Office of Utilities Regulation

Jamaica Public Service Company Limited
Rate Review 2019 - 2024

Determination Notice

OFFICE OF UTILITIES REGULATION

2020 December 24

DOCUMENT TITLE AND APPROVAL PAGE

1. DOCUMENT NUMBER: 2020/ELE/016/DET.003

2. DOCUMENT TITLE: Jamaica Public Service Company Limited Rate Review 2019 - 2024: Determination Notice

3. PURPOSE OF DOCUMENT:

This document sets out the Office's decisions on issues related to the Jamaica Public Service Company Limited Rate Review for the five (5) year period 2019 – 2024, which is the first such review under the Revenue Cap regime established by the Electricity Licence, 2016 .

4. ANTECEDENT DOCUMENTS:

2014/ELE/008/DET.004	Jamaica Public Service Company Limited Tariff Review for Period 2014 -2019: Determination Notice	2015 January 07
2015/ELE/003/ADM.001	Jamaica Public Service Company Limited Tariff Review for Period 2014 -2019: Determination Notice – Addendum 1	2015 February 27
2015/ELE/007/DET.001	Jamaica Public Service Company Limited Annual Tariff Adjustment 2015 - Determination Notice	2015 September 03
Ele 2016/ELE/004DET.001	Jamaica Public Service Company Limited Annual Tariff Adjustment 2016 - Determination Notice	2016 July 04
2017/ELE/001/DET.001	Jamaica Public Service Company Limited Extraordinary Rate Review 2017 Determination Notice	2017 February 01
2017/ELE/006/DET.003	Jamaica Public Service Company Limited Annual Review 2017 & Extraordinary Rate Review – CPLTD: Determination Notice	2017 August 31
2018/ELE/018/DET.004	Jamaica Public Service Company Limited Annual Review 2018 & Extraordinary Rate Review: Determination Notice	2018 October 1
2019/ELE/003/RUL.001	Final Criteria – Jamaica Public Service Company Limited: 2019 – 2024 Rate Review Process	2019 March 14
2019/ELE/007/ADM.001	Addendum to Final Criteria – Jamaica Public Service Company Limited:2019 – 2024 Rate Review Process	2019 April 24

APPROVAL:

This document is approved by the Office of Utilities Regulation and this Determination Notice becomes effective as of 2020 December 28.

On behalf of the Office:

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Ansord E. Hewitt
Director-General

2020 December 24

Abstract

The Electricity Licence, 2016 (Licence) makes provision for a review of the Jamaica Public Service Company Limited's (JPS') electricity rates at five-year intervals. The review process was scheduled to commence in 2019 April in accordance with the provisions of the Licence. JPS' rate submission, received 2019 July 31, was however refused by the Office of Utilities Regulation (OUR or Office) as it was deemed deficient, to the extent that it would not allow for a complete evaluation.

On 2019 December 30, JPS submitted a revised application to the Office of Utilities Regulation (OUR) for a review of rates, which application was accepted by the OUR for consideration (Application).

This Application is JPS' fourth five yearly filing with the OUR, and is the first under the Revenue Cap regulatory regime, which was introduced in the Licence. The revenue cap principle looks forward at five (5) year intervals and involves the decoupling of kilowatt hour sales and the approved revenue requirement. The revenue cap principle allows for the funding of the initiatives, which are proposed in JPS' Business Plan, while seeking to ensure that the Licensee's customers are not potentially overcharged for the service.

JPS stated that its proposal intends to do the following, among other things:

1. Recover the costs to operate its regulated power system for the period 2016 – 2023.
2. Complete the implementation of the terms of the Licence.
3. Elevate the customer experience by transitioning from less efficient, end of life oil-fired generation fleets, to new Liquefied Natural Gas (LNG) and renewable generation.
4. Improve operational efficiency while enabling customers to track, monitor and save on their electricity bills.
5. Facilitate continued investments to modernize and transform the electricity system to a smart system.
6. Review non-fuel rates to take account of past and future investments.
7. Redesign tariff structures to reflect more choices for its customers; and
8. Drive commercial growth, customer retention and safeguard the affordability of the product.

The Application also includes an Annual Adjustment Filing to adjust rates to 2019 levels.

Given that the Government of Jamaica's (GOJ's) Integrated Resource Plan (IRP) was not published at the time of its Application, JPS stated that its Business Plan did not reflect investment decisions that have the benefit of an updated comprehensive system impact analysis supporting its selection. In light of this, JPS argued that it will be of critical importance that its Business Plan be adapted, where possible, to bring consistency with the IRP when published. In the event that such a review/adaptation yields a different pool of revenues, JPS stated that a revenue requirement adjustment may become necessary.

Definitions, Acronyms and Abbreviations

2014-2019 Determination Notice	-	Jamaica Public Service Company Limited Tariff Review for Period 2014 -2019 Determination Notice, Document No. 2014/ELE/008/DET.004
2015 Annual Tariff Adjustment Determination Notice	-	Jamaica Public Service Company Limited Annual Tariff Adjustment 2015 – Determination Notice Document No. Ele 2015/ELE/007DET.001
2016 Annual Tariff Adjustment Determination Notice	-	Jamaica Public Service Company Limited Annual Tariff Adjustment 2016 - Determination Notice Document No. Ele 2016/ELE/004DET.001
2017 Extraordinary Rate Review Determination Notice	-	Jamaica Public Service Company Limited Extraordinary Rate Review 2017 Determination Notice, Document No. 2017/ELE/001/DET.001
2017 Annual and Extraordinary Rate Review Determination Notice	-	Jamaica Public Service Company Limited Annual Review 2017 & Extraordinary Rate Review-CPLTD: Determination Notice, Document No. 2017/ELE/006/DET.003
2018 Annual & Extraordinary Rate Review Determination Notice	-	Jamaica Public Service Company Limited Annual Review 2018 & ExtraordinaryExtra-Ordinary Rate Review: Determination Notice Document No. 2018/ELE/018/DET.0004
AATDAT	-	Advanced Automated Theft Detection Analytical Tool
ABNF	-	Adjusted Base-rate Non-Fuel
Addendum 1	-	Jamaica Public Service Company Limited Tariff Review for the Period 2014 – 2019: Determination Notice – Addendum 1, Document No. 2015/ELE/003/ADM.001
Addendum to Final Criteria	-	Addendum to Final Criteria - Jamaica Public Service Company Limited :2019 -20224 Rate Review Process, Document No. 2019/ELE/007/ADM.001
ADMS	-	Advanced Distribution Management System

ADO	-	Automotive Diesel Oil
ALRIM	-	Accelerated Loss Reduction Incentive Mechanism
AMI	-	Automated Metering Infrastructure
Annual Review Submission 2017	-	Jamaica Public Service Company Limited Annual Tariff Adjustment Submission for 2017 & Extraordinary Rate Review dated 2017 May 05
Application	-	The Jamaica Public Service Company Limited's Five Year Rate Review proposal submitted to the Office of Utilities Regulation on 2019 December 30
ARIMA	-	Auto Regressive Integrated Moving Average
ART	-	Annual Revenue Target
BOJ		Bank of Jamaica
BOPS	-	Bogue Power Station
CACU	-	Consumer Advisory Committee on Utilities
CAGR	-	Compound Annual Growth Rate
CAIDI	-	Customer Average Interruption Duration Index
CAPEX	-	Capital Expenditure
CAPM	-	Capital Asset Pricing Model
CCGT	-	Combined Cycle Gas Turbine
CF	-	Capacity Factor
CHP	-	Combine Heat and Power
CI	-	Customer Interruption
CIS	-	Customer Information System
CMI	-	Customer Minutes of Interruptions
COUE	-	Cost of Unserved Energy

CT	-	Current Transformer
CWIP	-	Construction Works in Progress
dCPI	-	Annual rate of change in non-fuel electricity revenues as defined in exhibit 1 of the Licence
DER	-	Distributed Energy Resources
dI	-	The annual growth rate in an inflation and devaluation measure
DG	-	Distributed Generation
DSM	-	Demand-side Management
EA	-	Electricity Act, 2015
EAF	-	Equivalent Availability Factor
ECF	-	External Coincidence Factors
ECS	-	Embedded Cost Study
EE	-	Energy Efficiency
EEIF	-	Electricity Efficiency Improvement Fund
EENS	-	Expected Energy Not Served
EFOR	-	Equivalent Forced Outage Rate
EGS	-	Electricity Guaranteed Standard
ELS	-	Energy Loss Spectrum
ENS	-	Energy Not Served
EOS	-	Electricity Overall Standard
ESI	-	Electricity Supply Industry
ETRPA	-	Employment Termination and Redundancy Payments) Act
EV	-	Electric Vehicle

FA	-	Fixed Asset
FCAM	-	Fuel Cost Adjustment Mechanism
Final Criteria	-	Final Criteria – Jamaica Public Service Company Limited: 2019 – 2024 Rate Review Process, Document No. 2019/ELE/003/RUL.001
FX	-	Foreign Exchange
GCT	-	General Consumption Tax
GDP	-	Gross Domestic Product
GIS	-	Geographic Information System
GNTL	-	Non-technical losses that are not totally within the control of JPS – -designated by JPS as general non-technical losses
GOJ	-	Government of Jamaica
GS	-	Guaranteed Standards
GT	-	Gas Turbine
HB	-	Hunts Bay
HBPS	-	Hunts Bay Power Station
HESS	-	Hybrid Energy Storage System
HFO	-	Heavy Fuel Oil
HGP	-	Hot Gas Path
HPS		High Pressure Sodium
IDC	-	Interest During Construction
IDT	-	Industrial Disputes Tribunal
IEEE	-	Institute of Electrical and Electronic Engineers
IFRS	-	International Financial Reporting Standards

IPP	-	Independent Power Producer
IRP	-	Integrated Resource Plan
IT	-	Information Technology
IVR	-	Interactive Voice Response
JEP	-	Jamaica Energy Partners Limited
JNTL	-	Non-technical losses that are within JPS' control
JPS/Licensee	-	Jamaica Public Service Company Limited
KSAN	-	Kingston and St. Andrew
KVA	-	Kilo Volt Amperes
KWh	-	Kilowatt-hours
LED	-	Light Emitting Diode
LF	-	Load Factor
Licence	-	The Electricity Licence, 2016
LLF	-	Load Loss Factor
LNG	-	Liquified Natural Gas
LOLP	-	Loss of Load Probability
LRAIC	-	Long Run Incremental Average Cost
LRMC	-	Long Run Marginal Cost
LSF	-	Loss Factor
LV	-	Low Voltage
MAIFI	-	Momentary Average Interruption Frequency Index
MED	-	Major Event Day/s
MHI	-	Manitoba Hydro International Limited

Minister's Retirement Schedule	-	The planned schedule for the replaced of existing JPS generation sets made pursuant to section 20 and the Third Schedule of the Electricity Act, 2015
MS	-	Mystery Shopping
MSET	-	Ministry of Science Energy and Technology
MV	-	Medium Voltage
MVA	-	Mega Volt Amperes
MW	-	Megawatt
MWh	-	Megawatt-hours
NBV	-	Net Book Value
NCP	-	Non-Coincident Peak
NEO	-	Net Energy Output
NEP	-	National Energy Policy
NFE	-	New Fortress Energy Company
NG	-	Natural Gas
NPV	-	Net Present Value
NTL	-	Non-technical losses
O&M	-	Operating and Maintenance
OCC	-	Opportunity Cost of Capital
OCGT	-	Open Cycle Gas Turbine
OEM	-	Original Equipment Manufacturer
Office/OUR	-	Office of Utilities Regulation
OHPS	-	Old Harbour Power Station
Old Licence	-	The Amended and Restated All-Island Electric Licence, 2011

OMS	-	Outage Management System
OPEX		Operating Expenditure
OS	-	Overall Standards
OUR Act	-	The Office of Utilities Regulation Act
PATH	-	Programme of Advancement Through Health and Education
PAYG	-	Pay As You Go
PBRM	-	Performance Based Rate-Making Mechanism
PCI	-	Non-fuel Electricity Pricing Index
PPA	-	Power Purchase Agreement
PPE	-	Property Plant and Equipment
PSOJ	-	Private Sector Organisation of Jamaica
RAMI	-	Residential Automated Metering Infrastructure
Rate Review period	-	2019 – 2024
RE	-	Renewable Energy
Revenue Cap period	-	2019 – 2024
RF	-	Responsibility Factor
RFP	-	Request for Proposal
ROE	-	Return on Equity
ROFR	-	Right of First Refusal
SAIDI	-	System Average Interruption Duration Index
SAIFI	-	System Average Interruption Frequency Index
SBF	-	System Benefit Fund
SCADA	-	Supervisory Control and Data Acquisition System

SJPC	-	South Jamaica Power Company
SLV	-	Streetlight Vision
SRMC	-	Short Run Marginal Cost
SSD	-	Slow Speed Diesel
SSP	-	Smart Streetlight Programme
STOD	-	Seasonal Time of Day
T&D	-	Transmission & Distribution
TFP	-	Total Factor Productivity
TL	-	Technical losses
TOU	-	Time of Use
USAID	-	United States Agency for International Development
UTL	-	Utilization Time of Loss
VOM cost	-	Variable Operating and Maintenance cost
VQ	-	Voltage Quality
VRE	-	Variable Renewable Energy
VSP	-	Voltage Standardization Programme
WKPP	-	West Kingston Power Partners
WT	-	Wholesale Tariff

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1. Executive Summary

JPS Tariff Proposal

1.1. The Jamaica Public Service Company Limited (JPS) on 2019 December 30, submitted its Rate Review Application (Application) to the Office of Utilities Regulation (OUR/the Office), which is its fourth rate review filing since privatization in 2001. JPS had previously submitted an application on 2019 July 31, but this was not accepted by the OUR on the basis that it was deficient to the extent that it would not allow for prudent decision making. The Application is the first under the new Revenue Cap regulatory regime established by the Electricity Licence, 2016 (the Licence).

1.2. In its Application, JPS proposed an average rate increase of 17.52% over its existing base tariff. Table 1.1 below shows the composition of the proposed increases, which varied across classes, ranging from an 8.6% reduction in the Streetlight (RT60) category to a 41.4% increase in the residential (RT10) group.

Table 1.1: JPS' Current Average and Proposed Rates (by Customer Classes)

	Current Rate @J$128	JPS Proposal @J$128	
		Rate	Increase
RT 10 -Residential	20.59	29.11	41.38%
RT 20 -Sm. Commercial	21.58	22.73	5.33%
RT 40 -Lg. Commercial (STD)	13.80	15.08	9.28%
RT 40 -Lg Commercial (TOU)	11.87	14.56	22.66%
RT 50 -Lg. Industrial (STD)	12.46	14.54	16.69%
RT 50 -Lg. Industrial (TOU)	12.38	13.43	8.48%
RT 60 -Street lighting	26.17	23.92	-8.60%
RT 70 -MV Power Serv.(STD)	9.13	10.18	11.50%
RT 70 -MV Power Serv. (TOU)	9.88	9.91	0.30%
Average	**17.35**	**20.39**	**17.52%**

1.3. The derivation of JPS' rates was predicated on its demand forecast, which shows a compound annual growth rate (CAGR) of 1.0% for total sales over the period 2018-2024. JPS' demand forecast also indicates that system losses will decline at a CAGR 1.8% (see Table 1.2 below).

Table 1.2: JPS' Demand Forecast (2018-2024)

	Unit	2018*	2019*	2020	2021	2022	2023	2024	CAGR (2018-2024)
Total Sales	GWh	3,212	3,215	3,248	3,285	3,323	3,362	3,400	**1.0%**
System Losses	GWh	1,144	1,126	1,113	1,099	1,082	1,059	1,025	**-1.8%**
Net Generation	**GWh**	**4,356**	**4,341**	**4,361**	**4,385**	**4,405**	**4,421**	**4,426**	**0.3%**

*Note: 2018 & 2019 reflects actual data

1.4. JPS stated that its proposal is intended, *inter alia*, to:

- Recover the costs to operate the power system over the period 2016-2023;
- Complete the implementation of the terms of the Licence;
- Elevate the customer experience by transitioning from less efficient, end of life oil-fired fleets, to new Liquefied Natural Gas (LNG) and renewable generation;
- Improve generation operational efficiency while enabling customers to track, monitor and save on their electricity bills;
- Facilitate continued investments to modernize and transform the electricity system to a smart system;
- Review non-fuel rates to take account of past and future investments;
- Redesign tariff structures to offer more choices for our customers;
- Drive commercial growth, customer retention and safeguard the affordability of the product.

1.5. The highlights of the Application are summarized below.

Revenue Requirement

1.6. JPS' proposed average total Revenue Requirement for the Rate Review period, (See Table 1.3 below) including IPP non-fuel cost was J$ 62,812.3M. The average annual IPP non-fuel cost over the period was J$21,460M. All costs and revenues were expressed in real 2018 dollars at an exchange rate of J$128:00:US$1.00.

Table 1.3: JPS' Proposed Revenue Requirement & Ratebase (2019-2023)

	Unit	2019	2020	2021	2022	2023	Average (2019-2024)
JPS Revenue Requirement	J$M	47,206.7	40,540.7	40,558.6	38,958.9	39,496.6	**41,352.3**
IPP Non-Fuel Cost	J$M	17,962.4	22,358.1	22,568.0	22,462.4	21,949.1	**21,460.0**
Total Revenue Requirement	**J$M**	**65,169.1**	**62,898.8**	**63,126.6**	**61,421.3**	**61,445.7**	**62,812.3**
Rate Base	**J$M**	**90,428.0**	**91,826.0**	**94,119.0**	**96,847.0**	**96,081.0**	**93,860.2**

1.7. Notably, the Application included its 2019 Annual Review Filing for a proposed increase of J$636.1 million (US$5.0 million) of the Annual Revenue Target (ART) for 2019 based on the company's performance in the previous year.

Decommissioning Costs

1.8. A significant component of JPS' Revenue Requirement proposal involves the recovery of US$81.3 million of decommissioning costs over two phases across the Rate Review period. Phase I of the decommissioning plan involves the Old Harbour #2, #3 and #4 plants along with the Hunts Bay B6 plant. The phase II component will see the decommissioning of the Hunts Bay GT5 and GT10, the Rockfort plant as well as the Bogue plant.

1.9. Of the proposed US$81.3M to be recovered, US$46.3M has been attributed to phase I and $35.0 million to phase II. However, when the salvage value of the proposed decommissioned plants is taken into account, the net decommissioning cost for the two phases amounts to US$77.6 million.

Depreciation

1.10. Based on the Application, JPS' forecasted Depreciation Expenses for the Rate Review period are as follows:

- **2019**: J$13.027 billion (US$101.77 M);
- **2020**: J$10.102 billion (US$78.92 M);
- **2021**: J$10.080 billion (US$78.75 M);
- **2022**: J$10.243 billion (US$80.02 M);
- **2023**: J$10.402 billion (US$81.27 M).

1.11. According to JPS, this depreciation forecast is mainly driven by the growth in the fixed asset base, reflecting the capital projects to be implemented in the Rate Review period.

Stranded Assets

1.12. JPS proposed the recovery of J$4.06 billion (US$31.8M) in costs for Stranded Assets over the Rate Review period. The Stranded Assets, JPS argues, have arisen as a result of meter replacements, streetlight replacements and the obsolescence of plant spare parts.

2016-2018 Incremental Depreciation and ROI

1.13. In its Application, JPS argued that it should be compensated by way of depreciation and return on investment (ROI) for assets prudently acquired over the 2016-2018 period. JPS' proposed incremental depreciation and ROI claim amounts to US$22.96M (or J$2,939.0M) and US$27.52M (or J$3,522.1M) respectively.

Rate Base and Medium Term Capital Investments

1.14. JPS' proposed average annual Rate Base of J$93,860.2M for the period is shown in Table 1.3 above. Given, the forward-looking orientation of JPS' tariff regime, the Rate Base reflects the capital inputs set out in the company's Business Plan.

1.15. JPS' proposed capital investment plan totaled US$463.5M over the Rate Review period. Capital expenditure in the plan was allocated to the various segments of the company's operations as follows:

- Generation – US$82.7M
- Transmission – US$87.6M
- Distribution – US$150.1M
- Loss Reduction – US$102.6M
- IT projects – US$26.3M
- General projects – US$14.2M

1.16. Among the items included in the distribution component of the plan was a US$23.9M expenditure for the Smart Streetlight Programme (SSP), which is specified in the Licence. The roll-out of the SSP commenced in 2017.

Cost of Capital

1.17. In computing its proposed return on investment, JPS applied a pre-tax WACC of 12.12% (i.e. a post-tax WACC of 8.08%) for the Rate Review Period. The proposed WACC is based on the Capital Asset Pricing Model (CAPM) methodology and was predicated on the following parameters:

(i) Cost of debt: 7.45%;
(ii) Gearing ratio is 50%;
(iii) The CRP is 2.53%;
(iv) The proposed return on equity is 11.20%.

Efficiency Targets

The Productivity Improvement (PI) factor

1.18. In the Application, JPS proposed a Productivity Improvement (PI) factor of 1.9% for the Rate Review period. The PI-Factor was derived using the Data Envelop Analysis (DEA) methodology. Implicit in this proposal is the concept that the company will move its operating expenditure (OPEX) efficiency level from 67% to 74%. This requires improvements to its OPEX efficiency at an annual rate of 1.9%.

Technical Targets

1.19. The average proposed heat rate target for the 2020 – 2023 period is 9,728 kJ/kWh. This is 15% lower than the current target of 11,450 kJ/kWh.

1.20. The system losses target is comprised of three (3) sub-targets: a Technical Losses target (TL), a Non-technical Losses target for which JPS is completely responsible (JNTL); and a Non-technical Losses target that JPS shares partial responsibility for (NGTL). Even though JPS' Demand Forecast indicates a decline in actual overall system losses at a CAGR of 1.8%, the overall average system losses target proposed by JPS was 25.0%. This represents a 0.93 percentage point reduction in the target over the period, 2019 – 2023. Table 1.4 shows the proposed sub-targets. Additionally, JPS also proposed that the current Resonsibility Factor (RF) of 20% that is applied to GNTL be reduced to 10% initially and adjusted annually based on the involvement of the Government of Jamaica (GoJ).

Table 1.4: JPS' Proposed System Losses Targets (2019-2023)

TARGET	SYMBOL	2019	2020	2021	2022	2023	Average (2019-2023)
TOTAL LOSSES	**Y**	**25.93%**	**25.53%**	**25.08%**	**24.58%**	**23.97%**	**25.0%**
TECHNICAL LOSSES	**TL**	**7.94%**	**7.92%**	**7.89%**	**7.85%**	**7.74%**	**7.9%**
NON-TECHNICAL LOSSES	**NTL**	**17.99%**	**17.61%**	**17.19%**	**16.73%**	**16.23%**	**17.2%**
-Totally within JPS CONTROL	JNTL	4.14%	4.93%	5.67%	6.36%	6.98%	**5.6%**
-Partially within JPS CONTROL	GNTL	13.85%	12.68%	11.52%	10.37%	9.25%	**11.5%**

1.21. The Application included a Quality of Service or Q-Factor proposal. This Rate Review period represents the first tariff period for which this factor will not be set at zero. The Q-Factor rewards or penalizes JPS based on its performance with respect to the duration and frequency of outages in relation to the established targets. Previously, the Q-Factor was set at zero because of the absence of reliable systems to capture the data. Table 1.5 below shows that JPS proposed compounded average rates of reduction in the indices of 7.6%, 6.7% and 0.9% for SAIDI, SAIFI and CAIDI respectively.

Table 1.5: JPS' Proposed Q-Factor Indices (2019-2023)

COMPONENT	Unit	BASELINE (2018)	2020	2021	2022	2023	CARG (2018-2023)
SAIDI	Mins/customer	1,973.4	1,502.9	1,423.8	1,360.5	1,328.9	**-7.6%**
SAIFI	Interruptions/ customer	15.5	12.4	11.7	11.2	11.0	**-6.7%**
CAIDI	Mins/customer	127.3	121.5	121.5	121.5	121.5	**-0.9%**

Rate Design

1.22. For residential (RT10) customers, JPS proposed a three-block structure to replace the existing two-block arrangement. The proposed structure is based on:

- *Block 1 or Lifeline Rate (less than or equal to 50 kWh):* this involves the reduction of the upper limit of the first consumption block from 100kWh to 50kWh;
- *Block 2 (greater than 50 kWh & less than or equal to 500 kWh):* This block will subsidize Block 1;
- *Block 3 (greater than 500 kWh):* This block is at a lower rate than Block 2, in order to discourage these large customers from moving to off-grid solutions.

1.23. Additionally, JPS proposed a time of use (TOU) category for residential customers. According to JPS billing, this would also include a demand charge.

1.24. JPS proposed the introduction of a second block from 150 kWh and above for small commercial (RT20) customers. In justifying the request for a second consumption block, JPS argued that the load profiles in this class are diverse; therefore, this approach is merited.

1.25. In the Application, JPS proposed to further split the existing large commercial and industrial customers (RT40 & RT50) classes into RT40X and RT50X. These new groups would be based on TOU rates and available to customers with demand of 1MVA and more. JPS posits that this is in keeping with its strategic objective to improve long term utilization of network assets through appropriate time varying price signals.

1.26. JPS also proposed in its Application the implementation of Distributed Energy Resources (DER) tariff for all customers with on-site generation and Electric Vehicle (EV) tariffs.

1.27. With respect to the approach to be applied to the recovery of non-fuel IPP costs, JPS proposed that a fixed charge be introduced for the large commercial and industrial classes, in order to enhance the price signaling capability for this expense. However, the company requested that the charge remains variable for all other classes.

Guaranteed Standards (GS) and Overall Standards (OS)

1.28. JPS requested a revision of performance target for EOS1 – Advanced Notification for Planned Outages from 100% to 95%. JPS is required to, in all instances (100%), advise its customers of its planned outages, allowing at least 48 hours' advanced notice.

1.29. JPS proposed that the standard for EOS 10 – Responsiveness of Call Centre Representatives, be reworded to include the Interactive Voice Response (IVR) system, which provides customers with self-help options to effectively address their concerns.

1.30. In its Application, JPS proposed the following changes to "the effectiveness of street lighting repairs" (EOS12):

- That the resolution time of street lighting complaints be increased to 20 working days; and
- The target be revised downward to 95%.

<u>OUR's Decisions</u>

The Revenue Requirement

1.31. The Office's decisions resulted in JPS' proposed total average annual Revenue Requirement for the Rate Review period of J$62,812.3M being reduced by 7.6% to J$58,026.2M (See Table 1.6 below). This is explained by, among other things:

- The reimbursement of funds to customers in relation to the SSP: (-J$3,028.9M);
- Lower levels of depreciation from the reduction in the CAPEX (-J$10,613 M);
- Lower return on investment from the reduction in the CAPEX (-J$1,699.6 M);
- Smaller levels of compensation for depreciation and ROI attributed to the 2016-2018 incremental CAPEX (-US$4,056.2 M);
- Reduction in JPS' proposed decommissioning cost (-US$63.5M).

1.32. All of the proposed IPP costs over the Rate Review period as presented by JPS were accepted. These costs are passed through directly to customers.

Table 1.6: JPS Proposed vs. OUR Allowed Revenue Requirement (2019-2023)

Year	Total Revenue Requirement (J$M)		Variance	
	JPS Proposed	OUR Allowed	J$M	%
2019	65,169.1	55,533.3	(9,636)	-14.8%
2020	62,898.8	57,535.8	(5,363)	-8.5%
2021	63,126.6	59,045.6	(4,081)	-6.5%
2022	61,421.3	59,024.4	(2,397)	-3.9%
2023	61,445.7	58,991.6	(2,454)	-4.0%
Total	**314,061.4**	**290,130.8**	**(23,931)**	**-7.6%**
Average (2019-2024)	**62,812.3**	**58,026.2**	**(4,786.12)**	**-7.6%**

Decommissioning Cost

1.33. Even though there were two phases to the JPS' decommissioning plan, the Office opted to delay the assessment of phase II until the 2024-2029 rate review because of the uncertainty surrounding such costs.

1.34. Further, only US$14.1M of the proposed US$43.8M, net of salvage value, for the phase I decommissioning, was approved by the Office. This decision took into account estimates based on data from JPS' 2013 Decommissioning Plan and an international benchmarking study. The approved cost is spread over the 4-year period 2020-2023.

Depreciation

1.35. While JPS proposed total depreciation of J$53,854M over the Rate Review period, the Office has allowed J$43,241M. This reflects, among other things, corrections for retired plants, presumably inadvertently included in the forecast and a reduction in the forecasted CAPEX depreciation, consistent with the reduction in the company's proposed capital investment spend.

Net Stranded Assets

1.36. JPS' proposal was to recover a total of J$4.06 billion (US$31.8M) in costs for Stranded Assets over the Rate Review period. The OUR approved, the amount of J$3.2 billion (US$25.0M), which is to be recovered over the period.

2016-2018 Incremental Depreciation and ROI

1.37. JPS requested the recovery of J$2.939 billion (US$23.0M) for what it claimed to be depreciation expense on capital investments made in 2016-2018. The OUR approved J$98.7M (US$0.77M) in addition to J$102.1M (US$0.80M) for Smart Streetlights.

1.38. JPS requested the recovery of return on investment, on capital investments made in 2016-2018: J$3.522B or US$27.5M. The OUR approved J$686M or US$5.4M in addition to J$100.9M (US$0.79M) for Smart Streetlights.

Rate Base and Medium Term Capital Investments

Rate Base

1.39. In its Application, JPS presented a forecasted Rate Base for the Rate Review period totaling J$469,301 billion. Consistent with the assessment of the company's CAPEX forecast and other adjustments to Fixed Asset Register presented to the OUR, the Rate Base was reduced by a total of J$13.1 billion or 2.8% over the period (see Table 1.7 below):

Table 1.7: JPS Proposed vs. OUR Allowed Rate Base (2019-2023)

	Rate Base J$M		Variance	
	JPS Proposed	OUR Allowed	J$M	%
2019	90,428	86,178	(4,250)	-4.7%
2020	91,826	89,582	(2,244)	-2.4%
2021	94,119	91,219	(2,900)	-3.1%
2022	96,847	94,011	(2,836)	-2.9%
2023	96,081	95,217	(864)	-0.9%
Total	**469,301**	**456,207**	**(13,094)**	**-2.8%**
Average (2019-2024)	**93,860**	**91,241**	**(2,619)**	**-2.8%**

Medium Term Capital Investments

1.40. JPS proposed **generation** capital expenditure of US$82.7M, excluding interest during construction (IDC). The OUR approved US$78.8M (see Table 1.8 below). The differences arose from the following:

- Removal of Old Harbour Critical Spares costs from the Critical Spares Project;
- Removal of the cost of the Rockfort Plant Auxiliaries Project;
- Removal of the cost of the Industrial Lathe Project;
- Removal of the cost of the Old Harbour mini overhaul.

Table 1.8: JPS Proposed vs. OUR Approved Capital Investments (2019-2023)

AREA	Capital Investment (US$M)		Variance	
	JPS Proposed	OUR Approved	US$M	%
Generation	82.7	78.8	(3.9)	-4.7%
Transmission	87.6	69.7	(17.9)	-20.4%
Distribution	150.2	144.8	(5.4)	-3.6%
Loss Reduction	103.0	89.9	(13.1)	-12.7%
IT projects	26.5	26.5	-	0.0%
General projects	18.6	14.2	(4.4)	-23.7%
Total	**468.6**	**423.9**	**(44.7)**	**-9.5%**
Average (2019-2024)	**78.1**	**70.7**	**(7.5)**	**-9.5%**

1.41. Whereas JPS proposed **transmission** capital expenditure of US$87.6M (excluding IDC), the OUR's approved capital expenditure is US$69.7M. The differences arose from the following:

- Extending the time for completing the structural integrity project outside the rate review period;
- Removal of the cost of the Bellevue to Roaring River Project;
- Removal of the cost of the Remedial Action Scheme Project;
- Removal of the cost of the Old Harbour mini overhaul;
- Reducing the cost of the interbus transformers project by reducing the scope of the project.

1.42. Whereas JPS proposed **distribution** capital expenditure of US$150.2M (excluding IDC), the OUR's approved capital expenditure is US$144.8M. The differences arose from the following:

- Reducing the cost of the Customer Growth CCMA Project;
- Reducing the cost of the Grid Modernization Programme;
- Removing IDC from the Distribution Line Re-Conductoring and Rehabilitation Programme.

1.43. Whereas JPS proposed **system losses projects/programmes** capital expenditure of US$102.596M (excluding IDC), the OUR approved capital expenditure of US$89.9M. The difference arose from the following:

- Reducing the cost of the Smart Meter Programme and extending the project from five to six years.

1.44. Whereas JPS proposed **IT projects/programmes** capital expenditure of US$26.5M (excluding IDC), the OUR approved capital expenditure of US$26.5M.

1.45. Based on the outcome of the OUR's assessment of JPS' proposed **<u>General projects/programmes</u>** capital expenditure, the OUR approved the amount of US$14.2M over the Rate Review period.

Cost of Capital

1.46. Consistent with the methodology outlined in the Final Criteria and Addendum to Final Criteria, the Office approves a pre-tax WACC and a post-tax WACC of 11.87% and 7.91% respectively for the Rate Review period. The approved WACC is based on the CAPM methodology and is predicated on the following parameters:

(i) Cost of debt: 7.57%;

(ii) Gearing ratio is 50%;

(iii) The CRP is 2.53%;

(iv) The return on equity is 10.78%.

Efficiency Targets

<u>The Productivity Improvement (PI) factor</u>

1.47. The OUR's analysis revealed that it would be reasonable for JPS' PI-Factor to be set within a range of 2%-3%. However, the Office determined that it should be set at the lower end of the range at 2%. This decision takes into account that the index is being applied to JPS' OPEX and not exclusively on the transmission and distribution (T&D). Most of the firms in the benchmark study were T&D companies, whereas JPS still retains some character of an integrated utility.

<u>Technical Targets</u>

1.48. In response to JPS average proposed heat rate target for the 2020 – 2023 period of 9,728 kJ/kWh, the OUR has established an average of 9,577 kJ/kWh. This is 1.55% lower than the average target 9,728 kJ/kWh proposed by JPS. The OUR's models indicate that its targets shown in Table 1.9 below are consistent with the improvement in JPS' thermal efficiencies given that it is now less reliant on old inefficient plants.

Table 1.9: JPS' Proposed vs. OUR's Approved Heat Rate (2020-2023)

Year	Target		Variance	
	JPS Proposed (kJ/kWh)	OUR Approved (kJ/kWh)	Absolute (kJ/kWh)	Relative (%)
2020	9,976	9,675	**-301**	**-3.02%**
2021	9,860	9,667	**-193**	**-1.96%**
2022	9,545	9,495	**-50**	**-0.52%**
2023	9,530	9,470	**-60**	**-0.63%**
Average	**9,728**	**9,577**	**-151**	**-1.55%**

1.49. Even though JPS had submitted its system losses targets in its Application, with the advent of the Covid-19 pandemic, it presented a set of revised targets to the OUR (see Table 1.10 below). The revised target registers an average total losses value of 27.02%, suggesting a 2.02 percentage points increase over the average target in its Application.

1.50. The OUR assessed JPS' revised submission and took into account the economic downturn as a result of the Covid-19 and its implications for losses. Against this backdrop, the Office determined the sub-components of the losses targets set out in Table 1.10 below. The result is an average total losses target (Y) of 22.98% over the Rate Review period.

Table 1.10: JPS' Revised Proposed vs. OUR's Approved System Losses Targets (2020-2023)

Year	JPS Revised Targets (Adjusted for COVID-19 Impact)				OUR Determined Targets (Adjusted for COVID-19 Impact)			
	JNTL	GNTL	TL	Y	JNTL	GNTL	TL	Y
2019	5.80%	12.33%	7.92%	**26.05%**	4.07%	10.50%	7.80%	**22.37%**
2020	7.54%	13.94%	7.85%	**29.33%**	4.71%	11.58%	7.78%	**24.07%**
2021	6.63%	12.94%	7.90%	**27.47%**	4.58%	11.50%	7.72%	**23.80%**
2022	6.50%	12.00%	7.93%	**26.43%**	4.24%	10.75%	7.67%	**22.66%**
2023	6.30%	11.59%	7.94%	**25.83%**	3.99%	10.39%	7.61%	**21.99%**
Average	**6.55%**	**12.56%**	**7.91%**	**27.02%**	**4.32%**	**10.94%**	**7.72%**	**22.98%**

1.51. Arising from the OUR's analysis of the quality of service data, the baseline for the Q-Factor indices was established using 2016 – 2018 data to derive the reference points. As shown in Table 1.11 below the OUR's targets set for the 2019 – 2023 require reductions in SAIDI, SAIFI and CAIDI based on CAGR of 3.43%, 3.20% and -0.20% in relation to the baseline indicators.

Table 1.11: JPS' Proposed vs. OUR's Approved Q-Factor Indices (2020-2023)

Year	JPS PROPOSED TARGETS			OUR APPROVED TARGETS		
	SAIDI	SAIFI	CAIDI	SAIDI	SAIFI	CAIDI
	Mins/cust.	Interrup/cust.	Mins/Cust	Mins/cust.	Interrup/cust.	Mins/Cust
BASELINE	**1,973.4**	**15.5**	**127.3**	**1,582.0**	**12.9**	**122.7**
2019	1,874.7	14.7	127.3	-	-	-
2020	1,736.6	13.6	127.3	1,502.9	12.4	121.5
2021	1,657.6	13.0	127.3	1,423.8	11.7	121.5
2022	1,598.4	12.6	127.3	1,360.5	11.2	121.5
2023	1,519.5	11.9	127.3	1,328.9	11.0	121.5
CARG (2019-2023)	**-5.09%**	**-5.09%**	**0.00%**	**-3.43%**	**-3.20%**	**-0.20%**

2020 Revenue Requirement True-Ups

1.52. The Annual Review and Extraordinary Rate Review of 2018 required a number of adjustments to be made to JPS' tariff that went beyond the typical yearly review. These adjustments included:

- *The Accelerated Loss Reduction Mechanism (ALRM)*; aimed at increasing the pace of JPS' loss reduction programme;
- *The Refinancing Incentive Mechanism (RIM)*; directed at supporting JPS' drive to reduce the cost of debt;
- *A Z-Factor payout;* associated with the accelerated depreciation cost incurred prior to 2018 in relation to JPS' Old Harbour Power Station and the Hunts Bay B6 plant that were slated for decommissioning by the end of 2020;
- *Accelerated Depreciation costs;* expected to be incurred by JPS over 2018-2020 as a result of the same decommissioning exercise.
- *Separation costs;* expected to be incurred by the company arising from the retrenchment of staff caused by the decommissioning events.

