

US

- ENERSIS S A ADR
- Covanta Holding Corp.
- Atlantic Power Corp.
- Calpine Corp
- Verenium Corp
- Daystar Technologies Inc
- NRG Energy
- EDP - Energias de Portugal
- U.S. Geothermal Inc
- Pacific Ethanol
- AES Corp.
- Highpower International Inc
- Korea Electric ADR
- China Energy Recovery Inc.
- Vista International Tech
- Enova Systems Inc
- A-Power Energy Generation Sys
- Titan Energy Worldwide Inc
- BioFuel Energy Corp
- Suntech Power ADS
- Nova Biosource Fuels Inc
- A123 Systems
- Hoku Corp
- Commerce Energy Group Inc
- USEC Inc
- Valence Technology
- Chapeau Inc

Vietnam

- NaLoi Hydropower JSC (HASTC: NLC)
- Can Don Hydro Power JSC (HOSE: SJD)
- Vinh Son-Song Hinh Hydro Power Joint-Stock Company (HOSE: VSH)
- Ba Ria Thermal Power Joint Stock Company (HOSE: BTP)
- Nam Mu Hydropower Joint Stock Company (HASTC: HJS)
- Ry Ninh II Hydroelectric Joint Stock Company (HASTC: RHC)
- ThacBa Hydropower Joint Stock Company (HOSE: TBC)
- Pha Lai Thermal Power JSC (HOSE: PPC)
- Khanh Hoa Power Joint Stock Company (HOSE: KHP)