1.53. These revenue adjustments were programmed to take place within a year. However, given that the Rate Review exercise has occurred in 2020 rather than 2019, this has led to the over-recovery of the approved costs for these elements of the current tariff by JPS.

1.54. On the other hand, embedded in the current tariff is a rate designed to reduce JPS' tariff by J$3.306 billion. This was based on the True-up calculation in the Annual Review 2018 & Extraordinary Rate Review Determination Notice. Consequently, these rates have over-compensated JPS' customers by dint of the fact that they have been in existence for two (2) years instead of one (1). The result is an under-recovery by JPS of J$3,793.8M.

1.55. Additionally, the absence of the Rate Review in 2019 removed the opportunity for the 2019 Annual True-up exercise which would be based on JPS' 2018 performance. The assessment of the 2019 true-up shows that JPS' rate was not adjusted and it therefore had an over-recovery of J$1,779.4M.

1.56. Accordingly, the OUR has assessed the extent of the over-recovery and under-recovery (see Table 1.12 below) by JPS and has determined that the net over-recovery by JPS is J$1,603.9M and that this shall be returned by way of a J$0.523 per kWh reduction in the 2020 rates.

Table 1.12: JPS 2020 Revenue True-up

Over/Under-Recovery	J$'000
ALRIM: Payment Over-recovery	1,170,890
AlRIM: System Losses Adjustment	834,268
Bond Refinancing Incentive Mechanism	105,399
Z-Factor	223,891
Accelerated Depreciation (2018-2020)	943,410
Separation Cost	340,517
Total Over-recovery (JPS)	**3,618,375**
2018 Revnue True-up Under-recovery	3,793,803.00
2019 Revene True-up	(1,779,351.00)
Total Under-recovery (JPS)	**2,014,452.00**
Net Over-recovery	**1,603,923**
2020 Sales Target (MWh)	3,067,886
2020 True-up Rate ($/kWh)	**0.523**

The Smart Streetlight Programme (SSP) and the System Benefit Fund (SBF)

1.57. In support of the SSP, the OUR approved the use of US$16.1M designated to be credited to the System Benefit Fund (SBF) by JPS in the roll-out of smart streetlights. The US$16.1M was based on the OUR's estimation of the amount that would be available from the terminated Electricity Efficiency Improvement Fund (EEIF) at 2018 December.

1.58. However, based on the outcome of the OUR's analysis, the amount available at 2018 December was US$17.2M. In addition, further analyses have shown that residual funds from the EEIF from 2019 December to 2023 December will amount to US$3.617M. In that regard, the total amount that will be owed to the SBF/EEIF by JPS over the period would be US$4.75M.

1.59. Based on the manner in which the SSP is being implemented and in light of the US$16.1M provided in the early phases of the programme, ultimately the situation would obtain where some streetlight assets are owned by customers and others by JPS. From a regulatory perspective the dual ownership is untidy to manage. Furthermore, if the assets are owned entirely by customers it would lead to higher rates over the short to medium term.

1.60. On the above basis, the Office has determined that:

- All streetlight assets shall be owned by JPS;
- Consequently, the US$16.1M used by JPS in the early phases of the SSP shall be treated as a loan over the 4-year period, 2020-2023. This amount including the opportunity cost shall contribute to the reduction of rates over the period;
- The OUR, after consulting with the Minister, will determine the precise treatment of the amounts that will become due to the EEIF/SBF at the next Annual Review.

The Tariff Design

1.61. With respect to the RT10 category, the Office has determined that:

- The existing *Lifeline Rate (less than or equal to 50 kWh) shall be retained;*
- The introduction of a third block for customers consuming greater than 500kWh shall be disallowed;
- A TOU category for residential customers should be introduced without a demand charge.

1.62. The Office takes the view that given the advent of the Covid-19 pandemic, a larger percentage of households would fall in the vulnerable income category. The proposed modification of the lifeline block at this time might therefore be ill-advised. Furthermore, JPS' current lifeline block compares favourably with rate structures in other Caribbean jurisdictions. Consequently, the Office has decided that the current lifeline block construct shall be retained.

1.63. The Office takes the view that a third residential block is likely to result in customers in the 2nd block subsidizing the higher and lower tier of customers.

1.64. JPS' proposal to introduce a second block (for >150 kWh consumption) has not been approved for small commercial (RT20) customers. The OUR is of the view that this neither accords with simplicity in design nor has it been justified on strong economic grounds.

1.65. The Office takes the view, that a RT20 TOU rate should be established and the time of use charges shall be applied strictly on the basis of the energy charge.

1.66. In the OUR's view, the introduction of RT40X and RT50X customer classes proposed by JPS, will add very little value, except that it could be somewhat of a deterrent to grid defection. It may be argued that the introduction of these new classes is likely to lead to an intra-class subsidy in which customers in the RT40 and RT50 customer classes, with lower demand subsidize those with higher demand in the RT40X and RT50X classes. Further, there is nothing from the perspective of load profile shape that distinguishes this group from the existing RT40 and RT50 classes.

1.67. As it relates to Net-billing customers, the RT10 TOU and the RT20 TOU should be implemented six (6) months after the effective date of this Determination Notice. During this interval, JPS shall engage customers in a well-structured education programme concerning their transition to TOU rates.

1.68. The Office takes the view that JPS' proposed DER rates has a serious weakness, even though the concept is plausible. It therefore requires additional work before it can be implemented. In light of this, the Office has decided that JPS may present its revised DER construct at the next Annual Review for regulatory consideration.

1.69. In the Office's assessment, TOU rates in the context of electric vehicle (EV) charging should be relatively straightforward to implement. Approval has been granted for the establishment of Public EV charging rates. These rates shall be based on the TOU rate format and shall be set at a level that is 5% more than the RT10 TOU charges.

1.70. Additionally, the Office concurs with JPS' view that introducing a charging framework that differentiates by type of charger (Level 2 or Level 3) may require more analysis and should be postponed to a later date.

1.71. In its review of the current IPP Cost Recovery Mechanism, the Office has determined that an embedded IPP rate should no longer be concealed in JPS' non-fuel tariff. Instead, full transparent recovery of the derived monthly total IPP cost should be achieved by way of the monthly billed kVA demand and kWh demand and kWh energy sales and shown as separate line(s) on customers' bills. KVA billing, however, would only be applicable to the large commercial and industrial classes.

Guaranteed Standards (GS) and Overall Standards (OS)

1.72. The Office has not accepted JPS' requested revision of performance target for EOS1 – Advanced Notification for Planned Outages from 100% to 95%. In this regard, JPS will be required to, in all instances (100%), continue to advise its customers of its planned outages, allowing at least 48 hours' advanced notice.

1.73. The Office has determined that EOS 10 – which addresses "Responsiveness of Call Centre Representatives" shall not be reworded to include the Interactive Voice Response (IVR) system. However, JPS may resubmit its proposal clearly justifying why it considers such a change to be warranted.

1.74. Based on the OUR's review of EOS12: "The Effectiveness of Street lighting Repairs", it takes the view that a change in the direction proposed by JPS would not be prudent, therefore:

- The resolution time of street lighting complaints shall remain at 14 working days; and;
- The 99% target shall remain unchanged.

1.75. In addition, the Office has decided to defer any changes to JPS' Guaranteed Standards until the project to conduct a comprehensive analysis of all Guaranteed Standards Schemes is completed.

JPS Approved Rates

1.76. Table 1.13 below shows the breakout of the overall average non-fuel tariff approved by the OUR and its rate component parts. The table also indicates that based on a Base Exchange Rate of J$128.00: US$1.00, JPS' average unadjusted non-fuel rate results in an overall average non-fuel rate of $18.65 per kWh (at the Base Exchange rate of J$128.00: US$1.00) which represents an average reduction of 4.73%.

Table 1.13: OUR's Approved Rates @ 128: US$1
(Unajusted for Inflation & Exch. Rate Movements)

	Current Non-Fuel Rate @J$128	Current Non-Fuel Rate With IPP Sur-charge		OUR Approved Without 'dI'				
		Base Level @J$128	After Fx Adj. @J$128	JPS	IPP	True-Up	Total	Increase
	J$/kWh	J$/kWh	J$/kWh	J$	J$	J$	J$	J$
RT 10 -Residential	18.68	22.40	22.40	13.74	8.20	-0.52	**21.42**	**-4.38%**
RT 20 -Sm. Commercial	19.96	23.67	23.67	9.26	13.73	-0.52	**22.47**	**-5.08%**
RT 40 -Lg. Commercial (STD)	12.10	15.67	15.67	13.55	3.01	-0.52	**16.04**	**2.40%**
RT 40 -Lg Commercial (TOU)	10.96	14.60	14.60	11.58	3.72	-0.52	**14.78**	**1.24%**
RT 50 -Lg. Industrial (STD)	10.86	14.43	14.43	7.60	5.40	-0.52	**12.48**	**-13.55%**
RT 50 -Lg. Industrial (TOU)	9.62	13.16	13.16	9.59	3.37	-0.52	**12.44**	**-5.48%**
RT 60 -Street lighting	24.52	29.05	29.05	11.19	13.45	-0.52	**24.12**	**-16.99%**
RT 70 -MV Power Serv.(STD)	11.25	15.78	15.78	9.42	1.48	-0.52	**10.38**	**-34.22%**
RT 70 -MV Power Serv. (TOU)	10.27	13.83	13.83	10.42	0.37	-0.52	**10.26**	**-25.76%**
Average	**15.92**	**19.58**	**19.58**	**11.89**	**7.29**	**-0.52**	**18.65**	**-4.73%**

Note: In some instances the data represents the OUR's aggregation of JPS' original rate.

1.77. The application of the Growth Rate to the revenue cap results in the elevation of the Base Exchange Rate to J$145: US$1 and a 2.02 percentage point increase in the overall average non-fuel rate as a result of inflation. This translates to an approved reduction in JPS' overall non-fuel rate of -2.71% (see Table 1.14 below).

Table 1.14: JPS' Proposed versus 2020 OUR's Approved Rates @ J$145: US$1
(Adjusted for Inflation & Exch. Rate Movements)

	Current Non-Fuel Rate @J$128	Current Non-Fuel Rate With IPP Sur-charge@J$145		2020 OUR Approved With 'dI'				
		Base Level @J$128	After Fx Adj. @J$145	JPS	IPP	True-Up	Total	Increase
	J$/kWh	J$/kWh	J$/kWh	J$	J$	J$	J$	J$
RT 10 -Residential	18.68	22.40	24.88	15.53	9.29	-0.52	**24.29**	**-2.35%**
RT 20 -Sm. Commercial	19.96	23.67	26.29	10.47	15.56	-0.52	**25.50**	**-3.00%**
RT 40 -Lg. Commercial (STD)	12.10	15.67	17.43	15.31	3.41	-0.52	**18.20**	**4.46%**
RT 40 -Lg Commercial (TOU)	10.96	14.60	16.25	13.09	4.22	-0.52	**16.78**	**3.28%**
RT 50 -Lg. Industrial (STD)	10.86	14.43	16.06	8.59	6.12	-0.52	**14.18**	**-11.70%**
RT 50 -Lg. Industrial (TOU)	9.62	13.16	14.66	10.84	3.82	-0.52	**14.14**	**-3.54%**
RT 60 -Street lighting	24.52	29.05	32.26	12.64	15.24	-0.52	**27.36**	**-15.20%**
RT 70 -MV Power Serv.(STD)	11.25	15.78	17.58	10.65	1.68	-0.52	**11.80**	**-32.86%**
RT 70 -MV Power Serv. (TOU)	10.27	13.83	15.39	11.78	0.41	-0.52	**11.67**	**-24.18%**
Average	**15.92**	**19.58**	**21.75**	**13.43**	**8.26**	**-0.52**	**21.17**	**-2.71%**

1.78. The new thermal IPP plants are fueled by natural gas and they are more efficient at converting fuel to energy. Consequently, there will be a 3.7% reduction in the fuel rate. When both the non-fuel and fuel rates are taken into account, the overall reduction in average electricity rate amounts to 3.2% (see Table 1.15 below). This compares with a 0.3% reduction in the tariff proposed by JPS had it been fully accepted.

Table 1.15: The 2020 OUR's Approved Average Rates by Customer Categories (Adjusted for Inflation & Exch. Rate Movements)

	Current Non-Fuel With IPP @J$145	JPS Proposed Non-Fuel @J$145		OUR Approved Non-Fuel		OUR's Fuel Rate @J$145					Overall Rate @J$145			Bill Impact @J$145	
		Rate	Increase	Avg. Rate	Increase	Current	JPS Proposal	OUR Approved	Proposed Increase	Approved Increase	Current	JPS Proposal	OUR Approved	JPS Proposal	OUR Approved
	J$	J$/kWh	%	J$	J$	J$	J$	J$	%	%	J$	J$	J$	J$	J$
RT 10 -Residential	24.88	32.20	29.4%	24.29	-2.4%	23.00	22.33	22.15	-2.9%	-3.7%	47.88	54.53	46.45	13.9%	-3.0%
RT 20 -Sm. Commercial	26.29	25.15	-4.4%	25.50	-3.0%	23.00	22.33	22.15	-2.9%	-3.7%	49.29	47.47	47.65	-3.7%	-3.3%
RT 40 -Lg. Commercial (STD)	17.43	16.68	-4.3%	18.20	4.5%	22.08	21.44	21.27	-2.9%	-3.7%	39.51	38.12	39.47	-3.5%	-0.1%
RT 40 -Lg Commercial (TOU)	16.25	16.11	-0.9%	16.78	3.3%	22.52	21.86	21.69	-2.9%	-3.7%	38.77	37.97	38.47	-2.1%	-0.8%
RT 50 -Lg. Industrial (STD)	16.06	16.08	0.1%	14.18	-11.7%	22.08	21.44	21.27	-2.9%	-3.7%	38.15	37.52	35.45	-1.6%	-7.1%
RT 50 -Lg. Industrial (TOU)	14.66	14.86	1.4%	14.14	-3.5%	21.90	21.26	21.09	-2.9%	-3.7%	36.56	36.12	35.23	-1.2%	-3.6%
RT 60 -Street lighting	32.26	26.46	-18.0%	27.36	-15.2%	22.08	21.44	22.15	-2.9%	0.3%	54.35	47.90	49.51	-11.9%	-8.9%
RT 70 -MV Power Serv.(STD)	17.58	11.26	-35.9%	11.80	-32.9%	22.08	21.44	22.15	-2.9%	0.3%	39.67	32.70	33.96	-17.6%	-14.4%
RT 70 -MV Power Serv. (TOU)	15.39	10.96	-28.8%	11.67	-24.2%	21.99	21.35	21.18	-2.9%	-3.7%	37.38	32.31	32.85	-13.6%	-12.1%
Average	**21.75**	**22.56**	**3.7%**	**21.17**	**-2.7%**	**22.60**	**21.65**	**21.76**	**-4.2%**	**-3.7%**	**44.35**	**44.21**	**42.93**	**-0.3%**	**-3.2%**

1.79. From the analyses of the revenue requirement along with the billing determinants in the demand forecast, the approved customer demand and energy charges were derived for each rate category. These charges and rates are set out in Table 1.16 below.

1.80. After assessing all aspects of the Application, the Office has determined that:

a) Subject to the Z-Factor conditions set out in Schedule 3 of the Licence and the provisions of the Final Criteria, the revenue caps (RC_y) for 2020 – 2023 are as follows:
- **2020:** J$36.470 billion
- **2021:** J$37.857 billion
- **2022:** J$37.957 billion
- **2023:** J$38.783 billion

b) The increase in JPS' average non-fuel tariff (including IPP cost and the accumulated True-up adjustment) shall be 10.28% instead of 17.52% requested by the company in its Application.

c) The rates to be applied by JPS to its customers' bills shall be those set out in Table 1.16 below. These rates are predicated on a Base Exchange Rate of J$145:00:US$1:00.

Table 1.16: JPS 2020 Approved Rates by Customer Categories

(Base Exchange Rate J$145:00: US$1:00)

Rate Category	Blocks	Customer Charge (J$/Month)	Energy Charge (J$/kWh)				Demand Charge (J$/kVA)				IPP Charge		True-up Adjustment (J$/kWh)
			STD	Peak	Partial Peak	Off Peak	STD	Peak	Partial Peak	Off Peak	Fixed IPP Charge (J$/kVA)	Est. Variable ($/kWh)	
Rate 10 STD	0 - 100	525.85	7.24									9.286	-0.523
	> 100	525.85	20.79										-0.523
Rate 10 Pre-Paid	0 - 117		22.47										
	> 117		29.56										
Rate 10 TOU		525.85		15.01	13.13	9.38							-0.523
Rate 20 STD		1,121.23	8.93									15.557	-0.523
Rate 20 Pre-Paid	0 - 10		136.09										
	> 10		23.97										
Rate 20 TOU		1,121.23		10.99	9.61	6.87							-0.523
Rate 40 STD		7,899.62	1.92				3935.24				664.67	1.195	-0.523
Rate 40 TOU		7,899.62		2.12	1.90	1.85		2148.00	1585.29	460.16	1003.76	1.476	-0.523
Rate 50 STD		7,899.62	2.14				2812.29				1745.29	2.141	-0.523
Rate 50 TOU		7,899.62		1.96	1.76	1.71		1622.89	1202.59	429.11	831.79	1.337	-0.523
Rate 60 Streetlight		3,185.33	12.25									15.239	-0.523
Rate 60 Traffic Signal		3,185.33	11.81										-0.523
Rate 70 STD		7,899.62	2.66				3106.16				424.14	0.587	-0.523
Rate 70 TOU		7,899.62		2.00	1.79	1.75		1861.95	1215.26	436.23	92.71	0.145	-0.523
Electric Vehicles				15.76	13.79	9.85							-0.523

2. Introduction

2.1. JPS is a vertically integrated electricity company, which was established on 1923 May 25 and at the time served 3,928 customers. Currently, the company is the sole supplier and distributor of electricity in Jamaica. With a current staff complement of 1,536 employees, JPS now serves approximately 658,052 customers, of which approximately 89% or 587,606 are residential consumers. The company has installed generation capacity of approximately 640MW, using steam (oil-fired), gas turbines combined cycle, diesel and hydroelectric technologies.

2.2. Approximately 262MW of firm capacity is purchased from Independent Power Producers (IPPs) under long-term Power Purchase Agreements (PPAs). The system also has over 121 MW of intermittent renewable energy, of which JPS owns 3 MW. The company also owns all 26 MW of hydro power capacity on the system.

2.3. The Licence establishes a rate review at five (5) year intervals, with one scheduled for 2019 April. The last rate review submission by JPS was on 2014 April 07. JPS submitted a Rate Review application on 2019 July 31. This submission was refused by the Office as it was deemed deficient, to the extent that it would not allow for a complete evaluation.

2.4. On 2019 December 30, JPS submitted revised Application to the OUR for its review. The Application was accepted by the OUR.

2.5. Consequently, on completion of the Rate Review, the new rates approved by OUR, among other things, will supercede and replace the rates which have been effective since 2015 March 1.

2.6. This Application represents JPS' fourth 5-year rate treview filing to the OUR since the company was privatized in 2001. However, it is the first Application under the new Revenue Cap regulatory regime, which was introduced in the Licence. The revenue cap methodology employs a 5-year forward-looking approach, and involves the decoupling of the billing determinants from the approved revenue requirement. This revenue cap methodology allows for the funding of the projects proposed by JPS in its Business Plan. The regulator is therefore required to ensure that the Licensee's customers are not potentially overcharged for the services delivered, even as the utility receives a fair return on its investment.

2.7. The OUR, in fulfilment of its mandate to protect utility consumers' interests, conducts public consultations as part of the Rate Review process. The public consultations, which normally include public meetings and town hall type engagements, are designed to provide an opportunity for dialogue on the tariff application by all stakeholders. However, the hosting of public meetings during this tariff review exercise was significantly constrained by the Covid-19 pandemic.

2.8. Eight (8) public meetings and two (2) business meetings were scheduled to be held across the island between 2020 March 10 to 25. However, only the meetings in St. Elizabeth (2020 March 10) and Manchester (2020 March 11) were held due to the health and safety concerns surrounding the Covid-19 pandemic and the guidelines imposed by the government on public gatherings.

2.9. Consequently, the OUR deployed other methods to canvass JPS' customers' views on the Application, which included an email campaign as well as the distribution of a short survey to gain insight into any local issues. The consultation sought to assess customers' knowledge of the Guaranteed Standards (GS) and capture their views on the Application. The OUR also attempted to engage a virtual town hall as part of the consultation, but JPS demurred, indicating that it considers the other alternatives the OUR had put in place for feedback to be adequate.

2.10. The OUR also made formal requests for written submissions on the Application from various stakeholders, consumer groups and customers. The survey was distributed at the two public meetings (Manchester and St. Elizabeth) and online with feedback being encouraged via social media.

2.11. The OUR received forty-nine (49) emails in addition to other written submissions from stakeholder groups, namely: The Private Sector Organization of Jamaica (PSOJ); the Consumer Advisory Committee on Utilities (CACU); Ambassador Anthony Hill and Professor Anthony Chen – UWI, Mona; Montego Bay Chamber of Commerce and Industry (MCCI) and the United States Agency for International Development (USAID).

2.12. In keeping with the OUR's practice in past Rate Reviews, it shared the draft Determination Notice with JPS in 2020 August. In response JPS raised a number of issues which were given due consideration by the OUR.

2.13. In arriving at its final determinations, the Office took into account the views and submissions from stakeholders, including those who participated in the public consultations and/or submitted written comments and the issues rasied by JPS in its response to the draft Determiantion Notice.

3. Legal Framework

3.1. 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 in Jamaica. Under Section 4(1)(a) of the OUR Act, the Office has regulatory authority over, inter alia, the generation, transmission, distribution and supply of electricity.

3.2. In the exercise of its powers and functions, the OUR is mandated under section 4(3) of the OUR Act to:

"…undertake such measures as it considers necessary or desirable to -

(a) encourage competition in the provision of prescribed utility services;

(b) protect the interests of consumers in relation to the supply of a prescribed utility service;

(c) encourage the development and use of indigenous resources; and

(d) promote and encourage the development of modern and efficient utility services …"

3.3. Among the various powers and functions of the OUR set out in section 4 of the OUR Act, is a power to determine rates in respect of the generation, transmission, distribution and supply of electricity. Section 4(4A)(a) of the OUR Act directs that:

"(4A) The rates determined by the Office in respect of prescribed utility services for the generation, transmission, distribution and supply of electricity shall –

(a) be in accordance with –

1. *the provisions of this Act and any regulations made under this Act;*
2. *the Electricity Act and any regulations made under that Act;*
3. *all policy directions issued by the Cabinet with respect thereto; and*
4. *the tariff provisions set out in all licences and enabling instruments with respect thereto;*

3.4. With respect to the determination of rates in the electricity sector, section 4(4A) of the OUR Act additionally requires that the OUR seeks guidance of the Bank of Jamaica in determining the appropriate rate of return on investment, and to take into account the following matters:

(a) the interest of consumers in respect of, among other things, the cost, safety and quality of services;

(b) Jamaica's economic development;

(c) the best use of indigenous resources;

(d) the possibility of specific tariffs to encourage regularization of and payment for electricity usage by consumers who are unable to pay for the full cost of the services; and

(e) the possibility of including specific tariffs for special economic zones and wholesale rates for large consumers to enhance competitiveness and Jamaica economic development.

3.5. Pursuant to Condition 2, paragraphs (2) and (3) of the Licence, JPS is authorized to "generate, transmit, distribute and supply electricity for public and private purposes in all parts of the Island of Jamaica", and is obligated to "…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."

3.6. Condition 15 and Schedule 3 of the Licence makes provision for the determination of JPS' rates. Paragraph 2 of Condition 15 and paragraph 5 of Schedule 3 specify respectively that:

Condition 15

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

...

Schedule 3

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

3.7. Schedule 3 of the Licence outlines the procedures for determination and review of JPS' electricity tariff. This Schedule provides for three (3) instances in which the OUR may be requested to review and determine rates, which may result in revisions or adjustments to JPS' non-fuel rates based on a revenue cap methodology, viz:

1) **Five-Year Rate Reviews (paragraphs 6 – 41):** As the name suggests, these reviews are scheduled at five-year intervals. The five-year rate review involves an exhaustive examination of all aspects of the revenue requirement, including rate base, return on investment, operating and maintenance cost, depreciation, as well as, efficiency targets and incentive mechanisms. The Licence requires that the rate proposal is supported by a five-year business plan, the most recent Integrated Resource Plan (IRP), the OUR's published Final Criteria, the Base Year data and a cost of service study. As per the provisions of the Licence, the date for the submission of the first such review under the Revenue Cap regime was 2019 April.

2) **Annual Review or Annual Rate Adjustment (paragraphs 42 – 56):** The Licence details the formula to be employed for an annual adjustment to the revenue target, the annual adjustment date (beginning 2016 July 1) and the time period for conducting the adjustment (sixty (60) days). Notably the formula specifically assumes, inter alia, that tariffs based on the revenue-cap regime are already in place. Therefore, changes are only required for the superstructure and not the substructure of the tariff.

   Exhibit 1 of Schedule 3 of the Licence specifies the Annual Review formula as follows:

$$\mathrm{ART}_y = \mathrm{RC}_y(1 + (\mathrm{dI} + \mathrm{Q} \pm \mathrm{Z})) + (\mathrm{RS}_{y-1} + \mathrm{SFX}_{y-1} - \mathrm{SIC}_{y-1}) * (1 + \mathrm{WACC})$$

Where:

$\mathrm{ART}_y = Annual\ Revenue\ Target\ for\ current\ year (i.e., y)$

$\mathrm{dI} = change\ in\ inflation$

$\mathrm{Q} = the\ quality\ of\ service\ improvement\ factor$

$\mathrm{Z} = the\ exogenous\ factor$

$\mathrm{RS}_{y-1} = Adjustment\ for\ previous\ year\ Revenue\ under/over - recovery$

$\mathrm{SFX}_{y-1} = Adjustment\ for\ previous\ year\ Net\ Foreign\ Exchange\ Losses$

$\mathrm{SIC}_{y-1} = Adjustment\ for\ Net\ Interest\ Income\ on\ unpaid\ Customer\ bills$

$\mathrm{WACC} = the\ Weighted\ Cost\ of\ Capital$

3) **Extraordinary Rate Reviews (paragraphs 59 – 61):** These reviews may be done between five-year rate reviews, and are occasioned by the impact of exceptional circumstances that have a significant impact on the electricity sector and/or JPS. Such a review is only permissible where the circumstances did not comprise factors that were considered or known when the last rate review was undertaken. Rate reviews of this type are done at the request of either the Minister with responsibility for electricity or JPS. The prescribed time period for such a review is sixty (60) days, unless the OUR and JPS otherwise agree, and the scope of the review is limited to the impact of the exceptional circumstances.

3.8. Within the framework of the Annual Review, provision is made for alterations to the tariff using the Z-factor mechanism. The application of the Z-factor is triggered by special circumstances that materially affect, inter alia, JPS' non-fuel costs, for which the recovery of such costs is done through an allowed percentage increase in the revenue cap. The special circumstances that trigger the Z-Factor mechanism, as set out in paragraph 46 of Schedule 3 of the Licence are summarized below:

a) Circumstances that affect JPS' costs, or recovery of such costs, that are not due to its managerial decisions, have an aggregate impact on the licensed business of more than fifty million dollars in any given year and are not captured by the other elements of the revenue cap mechanism.
b) Where JPS' rate of return with respect to the Licensed business is one percent higher or three percent lower than the approved regulatory target.
c) Where JPS' capital and special programme expenditure are delayed and the delay results in a variation of five percent or more of the annual expenditure.
d) Any Government imposed actions as defined in the Licence.
e) Where an extraordinary level of capital expenditure or a special programme (i.e. greater than ten percent in any given year relative to the agreed five-year business plan) is required upon agreement of JPS and the OUR.
f) Where JPS is required to make a change to the Guaranteed Standards, which will have a financial impact on the company in an amount greater than fifty million Jamaican dollars during any rate review period.

3.9. The Licence therefore makes provision for the treatment of exceptional and defined special circumstances affecting the tariff in between Five-Year Rate Reviews, by way of two channels - (1) the Z-Factor adjustment mechanism specified under the Annual Review, and the (2) Extraordinary Rate Review utilizing the rate review mechanism applicable to the Five-Year Rate Review (i.e. an adjustment to the base revenue requirement).

3.10. In accordance with Sections 4(4), 4(4A), 11 and 12 of the OUR Act, as well as Condition 15 and Schedule 3 of the Licence, the Office makes the **DETERMINATIONS** set out below.

4. Summary of JPS' Application

4.1. Revenue Requirement

4.1. JPS stated in its Application that the company is seeking approval for a five (5)-year levelized revenue requirement as shown in Table 4.1 below.

Table 4.1 – JPS' Proposed five (5) Year Revenue Requirement

Revenue Requirement	J$M	US$M
2019	63,904	499.3
2020	62,350	487.1
2021	62,493	488.2
2022	60,842	475.3
2023	60,970	476.3

The proposed revenue requirement includes the following key drivers of the increase:

i. Decommissioning Cost: J$4.428 Billion (US$34.6M).
ii. Stranded Asset Cost Recovery: 4.064B (US$31.8M).
iii. Recovery of depreciation expense on capital investments made in 2016-2018: J$2.939B – US$23.0M.
iv. Recovery of return on investment on capital investments made in 2016-2018: J$3.522B – US$27.5M.
v. Electricity Disaster Fund (EDF): J$256M – US$2.0M annually.

4.2. JPS stated that the associated average rate increase resulting from the Annual Revenue Target (ART) increase over the last approved rates, set out in the Jamaica Public Service Company Limited Annual Review 2018 & Extraordinary Rate Review: Determination Notice (the 2018 Annual & Extraordinary Rate Review Determination Notice), is 10.6%, adjusted for non-fuel IPP surcharge on current bills.

4.2. Proposed Revenue Caps for the Rate Review Period

4.3. JPS is seeking approval of revenue caps for the Rate Review period. The company stated that these revenue caps have been adjusted to reflect revenue from special contracts and the offsetting of unregulated expenses. The proposed caps are as shown in Table 4.2 below.

Table 4.2 – JPS' Proposed Revenue Caps 2019 - 2023

Proposed Revenue Caps	J$M	US$M
2019	60,922	476.0
2020	61,443	480.0
2021	62,249	486.3
2022	63,012	492.3
2023	63,784	498.3

4.3. Proposed Investment Plan

4.4. In its Application, JPS stated that the company is seeking to invest approximately US$508.7M gross (US$468.39 million, excluding IDC cost) over five (5) years. JPS argues that the key outcomes to be delivered are: 2.30% point reduction in electricity losses, 20% improvement in reliability of supply, 1.9% improvement in productivity and the achievement of the regulated target heat rate annually. Table 4.3 below shows the distribution of JPS' proposed planned investments by asset class as reported in JPS' Medium Term Investment Plan 2019-2023 document, which stated that the company is to invest approximately US$478.8M in its regulated business in order to achieve its operational and financial targets.

Table 4.3: JPS' Proposed Distribution of Planned Investments by Asset Class

Asset Class		2019	2020	2021	2022	2023	Total	%
Distribution	(US$'000')	60,288	54,823	57,078	48,225	36,691	**257,106**	50%
Generation	(US$'000')	18,563	16,511	13,643	22,208	13,277	**84,203**	28%
Transmission	(US$'000')	16,637	10,233	20,087	22,439	21,541	**90,937**	11%
IT	(US$'000')	3,045	6,947	7,878	7,712	3,825	**29,407**	7%
General Plant	(US$'000')	3,149	3,139	4,173	3,060	3,614	**17,136**	4%
Total	(US$'000')	**101,683**	**91,652**	**102,859**	**103,644**	**78,949**	**478,788**	**100%**

4.4. Performance Factors

4.4.1. Heat Rate (H-factor)

4.5. For the Rate Review period, JPS stated that it expects a material reduction in its use of thermal plants as well as the retirement of some of its less efficient units. As a result, JPS expects its thermal plants, heat rate to improve from the current target of 11,450 kJ/kWh to less than 9,550 kJ/kWh. See JPS' annual targets in Table 4.4 below.

Table 4.4: JPS' Forecasted Thermal Heat Rate Targets - July 2019 to June 2024

YEAR (July to June)	2019	2020	2021	2022	2023
Heat Rate Target (kJ/kWh)	10,986	9,976	9,860	9,545	9,530

4.4.2. System Losses (Y-factor)

4.6. System Losses targets proposed by JPS for the Rate Review period include targets for each of the three components – Technical Losses (TL), Non-Technical Losses that are within the control of JPS (JNTL), and Non-Technical Losses that are not totally within the control of JPS (GNTL). JPS states that its proposal is based on ongoing and planned capital, operational system losses reduction initiatives and strong support from the Government.

4.7. As shown in the Table 4.5 below, JPS is proposing a 2.30% points overall reduction in system losses by 2023 over 2018 comprising 0.20% points reduction target in TL, 2.76% points increase in JNTL, and 4.86% points reduction target in GNTL.

Table 4.5: Proposed System Losses Targets over 5 Years

Loss Component	2018	2019	2020	2021	2022	2023
TL	7.94%	7.94%	7.92%	7.89%	7.85%	7.74%
JNTL	4.22%	4.14%	4.93%	5.67%	6.36%	6.98%
GNTL	14.11%	13.85%	12.68%	11.52%	10.37%	9.25%
Total	**26.27%**	**25.93%**	**25.53%**	**25.08%**	**24.58%**	**23.97%**
Reduction		-0.34%	-0.40%	-0.45%	-0.50%	-0.61%
Total Reduction						**-2.30%**

4.4.3. Reliability Factor (Q-factor)

4.8. JPS proposed its first baseline targets to initiate the operation of the performance-based regulatory mechanisms for system reliability. The proposed Q-factor targets are outlined in the Table 4.6 below.

Table 4.6: Proposed Q-factor Targets (2019-2023)

YEAR	SAIDI (minutes)	SAIFI (interruptions /customer)	CAIDI (minutes)	% Improvement in SAIDA over previous year
Baseline (3-year Average)	1,973.37	15.50	127.33	
2019	1,872.41	14.70	127.33	5%
2020	1,745.26	13.71	127.33	7%
2021	1,659.84	13.04	127.33	5%
2022	1,594.91	12.53	127.33	4%
2023	1,516.13	11.91	127.33	5%

4.4.4. Guaranteed Standards

4.9. JPS requested the compensation methodology for breaches of the Guaranteed Standards to be made consistent across rate classes. Instead of linking the compensation for residential customers to the reconnection fee and the compensation for commercial customers to the customer charge, JPS' proposal is that all compensations be linked to the customer charges for the respective rate classes.

4.5. 2019 Annual Adjustment

4.10. JPS incorporated the annual adjustment for 2019 which is to reflect the performance in the fifth year of the last rate review period. This annual review primarily focuses on the performance-related adjustments for 2018 to the Annual Revenue Target (ART).

4.11. The results of JPS' analysis are as follows:

a) The 2018 revenue surcharge to result in the ART increasing by J$636.1 million (US$5.0 million) for 2019.
b) Volumetric performance adjustment of negative J$234.6 million (US$1.8 million).
c) System losses performance adjustment of positive J$346.0 million (US$2.7 million).
d) Foreign exchange surcharge of positive J$459.9 million (US$3.6 million).
e) Net interest expense surcharge of negative J$9.5 million (US$0.074 million).

4.6. Proposed Changes/Additions to the Tariff Structure

4.12. JPS proposed changes to the current tariff structure and new additions. The company argues that the tariff is designed to be more cost-reflective and it aims to keep electricity prices affordable to its vulnerable customers.

4.13. The proposed changes are:

a) Residential – Rate 10:

- Reduction of the lifeline block from 100 kWh to 50 kWh.

- Three (3) tiered structure (0-50 kWh, 51-500 kWh and over 500 kWh). Current residential rates consist of two consumption blocks.
- Increased fixed charges in order to recover more revenues from fixed charges to improve the alignment of revenue recovery with the split between the company's fixed and variable cost.

b) *Small Commercial – Rate 20:*

- Two (2) tiered structure (0-150 kWh and over 150 kWh). Currently, general service rates consist of a single block.
- Increased fixed charges in order to recover more revenues from fixed.

c) *Large Commercial – Rate 40:*

- Differentiated energy charge per time period for customers on TOU.
- The creation of a MT40X tariff for current rate 40 customers with demand between 1 and 2 MVA.

d) *Industrial – Rate 50*

- Differentiated energy charge per time period for customers on TOU.
- The creation of a MT50X tariff for current rate 50 customers with demand between 1 and 2 MVA.

e) *Large Commercial – Rate 70*

- Customers on TOU to benefit from a differentiated energy charge.

f) *Streetlight Tariff – Rate 60:*

- A redesigned tariff structure for Rate 60. The proposed structure will have a fixed charge per fixture and a variable charge designed to recover costs such as capital recovery, operations and maintenance, impairment and energy charges.
- Separate rates for streetlights, MT60S and traffic signals, MT60T.

4.14. The proposed new tariffs are:

a) *Distributed Energy Resource (DER) Tariff:*

- For customers with self-generation who wish to continue to rely on the grid as a reliable source of supplemental or contingent supply. The proposal is for fixed cost allocated to these customers to be recovered fully through a TOU demand charge based on the actual registered kVA, and a system reliability component billed on the customer's 12-month ratchetted kVA demand.

b) *Interim Electric Vehicle (EV) Tariff:*

- For the use of public-charging infrastructure for electric vehicles. JPS argued that in consultation with the OUR, EV rates should be appropriately revised as the EV market develops.

c) *Wheeling Tariff:*

- JPS argued that the contractual mechanism it has outlined, as well as the finalization of the Power Wheeling regulatory and legal framework, should first be approved. This would then provide the basis for offering Wheeling Service based on approved contracts and determined power wheeling fees and/or rates.

4.7. Tariff Adjustment Impact Mitigation Alternatives

4.15. JPS stated that in light of the passing of the first tariff adjustment year 2019, of the Rate Review period, and that its tariff proposal has been prepared on the basis of full five- (5) year revenue collection, a higher than expected increase in tariff will result. Consequently, in order to mitigate the required increase, JPS has proposed an alternative mechanism to address the recovery of stranded asset costs of J$4.064 billion (US$34.6 million), which the company has included in the revenue requirement and, which would account for an approximately 1.6% increase in its proposed non-fuel tariff rates.

4.16. JPS stated that the proposed asset swapping mechanism would see the inclusion of assets such as the smart meter assets purchased under the ALRIM 2, which was previously excluded from the rate base, replacing an equivalent value of the stranded assets slated to be recovered in the proposed revenue requirement.

4.8. Bill Impact per Rate Category

4.17. The overall net bill impact as proposed is expected to be a 4.7% increase over the five- (5) year Rate Review period, subject to annual review. This comprises an approximately 17.5% increase in non-fuel rates and projected reductions in fuel rates of approximately 6.1%. The average impact will vary by customer class, as well as within a customer class, depending on the customer's consumption and choice of tariff. Table 4.7 below highlights the average monthly bill impact per category.

Table 4.7: Bill Impact per Rate Category

Category	Non-Fuel Tariff (J$/kWh)			Fuel (J$/kWh)			Non-Fuel + Fuel (J$/kWh)		Bill Impact
	Current	Proposed	Variation	2019 Fuel Cost	2020 Fuel Cost	Variation	Current NF + F	Proposed NF + F	
MT 10 - Metered Residential	20.59	29.11	41.37%	21.46	20.15	-6.10%	42.05	49.26	17.14%
MT 20 - Metered Small Commercial	21.58	22.73	5.31%	21.46	20.15	-6.10%	43.04	42.88	-0.38%
MT 60 - Street lighting	26.17	23.92	-8.63%	19.81	18.60	-6.10%	45.98	42.52	-7.54%
MT 40 - Metered Large Commercial (STD)	13.80	15.08	9.28%	19.81	18.60	-6.10%	33.61	33.68	0.21%
MT 40 - Metered Large Commercial (TOU)	11.87	14.56	22.69%	19.81	18.60	-6.10%	31.68	33.16	4.69%
MT40X_TOU (*New)	11.87	13.66	15.12%	19.81	18.60	-6.10%	31.68	32.26	1.85%
MT 50 - Meter Industrial (STD)	12.46	14.54	16.70%	19.81	18.60	-6.10%	32.27	33.14	2.70%
MT 50 - Meter Industrial (TOU)	12.38	13.43	8.46%	19.81	18.60	-6.10%	32.19	32.03	-0.50%
MT50X_TOU (*New)	12.38	9.06	26.79%	19.81	18.60	-6.10%	32.19	27.66	-14.06%
MT 70 - MV Power Service (STD)	9.13	10.18	11.49%	19.81	18.60	-6.10%	28.94	28.78	-0.55%
MT 70 - MV Power Service (TOU)	9.88	9.91	0.34%	19.81	18.60	-6.10%	29.69	28.51	-3.96%
Total	**17.35**	**20.39**	**17.53%**	**20.64**	**19.38**	**-6.10%**	**37.99**	**39.77**	**4.69%**

5. OUR's Assessment of JPS' Risk Management Proposal and the Z-Factor

5.1. In an effort to offer relatively stable electricity prices, JPS proposes to manage the two main risks it identified as being major factors affecting the stability of monthly electricity prices faced by customers. The two (2) factors are: (i) FX market volatility and (ii) fuel price volatility. The company stated that the proper management of these risks will not only help to achieve price stability for customers, but also improve the accuracy of its budget planning and execution.

5.1. Foreign Exchange Risk Management Proposal

5.2. FX risk is the exposure of an entity to the potential impact of movements in FX rates. For a Jamaican operated company such as JPS, the risk is that adverse fluctuations in the USD to JMD exchange rates may result in a loss in Jamaican dollar terms to the company. There are two factors from which FX risk may arise: i) currency mismatches in an entity's assets and liabilities that are not subject to a fixed exchange rate, and ii) currency cash flow mismatches.

5.3. JPS stated that while the approved base tariffs are stable, the monthly adjustments to these base tariffs for FX fluctuations do not protect the customers from the volatility in the FX market. The company further explained that a 5% devaluation of the Jamaican dollar would result in a 4% increase in a customer's non-fuel bill amount whilst keeping other things constant. Conversely, a 3.1% appreciation of the Jamaican dollar against the USD results in a 2.5% decrease in customers' non-fuel bill amount. JPS highlighted that this monthly FX adjustment goes against the price stability objective. The company indicated that this is an even greater concern for its large customers, as the situation exacerbates the ongoing risk of grid defection by such customers.

5.4. In addition to the price volatility on customer bills, the company mentioned that the FX volatility creates other problems, namely, working capital deficits due to:

i) the mismatch in timing between billing and collection;
ii) difficulties sourcing foreign currencies for the timely payment to IPPs and fuel suppliers; and
iii) impacts on budgets for asset maintenance and capital investments.

5.5. JPS therefore proposed the use of an FX hedging mechanism to reduce the volatility caused by using spot market rates, and instead bill customers at a pre-determined exchange rate. The company hopes to do this by means of forward contracts that are reviewed periodically. The use of such contracts will result in two benefits to the customer, stable electricity bills for 12-month periods and certainty for budget planning and execution. Additionally, JPS proposed that it be allowed to recover the cost and fees associated with such contracts through an adjustment to the fuel-rates on a periodic or quarterly basis.

<u>OUR's Response to JPS' FX Risk Management Proposal</u>

5.6. In a document published by the Bank of Jamaica (BOJ) in 2005 on Foreign Exchange Risk Management, the central bank stated that implementing a risk management programme for FX risks involves prudently managing foreign currency positions in order to control the impact of changes in exchange rates in the financial position of the institution. The BOJ further stated that a comprehensive FX risk management programme requires:

i) Establishing and implementing sound and prudent FX risk management policies; and
ii) Developing and implementing appropriate and effective FX risk management and control procedures.

5.7. The OUR finds JPS' proposal for the FX hedging to be lacking in the details necessary to conduct the required comprehensive evaluation that is imperative to approving such a mechanism. JPS failed to provide, among other things, analyses of customer bill impact with the proposed FX hedging mechanism, the list of costs and fees associated with the forward contracts, and how the exchange rates would be initially determined and later reviewed.

5.8. The OUR further noted from the information provided by JPS, that the periodic adjustments proposed for the cost and fees on customers' bills for the forward contract would still cause fluctuations in customers' bills over a short term period. Another observation is that the proposed hedging could possibly make small commercial and residential customers worse off as rates and premiums billed to such customers could on average exceed the adjustments usually paid through the monthly FX exchange adjustments.

5.9. The OUR understands JPS' concerns regarding the FX losses and shares the view that price stability for customers should be a major priority in electricity pricing. However, at this time, the OUR will not approve JPS' proposal for the use of forward contracts for FX hedging due to the lack of information and analyses.

5.10. However, given the benefits that may be derived from FX hedging, JPS may if it chooses, submit for the OUR's consideration at the next Annual Review submission a comprehensive proposal outlining, at minimum, the following:

i) Justification for the use of forward contracts as a hedging technique over other possible techniques/tools;
ii) The objectives of the FX risk management programme;
iii) Bill impact analyses for all rate classes;
iv) List of all fees and costs to be incurred and how such costs will be recovered;
v) Cost benefit analysis;
vi) List of proposed controls for managing foreign currency transactions;
vii) Method or procedures used to accurately measure realized and unrealized foreign exchange gains and losses;
viii) Methodology for deriving the initial exchange rate of the forward contracts and mechanism for updating such rates, and how often such contracts will be updated.

DETERMINATION #1

The Office disapproves JPS' proposal to use forward contracts, as presented in its Application, for the purpose of foreign exchange hedging. Notwithstanding, JPS may if it chooses, submit a comprehensive foreign exchange hedging proposal for the OUR's consideration as a part of its submission at the next Annual Review.

5.2. Commodity (Fuel) Price Risk Management Proposal

5.11. JPS stated that its operations are still sensitive to fuel cost volatility despite the provisions made in the Licence for a fuel cost adjustment mechanism subject to heat rate performance. This risk, JPS explained, is as a result of the lag between the time of payment to its fuel vendors and the time of collection from customers. It further stated that working capital deficits will still occur as fuel price often change between the time of payment to suppliers and revenue collections from customers.

5.12. The introduction of LNG to Jamaica's fuel mix has further increased the complexity of fuel price management that JPS must pursue to extract maximum value for its customers. JPS therefore proposed a hedging mechanism similar to that of the FX hedging for its fuel prices. The company believes that such hedging can offer customers better stability and predictability of electricity prices, and also offers JPS certainty with respect to its budget planning and execution by removing fuel price volatility from its operations.

OUR's Response to JPS' Fuel Price Risk Management Proposal

5.13. JPS has failed to provide sufficient details for the OUR to consider the fuel price risk management for approval. Notwithstanding the lack of a comprehensive hedging proposal, the OUR declines to approve JPS' proposal for the use of a fuel hedging mechanism mainly on the ground that the OUR's analysis indicates that JPS is no longer as exposed to fuel price volatility risk as JPS claims.

5.14. Since the introduction of LNG to the system generation fuel mix, the portion of ADO and HFO used in power generation has been drastically reduced. Figure 5.1 below shows fuel mix for 2020. HFO and ADO collectively now account for 17.6% of the electricity generation while LNG accounts for 69.8%. Figure 5.2 below further shows the projection of the electricity generation fuel mix over the next four (4) years based on the generation expected to come online as per the draft IRP. The fuel mix projection for 2021 through 2024 shows that LNG will continue to be the dominant fuel source.

Figure 5.1: JPS' Fuel Mix for 2020 based on GWh Generation

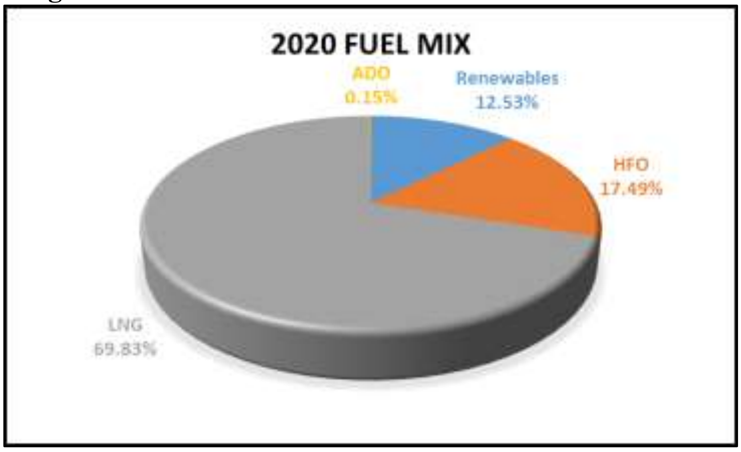
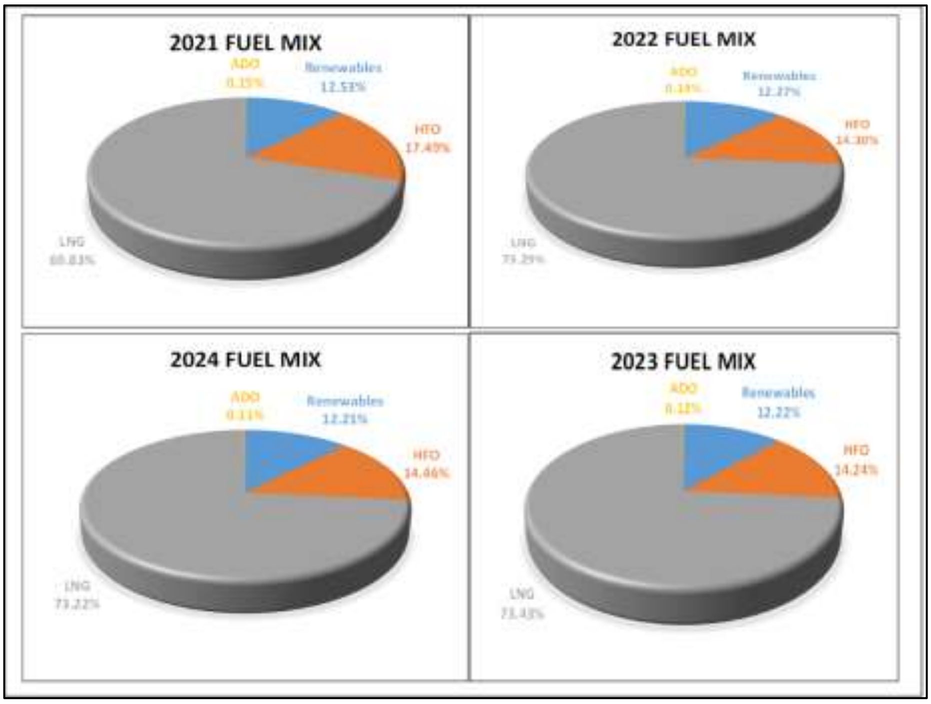


Figure 5.2: JPS' Fuel Mix Projection for 2021-2024 based on GWh Generation

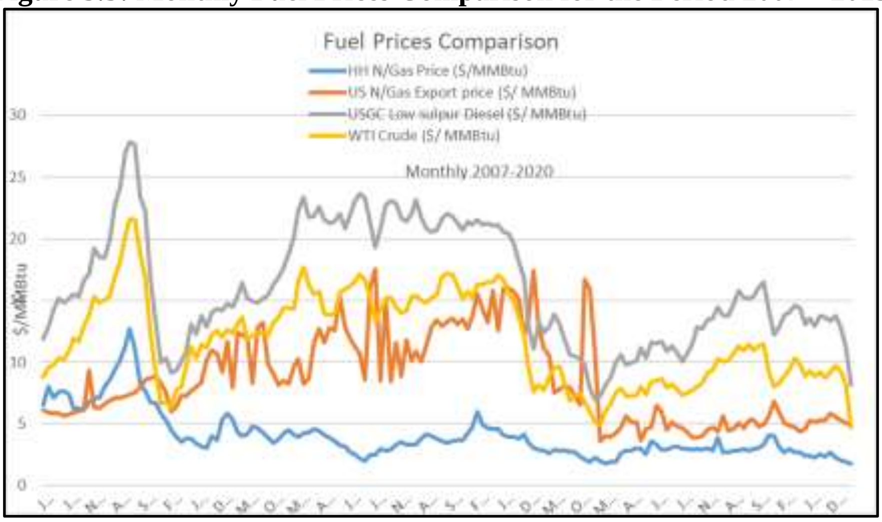


5.15. Within the last decade, crude oil price (from which HFO and ADO are derived) has been far more volatile than the price of natural gas. Figure 5.3 below provides an illustration of the relative volatility of natural gas versus crude oil. On this basis, a greater proportion of LNG in the electricity generation fuel mix is likely to reduce the level of fuel price volatility to which customers were previously exposed.

5.16. Additionally, in the gas supply contracts held by JPS and other IPPs, the commodity price (natural gas price) accounts for less than 30% of the overall burner tip price. This also dampens the impact of fuel price volatility.

5.17. With LNG prices being relatively stable and the commodity price accounting for only a small portion of the overall price for LNG, the OUR finds it unnecessary at this time for JPS to implement a hedging mechanism. Furthermore, there are inherent risks in hedging if not carefully designed and administered.

Figure 5.3: Monthly Fuel Prices Comparison for the Period 2007 – 2019



5.18. With regard to the ADO and HFO prices, though oil prices are relatively more volatile than LNG prices, these fuel sources account for less than 20% of JPS' generation fuel mix and this is projected to reduce to less than 15% by the end of 2024. Considering these factors and the lack of a detailed proposal by JPS, the OUR declines JPS' proposal for the use of a fuel price hedging mechanism in the tariff.

DETERMINATION #2

The Office declines JPS' proposal to include a hedging mechanism for fuel price in the tariff.

5.3. The Z-Factor Adjustment

5.3.1. Introduction

5.19. For the first time since the introduction of the Licence, JPS is undergoing a Rate Review. Apart from the fact that this Rate Review will see the implementation of a revenue cap regime in place of a price cap methodology, the Z-Factor component of the Performance Based Rate-making Mechanism (PBRM) reflects a modified construct.

5.20. Under the two previous licences[1] held by JPS, the Z-Factor represented a price escalator in the PBRM that captured the effects of exogenous circumstances. More specifically, the Z-Factor was applicable when an event (including those triggered by Government Imposed Obligations) occurred for which all of the following three conditions are satisfied:

a) the Licensee's costs are affected;
b) the event is not caused by JPS' management decision;
c) the event is not captured by the other elements of the price cap mechanism.

5.21. The Licence has expanded the scope of the events that trigger a Z-Factor adjustment. Therefore, to minimize the risk of interpretation differences on Z-Factor adjustments, and to ensure transparency, consistency and certainty in the OUR's approach with regard to these adjustments, issues pertaining to the overall framework and capital adjustments are set out below.

5.3.2. The Z-Factor Framework

5.22. The Z-Factor enables the maximum allowable change in annual non-fuel electricity revenues to be adjusted in response to special circumstances. Paragraph 46 (d) of Schedule 3 of the Licence details the special circumstances that could trigger a Z-Factor adjustment in an Annual Review:

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

a) affect the Licensee's cost or recovery of such costs, including asset impairment adjustments;

[1] The "All-Island Electricity License (2001)" and the "Amended and Restated All-Island Electricity License 2011"

b) *are not due to the Licensee's managerial decision;*

c) *have an aggregate impact on the Licensed Business of more than \$50 million in any given year; and*

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

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

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

iv) *Government Imposed Actions;*

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

vi) *where the Licensee is required to make a change to the Guaranteed Standards in Condition17(5) and such change will have a financial impact on the Licensee in an amount greater than Fifty Million Jamaican dollars (J\$50,000,000.00) during any rate review period.*

5.23. In the event of one or more of the above circumstances, Schedule 3 of the Licence states that the Z-Factor adjustment may be computed by using the formula;

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

Where;

Z is the Z-Factor adjustment

y-1 is the year prior to the annual tariff adjustment in which the Z-factor adjustment is to be applied

$RC\text{-}_{\text{Base year}}$ is the revenue cap for the base year for the tariff application.

5.24. Therefore, this means that in addition to changes in cost caused by exogenous factors including Government Imposed Obligations, the Z-Factor in the existing tariff regime also addresses, among other things:

1. *Profit Adjustments*: If the company's rate of return falls outside of a band of +1 percentage point and -3 percentage points of the approved regulatory target (after taking into consideration the allowed true-up annual adjustments, special purpose funds included in the Revenue Requirement, awards of the Tribunal

and determinations of the Office and adjustments related to prior accounting periods), adjustments may be made;

2. *Quality of Service Impositions:* If there are changes to the Guaranteed Standards that materially affects the company's cost, adjustments are permitted;
3. *Capital Investment Adjustments:* Capital investment adjustments may be applied under two circumstances:
   a) Where such expenditures are outside a ±5% tolerance limit of the annual planned amount;
   b) Where the regulator agrees an extraordinary capital expenditure in a given year, which is at least 10% beyond the level approved in the company's capital investment plan.

5.3.3. JPS' Comments on the Application of the Z-Factor

5.25. In its response to the Proposed Criteria Consultation Document, JPS had objected to elements of the proposed Z-Factor guidelines in the treatment of capital investment projects. However, JPS' concerns appeared to have been resolved through the consultation process and the Final Criteria. The Final Criteria is intended to assist the Rate Review process by outlining the targets, principles and methodologies of certain tariff components.

5.26. However, in its Application, JPS expressed the view that the risk/performance envelope (where the rate of return is 1 percentage point higher or 3 percentage points lower than the approved regulatory target) if fully implemented, would result in quantifiable financial risk. JPS therefore argued that the OUR "has a duty of care to ensure that it is not imposing or creating financial risk for JPS beyond what may be deemed resonable."

5.27. The OUR recognises the validity of JPS' concern regarding the implications of the risk envelope for performance. In this regard, the OUR continues to be open to projects for which the benefits of the investments are demonstrably greater than their cost, even as it seeks to balance the interests of the investor with those of its customers.

5.3.4. The Classification of Major, Minor and Extraordinary Maintenance Projects

5.28. In the Final Criteria, the OUR provided guidance to JPS on how it intends to apply paragraph 46 d. (iii) and 46 d. (v) throughout the Rate Review period. This interpretation and clarification was necessary because the OUR takes the view that the Licence did not adequately and practically define these special circumstances in the context of the Z-Factor implementation.

5.29. The Final Criteria provides a guide to the treatment of variations in the approved capital investment plan, which should be observed by JPS in the categorization of its projects. The categories are as follows:

- Major Projects:
  These are non-routine capital projects that are valued at US$10 Million or more which are clearly identified in JPS' capital investment plan. The Z-Factor adjustments will be assessed on the basis of their individual merit.
- Extraordinary Maintenance Projects:
  These are non-routine capital projects related to routine plant replacements and overhauls that are valued at US$10 Million or more which are clearly identified in

JPS' capital investment plan. The Z-Factor adjustments will be assessed on the basis of their individual merit.

- Minor Projects:
  These are non-routine capital projects that are valued at less than US$10 Million which are clearly identified in JPS' capital investment plan. The Z-Factor adjustments will be assessed collectively.

5.30. Consistent with the Final Criteria, the variations in capital investment projects that trigger the Z-Factor are categorized and deemed to be as follows:

1. Project Delays
   The delays in a Major Project or Extraordinary Maintenance Project can trigger the Z-Factor adjustment, if there is at least 5% variation in the annual expenditure for each of the various projects, in the prior year. Similarly, if the same variation occurs in the annual expenditure for Minor Projects as a whole there will be a corresponding Z-Factor adjustment.

2. Unimplemented Projects

   For the removal of projects that should be implemented within a given Rate Review period, JPS should provide justification for this action. If the justification is deemed reasonable by the OUR, the Z-Factor adjustment will be utilized to remove the expenditure which was associated with that project from the Revenue Requirement.

3. Unplanned Projects

   Where there arises a need for a project that is categorized as being either a Major Project or Extraordinary Maintenance Project, and this project was not included in the approved Business Plan, it will be classified as an unplanned project. Unplanned projects require a justification from JPS, and should be approved by the OUR prior to implementation. Where the project will result in an increase in the capital expenditure for that year by at least 10%, a Z-Factor adjustment will be applied.

4. Changes in Project Scope

   A change in the scope of a project that is classified as a Major Project or Extraordinary Maintenance Project, will require the prior approval of the OUR. In a given year, if the change in the scope of either of these types of projects results in a reduction in the project cost by at least 10% of the projected capital expenditure, a Z-Factor adjustment will be applied that will result in 50% of the savings being passed on to customers for the remainder of the Rate Review period.

5.3.5. Interpretation of Rate of Return

5.31. Paragraph 46 d. (ii) of Schedule 3 of the Licence states that the Z-Factor may be triggered:

> *ii) where the Licensee's rate of return with respect to the Licensed Business is one (1) percentage point higher or three (3) percentage points lower than the approved regulatory target (after taking into consideration the allowed true-up annual adjustments, special purpose funds included in the Revenue Requirement, awards of*

the Tribunal and determinations of the Office and adjustments related to prior accounting periods). This adjustment may be requested by the Licensee or Minister or may be applied by the Office;

5.32. The rate of return (ROR) referred to in the above clause is not defined in the Licence, and could refer to either the return on equity or the return on investments (i.e. the weighted average cost of capital/or WACC). In the general financial literature, there is no single concept of a rate of return as its exact meaning is dependent on context. The rate of return could refer to, for example, return on assets, return on equity, return on investment or a number of other meanings.

5.33. The OUR's interpretation is that ROR in this context is the return on investments made by the business. This definition considers all JPS' sources of capital (loans and equity). Hence, the ROR shall be interpreted as the post-tax WACC.

5.34. The WACC combines the approved ROR of all categories of funds in the business in proportion to each funds' contribution to the actual or deemed capital structure, to yield a single ROR for the company.

5.35. The OUR takes the view that the intent of subparagraph 46 d.(ii) of Schedule 3 of the Licence is to shield JPS from the impact of poor regulatory decisions. Taking account of the Licence condition that JPS provides an efficient service at reasonable rates and the requirement that rates promote economic efficiency, it is also the OUR's view that the intent of this provision was not to apply a Z-factor adjustment to compensate JPS for its own poor managerial decisions. Therefore, in the event that the rate of return falls below 3%, the OUR will conduct an assessment of JPS' financials to determine the cause.

5.3.6. <u>Summary of the Z-Factor</u>

5.36. The Z-Factor adjustment may be triggered in an Annual Review by the special circumstances in paragraph 46 d of Schedule 3 of the Licence. The special circumstances highlighted in subparagraphs 46 d(iii) and d(v) were interpreted and clarified in the Final Criteria to guide JPS as to the approach the OUR would take on the treatment of these special circumstances.

5.37. As presented in the Final Criteria, JPS was instructed that capital investment plan projects should be categorized as one of the following:

- Major Projects;
- Extraordinary Maintenance Projects;
- Minor Projects.

5.38. The Z-Factor adjustments for Major Projects or Extraordinary Maintenance Projects will be assessed on an individual merit while Minor Projects will be assessed collectively.

5.39. The various aspects of a project that could trigger the Z-Factor are as follows:

- Project Delays;
- Unimplemented Projects;
- Unplanned Projects;
- Changes in Project Scope.

5.40. Also for the special circumstances outlined in subparagraph 46 d. (ii), the OUR takes the view that it is within the ambit of its authority to clarify obscure elements of the regulatory framework in a just and reasonable manner, so as to ensure transparency, consistency and certainty in the exercise of its regulatory functions. In this regard the

ROR in subparagraph 46 d. (ii), which is interpreted to be the return on investment, shall be the WACC.

DETERMINATION: #3

In order to clarify terms that were not detailed in the Licence, the Office has determined that:

a) In keeping with the definitions set out in the Final Criteria, JPS' capital investment plan projects shall be categorized as follows:
   - Major Projects
   - Extraordinary Maintenance Projects
   - Minor Projects

b) The Z-Factor adjustments for Major Projects or Extraordinary Maintenance Projects shall be assessed on an individual merit while Minor Projects will be assessed collectively.

   As defined in the Final Criteria, the various aspects of a project that could trigger the Z-Factor is as follows:

   - Project Delays
   - Unimplemented Projects
   - Unplanned Projects
   - Changes in Project Scope

c) The rate of return referred to as one of the special circumstances that triggers a Z-Factor adjustment in subparagraph 46 d. (ii), shall be interpreted to be the return on investment, which is the weighted average cost of capital.

6. OUR Comments on JPS' FIVE (5) Year Business Plan 2019-2024

6.1. Purpose of the Review

6.1. Under the Licence, the Licensee is required to publish a Business Plan as part of its submission for a rate increase. This review presents the OUR's assessment of the JPS Business Plan for the period 2019-2024. It should be read in conjunction with the OUR's assessment of the Application and investment plan with which there is considerable overlap.

6.2. Objectives

6.2. JPS' vision, mission, and values are critical elements for providing the safe, reliable, and affordable electricity supply that is essential for Jamaica. The Business Plan elaborates these objectives through five strategic priority areas, namely:

a. delivering exceptional customer service;
b. ensuring the safety of the public and employees;
c. achieving end-to-end efficiency;
d. growing the business; and
e. strengthening relationships with key stakeholders, all of which are under-pinned by the key enablers of its people, processes, and technology.

6.3. JPS framed its activities within these five priority areas so as to provide a targeted approach to its operations. This framework is also used to structure the Business Plan.

6.3. Strategies

6.4. Table 6.1 below breaks down JPS' strategic priority areas into objectives, and highlights the key initiatives it proposed to undertake to achieve these objectives.

Table 6.1: JPS' Key Initiatives - Business Plan 2019-2023

Strategic Priority Area	Objectives	Key Initiatives
Customer Service		
Delivering value to our customers	Improve System Reliability	▪ Energy Storage ▪ Grid Modernization ▪ Smart LED Streetlight Programme ▪ Voltage Standardization ▪ T&D Upgrade and Expansion ▪ Life Cycle Asset Management
	Improve the Ease of Doing Business	▪ Outage Notification Automation ▪ Maximizing the benefits of smart meter technology (fewer estimations, quicker reconnections etc.)
	Customer Empowerment	Product and Service Offering Expansion: ▪ MyJPS Mobile App; Full Service Payment Kiosks ▪ Pay-as-You Go (PAYG) Metering ▪ Customer Education Programme
Safety		
Protecting Life and Property	Improve Safety Management	▪ Integrated Safety and Health Management System
	Improve Organization's Safety Culture	▪ Safety Leadership Programme ▪ Safety Training and Certification
End-to-End Efficiency		
More value, less waste	Lower Operating Costs	▪ Business Process Optimization
	Reduce System Losses	▪ Metering Programme (Smart, Transformer, RAMI) ▪ Audits and Investigations ▪ Measurement Programme
	Improve Heat Rate and Plant Performance	Commission: ▪ 194 MW LNG Old Harbour (SJPC) ▪ 37 MW Solar Plant (Eight Rivers) ▪ 94 MW JAMALCO
Growth		
Grow today, secure tomorrow	Increase Revenue Generation Services	▪ Commission 14 MW DG ▪ Renewable Energy Growth Projects ▪ EV Charging Stations
Stakeholder Relationships		
Success through partnerships	Strengthen Partnerships with Key Stakeholders	Stakeholder Engagement: ▪ Partner to reduce losses (JSIF and GOJ) ▪ Partner to achieve EV Policy (MSET) ▪ Corporate Social Responsibility

***Source**: JPS' Business Plan, p18.19*

6.5. The OUR took special note of the fact that the Business Plan places significant weight on ensuring the affordability of electricity. Affordability remains a challenge for many consumers, particularly in light of the impact of the Covid-19 pandemic and the forecasted slow-down in the global economy.

6.4. Operating Expense Forecasts

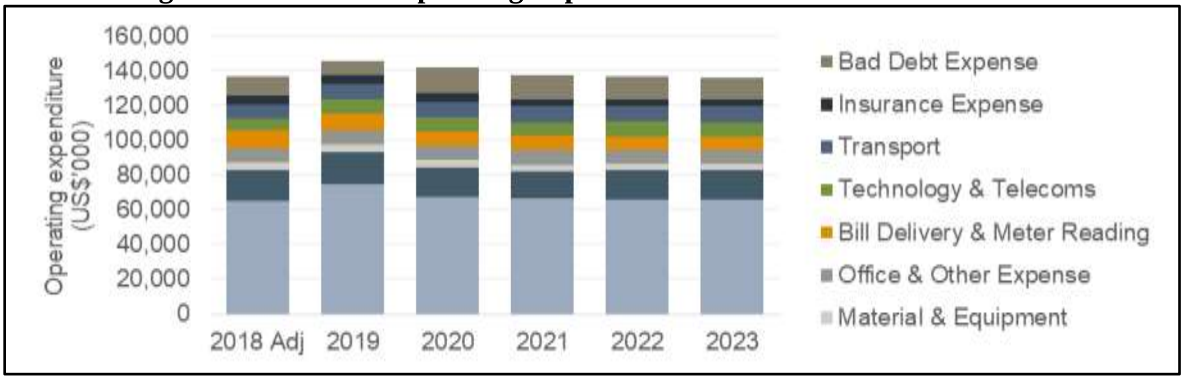
6.6. The Executive Summary of the Business Plan sets out the Operating and Capital Expenditure profiles for the five-year review period. Table 6.2 below presents a breakdown of the operating expenses forecast in the Business Plan, and Figure 6.1 below presents the same data in graphical form.

Table 6.2: Operating Expenditure Profile

(US$ '000)	2018 Adj	2019	2020	2021	2022	2023
Payroll Benefits & Training	65,150	75,033	67,173	66,351	66,255	66,187
Third Party Services	17,877	18,036	17,168	15,917	16,321	16,713
Material & Equipment	4,340	4,936	4,276	3,982	4,005	4,036
Office & Other Expense	7,899	7,701	8,450	8,209	8,173	8,158
Bill Delivery & Meter Reading	10,382	9,949	8,170	8,098	7,740	7,100
Technology & Telecoms	7,001	7,679	8,074	8,087	8,348	8,276
Transport	8,234	8,855	9,220	9,121	9,164	9,229
Insurance Expense	5,152	5,500	4,630	3,632	3,695	3,759
Bad Debt Expense	10,899	8,179	15,280	14,529	13,384	12,674
Total	**136,935**	**145,867**	**142,443**	**137,926**	**137,084**	**136,134**

Source: *JPS Business Plan, p21*

Figure 6.1: Trend in Operating Expenditure over the Rate Review Period



Source: *JPS Business Plan, p21*

6.7. These data show that staff costs remain the major component of operating expenses, contributing approximately half of costs in each year of the Rate Review period.

6.5. Anticipated Change to the Demand for Electricity

6.8. JPS' demand forecasts are set out in Section 6.4 of the Business Plan. The forecast is divided into two categories: 'billed sales' and 'billed customers'.

6.9. Billed sales are expected to grow by 1% per annum between 2018 and 2023, with a forecast of 3,356 GWh in 2023 versus 3,212 in 2018, which translates to a 4.6% increase. This represents a significant improvement in sales growth, which averaged only 0.6% for 2013-18 (Figure 2 of the Business Plan). The minimal growth in 2018 (0.1%) is attributed to low temperatures, customer defections, and large customers being off for maintenance activities.

6.10. Initial outcomes suggest JPS' sales forecast was too conservative. The Business Plan forecasts 3,215 GWh of sales in 2019, yet actual total sales for 2019 were 3,276 GWh, a level which the forecast did not expect to be reached until 2023. Regardless, given the emergence of Covid-19, the Business Plan's forecast needs to be updated. Section 11 provides further discussion of the impact of Covid-19 on JPS' Business Plan.

6.11. Billed customers are anticipated to grow by 1.4% per annum over the Rate Review period, which cumulates to growth of 9.2% between 2018 and 2023. Total billed customers are expected to grow from 658,052 in 2018 to 718,376 by 2023. This will be driven by growth in industry and households and reducing illegal connections, i.e. transitioning consumers into customers.

6.12. The Business Plan highlights some risks to demand and customer growth as follows:

- Energy conservation from energy efficiency improvements, including the transition to LED streetlights;
- Proliferation of rooftop solar PV, leading to load migration to self-generation and grid defections;
- Lower cost self-generation due to the introduction of natural gas to Jamaica.

6.13. In addition to continued investments in the grid to meet new demand, JPS is planning to diversify its revenue streams with behind the meter services. The services include, rooftop solar PV leases, smart home services, bundled services, and redirecting 14 MW of retired assets to customer sites as grid-connected distributed generation owned and operated by JPS with associated O&M services. Continued efficiency improvements are to be expected and are also driven by government policy. In the Business Plan, JPS states that it is seeking to establish an energy management and data services hub to take advantage of this trend as a 'non-traditional' revenue stream.

6.14. JPS appears to be well-aware of the demand trends, and the OUR would have expected that different scenarios would be presented as to the scale of the risks/consequences of increased self-generation for its revenue streams, and the extent to which JPS' laid out plans will counteract these effects. Furthermore, while plans to improve efficiency and non-technical losses should help to reduce customer bills, more consideration should be given to efforts to lower tariffs as a measure to reduce both the prevalence of self-generation and non-technical losses.

6.6. Allowed Return on Equity (ROE)

6.15. For the 2013-2018 period, JPS achieved an average return on investment of 6.9% relative to the allowed 12.25%. Average returns, falling below the allowed return was attributed to an inability to recover the depreciation charges incurred from sustained levels of capital investment. JPS notes that this anomaly will be corrected in the new Rate Review period. Notably, the Business Plan does not refer to the role that losses have played in JPS not achieving its ROE target.

6.16. The Business Plan does not provide an estimate for the ROE in the next period, but this metric is confirmed as part of the rate review process.

6.7. Annual Targets

6.17. The Business Plan helpfully concludes each section by discussing its strategic priorities with a table of measurable targets. For example, heat rates and system losses for End-to-End Efficiency. These provide a good basis for evaluating the success of JPS' strategic plans in the future and indicate an overall intent by JPS to produce demonstrable achievements.

6.18. The Business Plan sets out targets for 2023 for aggregate compliance with EGS and EOS, as well as for specific measures such as the Customer Satisfaction (CSAT) index, System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI), Equivalent Availability Factor (EAF%) and Equivalent Forced Outage Rate (EFOR%). However, more granular targets could be provided rather than only aggregate compliance with EGS and EOS to provide a more detailed picture of JPS' performance plans.

6.19. It is also noted that JPS has set multiple targets that are outside of the Licence standards, such as reducing motor vehicle accidents by 10% and reducing fuel leakages from 148 litres in 2018 to 0 by 2023. The setting and publishing of such targets, is an admirable move towards transparency and accountability. While neither requiring nor requesting these metrics, OUR believes that achieving these published metrics will enhance JPS' standing in the eyes of its customers.

6.20. More detailed performance reporting and target setting could be provided with respect to the service standards set out in the Licence: 'Guaranteed Standards' (EGS) and 'Overall Standards' (EOS). JPS' reporting of their performance and forecasts against these standard targets are only selectively reported in the Business Plan.

6.21. Further, in 2020-2021 the OUR will be conducting a broad stakeholder consultation to undertake a comprehensive review and analysis of the Guaranteed Standards (GS) scheme, which includes the standards established for JPS. Consequently, the OUR will defer any changes to EGS until the consultation is completed.

6.8. The Most Recent IRP

6.22. JPS is required to include the IRP as part of its submission to OUR for the Rate Review process. The Licence stipulates that the IRP should be published by the Ministry of Science, Energy and Technology (MSET) at least fifteen (15) months before the 2019 rate review filing. In the Business Plan, JPS noted that:

> *"at the point of preparing the plan (June 2019) a final IRP was not available. The plan therefore excludes projects and costs associated with the planning decisions to be informed by the IRP."*

6.23. The absence of a formal IRP was not the fault of JPS and, as discussed in the OUR's review of the Application, JPS substituted this with its own assessment of generation investment needs. The IRP may also require revision considering the impact of Covid-19.

6.9. Capital Investment Plan

6.24. JPS' planned capital investments are set out in Section 14 of the Business Plan.

6.25. Looking at JPS' investment trends over the Rate Review period, it is apparent that the company is planning a balanced capex investment approach, with some relative frontloading of investments in distribution, transmission, and losses, before major investments in generation are foreseen in 2022-2023.

6.26. The main investment items are well marked out and their purposes are clearly defined. Major investment items for facilities, business development, system control, and 'other' are not identified in the Business Plan, but the planned expenditure for these categories is less sizeable. Further assessment of the planned JPS investments is provided in a separate review of the JPS investment plan.

6.10. System Loss Mitigation Activities and Related Funding Requirements

6.10.1. Overview of Losses

6.27. JPS' historical and forecast losses indicate:

- There is a slow and steady decline in total losses over the tariff period 2014 - 2019, continuing the gradual decline seen since 2015. This is welcomed by customers who ultimately bear the cost of losses through higher tariffs.
- There is a higher reduction in non-technical losses (18% to 15.9%) than in technical losses (8.2% to 8.1%), in both absolute and relative terms. This suggests that more revenues associated with electricity delivered to customers are being collected.

6.28. Continued loss reduction is stated to be a high priority for JPS, and for this, the company is commended. In particular, efforts to reduce non-technical losses, which may be thought of as energy received by one customer and paid for by another through higher prices, has been a concern of the OUR for many years.

6.29. Loss reduction, at best, should be a collaborative effort between JPS and the GOJ. The OUR, on the other hand seeks to provide a framework for the reduction of losses, by addressing the alignment of the responsibility for loss reduction with the penalty-reward mechanism defined in the Licence.

6.30. In accordance with the provisions of the Licence, the OUR is to set a ten- (10) year loss reduction target.

6.10.2. Technical Losses

6.31. Technical losses, estimated at 8.24% in 2018, are not particularly high for a country at Jamaica's stage of development, but there is room for improvement. The Business Plan acknowledges this, detailing numerous planned investments to improve technical losses, which show an awareness of the issue and a determination to improve.

6.32. Table 33 of the Business Plan breaks down technical losses for 2018 into losses on the transmission network (2.24%), primary distribution lines, pole and pad-mounted transformers (2.80%) and secondary distribution lines (2.90%).

6.33. The disaggregation of technical losses in Table 33 is helpful, but ideally the time series of this breakdown should have been longer, so that there is visibility as to which specific aspects of technical losses have been improving/deteriorating over time. However, the OUR is aware that this may not be feasible since, as outlined in the Business Plan, JPS had to conduct an audit of distribution transformers in 2017 in order to arrive at the loss estimate for transformers, and the noted technical difficulties of estimating secondary distribution losses. Nevertheless, plans should be made to revisit the disaggregated 2018 technical loss estimates in future to assess the impact of approved grid investments. In the Business Plan, JPS notes that such estimates will be made easier by the advent of the smart meter programme.

6.10.3. Non-Technical Losses

6.34. In the Business Plan, JPS notes that more than 18% of electricity produced is stolen, and that there are over 200,000 illegal connections to the grid (around a third of the legitimate customer base). These unpaid electricity charges are passed on to legitimate customers, increasing their prices. Therefore, electricity theft is a problem that affects all JPS customers.

6.35. JPS has pursued a range of efforts to reduce this theft, which includes collaborating with GOJ and seeking assistance from the police. These efforts include:

- the deployment of technology to help identify and curtail theft;
- collaboration with the police for the arrest of electricity thieves;
- removal of illegal throw-up lines;
- account audits and investigations;
- public education and social marketing; and
- the Community Renewal programme.

6.36. It is noted that these programmes have contributed to a downward trend in non-technical losses.

6.10.4. Grid Security and Risk Management

6.37. At section 16 of the Business Plan, JPS asserts that it follows a rigorous risk management framework. The framework is said to follow international utility best practices for both operations and strategic planning, and a governance structure that ensures policies and procedures are followed throughout the organization.

6.38. The Business Plan details the risk mitigation options to follow for a variety of major identified risks, including:

- Prolonged disruption from a natural disaster;
- Major supply failure (fuel, equipment and tools, or a new power plant missing its COD);
- IT systems breach;
- Significant macroeconomic change (foreign exchange, interest rates, etc.);
- System losses (regulatory and financial impacts).

6.39. Section 16.2 of the Business Plan lists disruptions from natural disasters as a major risk for JPS. The case of Hurricane Maria destroying Puerto Rico's electricity grid in 2017 is cited as the type of event for which preparation is necessary. JPS asserts that it will continue to maintain a high level of emergency planning and disaster preparedness with continued training, simulations, and adoption of international lessons learned.

6.40. The outlined processes and initiatives, including a disaster management programme, disaster fund, structural integrity plan (US$41.8M towards making poles, towers, substation equipment, etc. more resilient), and a business continuity plan, are all sensible initiatives.

6.41. With respect to disaster management, JPS asserts that: '*The effectiveness of this disaster management program is evident when one looks at the historical restoration timeline after a natural disaster event*', but no actual data on this is presented in the Business Plan. Given that Jamaica has not suffered a direct hurricane impact in recent years or any recent massive outages, there may simply be no recent experience or data to draw on. In Section 3.3, the Business Plan cites two major shutdowns in 2016 of 230 and 337 minutes, respectively, which were the subject of a report sent to the OUR. However, these events cannot be considered equivalent to the outages caused by a major natural disaster. In the absence of empirical evidence, JPS could consider publishing some simulated data so that stakeholders can be assured of JPS' preparedness.

6.10.5. Losses (Y-factor)

6.42. The Business Plan provides an overall target of system loss reduction (2.25 percentage points) as part of its end-to-end efficiency, strategic priority, including estimates of how much each component of the smart meter programme will reduce non-technical losses. However, it would also be helpful if the Business Plan presented a final disaggregated table of expected technical losses and non-technical losses over the Rate Review period. The figures and tables in the Business Plan present a mix of aggregate system losses for 2013-2018 in percentage terms (Figure 5 of the Business Plan), projected losses for 2018-2023 in MW (Table 22 of the Business Plan). The percentage point reduction in losses attributed to the smart meter programme (Table 44 of the Business Plan), and the aggregate percentage reduction in system losses, although it is not clear if this figure represents a year-to-year improvement or a cumulative figure (Table 47 of the Business Plan).

6.43. A 'Y-factor' target is not set out in the Business Plan as this will depend on the losses target set by the OUR as part of the rate review. The Y-factor is a function of the difference between JPS' actual losses and a rolling 10-year target set by the OUR.

6.10.6. Heat rate (H-factor)

6.44. The Business Plan presents both a historical time series of JPS' achieved heat rate for 2013-2018 (Figure 3) and a projection of its target heat rate for 2019-2023 (Table 47). Explanations are provided as to the fluctuations of past heat rates, e.g. the Bogue Plant going offline for three months for its conversion to gas. The projected heat rate improvement is well-justified by a combination of routine maintenance, turbine overhauls, and the retirement of obsolete steam turbines. Overall, JPS exhibited a strong record of heat rate improvement for 2013-2018, declining by almost 7%. A greater improvement of almost 20% is expected for 2018-2023, which is largely driven by the planned retirement of 429.5MW of old steam and gas turbines.

6.10.7. Quality of service (Q-factor)

6.45. The Business Plan proposes an overall improvement of 20% in its system reliability indicators; an average annual improvement of 4% per annum. This includes improving SAIDI by 390.9 minutes and reducing SAIFI by 3.09 minutes. The Q-factor is based on the average of the past three years (2016-2018) of system reliability performance.

6.46. To achieve this improvement, the Business Plan cites continued investments in modernizing the grid, the installation of smart devices in strategic locations, standardizing voltage distribution, optimizing power flow, installing energy storage systems to mitigate the impact of intermittent renewables, expanding the grid, upgrading software and communication systems, and conducting routine maintenance according to a scheduled programme.

6.47. A calculated breakdown of the Q-factor is not provided in the Business Plan as, according to the Licence, the factor is based on a scoring system based on JPS' performance against the SAIFI, SAIDI, and CAIDI targets set out by the OUR in the rate review. Hence, the resulting Q-factor will depend on how JPS' target of a 23% improvement in its reliability indicators compares to the OUR's set targets.

6.11. Smart Technologies, Energy Efficiency and Other Policy Initiatives

6.11.1. Smart Technologies

6.48. The Business Plan outlines a range of Smart Technology that JPS has already commenced, and which they plan to undertake in the Rate Review period:

- Smart Meters;
- Smart Street Lighting;
- Smart Devices.

6.11.2. Energy Efficiency

6.49. JPS notes that there is strong customer interest in energy efficiency. Many of the energy efficiency actions are focused on the customer end, e.g. inverter technology ACs, energy-saving and LED light bulbs, energy efficient appliances, energy audits, retrofits, and load shifting. JPS has assisted in this promotion through partnerships with customers. Energy efficiency creates new opportunities for JPS' revenue streams.

6.11.3. Information Technology

6.50. The Business Plan proposed a range of investments in information technology (IT). Four primary investments are proposed:

- Replacement of the customer service platform;
- Expansion of the business intelligence platform;
- Completion of the Enterprise Asset Management (EAM) platform rollout;
- The Electric Grid Communication Network Rehabilitation and Upgrade programme which will provide enhanced communication across the network, which should lead to enhanced productivity.

6.51. The proposed investments all appear worthwhile and could bring direct and indirect benefits to customers. However, JPS has not explicitly stated in the Business Plan how these investments would provide real value to customers.

6.11.4. Electric Vehicles

6.52. JPS' Business Plan presents a discussion of the future potential for electric vehicles in Jamaica, and the necessary investments that the company will be required to make, e.g. installation of charging stations and other infrastructure, as well as supporting the development of an appropriate enabling framework. At this juncture JPS and GOJ are still in discussions, and so no significant investment commitments have been made.

6.11.5. Other Initiatives

6.53. The Business Plan outlines a series of other initiatives that will support JPS' drive towards greater customer service:

- Updating the JPS Mobile App to provide real-time updates of customer accounts, consumption, outages, bill payments, and other reports;
- Increased customer response through online customer service, providing 24-hour access for customers to contact JPS;
- Additional payment options for customers;
- Improved customer service through customer education.

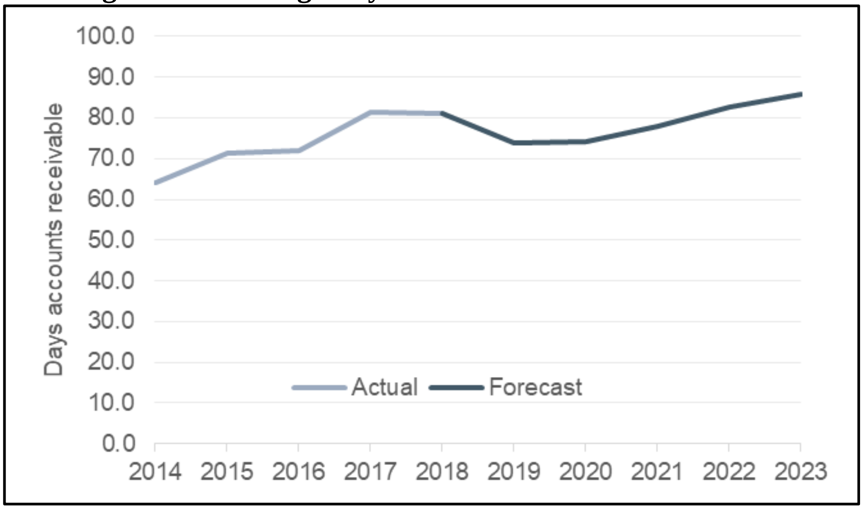
6.54. The OUR considers these initiatives reasonable and well-intentioned. However, the principle of delivering benefits to customers, relative to incurred costs, and quantifying this where possible, is a vital regulatory consideration. It is also noted that the Business Plan fails to set out specific targets or numbers for these initiatives.

6.12. Balance Sheet, Profit and Loss Statement and Cash Flow Statement

6.12.1. Average Days Receivable

6.55. The forecast profit and loss statement and balance sheet allow for the calculation of an average day's receivable for money owed from sales. Using the information provided, a profile of the trend in this metric has been produced as illustrated in Figure 6.2 below.

Figure 6.2: Average Day's Receivable For Sales Accruals



Source: *JPS Business Plan, pp42, 44, 216, 219*

6.56. This increasing trend is a matter of concern, if accurate, as it suggests a negative trend in JPS' collection.

6.12.2. Staff Costs

6.57. The Business Plan explains that the reduction in staff costs from 2020 is as a result of the closure of the Old Harbour and Hunts Bay plants between 2020 and 2021. The projected reduction in headcount is stated to be from 1,561 in 2018 to 1,468 in 2023. However, it is noted that no explanation was given for the significant increase in expenses in 2019.

6.12.3. Bad Debts

6.58. Similar to the discussion on staff costs, the profile of bad debt expenses suggests a reduction between 2018 and 2019, but then a significant (nearly 100%) increase between 2019 and 2020, which is then followed by a steady reduction year-on-year. JPS claims (outside the Business Plan) that this increase represents suppressed costs that occurred in 2018 because of the company's bad debt initiatives. The Business Plan should have elaborated further on this.

6.13. Impact of COVID–19 on JPS' Business Plan

6.59. The OUR accepts that the Business Plan would not address the fallout of the Covid-19 pandemic, since it was submitted prior to its onset. The extent to which Jamaica has been adversely affected by the pandemic is still unfolding, but measures to combat the virus in Jamaica and worldwide may very well have deleterious effects on JPS' original Business Plan. The IMF expects the Jamaican economy to contract by 5.3% in 2020/21, before rebounding by 3.9% in 2021/22. A worldwide economic slowdown may impact JPS' financing projections and demand growth in the commercial and industrial sectors, particularly the tourism sector.

6.60. For residential consumers, the imposition of curfews, the closing of non-essential businesses, and increased working from home may change demand patterns. Consumers spending more time at home may incur higher electricity bills, which may raise questions of affordability. A decline in remittances may also exacerbate this issue. These factors could also exacerbate the difficulty of reducing non-technical losses. The extent of these impacts will, however, ultimately depend on the length of the pandemic and the measures required to contain it. Given these factors, JPS' investment plans may need some reorientation to focus more on tariff affordability.

7. JPS' Medium Term Capital Investment Plan

7.1. Introduction

7.1. JPS' Medium Term Capital Investment Plan 2019 – 2023 (Investment Plan) provides an overview of the investments that the company proposes to undertake over the Rate Review period. The Investment Plan is required as a part of the Five-Year Rate Review Process as outlined in Schedule 3 of the Licence and Criteria 6 and 7 of the Final Criteria. The Investment Plan also contains accompanying business cases as requested in the Final Criteria, and provides justification for most of the proposed projects.

7.2. JPS stated that the main objectives of its Investment Plan, which will see the company spending US$478.8 over five years, are to improve customer satisfaction and to enhance the company's efficiency. The Investment Plan includes over seventy-two (72) individual projects and programmes. JPS asserted that these projects will deliver improvements to power quality and reliability, reduce electricity losses, improve power generation efficiency, boost productivity and improve customer service. Some of the major expected outcomes of the projects are:

- 2.30% reduction in electricity losses;
- 20% improvement in reliability of supply;
- 1.9% improvement in productivity;
- Achievement of regulated heat rate.

7.3. Criterion 18 of the Final Criteria specified the OUR's guidelines for presenting information on projects. Criterion 18 specified that JPS shall classify all relevant projects into three (3) main categories:

- **Major Projects**: non-routine projects valued at US$10M or more;
- **Extraordinary Maintenance Projects**: routine plant replacements and overhaul valued at US$10M or more;
- **Minor Projects**: non-routine projects valued below US$10M.

7.4. Criterion 18 also specified that in providing a plausible justification for each of its projects, JPS should be guided by one or more of the following investment drivers which are further defined in the Final Criteria:

- Efficiency;
- Growth;
- Maintenance/Replacement;
- Statutory;
- Upgrade.

7.5. Table 7.1 below shows the type of information that JPS was required to include for each of the main categories of projects as stated in the Final Criteria. Additionally, JPS was required to provide economic justification for all its major non-statutory projects.

Table 7.1: Project Classification and Information Matrix

Project Type	A Descript. of Facilities	B Specs. & Design	C Project Site	D Implem. Schedule	E Cost Estimate	F Models	G Risk	H Procurement Activities
Major Project								
Efficiency	✓	✓	✓	✓	✓	✓	✓	✓
Growth	✓	n/a	✓	✓	✓	✓	✓	✓
Replacement	✓	✓	n/a	✓	✓	✓	✓	✓
Statutory	✓	n/a	n/a	✓	✓	✓	n/a	✓
Upgrade	✓	✓	✓	✓	✓	✓	✓	✓
Extraordinary Maintenance								
Routine Replacement	✓	n/a	n/a	n/a	✓	✓	n/a	n/a
Overhaul	✓	n/a	n/a	n/a	✓	✓	✓	n/a
Minor Projects								
Efficiency	✓	✓	✓	n/a	✓	✓	✓	n/a
Growth	✓	✓	n/a	n/a	✓	n/a	✓	n/a
Replacement	✓	n/a	n/a	n/a	✓	n/a	✓	n/a
Statutory	✓	n/a	n/a	n/a	✓	n/a	n/a	n/a
Upgrade	✓	✓	n/a	n/a	✓	✓	✓	n/a

Source: Final Criteria

7.6. The OUR carried out an assessment of the Investment Plan with the following objectives in mind:

1. Assessing the project information submitted to ensure that the information scope provided is consistent with the requirements of the Final Criteria, and that the individual project information is complete and accurate;
2. Examining the justification proposed for the projects, the reasonableness of costs, schedules, and the economic feasibility;
3. Examining the project risk assessment and mitigation strategies, and determine the projects' ability to deliver on the objectives.

7.7. In carrying out its review, the OUR engaged a consulting firm (OUR's Consultant) to conduct an assessment of JPS' past track record of delivering projects on time and on budget and to provide an assessment of the reasonableness of the project costs proposed by JPS. The OUR believes that it is important to assess JPS' past project performance, as it provides a reasonable insight into the company's ability to successfully deliver the projects proposed in its capital investment plan. Additionally, from the OUR's perspective, it was important to obtain an independent assessment of JPS' project costs from qualified experts in the field, especially using suitable benchmarking information gathered from other utilities in the Latin American and Caribbean region.

7.8. The next section provides a summary of the Investment Plan followed by the OUR's assessment.

7.2. Summary of JPS' Proposed Capital Investment Programme

7.9. JPS indicated that its Investment Plan is aligned with its strategic priorities which are identified as customer service, efficiency, growth and safety. Table 7.2 below, which is reproduced from the Investment Plan, shows the spend that JPS is proposing over the Rate Review period to achieve these strategic priorities.

7.10. JPS identified the installation of a 43kM of the 138kV transmission line between Old Harbour, in St. Catherine and Hunts Bay, in Kingston at a cost of US$37M as one of its major customer service projects. According to JPS, with planned generation retirements and the growth of demand in the Corporate Area, the electric grid will not be able to safely or economically supply Corporate Area customers without a new transmission line to bring bulk power from the generation facility in Old Harbour. The company also stated that the project will also eliminate the transmission bottleneck at the Duhaney Substation with this critical bypass line leading to improved N-1 contingency under normal and abnormal operations.

Table 7.2: Level of Investment by Strategic Priorities

Strategic Priorities	2019	2020	2021	2022	2023	Total	Percentage %
Customer Service	40,169	38,988	50,227	46,728	43,711	219,822	46%
Efficiency (End to End)	49,602	42,451	43,717	46,513	27,618	209,901	44%
Growth	10,308	9,440	7,643	8,635	6,361	42,386	9%
Safety	1,605	773	1,273	1,768	1,259	6,679	1%
Grand Total	101,683	91,652	102,859	103,644	78,949	478,788	100%

***Source**: JPS Capital Investment Plan*

7.11. The Smart Street lighting project has also been identified by JPS, as a major customer service oriented project. JPS stated that the project will be implemented at a cost of US$24.3M between 2019 and 2021 and will lead to the replacement of 63,000 High Pressure Sodium (HPS) lamps with Smart light-emitting diode LED lamps, bringing the total to 105,000. Stated benefits of the project include a reduction in electricity consumption by streetlights by 50%, improved visibility, support of the smart grid and remote monitoring and control of all streetlights in Jamaica.

7.12. To achieve its end-to-end efficiency goal, JPS identified the roll-out of 470,000 smart meters, overhaul of critical generating plants and completion of the development of its Enterprise Asset Management (EAM) System, as major initiatives. According to JPS, by the end of the Rate Review period, there will be a 95% penetration of smart meters which will enable the company to reduce O&M expenditure by eliminating the need for manual meter reading. The company identified meter reading as one of its major O&M cost items. JPS identified the reduction in energy losses, customer energy conservation as well as customers' access to energy usage information as other benefits of the smart meter programme.

7.13. JPS indicated that the generation plants overhaul projects will allow its generating units to deliver power more efficiently and will ultimately lead to a reduction in maintenance costs. The EAM, according to JPS, will facilitate greater efficiency and accountability as the proper management of assets becomes more structured, scientific and achievable.

7.14. While JPS is expecting only moderate customer growth, it has identified that it needs to make provisions for 60 GWh of additional electricity demand over the Rate Review period and as such, needs to make US$31M of investments in the distribution network to allow for customer growth. JPS also identified the installation of 20 EV charging stations across the island and the installation of 14MW of distributed generation as other growth initiatives. In its Business Plan, the company also indicated its intent to provide behind the meter services to increase its non-traditional revenue stream. These include rooftop solar PV leases, smart home services and bundled services.

7.15. To achieve its safety goal, JPS identified safety of staff and of its information technology security systems as key priorities. The company proposed to roll out initiatives to improve its safety culture and to boost its IT security by installing cloud security, firewall infrastructure and other data security programmes.

7.16. JPS also categorised the projects based on investment drivers as shown in Table 7.3 below.

Table 7.3: Investment by Investment Driver

Investment Drivers	2019	2020	2021	2022	2023	Total	Percentage %
Replacement	39,444	39,563	40,637	49,064	35,786	204,495	43%
Efficiency	32,730	30,480	42,308	44,755	32,922	183,196	38%
Statutory	15,558	15,370	12,379	7,415	6,435	57,158	12%
Upgrade	13,451	5,646	7,135	2,410	3,806	32,448	7%
Growth	500	592	400	-	-	1,492	0%
Grand Total	101,683	91,652	102,859	103,644	78,949	478,788	100%

7.3. Information Provided by JPS

7.17. JPS provided the project information as outlined in Table 7.4 for all proposed projects for which construction began 2019 and later. For major projects, this included complete business cases with the following information status included in Table 7.4.

Table 7.4: Capital Project Information Status

Item	Business Case Category	Detailed Information
1	Description of Facilities	Justification Scale and Scope Timing Technical Characteristics
2	Specification and Design	Design and Configuration Specifications Drawings and General Layout Location Site Description Site Ambient Conditions Site Investigations
3	Implementation Schedule	Key Milestones Key Resources Project Plan
4	Project Cost Estimate	Total Cost Cost Methodology Cost Details
5	Project Benefits	Benefits Quantification of Benefits Financial Economic Analysis and Cost Benefit Analysis
6	Project Risk Assessment	Potential Risks Mitigation Strategies
7	Analysis of Alternatives	

7.18. For minor projects, information on the quantification of benefits and financial/economic analysis and cost benefit analysis were excluded.

7.19. JPS also elaborated on the approval process for projects within the organization and provided a summary of its costing methodology. In summarizing its costing methodology, the company indicated that it determined its cost projections by estimating the resources required and the unit costs of resources. JPS further explained that the approach taken differed based on the type of project and the information available. JPS explained that it used a retrospective approach to estimate unit cost for projects that are continuous in nature, or for those that the organization carry out on a yearly basis, that is, actual costs from past projects were utilized. Costs from JPS' stores were also utilized.

7.20. For non-routine projects, costs were estimated using preliminary designs completed, supplemented with quotations from suppliers who are typically engaged for the particular materials or services.

7.21. JPS explained that cost estimates included interest during construction (IDC) and applicable taxes. It further explained that in accordance with accounting standards (IAS 23), borrowing costs that are attributable to the construction of qualifying assets are capitalized as part of the cost of those assets. The current (2019) rate used for IDC applied to capital projects was 0.3422% per month.

7.22. JPS has identified the key assumptions that were made in developing its project cost and in conducting its cost benefit analysis. Some of these assumptions will be referred to and commented on later.

7.23. Following requests made by the OUR, JPS also provided electronic copies of invoices for materials and services for some of its continuous and routine projects. A few quotations were provided for non-routine projects, but these quotations did not cover the breadth of projects that JPS proposed.

7.24. Details of project costing for all projects and economic/financial analysis for major projects were provided in a separate Excel workbook titled "Investment Costs Final Document Refiling-Unlinked". JPS also provided a workbook called CWIP.xls which showed the proposed capex without IDC included.

7.4. JPS' Proposed Investments

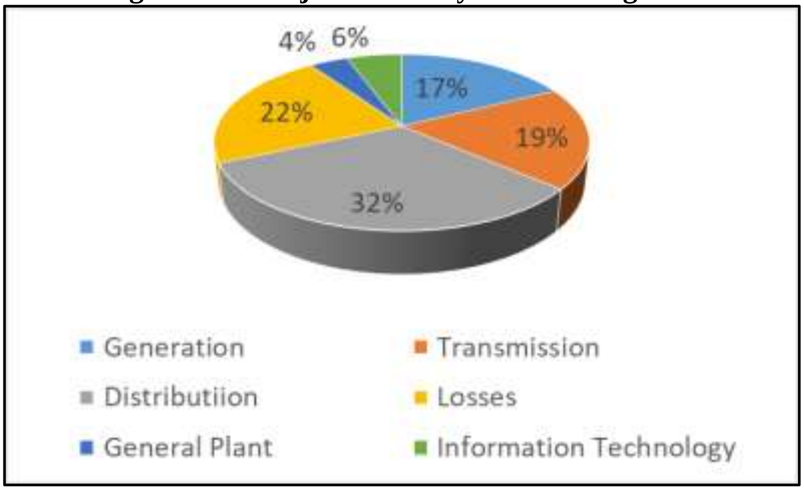
7.25. Table 7.5 below shows the projects that JPS proposed for the Rate Review period categorised by business segments. The table shows the forecasted total cost for each project and the forecasted capital expenditure for each year in the rate review period. The cost for each project and total project cost per annum is exclusive of IDC according to JPS.

Table 7.5: List of JPS' Proposed Projects by Business Segment

		Total Project Cost (US$' 000)	CAPEX (no idc) 2019	2020	2021	2022	2023
CAPITAL PROJECTS							
GENERATION	Combine Cycle Plant	31,452	9,140	5,514	-	8,794	8,004
	Critical Capital Spares-Generation	12,218	2,677	2,700	1,876	3,775	1,190
	Rockfort Major Overhaul - RF 1	8,740	3,831	422	4,129	357	-
	Rockfort Major Overhaul - RF 2	8,158	-	3,377	422	4,359	-
	Renewables - Woodstave Pipeline Repairs Program	4,984	982	313	1,000	1,688	1,000
	Renewables - Turbine & Generator Overhaul	3,413	-	-	2,394	920	98
	Bogue Peaking-Plants	3,242	-	1,474	1,277	491	-
	Bogue - GT11Overhaul	2,751	-	-	-	-	2,751
	Hunt's Bay - GT10 and GT 5 Hot Gas Path Inspection	1,474	196	688	589	-	-
	Bogue - Inlet Air Chiller Major Overhaul	1,033	-	504	-	529	-
	Rockfort - Plant Auxiliaries Rehabillitation	1,049	-	754	295	-	-
	Renewables Equipment Procurement and Replacement	837	-	320	517	-	-
	Bogue - GT3 Overhaul	700	-	-	700	-	-
	Bogue -HRSG Cleaning (Reduced scope)	500	-	-	-	500	-
	Bogue - GT11 Transformer Replacement(GSU)	491	491	-	-	-	-
	Old Harbour Unit 4 Mini Overhaul	476	476	-	-	-	-
	Hunt's Bay B6 Mini Overhaul	442	442	-	-	-	-
	Hunt's Bay - Plant Auxiliaries Rehabillitation	439	-	153	201	85	-
	Industrial Heavy Duty Lathe	295	-	-	-	295	-
TRANSMISSION	Transmission Line Structural Integrity	9,138	1,800	1,770	1,870	1,858	1,839
	Sub Station Structural Integrity	8,552	1,525	1,670	1,722	1,798	1,837
	Energy Storage	8,949	8,949	-	-	-	-
	New Bellevue - Roaring River 69kV line	6,640	-	491	3,114	3,035	-
	N-1 Protection Upgrade	5,931	1,086	1,295	1,239	1,183	1,127
	Interbus Transformers	6,383	196	1,641	2,971	297	1,279
	Protection RAS (Remedial Action Scheme)	2,918	-	1,061	1,857	-	-
	Michelton Halt (LILO)	1,785	1,785	-	-	-	-
	Tools and Equipment	1,319	159	277	285	294	303
	Old Harbour 190 Grid Interconnection	892	726	166	-	-	-
	Old Harbour - Hunt's Bay 138 kV Line	35,070	151	1,634	6,536	13,085	13,664
DISTRIBUTION	Distribution Structural Integrity	22,409	3,771	4,489	4,564	4,763	4,822
	Customer Growth (CCMA)	30,256	6,680	5,894	4,912	6,876	5,894
	Smart Streetlight	23,948	8,252	8,836	6,861	-	-
	Voltage Standardization Program (VSP)	17,282	1,940	3,434	3,196	4,165	4,547
	Meters & Service Wires (Replacement and Growth)	13,740	3,026	2,294	2,723	2,806	2,890
	Grid Modernization Program (FCI, DA, Trip Savers)	12,313	1,753	2,055	2,777	2,915	2,813
	Distribution Transformers	9,916	2,955	2,798	2,203	1,606	354
	Distribution Line Reconductoring and Relocation	10,007	2,000	1,345	2,173	2,084	2,405
	Replace Pole Mounted Transformers	5,256	1,377	927	946	995	1,010
	Capital Spares T&D (CKT Breaker, Recloser, DA switch, etc)	2,258	444	448	451	455	459
	Grid Interconnection	1,789	352	355	358	361	364
	Replace Padmounted Transformers	1,060	208	210	212	214	215
LOSSES	Smart Meter Program	83,772	21,316	17,652	19,786	16,968	8,048
	Rami Projects	16,954	4,126	3,020	4,788	3,001	2,019
	Check Meters	1,178	1,178	-	-	-	-
	Metering Infrastructure Replacements	750	-	200	192	183	175
	Analytical software procurement and Development	302	-	302	-	-	-
GENERAL PLANT	Facilities Improvements	4,640	638	509	1,000	1,492	1,000
	Funding for unforeseen projets	6,104	1,193	491	982	2,456	982
	Purchase of laptops, desktops, Tablets	1,760	-	440	440	440	440
	Install Charging Stations (Electric Vehicle Roll out)	1,465	491	582	393	-	-
	Security Cameras and Systems	1,179	196	250	250	246	237
	Battersea Operations Building	1,161	161	1,000	-	-	-
	Repurpose of Old Control Room for DTS & CEOC	1,000	-	-	-	-	1,000
	Safety Devices and Monitoring Stations	196	196	-	-	-	-
	Transportation Equipment	432	221	211	-	-	-
	Video Wall Upgrade	335	-	49	-	287	-
	Build Network Operations Centre	330	-	-	-	-	330
IT	Electric Grid Communication Network Rehabilitation and Upgrade	4,730	344	1,099	1,028	1,130	1,130
	Expansion of Enterprise Architecture, Business Intelligence and Ar	3,497	206	884	776	815	815
	Information Technology Security Program	1,510	-	378	524	286	321
	Business Efficiency	2,396	513	594	552	422	314
	Upgrade CS	2,751	-	196	1,375	1,179	-
	Enterprise Asset Management	2,410	953	795	662	-	-
	IT Infrastructure Modernization	2,576	430	586	659	296	605
	Introduce DERMS	700	-	-	-	700	-
	SCADA/EMS Project Upgrade	2,037	-	-	-	2,037	-
	Replacement of OMS	2,126	-	1,126	1,000	-	-
	Unified Communications Platform	393	-	196	196	-	-
	Data Centre Operations Modernization	475	-	-	270	205	-
	Phase 3 DMR Implementation & Radios for two-way Radios	545	545	-	-	-	-
	Oracle Modification Project (Seperation of Accounts)	336	-	196	139	-	-
SUB TOTAL CAPITAL PROJECTS		**468,548**	**100,081**	**90,068**	**99,387**	**102,729**	**76,284**

7.26. The share of the project costs (exclusive of IDC) by business segment is shown in Figure 7.1.

Figure 7.1: Projects Costs by Business Segment



7.4.1. JPS Proposed Generation Projects

7.27. In its submission, JPS proposed the implementation of a generation capital investment plan covering all its generating units and plant locations for the Rate Review period. JPS has stated that the objective of the programme is to:

- Improve the generating units' end to end efficiency;
- Improve the generating units' reliability and availability;
- Maintaining the generating units' output capacity;
- Extend the life of critical systems; and
- Ensure safety of operations, complying with statutory obligations under the relevant legislations.

7.28. JPS' strategy to achieve the stated objectives is to carry out targeted maintenance initiatives and programmes. The list of generation projects proposed by JPS are shown in Table 7.6 below.

Table 7.6: JPS' Proposed List of Generation Projects for the Rate Review period

Item	Business Unit	Project Category	Description of Maintenance Initiative
1	Bogue	Extraordinary Maintenance – Routine Replacement	GT12 Major Overhaul with Controls Upgrade GT13 HGPI and Controls Upgrade ST14 Major Overhaul with Controls Upgrade
2	Bogue	Minor Project - Replacement	Bogue Combined Cycle Air Chiller Major Overhaul HRSG cleaning
3	Bogue	Minor Project - Replacement	GT 3 Hot Gas Path Inspection (HGPI) GT 6 GG Major Overhaul GT 7 GG Major Overhaul GT 9 GG Major and Generator Rotor Out Overhaul GT11 Hot Section and Combustion Refurbishment
4	Hunt's Bay	Minor Project	Plant Auxiliaries Rehabilitation Hunts Bay GT 5 and GT 10 major overhaul
5	Hydro Plants	Minor Project	**Hydro Generators and Turbines Overhaul** Upper White River Hydro Power Plant (UWR-HPP) Lower White River Hydro Power Plant (LWR-HPP) Rio Bueno A Hydro Power Plant (RBA-HPP)
6	Hydro Plants	Minor Project	**Renewables Wood Stave pipeline repair program** Upper White River Hydro Power Plant (UWR-HPP) Lower White River Hydro Power Plant (LWR-HPP) Rio Bueno A Hydro Power Plant (RBA-HPP)
7	Hydro Plants	Minor Project	**Renewable Generation Equipment Procurement and Replacement** Rio Bueno A Hydro Power Plant De-silting and trash rack replacement Maggotty A Hydro Power Plant Intake De-silting and steel penstock Lower White River Hydro GSU Transformer Procurement Renewables – Remote Control Centre Infrastructure replacement Constant Spring Turbine Runner Procurement
8	Technical Workshop	Minor Project	Industrial Lathe Procurement

7.29. In order to achieve the planned objectives, JPS proposed a capital expenditure amount of US$84.203 million over the Rate Review period. This is an average of US$16.84 million per year over the period. This expenditure represents 17.58% of the period's total expenditure of US$478.8M . During the last tariff period of 2014-2019, JPS expended US$143 million on generating plant capital projects, according to information provided in its submission.

7.30. Table 7.7 below provides a summary of JPS' Generation Capital Investment Plan.

Table 7.7: JPS' Proposed Generation Capital Investment

Business Unit	Project Name	2019	2020	2021	2022	2023	Total
		US$000	US$000	US$000	US$000	US$000	**US$000**
Bogue	Combine Cycle Plant (GT12,GT13, ST14)	9,304	5,613		8,952	8,148	**32,017**
Bogue	Bogue Peaking Plants (GT6,GT9,GT7)		1,500	1,300	500		**3,300**
Bogue	Bogue GT3 Overhaul			700			**700**
Bogue	Bogue GT11 Overhaul					2,800	**2,800**
Bogue	Bogue Inlet Air Chiller Overhaul		513				**513**
Bogue	HRSG Cleaning (Reduced Scope)				560		**560**
Bogue	GT11 Transformer Replacement	500			509		**1,009**
GAMG	Critical Capital Spares - Generation	2,725	2,149	1,910	3,843	1,211	**11,838**
GAMG	Industrial Heavy Duty Lathe				300		**300**
Hunts Bay	GT 10 and GT 5 Hot Gas Path Inspection	200	700	600			**1,500**
Hunts Bay	B6 Mini Overhaul	450					**450**
Hunts Bay	Plant Auxiliaries Rehabilitation		156	205	87		**448**
Old Harbour	Unit 4 Mini Overhaul	485					**485**
Renewables	Wood Stave pipeline repair program	1,000	918	1,018	1,718	1,018	**5,672**
Renewables	Turbine & Generator Overhaul			2,437	937	100	**3,474**
Renewables	Equipment Procurement and replacement		326	540			**866**
Rockfort	Major overhaul unit 1	3,900	430	4,204	364		**8,898**
Rockfort	Major overhaul unit 2		3,437	430	4,438		**8,305**
Rockfort	Plant Auxiliaries Rehabilitation		768	300			**1,068**
TOTAL		**18,564**	**16,510**	**13,644**	**22,208**	**13,277**	**84,203**

7.31. JPS has provided the implementation scheduling and project plans, technical factors, costing and potential benefits to justify the implementation of the proposed projects. The following provides a brief description of some of the larger projects. Details of the other projects are included in the Investment Plan.

7.4.1.1. Bogue Combined Cycle Major Overall Project Proposal

7.32. The Bogue combined cycle generating plant is operated as a base load unit. This CCG unit is comprised of 2x40 MW Frame 6B gas turbines (GT12, GT13), and a steam turbine (ST14) in a 2-on-1 configuration and as a peaking plant using several open-cycle gas turbines. GT 12 and GT 13 are gas turbine units of name plate rating 40 MW and are manufactured by General Electric Limited (GE). These units are classified as industrial frame units and are of the designated class.

7.33. GT 12 and GT13 were commissioned in 2002 and ST14 in 2003 to complete the combined cycle unit. The unit was operated on automotive diesel oil (ADO) until 2016 December when it was converted to dual fuel capability with natural gas as the primary fuel and ADO as a backup fuel. In 2009 an air inlet cooling system was installed which increased the capacity by 10MW.

7.34. JPS has indicated that one concern regarding the CCGT, is the obsolescence of the control system, but overall its assessment shows that this unit is in a relatively good condition (71%). They have indicated in the submissions that this will be addressed in the project.

Project Justification - GT 12 and GT 13 Hot Gas Path Inspections

7.35. A key justification factor is based on the original equipment manufacturer (OEM) requirement for a major overhaul and inspections after specific operating hours and/or starts. JPS submitted that the project will be carried out following the OEM instructions and according to JPS' experience in previous maintenance events.

Project Scheduling

7.36. JPS has proposed the following scheduling for the project:

Table 7.8: JPS Proposed Project Schedules

	GT 12 MOH	GT 12 HGP	GT 13 HGP	GT 13 HGP	ST 14 MOH
Activity					
Project Approvals, Funding	12/03/18	08/03/22	08/05/19	10/03/22	08/03/21
Tender Works	12/10/18	08/10/22	08/12/19	10/13/22	08/10/21
Confirm Vendors' Proposals	12/14/18	08/17/22	08/20/19	10/20/22	08/17/21
Bid Evaluation and reviews	12/17/18	09/05/22	08/23/19	10/27/22	08/27/21
Procurement of Parts	12/20/18	09/27/22	09/12/19	11/08/22	09/14/21
Delivery of Parts	04/29/19	01/15/23	01/08/19	02/21/22	01/15/21
Outage Kick off Meeting	05/01/19	01/22/23	01/15/20	03/19/23	02/01/22
Execution of Projects	08/01/19	02/20/23	02/08/20	04/02/23	02/14/22
Commission of Unit	08/28/19	03/25/23	03/12/20	05/20/23	03/25/22
Close Project	09/16/19	05/04/23	05/07/20	06/14/23	04/18/22

Project Cost Estimate

7.37. JPS has submitted a project total cost estimate of US$32,017,000. JPS asserted that the costing methodology included the equipment quantities, unit prices and labour resources which were estimated based on the methodology outlined in Table 7.9, and detailed in the associated Excel workbook.

Table 7.9: Project Costing Methodology

Total Cost	**Total : US$32.017,000**
Costing methodology	Equipment quantities, unit prices and labour resources were estimated based on the following: 1. Expert judgement: Subject matter experts estimates and engineers' estimates 2. Historical data 3. Competitive Bidding 4. Project documents from past projects of similar nature: budget sheet templates, 5. Proposal from suppliers 6. Labour rates for JPS staff
Cost Details	The Project costing details are outlined in accompanying Excel book

Project Benefits

7.38. JPS identified the benefits shown in the table below

Benefits	Maintaining CC Plant Heat Rate Target of < 9,000 kJ/kWh. Surpassing Station EAF of 95% in order to provide continuous supply of electricity to customers and mitigate possible load shedding Maintain a stable power quality to customers Maintaining Station EFOR KPI of <2%. Improve the reliability of the unit in order to provide continuous operations until next maintenance intervention.

7.39. To estimate the monetary benefits of avoiding performance deterioration, associated with the proposed maintenance projects, JPS made the following assumptions:

- The major overhaul cannot be postponed indefinitely. Since the project covers the 2019- 2023 period, it is considered that the next overhaul would take place in 2026.
- Heat rate deterioration associated with non-execution of the programmed overhauls is considered to be 2% for the first period (2019-2022) and 3% for the second one (2023- 2025).
- The average price for the diesel oil is 0.8 USD/liter.

7.40. Using such assumptions, JPS' formula to determine the fuel cost savings is:

$$Cost\ Savings\ (USD\ Year/) = Avoid.\ deterioration\ (p.u) * Avg.\ H.R.\ (kJ\ /kWh) * Total\ production\ (kWh\ year/) * (1\ /(Fuel\ calorific\ value\ (kJ\ /liter)) * Fuel\ Price\ (USD/\ liter).$$

7.41. In computing the cost of not carrying out the prescribed overhaul, JPS cited a paper, "Reliability of Critical Turbo/Compressor Equipment" developed by H. Paul Barringer and Michael Kotlyar. JPS' cost computation took into account the deterioration in the components of the hot gas path of the gas turbine, which can significantly increase the probability of catastrophic failure of such components, leading to prolonged outages with the attendant costs.

7.42. Based on the following assumptions, JPS estimated the monetary impacts of postponing the projects. In case of failure, JPS assumed that:

- The cost of repairing is 20% higher than the cost of the major overhaul (7.54 MUSD), due to urgency reasons;
- The generator needs to be out of service for 3 months (with the associated consequences in the total dispatch costs);
- The additional dispatch costs due to unavailability of GT12, GT13 or ST14 has been calculated as 77,666 USD/day.

$$Reliability\ benefits\ (USDyear) = (Pr.fail\ without\ OH - Pr.failwith\ OH) * (Repair\ Cost\ (USD) + Add.dispatch\ costs(USDday) * 90\ days).$$

7.43. JPS asserted that associated with each programmed overhaul, there is a scheduled outage which duration was indicated above. This outage, in turn, increases the dispatch costs.

Using the same hypothesis as in the case of the repair, this scheduled outage has an associated incremental cost in the dispatch of 77,666 USD/day in the case of GT12 and GT13, and 108,852 USD/day in the case of ST14.

7.44. The following details the project viability based on the perceived project benefits and costs.

JPS Financial Economic Analysis and Cost-Benefit Analysis Model	The financial economic analysis and cost-benefit analysis are outlined in the Excel book provided. **NPV**: $5,834,347.15 at 12.12% discount rate **IRR: 36.81 %**

7.4.1.2. Rockfort Units 1 & 2 Rehabilitation Projects

7.45. Rockfort Power Station comprises two barge mounted slow speed generating units, Rockfort 1 and 2, each of 20 MW, utilizing HFO.

Table 7.10 Rockfort Units 1&2 Data

	Make		**Date**	**Capacity**
Unit	**Engine**	**Generator**	**COD**	**MCR**
RF 1	Mitsubishi	Medinsha	1985	20.0
RF 2	Mitsubishi	Medinsha	1985	20.0

7.46. JPS plans to carry out a major overhaul on each unit during the Rate Review period. JPS has submitted the project details consistent with the requirements of the Final Criteria. Both projects have similar characteristics, and where there are differences, these will be provided for the individual units.

7.47. Table 7.11 provides some of the details on the project.

Table 7.11: Rockfort Units 1& 2 Project submission summary

Justification	Rockfort Unit No. 2 has been in operation over 34 years and so regular maintenance is necessary for efficiency. Components within the Main Engine are subject to significant levels of wear based on the operating regime. The OEM recommends 12,000 hours between overhauls to sustain reliable operation. With experience, JPS has managed to increase this limit to 16,000 hours. Exceeding this limit will place the asset at high risk which could result in catastrophic failure as these components have exceeded their useful life and are now displaying significant wear and fatigue. Some key areas that will be affected are: (a) Impaired Generation Thermal Heat Rate Target (b) Generation Reliability (Availability & Forced Outage Rate) (c) Preservation of Shareholders' value in generation assets & JPS Generation Production Share (d) HSE, Failure of critical components impacting equipment & personnel.

	This Maintenance Project is expected to provide reliable base load power to the grid until the unit is retired and a suitable replacement is commissioned.
Scale and Scope	**Segment**: Generation **Area**: Rockfort Diesel Station **Scope:** Rehabilitation of cylinder assemblies, restoration of main bearing, X-head bearing & pin; Turbo-Charger life extension & Main Generator inspection. Other scopes will entail main engine block repairs (in situ) and critical supporting balance of plant equipment.
Timing	**Unit 1 Project duration**: Duration of the Outage is set at **35 days** per year in 2020 and 2022, breaker-to-breaker. **Start date**: January 18, 2019 and January 18, 2021 **End date**: February 23, 2019 and February 23, 2021 **Unit 2 Project duration**: Duration of the Outage is set at **35 days** per year in 2020 and 2022, breaker-to-breaker. **Start date**: January 18, 2020 and January 18, 2022 **End date**: February 23, 2020 and February 23, 2022

7.48. The project costing methodology is consistent with the costing methodology for other generation projects. The project benefits identified by JPS include the following:

- Sustain good unit/station heat rate performance (<9,070 kJ/kWh);
- Contributing to station availability target (>90%);
- EFOR below 6%;
- Sustain good generation support for the Corporate Area;
- Opportunity to implement risk mitigation recommendations from annual risk survey;
- Opportunity to implement life extension and performance enhancing activities;
- Opportunity to improve and refurbish specialized areas;
- Statutory generator protection system calibration and certification due.

7.49. Since this project falls within the category of minor projects, in accordance with the Final Criteria, JPS was not required to conduct a cost benefit analysis.

7.4.2. JPS' Proposed Transmission System Capital Investment Plan

7.50. JPS has proposed the implementation of a transmission capital investment plan covering all its transmission system and plant locations for the Rate Review period. JPS has stated that the objective of the transmission line improvement programme is to:

- Improve structural integrity;
- Address grid deficiencies;
- Improve overall reliability of transmission lines; and

- Ensure safety of operations, complying with statutory obligations under the relevant legislation.

7.51. The replacement of defective poles and hardware as well as the rehabilitation of wood and steel poles seek to address and improve the integrity of the transmission line system.

7.52. JPS has also asserted that the substation improvement programme will include:

- Life extension measures to include rehabilitation works on power transformers, tap changers and support structures; and
- Replacement of aged and problematic equipment such as power transformers, circuit breakers to improve the overall health of a substation.

Transmission Expansion and Upgrade

7.53. The strategy for grid security and stability is centred on JPS' transmission system expansion, upgrades and related initiatives to meet the growing needs of customers. JPS has proposed the installation of the following assets:

Major Projects - Efficiency

- Old Harbour to Hunts Bay 138 kV Transmission Line

Minor Projects - Efficiency

- Bellevue to Roaring River 69 kV Transmission Line
- Transmission Line Structural Integrity Programme
- Substation Structural Integrity Programme
- Protection Upgrade and Modernization (N-1)
- SMART Centralized Remedial Action Scheme (RAS)
- T&D Tools and Equipment
- Old Harbour 190 MW Grid Interconnection
- Michelton Halt (LILO)
- Inter-bus Transformer replacement and upgrades.

Substation	Description	Completion Date
Old Harbour	60/80 MVA transformer 138/69 kV	2021
Bogue	80/100 MVA transformer 138/69 kV	2022
Tredegar	60/80 MVA transformer 138/69 kV T1	2023
Tredegar	60/80 MVA transformer 138/69 kV T2	2023

7.54. In the 2014-2018 period, JPS invested US$185M in the network. JPS is now proposing an expenditure of US$90.937 million or 19% of overall capital expenditure of US$478.78

million to support transmission infrastructure upgrade. Table 7.12 shows JPS' proposed capital expenditure for each project.

Table 7.12: JPS' Proposed Capex Expenditure for 2019 - 2023

Total Capex (US$'000')							
Business Unit	**Project Name**	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
Engineering	Old Harbour - Hunt's Bay 138 kV Line	154	1,670	6,730	13,700	14,862	**37,116**
Energy Delivery	Tx Line Structural Integrity	1,800	1,770	1,870	1,858	1,839	**9,137**
Engineering	Energy Storage	9,110					**9,110**
Engineering	Sub Station Structural Integrity	1,553	1,700	1,753	1,830	1,870	**8,706**
Engineering	Bellevue - Roaring River 69kV line		500	3,170	3,089		**6,759**
Engineering	N-1 Protection Upgrade	1,106	1,365	1,365	1,365	1,365	**6,566**
Engineering	Interbus Transformers	200	1,670	3,024	302	1,302	**6,498**
Engineering	Protection Remedial Action Scheme		1,080	1,890			**2,970**
Engineering	Michelton Halt (LILO)	1,817					**1,817**
Engineering	Tools and Equipment	159	277	285	294	303	**1,318**
Engineering	Old Harbour 190 Grid Interconnection	739	200				**939**
TOTAL		**16,638**	**10,232**	**20,087**	**22,438**	**21,541**	**90,936**

7.55. The following provides a brief description of some of the larger projects. Details of the other projects are outlined in the Investment Plan.

Old Harbour to Hunts Bay 138 kV Transmission Line 43 Km

7.56. This project involves the construction of:
- A 138kV transmission line from Old Harbour to Kingston;
- Upgrade of the 69kV transmission line from Duhaney to Hunts Bay; and
- Re-conductor of the 138kV transmission line from Old Harbour to Tredegar.

7.57. According to JPS, the new transmission line will improve the grid security and reliability as well as provide the necessary voltage support. JPS has justified the project on the basis that its implementation will solve the following current and incipient problems on the transmission system, and greatly improve the efficiency and security of the power system.
- Inadequate connectivity of the large Corporate Area load centre to the generation centre at Old Harbour.
- The current bottle-neck situation at the Duhaney substation through which power is imported into the Corporate Area.

- The retirement of the Hunts Bay B6 unit scheduled for 2020 (MCR - 68 MW), JPS' Rockfort units (MCR- 40MW) and the JPPC unit scheduled for 2023 (MCR) 61.3 MW). Given these expected plant retirements, JPS has posited that the current situation will worsen, and as such there will be a need for additional transmission lines to be in place to import power into the Corporate Area.
- The long lead time to add baseload generation and the period between when B6 is retired in 2020 and new generation required by 2023 expose the grid to significant stability risks.

7.58. The OUR notes that JPS has also intimated that this project aligns with the IRP, Transmission Expansion Plan and the JPS power system plan.

7.59. The project is estimated to cost US$37,116,000 and spans the entire Rate Review period. The company asserted that US$1,824,000 will be used to develop the detailed designs, permits and approvals, easements and studies, so that an accurate costing for the complete project can be determined. In developing its costing methodology, JPS stated that the Applicable Design and Construction Standards were used to determine all major equipment and material required and that prices were estimated from previous projects to determine unit costs.

7.60. JPS has quantified the project benefits as follows:

- US$20.708 million per year in avoided dispatch cost due to out of merit dispatching of generating units in order to preserve the grid security under the operating requirement constraint of an N-1 contingency scenario.
- JPS' computation has determined that with the implementation of the project, a 0.25% loss reduction is observed, which translates to 6,200 MWh per year. JPS, however, did not choose to put a monetary value on this level of loss reduction.
- While not specifically stating the monetary benefit of the improved reliability, JPS pointed out that by increasing the number of transmission lines linking the Corporate Area with the rural area, the transmission network will be vastly improved from both reliability and grid security standpoints. However, JPS did not offer analyses to support this position.
- JPS also asserted that significant voltage improvements will be achieved at highlighting substations in the Corporate Area and St. Thomas. These are shown in Table 7.13 below.

Table[CJ1] **7.13: Voltage Improvement Due to OH-HB 138 kV Line**

Duhaney – 2.06%, Washington Boulevard – 3.16%, Naggos Head – 3.16%, PAJ – 3.13%, Constant Spring – 2.11%, West Kings House Road – 3.19%, Hope – 3.19%, Three Miles – 3.16%, Greenwich Road – 4.21%, Up Park Camp – 3.16%, Hunts Bay – 3.13%, Rockfort – 3.16%, Cane River – 4.30%, Good Year – 4.49% and Lyssons – 4.49%.

7.61. The results of JPS' Cost Benefit Analysis for the Project are displayed in the box below.

JPS Financial Economic Analysis and Cost-Benefit Analysis Model	The financial economic analysis and cost-benefit analysis are outlined in the Excel book provided. **NPV**: $121,591,827.28 at 12.12% discount rate **IRR: 49.54 %**

Bellevue to Roaring River 69kV Transmission Line

7.62. JPS has proposed to build a 15 km 69 kV transmission line in the parish of St. Ann from the Bellevue to Roaring River substations at an estimated cost of US$6,759,092. The project is slated to last for 32 months from 2020 March to 2022 December.

7.63. JPS has sought to justify the construction of this line as the preferred solution to resolve what JPS claimed to be the pervasive and persistent low voltage conditions affecting the Roaring River and Bellevue areas. JPS has further stated that in case of a failure of this line, in peak conditions, up to 31 MW of demand has to be shed, in order to keep voltages within acceptable limits.

7.64. Furthermore, JPS has pointed out that the possibility exists for a partial blackout of the power grid, if either the Bellevue – Lower White River or the Duncan's Rio Bueno transmission line is out of service for planned maintenance, and either of these transmission lines trips offline.

7.65. JPS affirmed that the construction of the new 69kV Transmission Line will lead to significant improvements in Bus Voltages, when either the Bellevue - Lower White River (LWR) or the Duncan's Rio Bueno 69 kV transmission line trips offline.

7.66. JPS has stated the following benefits:

- Compliance with the Electricity Act, 2015 and Grid Code for Transmission System Security Standards TC 4.4 and TC 8.3 & TC 8.4.8
- Increased reliability and quality from N-1 contingencies – single forced outage
- Customer retention/Customer Growth
- Improved grid stability with upgraded substation design
- Reduction in customer claims due to low voltages
- Improvement in T&D technical losses (reduction)
- Penalty avoidance: reduction in Regulatory penalties (Losses, Q-Factor, Guaranteed Standard)
- Improved asset management: ability to maintain critical lines and equipment

7.67. According to JPS, a quantification of the benefits of the project gave the following results:

- Total loss reduction of 1,657.4 $MWh/year$
- Approximately 138.5 MWh/year of avoided energy not served (ENS).

JPS' Proposed Distribution System Capital Investment Plan

7.68. For the Rate Review period, JPS is proposing the implementation of twelve (12) distribution system projects totalling US$152.55M. This represents approximately 32% of the total Capex budget. Eight (8) of these projects are classified as major projects. The distribution business segment consumes the largest share of JPS' proposed capital expenditure for the period.

7.69. The proposed list of projects and the capital expenditure are shown in Table 7.14 below.

7.70. The stated benefits of implementing the distribution system capital investment plan are to:

- Improve Customer Satisfaction
- Ensure 95% compliance with G.S.3
- Improve Power Quality & Reliability to customers

- Reduction in inventory costs
- Reduction in Technical Losses
- Reduction in subcontractor costs
- Support Customer Growth

Table 7.14: JPS' Proposed Distribution System Capital Investment Plan

		Total Capex (US$'000')					
Business Unit	**Project Name**	**2019**	**2020**	**2021**	**2022**	**2023**	**JPS Total**
Energy Delivery	Customer Growth (CCMA)	6,800	6,000	5,000	7,000	6,000	**30,800**
Engineering	Smart Streetlight	8,400	8,994	6,984	-	-	**24,379**
Energy Delivery	Distribution Structural Integrity	3,771	4,489	4,564	4,763	4,822	**22,409**
Engineering	Voltage Standardization Program (VSP)	1,975	3,496	3,254	4,239	4,628	**17,593**
Energy Delivery	Meters & Service Wires (Replacement and	3,026	2,294	2,723	2,806	2,890	**13,740**
Engineering	Grid Modernization Program (FCI, DA, Trip Savers)	1,784	2,092	2,827	2,968	2,864	**12,534**
Energy Delivery	Distribution Line Reconductoring and Relocation	2,000	1,345	2,173	2,084	2,405	**10,007**
Engineering	Distribution Transformers	3,008	2,848	2,243	1,635	361	**10,094**
Energy Delivery	Replace Pole Mounted Transformers	1,402	944	963	1,013	1,028	**5,350**
Engineering	Capital Spares T&D (Cct Breaker, Reclosers)	452	475	498	523	549	**2,497**
Engineering	Grid Interconnection	358	376	395	415	435	**1,979**
Engineering	Replace Padmounted Transformers	212	223	234	246	258	**1,172**
TOTAL		**33,189**	**33,576**	**31,859**	**27,692**	**26,239**	**152,555**

7.71. The following provides a brief description of some of the larger distribution system projects. Details of the other projects are outlined in the Investment Plan.

JPS' System Losses Capital Investment Plan

7.72. For the Rate Review period, JPS proposed the implementation of four (4) losses programmes totalling US$104.55M. This represents approximately 22% of the total Capex budget. Two (2) of these projects are classified as major projects.

7.73. The proposed list of projects and the capital expenditure are shown in Table 7.15 below. The stated benefits of JPS' Loss reduction programme are as follows:

- Reduction in Energy Losses
- Reduction in Operating and Maintenance costs (reduced meter reading cost)

Table 7.15: Proposed System Losses Capital Investment Plan for 2019 - 2023

Total Capex (US$'000')							
Business Unit	**Project Name**	**2019**	**2020**	**2021**	**2022**	**2023**	**JPS Total**
Losses	Smart Meter Programme	21,700	17,970	20,142	17,273	8,193	**85,277**
Losses	Rami Projects	4,200	3,074	4,874	3,055	2,055	**17,259**
Losses	Check Meter	1,200					**1,200**
Losses	Meter Infrastructure Replacement		204	204	204	204	**815**
TOTAL		**27,099**	**21,247**	**25,219**	**20,533**	**10,452**	**104,550**

7.4.3. JPS' IT Systems Capital Investment Plan

7.74. JPS proposed several IT-based projects for consideration by the regulator as part of its Investment Plan. These thirteen (13) projects covered various applications including: software and hardware replacements, upgrades, efficiency and statutory works as well as internet and web applications to be accomplished over the duration of the Rate Review period. Table 7.16 shows the list of projects as well as JPS' proposed capital investments.

Table 7.16: JPS' IT Capital Investment Projects (US$'000)

Business Unit	Project Name	2019	2020	2021	2022	2023	Total
IT	Electric Grid Communication Network Rehabilitation and Upgrade	350	1,119	1,046	1,150	1,150	**4,815**
IT	Expansion of Enterprise Architecture, Business Intelligence and Analytics Capability	210	900	790	830	830	**3,560**
IT	IT Infrastructure Modernization	438	615	715	375	705	**2,848**
IT	Upgrade CS	-	200	1,400	1,200	-	**2,800**
IT	Enterprise Asset Management	970	850	750	-	-	**2,570**
IT	Business Efficiency	522	605	562	430	320	**2,439**
IT	Purchase of laptops, desktops, Tablets	-	440	440	440	440	**1,760**
IT	Information Technology Security Program	-	385	550	330	380	**1,645**

Business Unit	Project Name	2019	2020	2021	2022	2023	Total
IT	Phase 3 DMR Implementation & Radios for two-way Radios	555	-	-	-	-	**555**
IT	Data Centre Operations Modernization	-	-	275	220	-	**495**
IT	Unified Communications Platform	-	200	200	-	-	**400**
IT	Oracle Modification Project (Separation of Accounts)	-	200	150	-	-	**350**
IT	Build Network Operations Centre	-	-	-	-	336	**336**
System Ops	Replacement of OMS	-	1,126	1,000	-	-	**2,126**
System Ops	SCADA-EMS Project Upgrade	-	-	-	2,037	-	**2,037**
System Ops	Introduce DERMS	-	-	-	700	-	**700**
Total		**3,045**	**6,640**	**7,878**	**7,712**	**4,161**	**29,436**

7.75. JPS indicated that it spent a total of US$51.245M on IT-related projects over the period 2014 to 2018. For the Rate Review period, JPS intends to spend US$20.04M which will provide several benefits to JPS' IT infrastructure, data centres and enable the company to operate using improved business intelligence from information gleaned from applying various analytical tools of its data streams. Some of the projects are also to improve JPS' ability to keep its data, communication and control networks operating reliably and to also monitor the entire network's performance for outages, system performance and losses.

7.76. According to the Application and Business Plan, the IT projects are in keeping with JPS' thrust to take advantage of available technological solutions to solve problems, improve efficiencies and productivity in its operations, as well as provide improved direct service to its customers via Mobile App and Web Portal access.

7.77. The following provides a brief description JPS' largest proposed IT project. Details of the other projects are outlined in the Investment Plan.

<u>Business Efficiency Project</u>

7.78. This project proposes to both improve operational efficiency and seamless interactions with customers in the areas of:

- Self-service customer care
- Case Management
- Billing Exception Handling
- Field Operations
- IT Reporting Processes to Parish and Customer Care Teams

- Reduction in Inventory Carrying Costs and stale assets

7.79. JPS claims that this project will create the following products and services:

1) Unified Customer Service Platform consisting of:
   a. Customer Self Service Web Portal – www.jpsco.com
   b. Customer Mobile Application – myJPS mobile
   c. Customer Care and Experience Platform – Harmony
2) Streamlined Processes through integration and automation of key enterprise systems CIS, Work Management and Outage Management System to automate customer facing processes.
3) An employee enterprise mobility platform to carry out work anywhere on any device.
4) Use robotic process automation/digital workers to eliminate a significant number of manual customers facing workflows.

7.80. The following benefits are expected to be achieved:

1) Improved customer experience
   a. Increased visibility of the customer lifecycle and relationship management
   b. Improved reporting and tracking of customer cases
2) Reduction in costs associated with customer interaction channels
3) Reduction in number of breaches and associated pay-outs
4) To reduce inventory carrying costs and reduce the stock of stale assets

7.81. The project is estimated to cost US$3.812M, and is to be achieved over the Rate Review period. The component costing was outlined in an accompanying spreadsheet. JPS used a costing methodology which implies that the accuracy of the costs ranges between -50% to +75%.

7.82. In examining the supporting estimate and economic evaluation in the accompanying spreadsheet, the OUR saw that the spreadsheet cost-estimate was US$2.439M in both references. It is unclear what accounted for the difference of US$1.373M.

7.83. JPS presented the following result of its economic assessment of the project:

Discount rate	Net present value
%	**USD**
8.08%	$3,924,548.06
12.12%	$2,673,107.03
IRR	35.02%

7.4.4. JPS' General Plant Capital Investment Plan

7.84. The projects in General Plant are necessary to support JPS' other project initiatives or to support general operations of the company. These include the projects in Table 7.17 below.

Table 7.17: General Plant Capital Investment Plan for 2019 – 2023

Total Capex (US$'000')							
Business Unit	**Project Name**	**2019**	**2020**	**2021**	**2022**	**2023**	**JPS Total**
Finance	Funding for Unforeseen Projects	1,214	500	2,500	1,000	1,000	**6,214**
Facilities	Facilities Improvement	650	518	1,018	1,518	1,018	**4,724**
BD	Install Charging Stations (Electric Vehicle Roll ou)	500	592	400	-	-	**1,492**
Security	Security Cameras and System	200	255	255	250	241	**1,200**
Facilities	Battersea Operations Building Room for DTS & CEOC	161	1,000	-	-	-	**1,161**
System Ops	Repurpose of Old Control Room	-	-	-	-	1,018	**1,018**
Environment	Safety Devices and Monitoring Stations	200	-	-	-	-	**200**
Logistics	Transportation Equipment	225	224	-	-	-	**449**
System Ops	Video Wall Upgrade	-	49	-	292	-	**341**
IT	Build Network Operations Centre	-	-	-	-	336	**336**
TOTAL		**16,638**	**10,232**	**20,087**	**22,438**	**21,541**	**90,936**

7.5. OUR's Assessment of JPS' Investment Plan

7.85. This section presents the OUR's analysis, findings and recommendations to inform the determination of the approved Capital Investment Plan for the Rate Review period. The Investment Plan was assessed using the methodology outlined below.

Methodology

7.86. The methodology used for the review of the projects was as follows:

- Determine the classification of each project as described and verify that the information provided, meets the information requirements in Table 08 of the Final Criteria.
- Review each project proposal to identify the problems to be solved and/or goals to be achieved, and the role it plays in the Business Plan.
- Review the approach posited and investigate any alternative solutions where applicable.
- Review the proposed schedule, dependencies of, and on the project to determine implications of not doing the project or of delaying the project.
- Assess the reasonableness of project costs. The findings of the OUR's Consultant, the OUR's expert judgment and data supplied by JPS, such as invoices and/or quotations were used in conducting this assessment. For projects whose costs were evaluated by the OUR's Consultant, the OUR accepted JPS' project costs if it were within 10% of the OUR's Consultant's estimate. Otherwise, if the OUR's Consultant's estimate was lower, it was accepted along with reasons for doing so.

- Where applicable, assess JPS' valuation of the benefits of the proposed project to determine the accuracy of JPS' analysis so as to determine whether to proceed with the project.

7.87. While the project costs, including IDC, will be used for economic evaluation, the final project costs approved by the OUR to be included in the Rate Base will not include IDC. This is because the Licence requires that JPS earns returns on CWIP. The inclusion of IDC in the approved capital expenditure would result in double counting of returns. The OUR understands that in preparing its accounts, JPS is required to capitalize project costs as per IAS 32, but this is a matter for its financial accounting system.

7.88. The OUR's assessment is presented below by Business Segment.

7.5.1. Generation Capital Investment Plan

7.89. In addition to vetting the costs for the projects, the OUR's assessment methodology calculates the potential benefits of the capital maintenance projects on the enhanced operations of the units, including the heat rate reduction benefit, capacity improvements benefit, the equivalent forced outage rate (EFOR) and the equivalent availability factor (EAF) improvement due to the project implementation. In short, a system benefit impact approach was utilized. This approach computes the impact on the system by determining the cost of operating the system with the plant before, and the cost of operating the system with the plant after maintenance. The OUR also assessed the system reliability benefit by computing the probability of consumers' energy not being met due to poor reliability of the units. The reduction in the energy demand not served was monetized using the cost of unserved energy to the economy. The cost of unserved energy presented by JPS, is based on a study carried out by JPS' Consultants. This is US$4.77/kWh, where the cost of unserved energy is the cost to the economy of not supplying to the consumers that incremental energy when required. In order to value the cost benefit (valuation) of the projects the OUR used the net present value (NPV) investment model analysis deterministic approach, where the total value of the investments is the sum of future discounted benefits of the investment less the cost of the investments.

7.90. The results of these analyses, among other factors such as the relevance of the project, determined which projects qualify for scheduled investments, which ones could be deferred and the ones to disallow.

7.91. The OUR has reviewed the business cases submitted by JPS for all generation projects and is satisfied that the scope and details of the information supplied by JPS are consistent with the requirements of the Final Criteria for most project submissions.

<u>Extra-ordinary Maintenance – Routine Maintenance - *Bogue Combined Cycle Plant and Minor Projects – Replacement of Bogue Combined Cycle Plant*</u>

7.92. The scope of these projects include:

Table 7.18: Bogue CC Extra-ordinary Maintenance Projects

Scope	Cost (US$'000)	Schedule
<u>Extra-ordinary Maintenance – Routine Maintenance *Bogue Combined Cycle Plant*</u>	32,017	
GT12 Major Overhaul with Controls Upgrade		**2019 Aug - Sept** **2023 Feb – Mar**
GT13 HGPI and Controls Upgrade		**2020 Feb – Mar** **2023 Mar - Apr**
ST14 Major Overhaul with Controls Upgrade		**2022 Feb - Mar**
<u>Minor Projects – Replacement Bogue Combined Cycle Plant</u>		
Bogue Generation Air Chiller Major Overhaul	513	**2020 Apr - May** **2022 June - July**
HRSG cleaning	560	**2022 Feb - Apr**

7.93. The Bogue tcombined cycle plant is rated at 120 MW, and is a base load unit due to its relatively high efficiency.

7.94. JPS has asserted that based on the OEM requirements for the plant regarding the hours of operation accumulated since the last overhaul, the units are due for major overhaul within the period scheduled. The OUR has reviewed the benefits due to improved reliability of the plant and the monetization of reliability benefits based on equipment failure avoidance put forward by JPS and has no technical basis to challenge JPS' assumptions in this regard. The OUR also recognizes that should a premature catastrophic failure occur as a result of extending overhaul periods, then significant costs will be incurred, including: extraordinary outage/replacement costs and, economic costs due to supply curtailment resulting from capacity shortfall. Additionally, the OUR is also of the view that JPS' insurance claim position may be compromised.

7.95. The OUR concurs with JPS' view that in general, the consequence of not conducting major maintenance as per the OEM recommendations is the uncertainty over the future reliability of the units, the deteriorating performance and remaining useful life of the equipment.

7.96. The heat rate gain of between 2-3% claimed by JPS due to the proposed HGP works is acceptable and is consistent with the OEM expectations. However, JPS' fuel cost assumption of US$0.8 per litre is not representative of the unit's fuel cost. The plant no longer utilizes automotive diesel oil (ADO), but instead natural gas. The assumed price of US$0.8 per litre of fuel represents a fuel cost of over US$120 per barrel or US$20.7/MMBtu. The natural gas price provided by JPS is estimated at US$9.97/MMBtu. This discrepancy will result in a significant exaggeration of the heat rate monetary benefit due to the projects. Given the fuel type and fuel costs assumed, the OUR is also uncertain about the veracity of the magnitude of the additional dispatch costs of US$77,666/day in the case of GT12 and GT13 and US$108,852/day in the case of ST

14. Based the OUR's assessment, these costs should be of the order of US$38,000/day for GT12 and GT13 and US$54,000/day for ST 14.

7.97. The OUR has reviewed the capital cost data and invoices submitted to procure and install new parts and refurbish and replace existing deteriorated parts. The appropriate taxes and duties are included and the OUR is satisfied that the capital costs of the projects submitted by JPS are reasonable given the costs of past projects of similar nature.

7.98. JPS submitted its project model which demonstrated the viability of the project as shown below.

JPS' Financial Economic Analysis and Cost-Benefit analysis model	The financial economic analysis and cost-benefit analysis are outlined in the Excel book provided. **NPV**: $5,834,347.15 at 12.12% discount rate **NPV: 8,131,756.83 at 8.08% discount rate** **IRR: 36.81 %**

7.99. The OUR's analysis of the benefits of the projects indicated the following results.

OUR's Financial Economic Analysis and Cost-Benefit analysis model	The financial economic analysis and cost-benefit analysis are outlined in the Excel book provided[2]. **NPV**: $6,323,828at 11.78%% discount rate NPV: $8,643,9583 **IRR: 35.61%**

7.100. The OUR is satisfied that the major risks to the projects not achieving the desired outcome have been identified and mitigation strategies have been developed by JPS. The phasing of the maintenance activities in distinct phases will allow for managing of the critical activities of procurement, execution and commissioning. The early awareness and monitoring of the critical components of the units will serve to identify incipient failures and schedule outages on a timely basis. Adherence to the OEM recommended outages based on operating duties including operating hours and starts should reduce the risk of catastrophic failures. The early start of planning for procurement should reduce the risk of the outage being delayed or prolonged due to parts, equipment and service personnel arrival on site. JPS has been operating and maintaining these units and is therefore adept at carrying out the recommended outages. However, it was not clear if the OEM or other suppliers will provide warranties or guarantees for parts and services.

[2] The discount rate is based on the OUR's initial estimate of the ROE

7.101. Based on the outcome of the OUR's review of the justification for the projects, cost and benefit analyses, the financial models, the risk assessment and mitigation strategies proposed, the OUR has no objection to the projects as submitted.

Extra-ordinary Maintenance – Routine Maintenance *Generation Critical Capital Spares and Balance of Plant Programme*

7.102. This project involves the procurement of critical spares for generation units over the Rate Review period.

7.103. The OUR is of the view that adequate critical spares and equipment should be available to perform maintenance works on the units in a timely and cost-effective manner to ensure plants' availability to meet demand.

7.104. The OUR is, however, concerned that the planned retirement of the Old Harbour units and the Hunts Bay B6 unit at the end of 2020, and a further 171 MW of JPS' plant, including Rockfort 1 and 2, especially in the context of the absence on an IRP, may lead to stranded critical spare assets. Based on the Minister's Retirement Schedule, the remaining JPS-owned thermal generating assets beyond 2023 would consist of the Bogue 120 MW Combined Cycle plant and GT 11 at the Bogue power station. Notwithstanding, the OUR understands that Hunts Bay B6 will be in service up to the end of 2020 and expects that Rockfort 1 and 2, GT 11 and Bogue 120MW plant will be in service during the Rate Review period. As such, critical spares for these units will be required. Critical spares for Old Harbour will not be approved, as in accordance with the Minister's Retirement Schedule for JPS' plants, this plant should have been retired in 2019.

7.105. The OUR therefore approves the project, but will reduce its costs by removing the procurement of critical spares for Old Harbour.

Minor Project – Replacement *Bogue Gas Turbines Overhaul*

7.106. The scope of this project is provided in Table 7.19

Table 7.19: Bogue Gas Turbines Overhaul Projects

Scope	Cost (US$'000)	Schedule
GT 3 Hot Gas Path Inspection (HGPI)	700	2021 Jun – July
GT 6 GG Major Overhaul GT 7 GG Major Overhaul GT 9 GG Major and Generator Rotor Overhaul	3300	2022 Sep - Oct 2021 Jun – July

7.107. The aero-derivative units are peaking units, which are required to fast start and operate to avoid load shedding. The absence of these units or unreliable starts will significantly impact JPS' ability to meet the demand during peak load periods and during times of forced outages of base load units. The OUR has no objection to the implementation of the projects as submitted.

7.108. The OUR has no objection to the costing proposed by JPS, as the company's supporting information and the OUR's expert judgement indicated that the cost is reasonable.

Minor Project – Replacement *Bogue Gas Turbines Overhaul*

7.109. The scope of this project consists of:

Scope	Cost (US$'000)	Schedule
GT11 Hot Section Inspection	2800	**2023 Feb – Mar**
GT 11 Transformer Replacement	500	**??**

7.110. This unit has been operating on natural gas since 2018 and based on expected operating hours, the unit is due for maintenance intervention in 2023. Based on the addition of the new 192 MW SJPC generating units and the Jamalco 94 MW CHP unit, the OUR is of the view that this unit will be largely restricted to peaking duty, thus reducing the operating hours but increasing the starts frequency. Given the importance of maintaining the high availability of the unit and its extended lifetime, the OUR has no objection to the scope, timing and cost of the works proposed.

7.111. With respect to the replacement of GT 11 transformer which JPS included in the project submission summary, the OUR's examination of the submission did not reveal information pertaining to this project. However, the OUR has discovered that recent work was on GT11 would have included such a transformer. As such, the cost associated for the transformer has already been captured in the Rate Base for 2019. The OUR has therefore disallowed the proposed US$491,000 associated with the transformer.

Minor Project – Replacement *Hunts Bay Plant*

7.112. The scope of these projects includes:

Scope	Cost (US$'000)	Schedule
Plant Auxiliaries Rehabilitation	448	**2020 Oct - 2021Aug**
Hunts Bay GT 5 major overhaul	1,500	**2019 Oct - 2020 Aug**

7.113. The location of these units in the island's load centres along with their quick start and fast acting spinning reserve capabilities provide peak load shaving, grid stability and voltage support, making them an integral part of the safe and stable operation of the grid. Given the importance of maintaining the high availability of the GT 5 unit and its role in grid stability and black start capability, in principle, the OUR has no objections to the scope, and cost of the works proposed.

7.114. The OUR is however of the view that with the impending retirement of the Hunts Bay B6 unit, and the proposed retirement of GT 5 and GT 10 by 2023, the Hunts Bay station will be out of operation as a generating station by 2024. The rehabilitation works on the station auxiliaries should, therefore, be reviewed in this context. In this regard, the OUR does not support the implementation of the Plant Auxiliaries project at this time.

Minor Project – Replacement *Rockfort Power Station*

7.115. The scope of these projects includes:

Scope	Cost (US$'000)	Schedule
Rockfort Unit 1 major overhaul	8,896.7	**2019 Jan18 –Feb 18**
Rockfort Unit 1 major overhaul	8,305.3	**2021 Jan 18-Feb 23**
Rockfort plant auxiliaries rehabilitation	1,068	**???**

7.116. Rockfort Power Station comprises two slow speed Diesel barge-mounted generating units, Rockfort Units 11 and 12, each of 20 MW capacity. The units were commissioned in 1985. The units utilize HFO and due to their high efficiencies are operated in a base load mode.

7.117. The OEM recommends 12,000 to 16,000 hours between overhauls to sustain reliable operation. Exceeding this limit can expose the units to high risks of failure, which could result in catastrophic outage.

7.118. JPS has asserted that carrying out the overhaul as submitted will provide heat rate improvements, reliability benefits due to reduced forced outages on the units, and avoided failure costs.

7.119. Based on the requirement of the Final Criteria, JPS was not required to provide a financial model given that the cost of each project did not exceed US$10 million. However, in assessing the projects, the OUR evaluated them as a batched project. The OUR is of the view that batching the project for evaluation is suitable given that the units are identical, and are at the same location. The OUR has carried out an economic evaluation of the projects to determine their economic viability in terms of their cost and benefits.

7.120. The outcome of the evaluation, which is given below, indicates that the project is viable.

OUR Financial Economic Analysis and Cost-Benefit Analysis Model	The financial economic analysis and cost-benefit analysis are outlined in the Excel book provided. **NPV**: $1,550,996 at 11.78% discount rate NPV: $2,491,755 **IRR: 22.92 %**

7.121. The OUR considers that undertaking the capital projects as described will maintain the ability of the system to:

1) Provide safe and reliable service to consumers by reducing the risk of catastrophic failure of key system components by upgrading and repairing components of the generating system to allow for sustained efficient operation.
2) Meet existing and new customers' demand.
3) Meet key performance indicators (KPI).

7.122. The OUR has no objection to the implementation of the Rockfort Units 1 and 2 projects as submitted.

7.123. The OUR has examined JPS' submission regarding the Rockfort plant auxiliaries rehabilitation projects and a number of inconsistencies in the scope of the projects were identified. The inconsistencies include the listing of items in the scope of the rehabilitation that are not related to the Rockfort plants. Consequently the projects are not approved at this time. JPS is requested to submit greater and more accurate details. Furthermore, given the expected retirement of the units based on the generation retirement schedule specified by the Minister with responsibility for Electricity on 2019 September 6 (the "Minister's Retirement Schedule"), the OUR will need to be convinced of its necessity in light of the expected Retirement.

Minor Project – Replacement *Renewables Hydro Plants Turbine and Generator Overhaul*

7.124. The scope of this project includes:

Scope	Cost (US$'000)	Schedule
Upper White River hydro plant	3,474	**2021 Apr – Dec**
Lower White River hydro plant		**2022 Apr – Dec**
Rio Bueno A hydro plant		**2021 Apr – Dec**

7.125. In keeping with the submission requirements of the Final Criteria, JPS submitted a project risk assessment and accompanying mitigation strategies. These are similar to the submissions made in regard to the other generation maintenance projects submitted by JPS.

7.126. The OUR has examined JPS' submission regarding the Renewable Generation Equipment Procurement and Replacement project and is satisfied that the information submitted is in keeping with the requirement of the Final Criteria for projects of the cost magnitude of the proposed project scope of work.

7.127. Based on the scope and costs of this project, JPS was not required to submit a project evaluation model. However, in its due diligence process, the OUR carried out a cost benefit assessment of the project to ensure that value is being created for the customers.

7.128. Table 7.20 below details the assumptions and parameters used by the OUR regarding the impact of the hydro plant projects on the generating system operations.

Table 7.20: Hydro Plants Project Benefits

Proposed Project costs	$ 10,012,000
20-Year Period Savings in Dispatch Costs due to Projects	$ 25,352,078
Total Benefits	$ 25,352,078
Benefit - Costs	$ 15,340,078
Discount Rate (Post Tax)	7.85%
Project NPV (Post Tax)	**$ 3,082,858**
Project IRR	**14.5%**

7.129. The last major overhaul and control systems upgrade on the hydro plants was carried out between 2001 and 2003. Historically, JPS-owned hydro plants have operated at relatively high capacity factors, in spite of being run-of-the-river plants. Hydro plant generation has averaged 146,000 MWh annually. This represents approximately 3.3% of system net generation. One of the main benefits of hydro generation is the displacement of imported fuels. These plants contribute to the renewable portfolio and assist the country to meet the mandated renewable energy target and assist to mitigate environmental impact of power generation.

7.130. Based on the average fuel price assumed over the Rate Review period, the hydro plants are expected to displace about US$16.8 million of imported fuel per annum. Given the benefits of the hydro plants to the system and the fuel replacement benefits, the OUR has no objection to the implementation of these projects as per submission.

Minor Project – Replacement *Wood stave pipeline repair program*

7.131. The scope of this project includes:

Scope	Cost (US$'000)	Schedule
Wood stave pipeline repair program	**5,672**	
Upper White River hydro plant		**2021 Apr – Dec**
Lower White River hydro plant		**2022 Apr – Dec**
Rio Bueno A hydro plant		**2021 Apr - Dec**

7.132. The OUR's assessment of this project is similar to the Renewables Hydro Plants Turbine and Generator Overhaul project. The OUR has no objection to the implementation of these projects as per submission.

Minor Project – Replacement *Renewable Generation Equipment Procurement and Replacement*

7.133. The scope of this project includes:

Scope	Cost (US$'000)	Schedule
	866	
Rio Bueno A hydro plant de-silting and trash rack replacement		**2023 Feb-Dec**
Maggotty A hydro plant intake de-silting and steel penstock		**2023 Feb-Dec**
Lower White River hydro GSU Transformer Procurement		**2020 Feb-Dec**
Renewables – Upper White River Remote Control Centre		
Infrastructure replacement Constant Spring turbine runner procurement.		**2021 Feb-Dec**

7.134. The OUR's assessment of this project is similar to the Renewables Hydro Plants Turbine and Generator Overhaul project. The OUR has no objection to the implementation of these projects as per submission.

Minor Project – Replacement Procurement of an Industrial Lathe

7.135. This project involves the procurement of an Industrial Lathe at a cost of US$300,300 in 2022.

7.136. The OUR is of the view that sufficient justification for the acquisition of a new lathe was not provided. The OUR is also of the view that the impending retirement of a significant portion of JPS-owned capacity would significantly reduce the need for this piece of equipment. The ability to undertake work from external entities as asserted by JPS is not considered a function of the regulated business and does not qualify for consideration under the Rate Review. The OUR rejects this procurement at this time.

Minor Project – Old Harbour Mini Overhaul

7.137. This project involves a mini overhaul on the Old Harbour plant in 2019. JPS proposed a project cost of US$485,000.

7.138. JPS did not provide a business case for the project, so the OUR is unable to understand the justification for the project given that the plant was slated for retirement in early 2020. The OUR had also awarded JPS accelerated depreciation on assets to be installed up to 2019.

7.139. The OUR does not approve this project because JPS has provided no basis for its implementation.

Approved Capital Expenditure for Generation Projects 2019 – 2023

7.140. Table 7.21 below shows JPS' proposed capital expenditure for generation projects versus the OUR's approved capital expenditure. These costs do not include IDC as explained earlier.

7.141. JPS' proposed capital expenditure is indicated as US$82.7M (excluding IDC), while the OUR's capital expenditure is US$78.8M. The differences arose from the following:

- Removal of Old Harbour Critical Spares costs from the Critical Spares Project;
- Removal of the cost of Rockfort Plant Auxiliaries Project;
- Removal of the cost of Industrial Lathe Project;
- Removal of the cost of the Old Harbour mini overhaul;
- Removal of the GT11 transformer replacement.

DETERMINATION #4

The Office's approved capital expenditure for generation projects/programmes during the Rate Review period is detailed in Table 7.21 below.

Table 7.21: JPS' Proposed versus OUR's Approved Capital Expenditure for Generation Projects for the Rate Review Period

Generation Capital Projects	JPS Total Project Cost (US$'000)	JPS Proposed CAPEX (no idc) (US$'000)					OUR Approved Total Project Cost (US$'000)	OUR Approved CAPEX (no idc) (US$'000)				
		2019	2020	2021	2022	2023		2019	2020	2021	2022	2023
Combine Cycle Plant	**31,451.95**	9,140	5,514	-	8,794	8,004	**31,451.95**	9,140	5,514	-	8,794	8,004
Critical Capital Spares-Generation	**12,218.39**	2,677	2,700	1,876	3,775	1,190	**11,085**	2,677	2,738	1,555	3,129	986
Rockfort Major Overhaul - RF 1	**8,740.02**	3,831	422	4,129	357	-	**8,740**	3,831	422	4,129	357	-
Rockfort Major Overhaul - RF 2	**8,158.05**	-	3,377	422	4,359	-	**8,158**	-	3,377	422	4,359	-
Renewables - Woodstave Pipeline Repairs Program	**4,983.99**	982	313	1,000	1,688	1,000	**4,984**	982	313	1,000	1,688	1,000
Renewables - Turbine & Generator Overhaul	**3,412.62**	-	-	2,394	920	98	**3,413**	-	-	2,394	920	98
Bogue Peaking-Plants	**3,241.73**	-	1,474	1,277	491	-	**3,242**	-	1,474	1,277	491	-
Bogue - GT11Overhaul	**2,750.56**	-	-	-	-	2,751	**2,751**	-	-	-	-	2,751
Hunt's Bay - GT10 and GT 5 Hot Gas Path Inspection	**1,473.52**	196	688	589	-	-	**1,474**	196	688	589	-	-
Bogue - Inlet Air Chiller Major Overhaul	**1,033.44**	-	504	-	529	-	**1,033**	-	504	-	529	-
Rockfort - Plant Auxiliaries Rehabillitation	**1,049.14**	-	754	295	-	-	**-**	-	-	-	-	-
Renewables Equipment Procurement and Replacement	**837.04**	-	320	517	-	-	**837**	-	320	517	-	-
Bogue - GT3 Overhaul	**700.00**	-	-	700	-	-	**700**	-	-	700	-	-
Bogue -HRSG Cleaning (Reduced scope)	**500.25**	-	-	-	500	-	**500**	-	-	-	500	-
Bogue - GT11 Transformer Replacement(GSU)	**491.00**	491	-	-	-	-	**-**		-	-	-	-
Old Harbour Unit 4 Mini Overhaul	**476.44**	476	-	-	-	-	**-**	-	-	-	-	-
Hunt's Bay B6 Mini Overhaul	**442.05**	442	-	-	-	-	**-**	-	-	-	-	-
Hunt's Bay - Plant Auxiliaries Rehabillitation	**439.22**	-	153	201	85	-	**439**	-	153	201	85	-
Industrial Heavy Duty Lathe	**294.70**	-	-	-	295	-	**-**	-	-	-	-	-
TOTALS	**82,694**	**18,236**	**16,219**	**13,402**	**21,795**	**13,043**	**78,808**	**16,826**	**15,503**	**12,786**	**20,854**	**12,839**

7.5.2. Transmission System Capital Investment Plan

7.142. Within the electric power industry, the security of the power grid is always a matter of grave concern for regulators, system operators, and other stakeholders. This is becoming even more relevant given the cyber-attacks that electric power utilities have been experiencing in several countries in the recent past. Therefore, as a part of their business planning process, electric utilities, have been making provisions with regard to grid security.

7.143. Schedule 3 of the Licence states that the JPS' Business Plan shall include provisions for grid security. However, 'Grid Security' was not defined in the Licence.

7.144. Grid Security was also not defined in the Jamaica Electricity Sector Book of Codes (The Codes). However, in both the Despatch and Transmission Codes, sub-subsection TC 3.12.1 of the Transmission Code stated that "the System Operator shall conduct Transmission System planning studies consistent with the planning process and established planning criteria to ensure the safety, reliability, security and stability of the transmission system". The aspect of the system (grid) security that the Code mentioned, however, is more representative of physical infrastructure failures, equipment failure, system faults, and the ability to operate within prescribed limits of voltage, frequency and equipment loading limits under normal and specified contingency conditions. In carrying out the assessment of JPS' transmission system capital investment plan, grid security in the context of the transmission system planning studies was a major consideration.

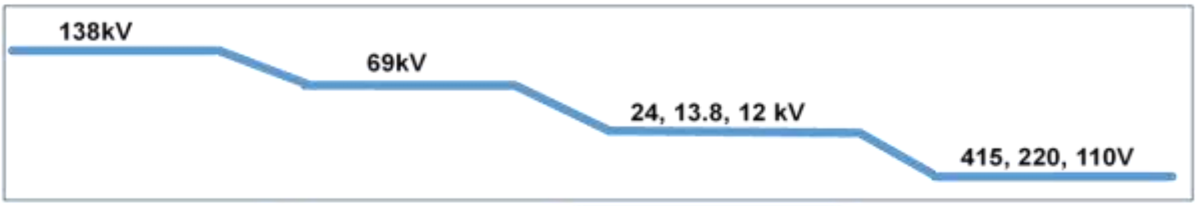
7.145. The following sets out the details of the OUR's assessments of the Transmission System Capital Expenditure and forecasts for the Rate Review period. It also includes the methodology utilized in carrying out the assessments, the findings of the assessments and the recommendations arising therefrom in order to facilitate a determination on the Transmission Investment activities over the Rate Review period.

<u>Existing Transmission System</u>

7.146. JPS has submitted that its Transmission Network is comprised of 138 kV and 69 kV lines of which the 138 kV is the bulk power transmission network and spans 382 km in length (See Table 7.22 below). The 69 kV circuits, which operate as the sub-transmission system, span a length of 826 km and include 1.6 km of underground cable. The Corporate Area, which is the main load centre, is served by 105 km of 69 kV lines that accounts for 13% of the total sub-transmission network.

7.147. There are presently fifty-one (51) JPS-owned substations island-wide. This include ten (10) 138 kV and forty-one (41) 69 kV substations. There are seven (7) privately owned substations connected to the transmission grid. The major equipment within the substation are circuit breakers, re-closers and transformers.

Table 7.22: Representation of Voltages and JPS' T&D Network



Transmission (138KV)	Transmission (69kV)	Distribution Primary	Distribution Transformers & Secondary
Circuit Length: **382Km** Inter-bus Transformers: **13** Substations: **10** Number of Poles: **632** Wood: 605 Steel: 27 Steel Towers: **659** Circuit Breaker: **50** GSU Transformers: **3**	Circuit Length: **826 Km** Circuit Breaker: **196** Substations: **41** Number of Poles: **6336** Wood: 6008 Steel: 271 Concrete: 57 Composite: 6 Steel Towers: **368** Radial: **6** Tap: **3** Power Transformers: **56** GSU Transformers: **24**	Circuit Length: **11,334Km** Poles: **311,271** Concrete: 126,000 Wood: 185,271 Capacitor Banks – **475** Switches – **13,442** DA &, LCB & PMR – **265** Recloser & Main Breaker: **165**	Circuit Length: **9,200Km** No. of Transformers: **47,435** No. of Meters: **> 600,000**

7.148. In assessing JPS' Transmission Capital Investment proposal, the OUR examined the submissions to ensure that the scope of the project information provided is consistent with the requirements of the Final Criteria.

7.149. In addition, JPS was required to submit the transmission system equipment data base in order to facilitate the OUR's review of the transmission system operation simulations.

7.150. The project information was then checked for completeness, accuracy, reasonableness of costs, schedule, the economic feasibility of the project and its ability to deliver on the objectives.

7.5.3. Technical Evaluation

7.151. The OUR's assessment of the JPS' proposed transmission system capital projects involved the examination of (i) the adequacy of the existing system to meet current demand within the specified operating limits and (ii) the infrastructural requirements, in terms of material/equipment and expenditure, needed to meet the targets for network security and reliability at economic cost. The assessment methodology involves the calculation of the potential benefits of the capital projects. A system benefit impact approach similar to the approach used for generation projects was utilized.

7.152. The OUR assessed the system reliability benefits by examining the ability of the system to meet the specified operating limits according to the Electricity Sector Codes. The reduction in the energy demand not served was computed and monetized. A similar approach was used for the value of the transmission system loss reduction.

7.153. The OUR simulation of the transmission system performance over the Rate Review period was carried out utilizing the DigSilent power system analysis package. This is a power system analysis software which is widely used internationally for network planning and operations.

7.154. In carrying out the assessment of JPS' investment proposal, the following studies were carried out:

- System Load/Power Flow analysis;
- System Short Circuit/Fault Analysis;
- System Stability Studies;
- System Power Quality Studies.

7.155. JPS submitted DigSilent models of the transmission system, but the OUR identified several inconsistencies in the files, with regard to the representation of:

a. Voltage support equipment;
b. Wind farms; and
c. Some of the parameters of the transmission lines.

7.156. In addition, the Supervisory Control and Data Acquisition (SCADA) data utilized to calibrate the model was incomplete since not all voltage supporting equipment were properly represented or included in the data set. Measurements were provided for only eighteen (18) or 32% of the 69 kV bus voltages in the database. These included remote locations on the grid that usually experience low voltage conditions and some generator terminal voltages.

7.157. Based on the high level of inconsistencies and omissions observed, the OUR took the decision to use one of the in-house transmission system databases that was received from JPS and used by the OUR in the past.

7.158. The OUR ensured the accuracy of its model by comparing it with data from JPS' SCADA database. The OUR was satisfied with the level of accuracy of its model in representing the operations of the transmission system and used it to carry out the technical assessments of the projects under the following assumptions.

<u>Grid security operating conditions</u>

- System performance under normal operating conditions (N-0);
- System operating with one network element out (N–1 contingency); and
- System operating with a generating plant and a network element out (N–G–1 contingency).

<u>Generation plants retirement/additions assumptions</u>

a. 2023 December - JPS 2 x 20 MW Rockfort slow speed diesel plant to be retired;
b. 2024 December - JPPC 2 x 30 MW power plant;
c. 2025 January - 120 MW combined cycle plant commissioned.

<u>Major Project – Old Harbour to Hunts Bay Transmission Line</u>

7.159. JPS proposed the construction of 138 kV transmission lines to support the Corporate Area electrical subsystem. The project comprises:

a. Building of 43 km of transmission line from Old Harbour to Hunts Bay substation;
b. Building of 8 km of the 138 kV line from Hunts Bay to Duhaney substation;

c. Re-conductoring of 8 km of 138 km of 138 kV line from Duhaney to Tredegar substation; and
d. Upgrade and expand substations at Old Harbour, Hunts Bay, and Duhaney to accommodate the new lines.

7.160. The OUR simulated JPS' 2020 Transmission network (no new additions) including the three existing 138 kV transmission lines that directly or indirectly take power into the Corporate Area, under normal operating conditions (with the system intact). The results of the simulation show that some of the bus voltages are at least 5% below nominal voltage, a violation of voltage conditions.

7.161. As shown in Table 7.23 below, an outage of any of the lines carrying power to the Corporate Area will see the others loaded over 90% of their ratings. The situation is further aggravated as the system will not be able to withstand an N-G-1 contingency (the outage of one of the JPPC 30 MW units and one of the lines).

7.162. Table 7.23 shows that under an N-1 contingency, all but one of the lines are loaded in excess of 90% of the rating. The three critical 138 kV lines exporting power into the Corporate Area will be overloaded under an N-G-1 contingency, and will therefore risk system security and expose the system to the possibility of a major system outage. This situation has therefore underscored the need to strengthen the power importation capabilities into the Corporate Area.

Table 7.23: Existing 138 kV line loading import, N-1 contingency

Equipment Outage	Equipment Loading			
	Name	Rating	Loading	
		Amps	%	Amps
Old Harbour to Duhaney	Old Harbour to Tredegar	900	90.9	865
	Tredegar to Duhaney	650	96.1	625
	Old Harbour interbus (LV)	313	92.2	289
Old Harbour to Tredegar	Old Harbour to Duhaney	900	91.5	824
	Tredegar to Duhaney	650	21.8	142
	Old Harbour interbus (LV)	313	92.8	291

7.163. Based on the Minister's Retirement Schedule for generating plants, JPS indicated the following plant retirements in the Rockfort area in its report (2023 for JPS units and 2024 for JPPC). However, no network analysis was provided regarding the impact that these retirements will have on the grid.

7.164. The network planning process usually involves the development of a 20-year plan for the grid. However, it is important to analyze the impact on the grid when major changes take place, such as the retirement or commissioning of generating plant(s). It is also important that detailed analyses are done within a 10-year term (medium-term) because it is during this timeframe when major changes on the grid are most likely to occur.

7.165. The OUR assessment analyzed the system performance for the years 2020, 2024 and 2030.

7.166. The OUR assumed that with the proposed retirement of the generating plants in the Rockfort area in 2023 and 2024, a 120 MW plant will have to be placed in Kingston to maintain load generation balance.

7.167. The OUR's simulation results show that with the addition of the proposed Old Harbour – Hunts Bay 138 kV line, the proposed re-conductoring of the Duhaney to Tredegar line and the construction of a new Hunts Bay to Duhaney line, the system will be able to operate within normal line loadings in the extreme case of an N-G-1 contingency.

7.168. In its assessment, the OUR considered two alternative options to evaluate the benefits of JPS' proposals:

a. Option A - Only build the section of the line from Old Harbour to Hunts Bay 138 kV line, using the 927.2 AAAC conductor rated at 900 Amps and upgrade the Hunts Bay substation to 138 kV with 2 x 100 MVA interbus transformers; and

b. Option B - Only build the section of the line from Old Harbour to Hunts Bay 138 kV line, using the 559.5 AAAC conductors which are rated at 650 Amps and upgrade the Hunts Bay substation to 138 kV with 2 x 100 MVA interbus transformers.

7.169. Table 7.24 below shows the cost of JPS' project proposal and the OUR's proposed alternatives A and B.

Table 7.24: Project Options Costing

Transmission Line	US $
Old Harbour - Hunts Bay (JPS' proposal)	37,116,014
Old Harbour - Hunts Bay (OUR's option A)	31,907,876
Old Harbour - Hunts Bay (OUR's option B)	31,273,796

7.170. A comparison of these two alternatives is given in Table 7.25 and Table 7.26 below. Both tables show that the two alternatives will be able to evacuate power from Old Harbour into the Corporate Area under the most severe contingency condition. Table 7.27 shows that the voltage levels for the JPS proposal and alternatives A and B at the same level.

Table 7.25: 138 kV line loading for expansion options considered - System intact 2030

Proposed 138 kV Transmission Line	(kV)	% Loading		
		JPS	Option A	Option B
Old Harbour to Duhaney	138	33.9	35.8	38.2
Old Harbour to Tredegar	138	37.3	38.7	40.8
Duhaney to Tredegar	138	6.9	12.1	14.5
Old Harbour to Hunts Bay	138	32.8	29.4	32.8
Old Harbour interbus transformer	138/69	61.5	61.7	63.5

7.171. Table 7.26 indicates that from a system operations performance under the N-G-1 contingency the JPS proposal and the Alternative A are comparable and the lines are within their loading limits.

Table: 7.26: 138 kV line loading for expansion options considered – N-G-1, 2030

Proposed 138 kV Transmission Line	(kV)	% Loading		
		JPS	Option A	Option B
Old Harbour to Duhaney	138	-	-	-
Old Harbour to Tredegar	138	66.8	77.0	89.1
Duhaney to Tredegar	138	50.9	68.8	84.1
Old Harbour to Hunts Bay	138	65.9	54.6	59.7
Old Harbour interbus transformer	138/69	79.7	83.0	92.0

Table 7.27: Min voltage comparison for the 138 kV options – system intact, 2030

Proposed 138 kV Transmission Line	(kV)	Voltage		
		%	kV	Areas
JPS Proposal	69	0.974	67.21	Old Harbour, St. Catherine
OUR Option A	69	0.974	67.21	Old Harbour, St. Catherine
OUR Option B	69	0.974	67.21	Old Harbour, St. Catherine

Losses Reduction

7.172. The OUR computed transmission system losses for the three 138 kV configurations assessed. A Load Loss Factor (LLF) of 0.688[3] was used in the calculation and was based on a Load Factor (LF) of 0.76, which was calculated based on the 2018 energy production of 4,361 GWh and a system demand of 621.3 MW.

7.173. JPS ascribed 6.0 GWh as the loss improvement due to the inclusion of the line. The OUR's analysis, as reported above, indicated a value of more than twice this amount. JPS reported that it did not calculate the energy reduction benefit that would be realised with this project. The OUR computed the value of the loss reduction as shown in Table 7.28 below.

[3] LLF $=0.4LF+0.6LF^2$

Table 7.28: Proposed Old Harbour – Hunts Bay 138 kV line, loss comparison

Network Addition	Years				
	2020	2024	2030	2024	2024
	Energy Losses (GWh)			Loss Reduction (GWh)	Value of Loss Reduction US$
Existing system (no network additions)	125.4	126.6	131.3		
Old Harbour - Hunts Bay (JPS proposal)		112.7	116.5	12.7	2,052,613
Old Harbour - Hunts Bay (OUR option A)		113.0	117.2	12.4	2,008,312
Old Harbour - Hunts Bay (OUR option B)		116.4	120.0	9.0	1,506,234

7.174. The results show that JPS' proposal would achieve the greatest loss reduction benefit, but this is just marginally above the benefit from Option A.

Additional Dispatch Costs

7.175. The operation of the system was simulated under the condition that the generation imported to the Corporate Area was restricted by 60 MW in order to prevent line overloading under an N-G-1 contingency condition. In order to preserve the security of the grid under this contingency, it was necessary to restrict the generation from SJPC 192 MW plant. Based on that premise, the OUR's computation has shown that the import of power into the Corporate Area has to be restricted to operating SJPC at 132 MW. Table 7.29 shows the additional cost incurred based on an annual availability of a transmission line of 95%.

Table 7.29: OUR's Dispatch Costs Increment

Summary	With Old Harbour – Hunts Bay Line	Without Old Harbour –Hunts Bay Line
Total Generation Cost (US$/year)	350,880,000	369,940,000
Difference in Cost (US$/year)	19,060,000	
Difference in cost for 5% line outage (US$/year)	953,000	

7.176. The OUR notes the annual dispatch cost savings of US$20,708,424 computed by JPS due to the implementation of the project. The OUR is of the view that this level of additional dispatch cost may be highly exaggerated, since it is implying that the transmission line system is in a constant N-1 state of operation, which is not the case in reality. The OUR is also of the view that the availability of transmission lines is in excess of 95% and this should be taken into account when computing additional dispatch costs. Taking this into account, the annual dispatch cost savings are estimated at US$1,035,421 per year.

Reliability Benefits

7.177. JPS, in its evaluation, has not assumed the value of the reliability benefits, but relied mainly on the incremental dispatch in carrying out the economic evaluation.

7.178. While the investment costs of transmission infrastructure are well understood, readily identified and are readily monetized, the benefits are not readily understood, more challenging to identify[4], and in general, a limited number of categories are considered. In Jamaica, the cost of unserved energy is primarily used to allocate the societal costs of energy shortfall due to poor reliability from the customers' point of view. The utility is also concerned with the loss revenue, as well as public perception and political pressure. The OUR assumed that curtailment of power importation into the Corporate Area would occur if the existing system is unable to convey 150 MW. Such a situation would result in 900 MWh of unserved energy. Assuming US$4.77/kWh for unserved energy cost, then the avoidance of this outage would save the society about US$4,293,000.

Summary of Economic Benefits

7.179. Table 7.30 below gives a summary of the project computed benefits and costs.

Table 7.30: Project Benefits and Costs

	JPS Proposal	Alt A	Alt B
Benefit	US$	US$	US$
Dispatch	1,035,421	953,000	953,000
Loss Reduction	2,052,613	2,008,312	1,506,234
Reliability	4,293,000	4,293,000	4,293,000
Total Benefits			
Investment Cost	37,116,014	31,907,876	31,273,796

7.180. Based on the project cash flow, the project NPV and IRR were computed. The results are provided in Table 7.31 below.

Table 7.31: OUR's Assessment Project NPV and IRR

Discount rate	Net present value US$
8.08%	26,631,929
IRR	18.85%

7.181. Based on the outcome of the OUR's economic evaluation, the project is deemed economically feasible.

7.182. Based on the technical and economic assessment, the OUR is of the view that the project in its original form will enhance the system capability to import power to the Corporate Area while also alleviating the security risk of a major system outage. However, the

[4] Evaluating Proposed Investments in Power System Reliability and Resilience: Preliminary Results from Interviews with Public Utility Commission Staff.

OUR has concluded that this enhancement to the system can be achieved with a reduced scope and costs. The OUR is therefore proposing the following option:

7.183. Option A - Only build the section of the 138kV line from Old Harbour to Hunts Bay 138 kV using the 927.2 AAAC conductor rated at 900 Amps and upgrade the Hunts Bay substation to 138 kV with 2 x 100 MVA interbus transformers at an estimated cost of US$31,907,876 (including IDC).

Minor Project Efficiency Bellevue to Roaring River 69 kV Transmission Line

7.184. JPS has proposed to build a 15 km 69 kV transmission line in the parish of St. Ann from Bellevue to Roaring River substation at an estimated cost of US$6,759,092.

7.185. JPS has sought to justify the construction of this line as the preferred solution to resolve what it claimed to be the pervasive and persistent low voltage conditions affecting the Roaring River and Bellevue areas. JPS has further stated that in case of a failure of this line, in peak conditions, up to 31 MW of demand has to be shed in order to keep voltages within acceptable limits.

7.186. Furthermore, JPS has pointed out that the possibility exists for a partial blackout of the grid, if either the Bellevue – Lower White River or the Duncans to Rio Bueno transmission line is out of service for planned maintenance, and either of these transmission lines trips offline.

7.187. JPS affirmed that the construction of the new 69kV Transmission Line will lead to significant improvements in Bus Voltages, when either the Bellevue - Lower White River (LWR) or the Duncans to Rio Bueno 69 kV transmission line trips offline.

7.188. The OUR's load flow analysis results have confirmed low voltage conditions in the general areas as indicated by JPS.

7.189. Load flow simulations taking into account the implementation of the proposed Bellevue to Roaring River 69 kV lines have shown that the proposed line will not be able to address an outage of the Bellevue substation interbus transformer, which is the worst outage contingency in that area.

7.190. Tables 7.32 and 7.33 below give the current loading on the most affected lines in the area, with and without the proposed line. It is also shown that the lines are lightly loaded before and after the inclusion of the Bellevue to Roaring River 69 KV lines, which was loaded to about 6.5% of its rating.

Table 7.32: Line loading before Bellevue to Roaring 69 kV line

No.	Transmission Line Name	Voltage (kV)	% Loading
1	Lower White River to Ocho Rios	69	23.1
3	Cardiff Hall to Roaring River	69	19.1

Table 7.33: Line loading with the Bellevue to Roaring 69 kV line

No.	Transmission Line Name	Voltage (kV)	% Loading
1	Lower White River to Ocho Rios	69	18.0
2	Ocho Rios to Roaring River	69	8.8
3	Cardiff Hall to Roaring River	69	18.0
4	Bellevue to Roaring River	69	6.5

7.191. The OUR's assessment of the JPS' proposal indicated that the installation of a second transformer at Bellevue will correct the contingency problem identified, and most likely will be a cheaper option. The disadvantage of this option is that the system losses will increase at 0.15 GWh annually over the ten years, when compared with the JPS' proposal. However, it will significantly improve the static and dynamic voltage stability of the network in that area. It should also be noted that with adequate reactive support on the system, by adjusting the tap position on the interbus transformers at Bellevue, the transmission system losses in that area can be reduced. Table 7.34 below shows the loss comparison with the proposed project and OUR's proposed alternative.

Table 7.34: Proposed Bellevue – Roaring River 69 kV transmission line, loss comparison

Network Addition	Years		
	2020	2024	2030
	Energy Losses (GWh)		
Existing system (no network additions)	125.4	126.6	131.3
Bellevue – Roaring River (JPS' proposal)	125.1	126.3	131.1
Bellevue 2nd IB (OUR's proposal)	125.5	126.7	131.5

7.192. Table 7.35 below provides the cost estimate of JPS' proposal and OUR's proposed alternative.

Table 7.35: Bellevue to Roaring River 69 kV transmission line cost

Transmission project options	US $
Bellevue - Roaring River 69 kV line (JPS' proposal)	6,759,092
Bellevue 2nd Interbus transformer ('s proposal)	2,600,000

Loss Reduction Benefits

7.193. Table 7.36 below shows the computed loss reduction benefits.

Table 7.36: Loss Reduction Benefits

Network Addition	Years			
	2020	2024	2030	
	Energy Losses (GWh)			Cost of Loss reduction(US$)
Existing system (no network additions)	125.4	126.6	131.3	
Bellevue – Roaring River (JPS proposal)	125.1	126.3	131.1	44,301
Bellevue 2nd IB (OUR proposal)	125.5	126.7	131.5	-14,767

Summary of Economic Benefits

7.194. Table 7.37 below summarizes the project benefits and costs for JPS' proposal and OUR's proposed alternative.

Table 7.37: Project Benefits and Costs

	JPS Proposal	Alt A
Benefit	US$	US$
Dispatch	N/A	N/A
Loss Reduction	44,301	(14,767)
Reliability		
Total Benefits		
Investment Cost	**6,759,092**	**2,600,000**

7.195. Based on the scope of costs for minor projects, the financial modelling is not required.

7.196. Based on the OUR's analyses and the relative ineffectiveness of the JPS proposed solution, the Bellevue to Roaring River 69 kV line is not approved. As indicated, the installation of a second 40/60 MVA transformer at Bellevue will address the contingency problem identified and is recommended by the OUR. The alternate project cost is estimated at US$2,600,000. The OUR will offer JPS the opportunity to explore the OUR's proposed alternative and submit a capital plan for this in the next Annual Review.

Minor Project - Replacement

Transmission Line Structural Integrity Programme

7.197. According to JPS, its structural maintenance programme at some of its substations, has been lagging over the years. The result is that for several years the hot dipped galvanized surfaces have been completely eroded and the steel exposed to the agents of corrosion on some structural components. Some members have lost the ability to provide structural support and need replacement or overhaul. JPS further indicated that a failure of these structures, especially in a major substation, can create a grid security problem for the system.

7.198. In order to improve the integrity and security of the grid JPS plans to undertake a number of structural integrity projects, totaling twenty-two (22) projects, which include six (6) 138 kV lines and sixteen (16) 69 kV line projects.

7.199. JPS has stated that the expected benefits from these activities include:

- Improved Reliability of Transmission Lines;
- Decreased Grid Security Risk;
- Improved Transmission Line Performance;
- Improved Operational Efficiency;
- Reduction in Possibility of a System Separation or System Shutdown;
- Improved Public Image;
- Improved Customer Service.

7.200. The scope of the project encompasses the following initiatives over the five years - 2019-2023 shown in Table 7.38 below.

Table 7.38: Scope of JPS' Transmission Structural Improvement Projects

Scope	Cost (US$'000)	Schedule
• Lightning Mitigation and Grounding – A total of 820 lightning arrestors will be replaced along with grounding improvement • Structural Integrity Pole and Hardware Replacement – A total of 416 poles and 1540 insulators will be targeted for replacement • Structural Integrity Pole Rehabilitation - A total of 2300 poles will be rehabilitated • Steel Pole and Steel Tower Rehabilitation - A total of 166 structures will be targeted • Fire Retardant Application - A total of 534 poles will be targeted • Fault Circuit Indicator Installation - 270 fault circuit indicators will be installed • Procurement of Hotline Tools and Equipment • Procurement of Transmission Tools & Equipment	**$9,137**	**2019 Jan – 2023 Dec**

7.201. With these initiatives, the company is expecting to improve grid security and the reliability performance of the system by 10-15% over the next five (5) years.

7.202. The OUR understands that there are several transmission system infrastructures in the system that have deteriorated over time and need repair and rehabilitation. However, the OUR has some reservation regarding the company's capacity to execute all of these projects within the timeframe. Notwithstanding, the Office has approved the proposed US$9.14M. The OUR noted that while JPS stated that the US$9.14M did not include IDC, the IDC was in fact included.

Minor Project Protection Upgrade and Modernization (N-1)

7.203. According to JPS, the increasing penetration of renewable energy sources such as wind and PV Solar, along with other network dynamics, has impacted the stability and security of the grid. It is therefore important for the company to implement protection system schemes on the system that can respond faster than the current schemes, and with a higher level of availability. This is also necessary in order to improve the security of the grid, and to provide some level of redundancies for the protection system on critical network elements.

7.204. The key initiatives and benefits are outlined as follows:

- Expanding equipment protection schemes redundancy to mitigate the effects of an "N-1" protection outage by procuring and installing additional distance relays and implementing redundant tele-protection schemes;
- Improve fault detection and isolation on critical lines with the implementation of current differential protection on eleven (11) 138 kV lines and three (3) 69kV lines;
- Improve System Average Interruption Duration Index (SAIDI) and transmission system security through better selectivity with the installation of transformer HV breakers at Queens Drive, Rose Hall, Greenwood, Oracabessa, Maggoty, Savanna-la-Mar, Hope, Cane River and Greenwich Road substations, among others;
- The gradual replacement of aging infrastructure such as control cables and panels as part of the modernization programme to reduce failures due to "end-of-life" and hidden failures associated with control circuits;
- Compliance with regulatory directives.

7.205. The duration of the project is for the Rate Review period and the project cost is US $6,565,676.

7.206. This is one of the projects on which the OUR's Consultants conducted a costing assessment. The Consultant estimated the project cost at US$6,438,405 versus US$6,565,676 originally submitted as shown in the Table 7.39 below. The Consultants, however, identified that JPS added 30% to duties for all materials, when the correct amount should have been 10% for protection panels and 0% for the rest of the items. If this correction is applied to the project, the project cost would have decreased to U$$5,589,708. The OUR however, noted that JPS did not include transportation cost in its project costing. The Consultant's analysis included transportation cost and varied less than 2% from JPS' original proposal. On this basis, the OUR will approve JPS' proposed project cost.

Table 7.39: JPS' versus Consultant's Estimate of Cost

JPS Proposed Investment Cost (including IDC)	Consultants Estimated Costs (including IDC	Variation
US$6,565,676	US$ 6,438,405	< 2%

7.207. The protection system performs a very critical role in ensuring the security and stability of the power grid. The historical performance has shown that the ability to clear faults quickly will ensure grid stability, especially in light of the penetration of renewable energy sources. The OUR is therefore in agreement with the technical justification of the project and approves the project as proposed.

Substation Interbus Transformer Replacement/Upgrade

7.208. According to JPS, there are seven (7) aged interbus transformers on the grid with varying degrees of defects such as low winding resistance levels and oil leaks which are difficult to repair. Additionally, it is difficult to source spare parts for them, and the four (4) most at risk interbus transformers that are at risk of failure are shown in Table 7.40 below.

Table 7.40: Status of JPS' Interbus Transformers

Region	Existing Transformer	Existing Transformer Capacity (MVA)	Year of Manufacture	Age	Remaining OEM Lifetime	Condition	No. of Customers Fed	Planned Rationalization	Peak Loading (%)	Planned Expansion	Planned Date
INTERBUS TRANSFORMERS											
South	Old Harbour T1	37.5	1968	50	-25	POOR	N/A	Scrap	55	Replace with New 60/80 MVA	2020-2021
West	Bogue T1	80/100	1983	35	-10	POOR	N/A	Scrap	40	Install Additional 80/100 MVA	2021-2022
South	Tredegar T1	30	1968	50	-25	POOR	N/A	Scrap	31	Replace with New 40/60 MVA	2022-2023
South	Tredegar T2	30	1968	50	-25	POOR	N/A	Scrap	68	Replace with New 40/60 MVA	2022-2023

7.209. JPS also stated that they are proposing a phased approach for the replacement of the transformers to reduce the probability of interbus transformer failures impacting the grid in the form of blackouts, brown-outs, or system separations leading to widespread outages.

7.210. The overall project cost will be US $6,499,030 and will span the Rate Review period.

7.211. In addition to the age of the transformers, the OUR also carried out simulation studies to assess the impact of each of the interbus transformers on the system.

7.212. The simulations for the Old Harbour T1 interbus transformer show that if 30 MW of generating plants in the Corporate Area was taken out of service, the network could not accommodate a forced or planned outage of the Old Harbour to Duhaney 138 kV transmission line. Especially during weekdays. The forced or planned outage would result in grid stability issues for the system, which could result in the collapse of the Corporate Area power system. The OUR is therefore in agreement with JPS' request as submitted, that is, to replace the existing 37.5 MVA interbus transformer with a 60/80 MVA interbus transformer.

7.213. For the Bogue T1 interbus transformer, JPS stated that in order to repair the existing 80/100 MVA T1 transformer at Bogue, a new 80/100 transformer will have to be commissioned and operated in parallel with the existing transformer to allow for a secure cut-over. The activities to be carried out will include the expansion of the existing 138kV Bus, installation of 138kV and 69kV power transformers (PTs), installation of 138kV and 69kV circuit breakers, installation of new protection panels and construction of a new 69kV bus including a bus tie to the existing south bus. The completion of designs and request for proposal (RFP) documentation, the procurement of the transformers, circuit breakers, PTs and associated material and completion of civil works will be completed in 2020. Full implementation, including installation of transformer, circuit breaker, PTs and steel structures and protection scheme, as well as full commissioning, are to be completed in 2021.

7.214. The Bogue T1 existing transformer will remain in service and a second 100 MVA Transformer will be installed in parallel with it.

7.215. Although JPS stated that the two interbus transformers will be operating in parallel, the company also stated that the parallel operation is necessary to ensure “a secure cut-over”. It is not clear what is meant by JPS’ statement and the company did not explain the phrase - “a secure cut-over”.

7.216. However, the OUR conducted its own in-house power system simulation studies with network data and the following observations were made:

a. Under normal system operating conditions, the Bogue interbus transformer is normally loaded below 10% of its rating;
b. The system will be able to operate under normal dispatch conditions with the interbus transformer out of service, without compromising the security of the grid; and
c. The outage of the Bogue interbus transformer and another 69 kV transmission line emanating from the Bogue substation will not compromise the security of the grid.

7.217. The above observations have therefore indicated that the interbus transformer can be repaired without the need to install an additional interbus transformer at Bogue. Also, section TC 3.4.3 of the Electricity Sector Codes which states that, “The loss of any single transmission element or interbus transformer, except in cases of radial lines, shall not affect the System’s ability to adequately supply the required demand of its sub-station(s)”, will not be violated.

7.218. The OUR therefore does not agree with JPS’ request to install an additional interbus transformer at Bogue, in order to effect the repair on the existing transformer. Therefore, the OUR does not accept this proposal.

7.219. Simulation studies for the impact of the Tredegar T1 and T2 interbus transformers show that the existing interbus transformers at Tredegar (T1 and T2) will not create any network security problem should either of them be taken out of service.

7.220. The OUR is therefore not in agreement with the JPS’ request for the replacement of these interbus transformers at this time.

7.221. However, the OUR would suggest that for the Bogue T1 and the Tredegar T1 and T2 interbus transformers, JPS purchases a 60/80 MVA interbus transformer for 2021 and keep it in store as a spare interbus transformer.

7.222. On the basis that the OUR did not approve all of the interbus transformer replacements as proposed by JPS, the overall project cost of this project will be reduced by US $2.165 million.

Minor Project – Upgrade

7.223. To further improve the stability of the grid, JPS proposed the implementation of a Remedial Action Scheme (RAS), which is also called a Special Protection Scheme. These are protection system devices that are designed to detect abnormal or predetermined system conditions, and take corrective actions to secure the integrity of the system.

7.224. According to JPS, the proposed scheme is necessary, because the grid is susceptible to collapse due to transient stability issues arising from:

a. Low inertial generators/energy sources, such as wind turbines, solar PV system, small diesel units and small hydro units;
b. Weak transmission grid that cannot support an "N-1-1" system contingency in most situations;
c. Occasional failures in the protection system (circuit breakers, batteries, control cables and relays).

7.225. The duration of the project is from 2020 January to 2021 November, and the cost for its implementation is US$2,970,490.

7.226. Apart from the RAS, JPS has made a number of other submissions that the company said are necessary to improve the stability of the grid, which have been approved by the OUR, which eliminates the necessity for this project. The most critical among which are:

a. The construction of a 138 kV transmission line from Old Harbour to Hunts Bay. This transmission line will significantly improve grid stability because its inclusion will reduce the importance of the Duhaney substation, which at present is the only point on the grid where bulk electric power from outside of the Corporate Area can be imported. This would remove the bottleneck that presently exists at Duhaney;

b. Protection Upgrade and Modernization (N-1). JPS indicated that this will significantly improve the operating time of network protection equipment, which will result in an improvement in grid stability.

7.227. Further, the OUR is of the view that JPS can develop an in-house Remedial Action Scheme, that will be able to satisfy the N-1-1 contingency and at much cheaper cost. Therefore the OUR does not approve the implementation of the RAS project.

Other Minor Transmission System Projects

7.228. Other projects in the Capital Investment Plan include the implementation of a Line-in-Line-out (LILO) at Michelton, the procurement of tools and equipment and the Old Harbour 190 Grid Interconnection.

7.229. The OUR has no objections to these projects as proposed by JPS as they are justified. For example, the Old Harbour 190 Grid Interconnection is necessary to interconnect the 192MW SJPC plant at Old Harbour. Therefore, the OUR approves these projects for implementation as proposed.

7.5.4. Summary of the OUR's Assessment of JPS' Proposed Transmission System Investment Plan

7.230. Based on the outcome of the OUR's assessment of JPS' transmission capital expenditure contained in JPS' Transmission System Investment Plan, the OUR makes the following determination.

7.231. Total transmission capital expenditure approved is **US$69.7M** over the Rate Review period.

7.232. Table 7.41 below shows JPS' proposed capital expenditure for transmission projects versus the OUR's approved capital expenditure. These costs do not include IDC as explained earlier.

7.233. The JPS proposed transmission capital expenditure isUS$87.6M (excluding IDC), and the OUR's approved transmission capital expenditure is US$69.746M. The differences arose from the following:

- Removal of the cost of the Bellevue to Roaring River Project;
- Removal of the cost of the Remedial Action Scheme Project;
- Removal of the cost of the New Bellevue - Roaring River 69kV line project;
- Reducing the cost of the interbus transformers project by reducing the scope of the project.

DETERMINATION # 5

The Office-approved capital expenditure for transmission projects/programmes during the Rate Review period is detailed in Table 7.41 below.

Table 7.41: The OUR-Approved Capital Investment Plan for JPS' Transmission System

Transmission Capital Projects	JPS Total Project Cost (US$'000)	JPS Proposed CAPEX (no idc) (US$'000)					OUR Approved Total Project Cost (US$'000)	OUR Approved CAPEX (no idc) (US$'000)				
		2019	2020	2021	2022	2023		2019	2020	2021	2022	2023
Transmission Line Structural Integrity	**9,138**	1,800	1,770	1,870	1,858	1,839	**9,137.71**	1,800	1,770	1,870	1,858	1,839
Sub Station Structural Integrity	**8,552**	1,525	1,670	1,722	1,798	1,837	**8,552**	1,525	1,670	1,722	1,798	1,837
Energy Storage	**8,949**	8,949	-	-	-	-	**8,949**	8,949	-	-	-	-
New Bellevue - Roaring River 69kV line	**6,640**	-	491	3,114	3,035	-	**-**	-	-	-	-	-
N-1 Protection Upgrade	**5,931**	1,086	1,295	1,239	1,183	1,127	**5,931**	1,086	1,295	1,239	1,183	1,127
Interbus Transformers	**6,383**	196	1,641	2,971	297	1,279	**4,218**	196	2,988	**1,034**		
Protection RAS (Remedial Action Scheme)	**2,918**	-	1,061	1,857	-	-	**-**	-			-	-
Michelton Halt (LILO)	**1,785**	1,785	-	-	-	-	**1,785**	1,785	-	-	-	-
Tools and Equipment	**1,319**	159	277	285	294	303	**1,319**	159	277	285	294	303
Old Harbour 190 Grid Interconnection	**892**	726	166	-	-	-	**892**	726	166	-	-	-
Old Harbour - Hunt's Bay 138 kV Line	**35,070**	151	1,634	6,536	13,085	13,664	**28,962**	151	1,348	5,393	10,796	11,274
TOTALS	**87,577**	**16,378**	**10,006**	**19,594**	**21,550**	**20,049**	**69,746**	**16,378**	**9,515**	**11,543**	**15,930**	**16,380**

7.5.5. Distribution System Capital Investment Plan

7.234. In the Application and Business Plan, some components relating to the expansion of the Distribution System were addressed in the Distribution System Capital Investment Plan. However, a comprehensive Distribution System study/plan, that integrates all the relevant components, establishes their interrelationship, describes the projected network configuration in the new review period, and required to substantiate the company distribution expansion proposals, was not provided.

7.235. During the Rate Review data clarification and additional information phase, the OUR requested a copy of JPS' most recent Distribution System plan. In response, the company submitted a copy of an outdated 2004 plan, along with a 2012 revised version of its Corporate Area distribution system plan. The OUR's review of the documents found that based on the time factor, their assumptions and recommendations were no longer relevant and reflective of the configuration and characteristics of the distribution network, and do not provide a basis to substantiate the 2019-2024 Distribution System expansion proposals. Accordingly, these plans were not considered acceptable by the OUR for this Rate Review process.

7.236. Given the time constraints compounded by the efforts required to produce an updated Distribution Plan, JPS informed the OUR that such a plan could not be completed before 2021. Subsequently, JPS submitted a copy of its Distribution Strategy Statement, which outlines its approach for developing the study/plan, with an emphasis on the "Service Area" concept, used in developing the previous plans.

7.237. Recognizing the described deficiencies with the information to support JPS' distribution proposals, the OUR utilized all available and relevant data, to establish a model to evaluate the proposed "security of supply" projects. There were two projects which fell in this category as shown in Table 7.42 below.

Table 7.42: JPS' Proposed Security of Supply Projects

Index	Project Category	Project Type	Description	Schedule	Project Cost (US$ M)
1	Major	Efficiency	Grid Modernization	2019-2023	12,534,420
2	Major	Replacement	Substation Distribution Transformer Replacement/Upgrade Program.	2019-2023	10,094,000
			TOTAL		**22,628,420**

7.238. In addition to the assessments carried out for these two projects, the OUR examined the justifications JPS provided for the projects and programmes, the scheduling, project costs and risk mitigation to determine whether the project should be approved as submitted by JPS. Details of the OUR's assessment of these projects is provided below.

7.5.5.1. Major Projects Efficiency – Grid Modernization

7.239. In the Application and Business Plan, JPS indicated that it will embark on the full implementation of the Smart Grid programme over the next five (5) years, with equipment installation as given in Table 7.43 below. According to JPS, the phased roll-out of this aspect of the project will start with the pilot phase in the Portmore community, and will include all four (4) primary distribution feeders that supply that area, which was projected to be completed in 2019. However, it is not clear at this point whether this target was achieved.

Table 7.43: JPS' Grid Modernization Investment Plan

Device	2019	2020	2021	2022	2023	Total
Trip Saver II drop-out reclosers (TS)	200	200	320	320	250	*1290*
Distribution Automation Sectionalizes (DA Switches)	15	20	30	30	30	*125*
Pole-mounted reclosers (PMR)	3	4	5	4	4	*23*
Faulted-Circuit Indicators (FCI)	12	30	48	90	33	*213*
Faulted-Circuit Indicators Communication Boxes	5	3	10	16	42	*76*

7.240. Based on the proposal, a total of 1,648 smart devices will be installed on the system over the five (5) year period, at a cost of **US$12,534,420.** For the Portmore pilot programme, there will be a total of 171 installations, as shown in Table 7.44 below.

Table 7.44: Portmore Pilot - Smart Grid Device Installations for 2019

Feeder Name	DA Switch	Trip Saver	FCI	PMR
Duhaney 210	4	24	0	1
Twickenham 210	6	30	12	0
Naggo Head 610	2	38	6	1
Naggo Head 510	2	35	9	1
Total	**14**	**127**	**27**	**3**

7.241. According to JPS, the benefits to be derived from this project will result in a reduction in outage time, improve service reliability to customers, reduce the cost of dispatching crew members and reduce the Cost of Unserved Energy (COUE). The overall benefit should result in a 30% reduction in SAIDI, however, this benefit was not quantified. JPS conducted a cost benefit analysis where the amount of avoided ENS was used along with the COUE to quantify the reliability benefit.

7.242. The OUR's evaluation of cost benefit is shown below:

Discount rate %	Net present value USD
7.85%	$10,211,412.94
11.78%	$7,443,949.57
IRR	55.15%

7.243. The OUR takes the view that the implementation of the Grid Modernization Programme is a positive development, based on the benefits that can accrue to ratepayers, if properly executed. Additionally, the Licence requires that JPS submits a smart grid plan. Therefore, the most critical component in trying to ensure the success of the programme will be the pilot project. The pilot project will give an indication of how the system will perform on a small scale and the experience gained from this implementation can be adopted for the system installation.

7.244. In its submission, JPS did not give a schedule for the implementation of the pilot phase of the project, which should be independently reviewed by the OUR to determine its performance and before other capital expenditures can be expended.

7.245. The OUR is recommending that JPS implements the pilot programme using only the Naggo Head 510 and 610 feeders, for the following reasons:

a. JPS is in the process of developing its distribution system study/plan, using the Service Area concept, and which completion is expected in the latter part of 2021. Upon the completion of such study/plan, the possibility exists that the configuration of the electricity supply from both the Duhaney and New Twickenham substation, into Portmore will change. Whereas, modifications to the Naggo Head feeder, if any will be minimal;

b. The Naggo Head feeders represent about 47% of the Portmore peak demand, which will still provide a substantial sample for review;

c. With these two feeders, the pilot project can be completed with the necessary review, within the second quarter of 2021;

d. Upon the completion of the distribution system expansion study/plan, which will give an indication of the service area and the remaining supply point from which Portmore will get its electricity supply, JPS can go ahead with the full implementation of the smart city programme to the Portmore community;

e. JPS can also use that community smart grid system and its service area to test the effectiveness of both programmes and to make the necessary adjustments, to ensure that there is no overlapping of devices, and that the protection and communication systems for both schemes are coordinated;

f. Lessons learned from this implementation strategy can then be used for both schemes for the entire country, with some modification(s), where necessary.

7.246. Since the results of this project is contingent on the pilot study, the OUR has determined that subject to the availability and OUR's review of the results of the pilot study, the scope of the project proposed by JPS is approved. JPS is required to submit the results of the pilot within two (2) months of the completion of the pilot programme. The OUR will use the results to determine whether the scope of the programme should be modified and consequently, whether project costs should be adjusted and adjustments to the approved rate base done accordingly.

7.247. The OUR's external Consultant reviewed the cost of the project proposed by JPS. Some inconsistencies were observed:

- JPS had applied inflation to the cost of some materials rather than using 2018 costs;

- JPS applied duties of 5% to all materials when the customs schedule indicate that this should be 0%.

7.248. Table 7.45 shows the Consultant's costing for the project versus the costing proposed by JPS. The costing for JPS in the table includes an adjustment to cost due to the above inconsistencies identified by the Consultant.

Table 7.45: Consultant's Project Cost Estimate versus JPS'

DISAGGREGATED COSTS COMPARISON			
	JPS INV. COST	SCUs SIGLA COSTS	DIFERENCE
TOTAL COST	11,807,681	8,057,769	3,749,912

7.249. JPS' corrected cost is 46% above the Consultant's estimate. Moreover, the Consultant's analysis also included a range of cost within which the project costs could fall based on variation in unit prices observed across the Latin America and Caribbean (LAC) region. This cost range is shown in Table 7.46 below:

Table 7.46: Possible Range of Project Costs for the Grid Modernization Project Cost (US$)

Minimum	Average	Maximum
5,111,592	8,057,769	10,098,715

7.250. JPS' project costs is above the maximum project costs estimated by the Consultant. The Consultant's Report in **Annex 3: Supporting Papers #2** presents details on what were the drivers of JPS' high cost.

7.251. Based on the analysis of costing done by the Consultants, the OUR is not satisfied with JPS' costing for this project and will therefore not approve JPS' project cost as proposed. The OUR will approve the Consultant's maximum project cost stated for this project, that is, US$10,098,715.

7.5.5.2. <u>Growth - Customer Growth (CCMA)</u>

7.252. According to JPS, Customer Growth Projects are considered as primary and secondary line extensions and transformer upgrades. JPS stated that it has an obligation to provide service to customers who have requested supply for power. This is facilitated through the extension of the distribution network or the upgrading of the existing infrastructure. The type of projects that are incorporated in this category are:

- Line extensions greater than 250m of existing distribution line;
- Sub-divisions;
- Customer required pad-mounted transformer;
- Customer required underground or transmission work;
- Customer required relocation of existing distribution circuit;
- Service upgrade request from an existing customer.

7.253. The project spans all fourteen (14) parishes in Jamaica and is slated to run for the entire Rate Review period. JPS' proposed project cost is US$30.8M. While the project cost in the Investment Plan was stated to be US$30.8, in the Excel workbook accompanying the Investment Plan, the project cost was US$29.02M.

7.254. In the Investment Plan, the benefits of the project were quantified as the increase in energy sales. JPS claims that this amounts to 107.972GWh of sales over the five years. This analysis is, however misaligned with the analysis JPS provided in the accompanying Excel workbook, which quantifies the benefit as a reliability benefit. The OUR, however, does not understand how reliability benefits could be derived and is of the view that the analysis in the Excel workbook should be disregarded. Therefore, the analysis in the Investment Plan is taken to be the correct one. JPS did not calculate the value of increased sales to customers.

7.255. Notwithstanding the absence of a cost benefit analysis for this major project, the OUR agrees with JPS that this project is mandatory because the company has an obligation to supply customers.

7.256. The OUR's external Consultants conducted a costing study on this project. The Consultant's cost estimate was 3.58% higher than the US$29.04M proposed by JPS. JPS' cost estimate is therefore considered reasonable.

7.257. The project budget set by JPS is based on the historical cost of conducting similar projects. The OUR however, recognizes that some CCMA customers pay a 50% non-refundable contribution towards these projects. The OUR requested further information from JPS on what percentage of these projects fell into this category. Table 7.47 below shows this analysis.

Table 7.47: JPS' Analysis of CCMA Projects

	2018				2019			
	# of Projects	% of # of Projects	JA$	% of Spend	# of Projects	% of # of Projects	JA$	% of Spend
50% NON REFUNDABLE	192	54%	323,987,490	45%	205	55%	277,088,092	47%
100% REFUNDABLE DEPOSITS	63	18%	352,628,066	49%	51	14%	241,005,809	41%
100% NON REFUNDABLE DEPOSITS	3	1%	12,572,255	2%	1	0%	1,173,703	0%
OBLIGATORY	95	27%	30,202,953	4%	114	31%	68,826,213	12%
TOTAL	**353**	**100%**	**719,390,764**	**100%**	**371**	**100%**	**588,093,817**	**100%**

7.258. JPS' analysis showed that an average of 46% of the CCMA project revenues were from customers who contributed a 50% non-refundable portion to the project. Thus, approximately 14% of project costs is contributed by customers, and this amount should be removed from JPS' project costs. In an email to the OUR dated 2020 June 23, JPS indicated the following:

> "*Kindly note that JPS' current experience with the 50% Non-refundable contribution is not good. Generally, once the customer makes the contribution, the process starts and JPS then construct the line extension within reasonable time. However, in many instances there is a protracted delay between the time the line is constructed and the completion of the sub-division (housing, etc) and therefore application for service connection (and the generation of revenue from this investment). When the customer chooses the 50% Non-refundable option, he has no incentive for completing this project and there are many instances when line equipment is stolen and therefore JPS suffers a loss on its investment. Consequently, JPS is reviewing this option with a view to eliminating it.*"

7.259. JPS later clarified that it would remove the 50% option starting in 2021. The OUR assumed that JPS would follow through with this decision to discontinue the 50% policy starting in 2021. Costs after 2020 were not adjusted by this 14% factor.

7.260. The total project cost excluding IDC approved by the OUR is US$27.3M.

7.5.5.3. The Voltage Standardization Programme (VSP)

7.261. This programme involves the upgrading of twelve (12) distribution feeders across the island to 24kV. These include the following feeders:

- Oracabessa 110 and 210 12kV Distribution Feeders;
- Upper White River 110 and 210 12kV Distribution Feeders;
- Blackstonage 110 12kV Distribution Feeders;
- Highgate 110 and 210 12kV Distribution Feeders;
- Michelton Halt 110 and 210 12kV Distribution Feeders;
- Rhodens Pen 210, 310 and 410 12kV Distribution Feeders.

7.262. The Voltage Standardization Programme involves extensive replacement of all pole line assets rated at 12kV with 24kV assets. These include isolators, switches, pole mounted transformers, pedestal transformers, and broken poles. The substation transformers (T1) will also be reconnected for 24 kV operation.

7.263. JPS proposes to implement the project at a cost of US$17.59M (including IDC) or US$17.29M (excluding IDC) and spans the Rate Review period.

7.264. The expected benefits of the programme according to JPS are:

- Reduction in technical losses;
- Improvement in reliability.

7.265. JPS' cost benefit analysis yielded the following results:

Discount rate %	Net present value USD
8.08%	$34,049,728.04
12.12%	$15,351,635.29
IRR	23.11%

7.266. JPS submitted all the relevant project information in accordance with the Final Criteria. The OUR has reviewed the scope of the project and believes that JPS will be able to implement it within the timeframe proposed.

7.267. JPS' quantification of the technical losses reduction and reliability improvement seems reasonable and there is no technical basis to challenge it. The OUR's assessment of the cost/benefit is shown below.

Discount rate %	Net present value USD
7.85%	$34,902,558.03
11.78%	$15,908,956.90
IRR	22.57%

7.268. The project is therefore economically feasible and therefore should be implemented.

7.269. The OUR’s external Consultant estimated the cost of implementing the project. The Consultant’s results compared to JPS’ is shown below:

JPS	Consultant	Difference	Percentage
17,295,623	16,926,109	369,514	2%

7.270. JPS’ project cost estimate was 2% above the Consultant’s. The Consultant additionally estimated the possible range of project costs to be between US$13.2M and US$20.638M. JPS’ project cost falls towards the middle of this range and is therefore considered reasonable.

7.271. The OUR therefore approves this project at the cost of US$17.295M.

Distribution Structural Integrity Programme

7.272. According to JPS, the Structural Integrity Programme is designed to address any defect in pole, equipment, and street lighting in the system due to seniority, accidents, and third-party failures, ensuring that the company's core function of providing a safe, reliable, and cost-effective supply is maintained.

7.273. JPS stated that the programme estimates the recovery of damaged assets, according to the following criteria:

1. Replacement of 80% defective poles or failures caused by third parties (car accidents, online tree cutting, etc.). Estimated 10,979 poles;
2. Rehabilitation of wooden poles to extend their useful life. Estimated 25,826 poles;
3. Replacement of faulty HPS luminaires with 58W, 108W and 161W LEDs as the case may be;
4. Replacement of insulators, cross arms, and other equipment that are failing or nearing the end of its life cycle.

7.274. JPS claimed that improvement in reliability would be the main benefit to be derived from the programme due to a reduction in ENS. JPS’ cost benefit analysis achieved the following results.

Discount rate %	Net present value USD
8.08%	$39,933,721.12
12.12%	$25,328,102.75
IRR	41.43%

7.275. The OUR’s external Consultant’s estimated project cost was US$20,797,719 versus the US$22,409,065 proposed by JPS. JPS’ project cost estimate is 7.7% above the Consultant’s.

7.276. The Consultant also examined the range of values in which the project cost could fall and achieved the following results:

Total Cost		
Minimum	Average	Maximum
14,465,259.41	20,524,772.66	26,753,824.81

7.277. JPS' project costs fall within this range.

7.278. The OUR therefore approves the project cost excluding IDC of US$22.409M.

Meter and Service Wires Replacement

7.279. The project consists of the evaluation of the equipment and materials needed for the connection of new customers, as well as the replacement of some meters and connections in poor condition.

7.280. This project will meet the customer growth requirements in all fourteen (14) parishes. Customer types include residential, commercial, and industrial customers.

7.281. JPS proposed to implement the project at a cost of US$13,790,311. No IDC was included in this cost estimate. The proposed schedule is from 2019 January to 2023 December.

7.282. JPS claimed that the replacement of the meters and connections in poor condition will result in improved reliability and that the company will reduce ENS by 26.6GWh per annum. The results of JPS' cost/benefit analysis is shown below:

Discount rate %	Net present value USD
8.08%	$79,729,014.23
12.12%	$73,975,246.22
IRR	3225.54%

7.283. JPS provided the requisite information that allowed the OUR to assess the project.

7.284. The OUR notes that although it has no technical basis for challenging the reliability improvement that JPS claims it will get from this programme, the results of the cost/benefit analysis indicate that the benefits may be overstated. Nonetheless, this is a mandatory project, as JPS has the obligation to connect new customers.

7.285. The OUR assessed the number of meters that JPS proposed to install under this programme and these numbers are generally in line with the expected customer growth over the period. The OUR's external Consultant also conducted this assessment and these were generally in line with JPS' estimates.

7.286. The Consultant detected that within JPS' project costing model incorrect duties were being applied to some items. In the case of this project, duties of 5% import are only applied for meters, for other items it should be zero. Additionally, they observed that JPS was applying an inflation factor to materials when this was not to be applied. If these correction factors are applied, JPS' project cost would be reduced to US$11.7M versus the US$12.84M estimated by the Consultant. The Consultant's cost estimate was 11% above JPS' adjusted project cost.

7.287. JPS' originally proposed project cost of US$13.79M, however, fell within the range of project costs estimated by the Consultant, and on that basis, the OUR approved the proposed cost.

<u>Substation Distribution Transformers Replacement/Upgrade Programme</u>

7.288. JPS proposed to implement the substation transformer replacement/upgrade programme at a cost of US$10M. The project is slated to span the Rate Review period.

7.289. Table 7.48 below lists eight (8) substation distribution transformers that JPS said needed to be upgraded/replaced, for the following reasons:

7.290. A number of the transformers are in a state of deterioration, resulting in high acid and combustible gas content (based on oil test results), as well as severe degradation of the paper insulation, and at a stage of a high risk of failure. Distribution Transformers are essential in maintaining grid security and as such transformers must be procured and installed to mitigate the effects of a failure of any of these units.

7.291. In addition to exceeding their economic life, some of these transformers are heavily overloaded.

Table 7.48: List of Substation Distribution Transformers to be replaced

Transformer Name	Comments
Hope T2	Transformer 12 years past its useful life. Test results are indicating very aggrestive overheating of the transformer paper insulation. Unit has a high core to ground current which causes transformer to overheat. Unit has a High risk of failure
Tredegar T3	Transformer Overloading and is 2 years past its useful life. Medium risk of failure.
Cane River T1	Transformer 28 years past its useful life. Test results show deteriorated wet and dry insulation. Kraft paper is severely degraded which will lead to transformer failure. Unit is at a High risk of failure.
Duhaney T3	Transformer is 5 years old however it has been consistently loaded to above 80% loading. There is a moderate risk of failure if transformer is not upgraded.
Parnassus T3	Transformer is 6 years old however it has been consistently loaded to above 90% loading. High risk of failure if transformer is not upgraded. No loads can be transferred within the service area
Rose Hall T1	Transformer is 12 years old however it has been consistently loaded to above 75% loading. There is a moderate risk of failure if transformer is not upgraded. Thre is not much room for transfers within the service area which has a high rate of load grawth due to tourism industry.
Spur Tree T1	Transformer Overloading and is 3 years past its useful life. Moderate risk of failure.
Porus T1	Transformer 13 years past its useful life. Test results shows borderline wet and dry insulation. Very high Acetylene value. This gas is combustible and will cause failure of transformer. Unit is at a High risk of failure.

7.292. The stated benefits of the programme are:

- Improved flexibility in transferring loads within the service areas;
- Compliance with the T&D Grid Code DC 3.4.4 and DC 3.5, thus allowing for load growth within the service areas;

- Make spare Distribution Transformer available for use in case of failures at other critical Substations. This will reduce the negative impact of a failure of an existing Transformer and result in a reduction in time to replace;
- Allow for the implementation of Fault location, isolation, and service restoration (FLISR) for automatic FLISR that may include load transfers. This will result in a reduction in the number of customers affected by an outage;
- Reduction in Unserved Energy.

7.293. JPS estimates that by the end of the programme in 2023, there will be 64,128 MWh/year of avoided ENS. The company's economic analysis achieved the following results:

JPS Financial Economic Analysis and Cost-Benefit Analysis Model	The financial economic analysis and cost-benefit analysis are outlined in the Excel book provided. **NPV**: $1,388,618,794 at 12.12% discount rate **IRR: Greater than 100%**

7.294. The OUR's technical analysis of this project is detailed in **Annex 3: Supporting Papers #2** and the results are summarised in Table 7.49 below:

Table 7.49: Summary of OUR's Recommendation based on Technical Analysis

Transformer	OUR's Technical Recommendation	JPS Proposed Project Cost
Duhaney T3	Do not implement project, but reconfigure the network within the SA to accommodate the necessary changes and to optimize the network operations.	1,786,870
Tredegar T3	Implement the project, but locate the transformer at the New Twickenham Substation rather than Tredegar.	2,404,855
Parnassus T3	JPS should review this proposal because it seems to be inadequate to satisfy the relevant system criteria it is trying to satisfy.	985,338
Spur Tree T1	Recommended to implement the project, but OUR is of the view that JPS should review this proposal, to see if it is feasible to incorporate the Maggotty substation in SA3.	1,835,830
Porus T1	Replace the transformer.	392,334
Rose Hall T1	Replace the transformer, but OUR is of the view that JPS should review this proposal, giving a wider perspective to SA2. Especially with regards to the loading of the Bogue T2 distribution transformer and the 210 feeder in particular.	923,540
Hope T2	Replace the transformer.	838,783
Cane River T1	Replace the transformer. JPS should assess the reconfiguration option, with the possibility of integrating Service Areas SA3 and SA4.	926,630

7.295. The OUR has reviewed JPS' quantification of the benefits to be derived from doing this project and has no technical basis to challenge it. However, based on the results achieved, the benefits seem to be overstated.

7.296. The OUR's external Consultant's costing assessment of the overall project cost revealed that JPS applied the duties on transformers twice. When these rates are corrected, the project cost would reduce from US$10.199M to US$10.094M. The Consultant's estimate for implementing the project was US$9.89M which was 7% lower than JPS' adjusted project cost.

7.297. The OUR recommends that the project be implemented even though it is recommended that some components of the project be reassessed. The approved project cost is US$9.802M (exclusive of IDC).

Distribution Line Upgrade (Re-Conductoring and Rehabilitation)

7.298. The programme includes maintenance work on the 112 distribution feeders across all fourteen (14) parishes in Jamaica. According to JPS, the programme's scope consists of:

- Reconstruction of approximately 71km of distribution lines;
- Rehabilitation of approximately 677 pole-mounted transformer circuits across the distribution grid;
- Installation of 1,091km of 2/0AA MV Covered Conductors across the 112 distribution feeders;
- Rehabilitation of approximately 122km of lines.

7.299. The project is slated to span the duration of the Rate Review period at a cost of US$10.007M.

7.300. The benefits that JPS states that will be derived from this project are:

- Improved power quality;
- Reduction in number of forced outages by 30% over five (5) years;
- Reduction in the number of customers impacted by forced outages;
- Reduction in emergency calls (truck rolls);
- Increase in kWh sales;
- Improved customer satisfaction. CSAT index of 60%;
- Increased productivity of businesses that are dependent on the power grid;
- Reduction in claims related to damaged equipment.

7.301. JPS' cost benefit analysis achieved the following results:

Discount rate %	Net present value USD
8.08%	$1,768,347,196.24
12.12%	$1,388,616,794.28
IRR	4446.99%

7.302. The OUR has no technical reason to challenge JPS' assessment of the quantification of the benefits, however, these benefits seem to be overstated. The OUR, is however of the view that the project should be implemented because it is likely to provide significant reliability improvement.

7.303. The Consultant's estimate of project cost was 8% above JPS' estimate. JPS' project cost was therefore acceptable for this project. The approved project cost is US$9.780M, which is the project cost without IDC.

7.5.5.4. The Smart Streetlight Programme

7.304. JPS included the Smart Streetlight programme (SSP) in its Distribution System Capital Investment Plan. In the earlier phases of the SSP financing was provided from customer sources by way of the EEIF/SBF. However, the Office has determined that all streetlights are to be owned by JPS. Consequently, the proposed CAPEX of US$23.9M for the SSP has been approved.

7.5.5.5. Minor Projects

7.305. The list of minor distribution system projects proposed by JPS are:

1. Replace Pole Mounted Transformers;
2. Capital Spares T&D (CKT Breaker, recloser, DA switch, etc);
3. Grid Interconnection;
4. Replace pad mounted transformers.

7.306. As stipulated in the Final Criteria, no economic cost/benefit analysis was required and JPS did not provide these. The OUR reviewed the justification and scope of the projects and is of the view that the projects are acceptable and should be approved.

7.307. The costing assessment done by the OUR's external Consultant where applicable, indicate that the projects are reasonably priced and as such, the OUR approves the project costs proposed by JPS (excluding IDC).

7.5.6. Summary of the OUR's Assessment of JPS' Proposed Distribution System Investment Plan

7.308. Based on the outcome of the OUR's assessment of JPS' Distribution Capital Expenditure proposal submitted in its Application, the OUR makes the following determination:

7.309. Total distribution capital expenditure approved is **US$144.8M** over the Rate Review period.

7.310. Table 7.50 shows JPS' proposed capital expenditure for distribution projects versus the OUR's approved capital expenditure. These costs do not include IDC as explained earlier.

7.311. Whereas JPS' proposed capital expenditure is US$150.235M (excluding IDC), the OUR's approved capital expenditure is US$144.84M. The differences arose from the following:

- Reducing the cost of the Customer Growth CCMA Project;
- Reducing the cost of the Grid Modernization Programme;
- Removing IDC from the Distribution Line Re-Conductoring and Rehabilitation Programme.

DETERMINATION # 6

The Office approved capital expenditure for Distribution projects/programmes during the Rate Review period is detailed in Table 7.50.

Table 7.50: Approved Distribution System Capital Investment Plan

Distribution Capital Projects	JPS Total Project Cost (US$'000)	JPS Proposed CAPEX (no idc) (US$'000)					OUR Approved Total Project Cost (US$'000)	OUR Approved CAPEX (no idc) (US$'000)				
		2019	2020	2021	2022	2023		2019	2020	2021	2022	2023
Distribution Line Structural Integrity	**22,409**	3,771	4,489	4,564	4,763	4,822	**22,409**	3,771	4,489	4,564	4,763	4,822
Customer Growth (CCMA)	**30,256**	6,680	5,894	4,912	6,876	5,894	**27,301**	5,110	4,509	4,912	6,876	5,894
Smart Streetlight	**23,948**	8,252	8,836	6,861	-	-	**23,948**	8,252	8,836	6,861	-	-
Voltage Standardization Program (VSP)	**17,282**	1,940	3,434	3,196	4,165	4,547	**17,282**	1,940	3,434	3,196	4,165	4,547
Meters & Service Wires (Replacement and Growth)	**13,740**	3,026	2,294	2,723	2,806	2,890	**13,740**	3,026	2,294	2,723	2,806	2,890
Grid Modernization Program (FCI, DA, Trip Savers)	**12,313**	1,753	2,055	2,777	2,915	2,813	**10,099**	1,425	1,645	2,299	2,410	2,320
Distribution Transformers	**9,916**	2,955	2,798	2,203	1,606	354	**9,916**	2,955	2,798	2,203	1,606	354
Distribution Line Reconductoring and Relocation	**10,007**	2,000	1,345	2,173	2,084	2,405	**9,781**	1,955	1,314	2,124	2,037	2,351
Replace Pole Mounted Transformers	**5,256**	1,377	927	946	995	1,010	**5,256**	1,377	927	946	995	1,010
Capital Spares T&D (CKT Breaker, Recloser, DA switch, etc)	**2,258**	444	448	451	455	459	**2,258**	444	448	451	455	459
Grid Interconnection	**1,789**	352	355	358	361	364	**1,789**	352	355	358	361	364
Replace Padmounted Transformers	**1,060**	208	210	212	214	215	**1,060**	208	210	212	214	215
TOTALS	**150,235**	**32,758**	**33,085**	**31,377**	**27,242**	**25,774**	**144,840**	**30,815**	**31,259**	**30,850**	**26,689**	**25,226**

System Losses Capital Investment Plan

7.312. There are five (5) projects/programmes specifically related to reducing System Losses in JPS' Capital Investment Plan for 2019 – 2023. These include the following:

- Smart Meter Programme;
- Rami Projects;
- Check Meters;
- Metering Infrastructure Replacements;
- Analytical software procurement and Development.

7.313. The OUR examined the justifications for the losses projects and programmes, the scheduling, project costs and risk mitigation to determine whether the projects should be approved as submitted. Details of the OUR's assessment of these projects are provided below.

Major Projects

Smart Meter Programme

7.314. According to JPS, this programme will involve the installation of approximately 470,000 smart meters over the Rate Review period across all operational zones. The cost proposed by JPS for implementing the programme is US$85.277M (inc. IDC).

7.315. The project is the continuation of the Smart Metering programme which JPS began in 2017, and when completed, it is expected that all of JPS' customer base will be equipped with smart meters.

7.316. The benefits identified after the implementation of the programme are:

- Improved operational efficiency and reduced electricity waste through voltage optimization;
- Savings in operating costs will be achieved through the following efficiencies:
- Reduced meter reading costs;
- Improved meter reading accuracy;
- Reduced estimated bills and fines for breach of Guaranteed Standards;
- Reduced disconnection and reconnection operating costs;
- Reduced costs associated with billing (potential to fully automate billing);
- Improved reading time to invoice;
- Reduced calls associated with the estimates;
- Using the SMART meter as sensors to instantly detect power outages and improve restoration times with remote problem resolution. Interruptions are known in near real time and customers are no longer required to call.

7.317. At the end of the five-year implementation period, the project is expected to save 122,436 MWh in energy losses every year, in addition to US$3.48M saved in O&M expenses.

7.318. JPS' cost benefit analysis for the project yielded the following results:

Discount rate %	Net present value USD
8.08%	$95,658,664.69
12.12%	$65,487,094.45
IRR	40.85%

7.319. The OUR does not challenge JPS' assumption on the quantification of the benefits of the project. However, the assumption on avoided system losses does not align with the information provided in JPS' System Losses Chapter in its Application. Nonetheless, the OUR used these assumptions in conducting a cost/benefit analysis which yielded the following results.

Discount rate %	Net present value USD
7.85%	$83,529,075.86
11.78%	$56,382,047.20
IRR	35.72%

7.320. The OUR is convinced that if properly implemented, the programme could yield significant benefit to consumers, hence its approval for implementation. The OUR took the decision to extend this project to six (6) rather than the five (5) years proposed by JPS. This is because of the monetary value of the project. It is JPS' largest programme based on monetary value and thus would have the most impact on rates. The OUR takes the view that by spreading the programme over six (6) years rather than five (5) it would have a favourable effect on the tariff, without seriously jepordizing the benefit to customers as a whole.

7.321. The OUR's external Consultant's costing assessment indicate that 85,000 current transformers (CT) were included in the project when only 3,500 three (3) phase meters were to be installed. For the 3,500, 3-phase meters, 10,500 CTs would be required. The Consultant assumed that additional amounts were being purchased for inventory and allowed these in its assessment of the programme cost. The OUR made a similar observation for the meter enclosures where JPS was procuring 22,500 meter enclosures when the project would only require 3,500.

7.322. In JPS' business case for the project, it indicated that it was procuring 10% CTs for inventory and 5% for meter enclosures. Without additional information from JPS, the OUR can only assume that the inventory purchase is associated with the current project, hence, the OUR is unable to understand why JPS would be purchasing the quantities it proposed. The OUR thus allowed for an additional 10% of CTs and 5% of meter enclosures for inventory. These amounted to 11,550 CTs and 3,850 meter enclosures. When these changes were made to the quantities, the project cost reduced to US$76.680M (excluding IDC) from the US$83.746M (excluding IDC) originally proposed by JPS.

7.323. In estimating the cost of the programme, the Consultant had not corrected for the observed discrepancies in quantities. The estimate of project cost (including IDC) was US$87.348M which is 2.43% higher than JPS' estimate. JPS' estimate was therefore considered reasonable.

7.324. The OUR approves this project with the correction for quantities highlighted above. The approved project cost is US$76.680M (excluding IDC), but only US$70.746 is approved for the Rate Review Period.

Residential Automated Metering Infrastructure (RAMI) Programme

7.325. JPS indicated that there are areas where the installation of regular ANSI type smart meters will not be sufficient to reduce electricity theft. According to JPS, this is due to the fact that meter investigations and corrections cannot be effectively executed in these areas. These areas require a more robust anti-theft solution where the meters are not readily accessible to the customer. These areas will use metering with prepaid capability with anti-theft enclosures to serve customers. The company further states that losses erode approximately 13% of its revenue in these high loss areas.

7.326. The project will be implemented at a cost of US$17,259,178 (including IDC) and is expected to span the entire Rate Review period.

7.327. The stated benefits of the programme are:

- Reduction of system losses through anti-theft solution;
- Customer growth through customer on-boarding;
- Automated Meter Reading, Disconnection and Reconnections;
- Improved power quality.

7.328. JPS' cost benefit analysis yielded the following results:

Discount rate %	Net present value USD
8.08%	$9,858,879.49
12.12%	$5,509,675.84
IRR	18.17%

7.329. The results of the OUR's economic analysis is shown below:

Discount rate %	Net present value USD
7.85%	$7,849,636.57
11.78%	$4,021,440.62
IRR	14.10%

7.330. Based on the cost/benefit analysis, the OUR is of the opinion that this is a project that should be implemented.

7.331. Below is the comparative table of the programme cost value presented by JPS and that obtained by the OUR's external Consultant:

	JPS INV. COST	SCUs SIGLA COSTS	DIFERENCE
TOTAL COST	17,258,703	15,405,193	1,853,509

7.332. JPS' programme cost is 12% above the Consultant's. Since it falls within the possible range of project costs identified by the Consultant, the OUR approves it. The approved cost for the programme is US$16,784,970 (excluding IDC).

Minor Projects

7.333. The list of minor projects in the Losses Capital Investment Plan are:

- Installation of Check Meters;
- Metering Infrastructure Replacements;
- Analytical software procurement and Development.

7.334. As minor projects, no cost/benefit analysis were required for them. The OUR reviewed the justification provided for these projects, and is of the opinion that the projects should be implemented, as the overall success of the losses programme is dependent on their implementation. The OUR has no objection to the costing that was provided, and hence they are approved, excluding IDC.

7.5.7. Summary of the OUR's Assessment of JPS' Proposed Losses Investment Plan

7.335. Based on the outcome of the OUR's assessment of JPS' Losses capital expenditure proposal submitted in its Application, the OUR makes the following determination.

7.336. Total Losses capital expenditure approved is **US$90.0M** over the Rate Review period.

7.337. Table 7.50 shows JPS' proposed capital expenditure for distribution projects versus the OUR's approved capital expenditure. These costs do not include IDC as explained earlier.

7.338. Whereas JPS' proposed capital expenditure is US$102.596M (excluding IDC), the OUR's approved capital expenditure is US$89.93M. The differences arose from the following:

- Reducing the cost of the Smart Meter Programme and extending the project from five (5) years to six (6) years.

DETERMINATION # 7

The Office approved capital expenditure for Losses projects/programmes during the Rate Review period is detailed in Table 7.51.

Table 7.51: Approved Capital Investment Plan for System Losses for 2019 – 2023

Losses Capital Projects	JPS Total Project Cost (US$'000)	JPS Proposed CAPEX (no idc) (US$'000)					OUR Approved Total Project Cost (US$'000)	OUR Approved CAPEX (no idc) (US$'000)				
		2019	2020	2021	2022	2023		2019	2020	2021	2022	2023
Smart Meter Program	**83,772**	21,316	17,652	19,786	16,968	8,048	**70,746**	20,955	8,677	14,588	12,511	14,016
Rami Projects	**16,954**	4,126	3,020	4,788	3,001	2,019	**16,954**	4,126	3,020	4,788	3,001	2,019
Check Meters	**1,178**	1,178	-	-	-	-	**1,178**	1,178	-	-	-	-
Metering Infrastructure Replacements	**750**	-	200	192	183	175	**750**	-	200	192	183	175
Analytical software procurement and Development	**302**	-	302	-	-	-	**302**	-	302	-	-	-
TOTALS	**102,956**	**26,621**	**21,174**	**24,766**	**20,153**	**10,242**	**89,930**	**26,259**	**12,198**	**19,568**	**15,695**	**16,210**

7.5.8. Information Technology (IT) Capital Investment Plan

7.339. The capital projects in the IT Capital Investment Plan were classified in the Final Criteria as minor projects. These projects spanned the categories of efficiency, growth, replacement, statutory and upgrades.

7.340. The assessment approach used to review the projects to determine how well they supported JPS' business plan and strategy to accomplish the company's objectives was an examination of the functions of the projects and what they were intended to deliver. The viability of the projects was checked by determining if the approach taken by the projects could accomplish the projects' objectives. Cost effectiveness was judged based on a review of the economic models provided, while the efficiency of the projects was evaluated for best use of resources. The urgency of the projects was determined by way of the importance of the project's purpose and the level of integration with other projects.

7.341. The results of these analyses determined which projects qualify for scheduled investments, which ones should be deferred and which ones should be rejected.

7.5.9. The OUR's Assessment

7.342. The IT capital investment of US$20.039M represents 4.19% of JPS' total capital expenditure, which is spread over the Rate Review period with the majority of the spend over the period 2022 – 2023.

7.343. The projects were typically found to support JPS' intention to use technology to improve their hardware capabilities, storage, business and system monitoring & control processes, efficiency, loss reduction, security, system awareness and data collection, mining and analytics.

7.344. From the submission, JPS intends to do major updates and changes to its computer and storage infrastructure. This includes, its upgrades to its data centres; updating its System Control and Data Acquisition software, as well as hardware enhancements to its power grid, Customer Information and Billing system. Additionally, it has proposed to establish a new communication and collaboration platform, expand its Smart Grid network operations and develop analytics for its various data streams to be more data driven.

7.345. OUR observed that there were elements of potential overlap and that the proposed sequence of projects could have benefited from an integrated review to maximize on purchases of equipment in bulk across projects. This will ensure that updated systems are in place for those that may be associated with them and thereby better inform the schedule of its team members' involvement in the various projects to ensure availability of resources.

7.5.10. Summary of OUR's assessment of JPS' IT Capital Investment Programme

Table 7.52: Summary of OUR's Assessment of JPS' IT Capital Investment Programme

No.	Project Description	Is the Project Necessary?	Can the Project be delayed? And if so, for how long?	Are there any cost effective alternatives?	Schedule	Cost (USD M) (including IDC)
1	Business Efficiency Project	Yes.	Yes. But not recommended	Unknown. As this type of business exists in a mature environment it would stand to reason that there may be applications that already exist for these purposes.	2019 October - 2024 September	3.182
2	Customer Suite Upgrade	Yes.	Yes it could be delayed for about one (1) year, but this is not recommended	It is likely that an alternative could exist.	2021 January - 2022 December	2.8
3	Monarch SCADA/EMS/DMS Full Replacement	Yes	Yes. But not recommended	Yes. There are many alternatives to choose from.	2020 January - 2022 December	2.037
4	IT Infrastructure Modernization Programme	Yes	Yes but not recommended.	No. Not from the approach but possibly at the level of the grade of hardware chosen.	2019 March - 2023 December	2.846
5	Unified Communications Platform	Yes	Yes but is not recommended	No	2020 March - 2023 November	0.4
6	Data Centre Operations Modernization	Yes.	No.	No	2020 March - 2023 November	0.639
7	Enterprise Analytical Tool – Loss Reduction	Yes	Yes. For approximately one (1) year at least.	No	2020 January - 2021 December	0.307
8	Information Security Strategy	Yes	No	No	2019 February - 2023 November	1.645
9	Oracle Modification Project	Yes	No	No	2020 March - 2020 December	0.35

No.	Project Description	Is the Project Necessary?	Can the Project be delayed? And if so, for how long?	Are there any cost effective alternatives?	Schedule	Cost (USD M) (including IDC)
	(Separation of Accounts)					
10	Expansion of Enterprise Architecture, Business Intelligence and Analytics Capability	Yes	Yes. For approximately two (2) years.	No.	2019 January - 2023 December	3.56
11	OMS Replacement - OSI Electra OMS – Project No. 60	Yes	No	No	2020 June – 2021 May	
12	ADMS Rollout - OSI Integra DERMS – Project No. 61	Yes	No	No	202 January 1 – 2021 June	

7.346. Even though JPS provided economic cost/benefit analysis for some of the IT projects, this was not necessary as per the Final Criteria. The analysis that JPS provided indicated that the projects should be implemented. The OUR has no technical basis to challenge this at this time.

7.347. In terms of costing, the OUR did not receive enough information to do any meaningful cost benefit analysis of these projects. Very few quotations were provided and these did not allow for a review of overall project costs. The OUR's analysis of JPS' IT project as set out in Table 7.52 above is very limited. The OUR however, is of the view that these projects are critical to the success of the initiatives in transmission, distribution and system losses that the projects should be implemented.

7.348. The OUR therefore approves the implementation of the projects at the cost proposed by JPS (excluding IDC). A summary of the OUR approved IT Capital Investment Plan follows.

7.5.11. Summary of the OUR's Assessment of JPS' Proposed IT Capital Investment Plan

7.349. Based on the outcome of the OUR's assessment of JPS' IT capital expenditure proposal submitted in its Application, the OUR makes the following determination.

7.350. Total IT capital expenditure approved is US$26.481M over the Rate Review period.

7.351. Table 7.53 below shows JPS' proposed capital expenditure for IT projects versus the OUR's approved capital expenditure. These costs do not include IDC as explained earlier.

7.352. The OUR approves JPS' proposed capital expenditure of US$26.2481M (excluding IDC).

DETERMINATION # 8

The Office approved capital expenditure for IT projects/programmes during the Rate Review period is detailed in Table 7.53 below.

7.5.12. General Plant Capital Investment Plan

7.353. Given that the General Plant projects were only 4% of the Capital Investment Plan portfolio, the OUR did not conduct a detailed review of these projects.

7.354. The OUR however reduced the budget for the project titled "Funding for Unforeseen Finance Projects". JPS did not provide a business case for the project and so the OUR is unable to determine the nature of the unforeseen projects. The budget allocated to such project was US$6.2M. This level of allocation appears to be fairl even though it falls into minor projects based on the classification in the Final Criteria.

7.5.13. Summary of the OUR's Assessment of JPS' Proposed General Plant Investment Plan

7.355. Based on the outcome of the OUR's assessment of JPS' General Plant capital expenditure proposal submitted in its Application, the OUR makes the following determination:

7.356. Total General Plant capital expenditure approved is US$14.185M (excluding IDC) over the Rate Review period.

7.357. Table 7.53 below shows JPS' proposed capital expenditure for General Plant projects versus the OUR's approved capital expenditure. These costs do not include IDC as explained earlier.

DETERMINATION # 9

The Office approved capital expenditure for General projects/programmes during the Rate Review period is detailed in Table 7.54 below.

Table 7.53: Approved Capital Investment Plan for IT for 2019 – 2023

IT Capital Projects	JPS Total Project Cost (US$'000)	JPS Proposed CAPEX (no idc) (US$'000)					OUR Approved Total Project Cost (US$'000)	OUR Approved CAPEX (no idc) (US$'000)				
		2019	2020	2021	2022	2023		2019	2020	2021	2022	2023
Electric Grid Communication Network Rehabilitation and Upgrade	**4,730**	344	1,099	1,028	1,130	1,130	**4,730**	344	1,099	1,028	1,130	1,130
Expansion of Enterprise Architecture, Business Intelligence and Analytics Capability	**3,497**	206	884	776	815	815	**3,497**	206	884	776	815	815
Information Technology Security Program	**1,510**	-	378	524	286	321	**1,510**	-	378	524	286	321
Business Efficiency	**2,396**	513	594	552	422	314	**2,396**	513	594	552	422	314
Upgrade CS	**2,751**	-	196	1,375	1,179	-	**2,751**	-	196	1,375	1,179	-
Enterprise Asset Management	**2,410**	953	795	662	-	-	**2,410**	953	795	662	-	-
IT Infrastructure Modernization	**2,576**	430	586	659	296	605	**2,576**	430	586	659	296	605
Introduce DERMS	**700**	-	-	-	700	-	**700**	-	-	-	700	-
SCADA/EMS Project Upgrade	**2,037**	-	-	-	2,037	-	**2,037**	-	-	-	2,037	-
Replacement of OMS	**2,126**	-	1,126	1,000	-	-	**2,126**	-	1,126	1,000	-	-
Unified Communications Platform	**393**	-	196	196	-	-	**393**	-	196	196	-	-
Data Centre Operations Modernization	**475**	-	-	270	205	-	**475**	-	-	270	205	-
Phase 3 DMR Implementation & Radios for two-way Radios	**545**	545	-	-	-	-	**545**	545	-	-	-	-
Oracle Modification Project (Seperation of Accounts)	**336**	-	196	139	-	-	**336**	-	196	139	-	-
TOTALS	**26,481**	**2,991**	**6,053**	**7,182**	**7,070**	**3,185**	**26,481**	**2,991**	**6,053**	**7,182**	**7,070**	**3,185**

Table 7.54: Approved Capital Investment Plan General Plant for 2019 – 2023

IT Capital Projects	JPS Total Project Cost (US$'000)	JPS Proposed CAPEX (no idc) (US$'000)					OUR Approved Total Project Cost (US$'000)	OUR Approved CAPEX (no idc) (US$'000)				
		2019	2020	2021	2022	2023		2019	2020	2021	2022	2023
Facilities Improvements	**4,640**	638	509	1,000	1,492	1,000	**4,640**	638	509	1,000	1,492	1,000
Funding for unforeseen projets	**6,104**	1,193	491	982	2,456	982	**1,684**	1,193	491	-	-	-
Purchase of laptops, desktops, Tablets	**1,760**	-	440	440	440	440	**1,760**	-	440	440	440	440
Install Charging Stations (Electric Vehicle Roll out)	**1,465**	491	582	393	-	-	**1,465**	491	582	393	-	-
Security Cameras and Systems	**1,179**	196	250	250	246	237	**1,179**	196	250	250	246	237
Battersea Operations Building	**1,161**	161	1,000	-	-	-	**1,161**	161	1,000	-	-	-
Repurpose of Old Control Room for DTS & CEOC	**1,000**	-	-	-	-	1,000	**1,000**	-	-	-	-	1,000
Safety Devices and Monitoring Stations	**196**	196	-	-	-	-	**196**	196	-	-	-	-
Transportation Equipment	**432**	221	211	-	-	-	**432**	221	211	-	-	-
Video Wall Upgrade	**335**	-	49	-	287	-	**335**	-	49	-	287	-
Build Network Operations Centre	**330**	-	-	-	-	330	**330**	-	-	-	-	330
TOTALS	**18,604**	**3,097**	**3,532**	**3,066**	**4,920**	**3,990**	**14,184**	**3,097**	**3,532**	**2,084**	**2,464**	**3,008**

7.6. Conclusion

JPS presented a Capital Investment Plan for the Rate Review period with projects spanning the following areas of operations:

- Generation;
- Transmission;
- Distribution;
- System Losses mitigation;
- Information Technology (IT);
- General Plant.

7.358. The total value of the projects proposed by JPS was US$468.548M (excluding IDC) while the OUR approved a budget of US$423.99M (excluding IDC). While IDC will be recognized while computing Depreciation, for the purposes of inclusion in the Rate base, IDC will be excluded. This is because JPS will earn a return on CWIP, and including IDC in the project case in the rate base will enable JPS to earn a return twice.

7.359. In conducting its assessment of the Capital Investment Plan, the OUR applied a methodology which included technical, financial/economic and costing assessment of JPS' projects. The OUR found that JPS generally followed the guidelines established in the Final Criteria when submitting information for the projects. JPS, also for the most part, supplied invoices and quotations which allowed OUR's external Consultant to do the necessary costing studies. This information was somewhat lacking for IT and General Plant projects/programmes.

7.360. The OUR takes the view that most of the projects proposed were justified based on the cost/benefit analysis or other justifications provided. There were instances in which the OUR's technical or other analysis indicate that aspects of some projects should not be done or in a few cases, projects were removed from the Capital Investment Plan. The Bellevue-Roaring River project was removed because the OUR's technical analysis indicates that the project will not solve the problem identified by JPS and in any case, a cheaper alternative was identified, which the OUR urges the JPS to explore further and to present to the OUR. The OUR also determined that the implementation time for the Smart Meter programme should be extended by one (1) year to balance the need for investment against the potential rate impact on customers.

7.361. Generally, the project cost for most projects were approved. Where changes were made, the OUR provided the extent of the changes and full explanation of the rationale for the changes.

8. Rate Base

8.1. Introduction

8.1. The Rate Base is defined in section 3.6.1 of the Final Criteria as the value of the net investment in the Licensed Business. JPS' Rate Base includes the assets that are in use, will be expected to be in use over the Rate Review period and are deemed useful in providing electricity services to its customers. The Rate Base shall be based on the approved net book value of the company's assets for the Rate Review period as informed in the Business Plan.

8.2. Consistent with paragraph 29, Schedule 3 of the Licence, the Rate Base shall be computed as follows:

$$\begin{aligned} \textbf{\textit{Rate Base}} = {} & \textbf{\textit{Property Plant and Equipment}} + \textbf{\textit{Intangible Assets}} \\ & + \textbf{\textit{Working Capital}} + \textbf{\textit{Long Term Receivables}} + \textbf{\textit{Other Assets}} \\ & - \textbf{\textit{offsets}} \end{aligned}$$

8.3. The components of the Rate Base identified in the above formula shall be as follows:

i. The Property Plant and Equipment ("PPE"); along with the net book value of the company's assets, it shall also include construction work in progress offset by: impaired assets, customer financed assets (including electricity efficiency improvement fund assets), rural electrification assets, less revaluation balance/capital reserve;

ii. Intangible Assets (i.e. assets that are not physical in nature, e.g. copyright, software licences);

iii. The working capital (i.e. accounts receivable + cash & short term deposits + tax recoverable + inventory – account payable – customer deposits – bank overdraft – short term loans) deployed;

iv. Long Term Receivables;

v. Other Assets; and

vi. Offsets which, refer to:

- Employee benefit obligations; and
- Deferred revenue.

8.4. The EEIF, SBF and other customer contributed assets shall not be included in the rate base, but JPS is required to list these assets along with their net book value as of 2018 December 31.

8.5. The value of the Electricity Disaster Fund (EDF) assets as of 2018 December 31, shall be clearly stated and shall not be included in the Rate Base. JPS shall also clearly identify the forecasted value of EDF assets for the Rate Review period.

8.2. JPS Proposal

8.6. JPS' proposed forecasted Rate Base for the Rate Review period is as follows:

- 2019: J$90,428 million (US$706.4 million);

- 2020: J$91,826 million (US$717.2 million);
- 2021: J$94,119 million (US$735.4 million);
- 2022: J$96,847 million (US$757.0 million);
- 2023: J$96,081 million (US$751.3 million).

8.7. JPS stated that its forecasted Rate Base reflects the NBV of fixed assets in-service, five-year capital plan forecast, allowance for working capital and customer funded assets offset. Details of JPS' proposed Rate Base are shown in Table 8.1 below.

Table 8.1 – JPS' Proposed Rate Base 2019-2023 (J$ millions)

	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
Gross Plant in Service (Opening Balance)	284,056	298,271	310,328	321,681	334,439	347,419
Additions:						
Capital Investment	14,215	8,403	10,376	11,221	10,934	10,981
Other (capital Spares)		11,432	1,881	0	0	0
Disposal /Retirement		(7,778)	(904)	1,537	2,046	(847)
Gross Plant in Service (Closing Balance)	298,271	310,328	321,681	334,439	347,419	357,552
Accumulated Depreciation (Opening Balance)	188,375	198,835	209,885	221,060	232,212	243,507
Addition	10,459	7,371	8,780	9,666	10,243	10,513
Retirement						
Accelerated Depreciation (OH and HB)		1,606	398			
Accelerated Depreciation (Bogue, Rockfort and HB)		689	689	689	689	689
Stranded Asset Write Off		1,385	1,309	797	364	210
Accumulated Depreciation (Closing Balance)	198,835	209,885	221,060	232,212	243,507	254,920
Net Fixed Assets Closing Balance	99,436	100,443	100,621	102,227	103,912	102,632
Working Capital	3,872	5,921	5,994	5,564	5,466	4,970
Other Offsets: SSP Tax Allowance	0	(206)	(146)	(112)	(81)	(80)
Other Offsets: ALRIM Tax Allowance		(150)	(127)	(109)	(48)	(47)
Offsets	(15,389)	(15,580)	(14,516)	(13,451)	(12,402)	(11,394)
Rate Base	**87,919**	**90,428**	**91,826**	**94,119**	**96,847**	**96,081**

8.8. JPS further argued that the value of its proposed net fixed assets has increased primarily as a result of greater capital investments driven by the fact that the company has been investing a higher level of capital expenditure in acquiring new plants compared to that recovered through the depreciation charge.

8.2.1. Other Rate Based Components: Long-term Receivables, Other Assets and Working Capital

8.9. Long-term Receivables are stated as zero (0) for the forecasted Rate Review period.

8.10. Other Assets are stated to be tax allowances on the Accelerated Losses Reduction Incentive Mechanism (ALRIM) and EEIF assets, which JPS estimates at J$356 million in 2019 and at

J$751 million for the remainder of the Rate Review period. The proposed Rate Base has been reduced by these amounts.

8.11. JPS' proposed Working Capital requirements for the Rate Review period for addition to the Rate Base are as follows:

- 2019: US$46.3 million (J$5,921 million);
- 2020: US$46.8 million (J$5,994 million);
- 2021: US$43.5 million (J$5,564 million);
- 2022: US$42 7 million (J$5,466 million);
- 2023: US$38.8 million (J$4,970 million).

8.12. JPS stated that to date, in determining its working capital requirement, the practice is to calculate the difference between current assets and current liabilities using end of year results. JPS is of the opinion that the point in time approach is not prescribed either in the Licence or in the Final Criteria.

8.13. JPS stated further that in past review periods, the company experienced significant financing challenges, due to having low levels of working capital, which translated into higher costs to the company. In 2013, JPS stated that it had a net finance cost of US$14.2 million, of which $5.7 million was interest costs associated with the low level of working capital. JPS argues that financing for the low level of working capital cannot be solved by taking on additional funding, given that it is marginally compliant with its loan financial covenants.

8.14. In computing the Cash Working Capital (CWC) component of the working capital, JPS used a lead-lag methodology in replacement of the difference between accounts receivable and accounts payable.

8.15. JPS stated that the lead-lag methodology more accurately reflects the actual time between payments for expenses it incurred in providing the service and revenues collected from customers during the year. This method of determining the amount of cash that the company requires on a day-to-day basis, JPS argues, is consistent with the Licence definition of working capital deployed.

8.16. The revenue lag measures the time period between when JPS provides service to its customers and when it collects revenues from the customers for the service provided. This JPS derived from three components;

1. Service (or meter reading Lag)
2. Billing Lag; and
3. Collection Lag

8.17. In determining the proposed service lag, JPS used 15 days, which is the mid-point between meter-reads. JPS stated that meters are read every 28-31 days.

8.18. Billing lag, which is the time between when meter readings are entered into the billing system and when invoices are sent out to customers, was stated as three (3) days.

8.19. Collection lag is the number of days between bills/invoices being posted into accounts receivable and the receipt of payments for these billed revenues. This JPS estimated to be 57.46 days using the accounts receivable turnover ratio approach. The derivation was presented and is represented in Table 8.2 below.

Table 8.2: JPS' Proposed Collection Lag Computation

2018	Accounts Receivable Adjusted for Bad Debt	Billed Revenue
January	155,493,323	67,707,617
February	156,902,038	65,828,682
March	143,651,738	72,637,577
April	144,453,979	66,726,817
May	140,452,747	70,886,394
June	144,343,786	73,273,404
July	144,824,575	81,313,392
August	134,350,213	77,398,374
September	134,148,306	80,040,049
October	125,822,365	76,630,977
November	127,929,445	78,803,452
December	120,237,832	74,149,618
Total Net Receivables	1,672,610,348	
Average Receivables	139,384,196	
Revenue	885,396,351	
AR to Revenue Ratio	0.16	
Collection Lag	57.46	

8.20. JPS computed a total revenue lag of 75.46 days, which is the sum of service, billing and collection lags as represented in Table 8.3 below.

Table 8.3: Computation of JPS' proposed Revenue Lag

Revenue Lags	Number of Days
Service Lag	15.00
Billing Lag	3.00
Collection Lag	57.46
Total	**75.46**

8.21. JPS stated that the Expense Lead was calculated by determining Service Lead and Payment Lead for operating expenses by category based on the 2017 actual O&M expenses.

8.22. JPS stated that it used the weighted average of each expense item, shown in Table 8.4 below, to determine the overall average for the proposed expense lead. The computed overall average for the proposed expense lead is 29.55 days as represented and shown in Table 8.4 below.

Table 8.4: Computation of JPS' Proposed Expense Lead

O&M EXPENSES	2017 Actual Expenses (US $000)	Weighting Factor	Service Lead	Payment Lead	Total Lead	Weighted Lead
PAYROLL	58,448	19.7%	15	0	15.00	2.96
OTHER BENEFITS	12,213	4.1%	15	0	15.00	0.62
TRAINING	334	0.1%	0	30	30.00	0.03
POWER PURCHASES FROM IPP	157,270	53.1%	15.00	22	37.00	19.64
THIRD PARTY SERVICES	27,962	9.4%	15.00	30	45.00	4.25
MATERIALS AND EQUIPMENT	5,876	2.0%	0	30	30.00	0.59
OFFICE AND OTHER EXP	26,384	8.9%	15.00	30	45.00	4.01
PREPAID INSURANCE	5,621	1.9%	-91.25	30	-61.25	-1.16
PREPAID SOFTWARE	2,249	0.8%	-182.5	0	-182.50	-1.39
PREPAID PROPERTY TAX						
	296,357	100.0%				29.55

1. Payroll and benefits expense leads are based on monthly payments.
2. The insurance payments are done multiple times throughout the year, but the main payments are done twice a year.
3. Software payments are done in the beginning of the period.

8.23. With the application of the results of the lead-lag study on the financials for 2018, JPS computed the cash working capital at J$3,432 million as reproduced in Table 8.5 below.

Table 8.5: JPS' Proposed Cash Working Capital for 2018 (J$ Million)

JAMAICA PUBLIC SERVICE COMPANY
2019-2023 RATE REVIEW FILING
2018 ACTUAL CASH WORKING CAPITAL
(in millions of JA dollars)

Line No.		Forecast Expense	Daily Expense	Revenue Lag Days	Expense Lead Days	Net Lag Days	Cash Working Capital
		A	B=A/365	C	D	E=C-D	F=BxE
1	Non-fuel Purchase Power Costs	18,326	50	75.46	45.00	30.46	1,529
2	Payroll, benefits, and training	8,046	22	75.46	15.00	60.46	1,333
3	Third Party Services	2,028	6	75.46	45.00	30.46	169
4	Materials & Equipment	556	2	75.46	30.00	45.46	69
5	Office & Other Expenses	1,011	3	75.46	45.00	30.46	84
6	Insurance	660	2	75.46	(61.25)	136.71	247
7	Bad Debt Written Off	1,110	3	75.46	75.46	0.00	-
8	**Total 2018 Cash Working Capital**	**31,736**	**87**				**3,432**

8.24. The total working capital requirement for 2018 based on the cash working capital approach outlined above was computed at J$3.872 billion as reproduced and displayed in Table 8.6 below.

Table 8.6: JPS' Proposed 2018 Total Working Capital Estimate (J$ Million)

	2018 JPS Actual
Cash Working Capital (lead-lag approach)	3,432
Supplies Inventory (year-end)	3,430
Fuel Inventory (year-end)	1,700
Less: Customer Deposits	(2,129)
Less: Short-term Loan	(2,560)
Less: Bank Overdraft	-
Total Working Capital Requirement	**3,872**

8.25. Based on the foregoing approach, JPS forecasted and proposed the 2019-2023, five-year average working capital requirement as J$5.58 billion. The amounts for the years are shown in Table 8.7 below.

Table 8.7: JPS' Proposed Working Capital Requirement 2019 to 2023

JAMAICA PUBLIC SERVICE COMPANY
2019-2024 RATE REVIEW FILING
WORKING CAPITAL REQUIREMENT
(in millions of JA dollars)

	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
Cash Working Capital	3,432	3,683	4,414	4,271	4,269	4,219
Supplies Inventory	3,430	3,145	3,004	2,670	2,525	2,058
Inventory Adj- Decomm. Cost		(24)	(486)	(396)	(396)	(396)
Fuel Inventory	1,700	1,231	1,182	1,081	1,053	1,028
Less: Customer Deposits	(2,129)	(2,113)	(2,120)	(2,062)	(1,984)	(1,939)
Less: Short-term Loan	(2,560)	-				
Total Working Capital Requirement	**3,872**	**5,921**	**5,994**	**5,564**	**5,466**	**4,970**

8.3. OUR Response

8.3.1. Other Rate Base Components: Long-term Receivables, Other Assets and Working Capital

8.26. Long-term Receivables – The OUR accepts JPS' proposal of zero (0) for the forecasted period 2019-2023.

8.27. Other Assets – These are listed as tax allowances on ALRIM and EEIF assets combined, and are offsets to the Rate Base. These assets are estimated by JPS to be valued at J$356 million for 2019 and J$751 million for the remainder of the Rate Review period. The OUR's evaluation shows that the amount that is to be offset for 2019 is $150 million and J$331 million for the remainder of the Rate Review period. The Rate Base has been reduced by these amounts. See details in Table 8.8 below.

Table 8.8: Other Assets for Period 2019 to 2023

Other Assets (J$'millions')	2019 JPS Proposed	2019 OUR Allowed	2020 JPS Proposed	2020 OUR Allowed	2021 JPS Proposed	2021 OUR Allowed	2022 JPS Proposed	2022 OUR Allowed	2023 JPS Proposed	2023 OUR Allowed
Other Offsets: SSP Tax Allowance	205.57	-	146.08	-	112.06	-	81.04	-	80.21	0
Other Offsets: ALRIM Tax Allowance	150.47	150.47	127.42	127.42	108.82	108.82	48.49	48.49	46.74	46.74
Total	**356.04**	**150.47**	**273.51**	**127.42**	**220.88**	**108.82**	**129.54**	**48.49**	**126.95**	**46.74**

8.28. Working Capital – Generally this refers to the funding that is required to manage the company's day to day trading operations and is usually calculated as current assets minus current liabilities. This funding is used to satisfy short-term obligations such as salaries, vendor payments, inventory management and other current expenses. The collection of receivables from customers is an important factor in the working capital computation.

8.29. JPS used a lead-lag methodology in its computation of the cash working capital component of the proposed working capital. JPS' use of this methodology as a replacement for the calculation of difference between accounts receivable and accounts payable was not used by the OUR in its calculation as it was not included in the Final Criteria, which guides the rate setting process.

8.30. However, it is observed that in JPS' computation of its proposed working capital customer deposits, which is an offset, did not include the amount of US$13.4 million for "customers' advances for construction". Customer advances for construction relate to non-interest-bearing deposits obtained by JPS in relation to construction projects being undertaken by potential customers. These amounts are refundable subject to certain conditions.

8.31. Customers' deposit as reported in the 2018 audited financial report is US$30 million and not US$16.6, which was offset by JPS. This adjustment was made to JPS' proposal and the results are shown in Table 8.9 below.

Table 8.9: Working Capital Computation Methods Results 2018 to 2023

Working Capital Computation Methods (J$ millions)	2018	2019	2020	2021	2022	2023
JPS Proposal Using Lead_Lag CWC	3,872	5,921	5,994	5,564	5,466	4,970
JPS Proposal Using Lead_Lag CWC (OUR adjusted)	2,163	2,915	3,953	3,522	3,424	2,929
OUR Computation Using Final Criteria Method	1,116	5,046	3,494	3,509	3,581	3,396

8.32. Paragraph 29 c. of Schedule 3 of the Licence and Criterion 3: b) iii of the Final Criteria defines working capital as the sum of accounts receivable, cash and short-term deposits, tax recoverable, and inventory; *less* accounts payable, customer deposits, bank overdraft and short-term loans.

8.33. The OUR applied the methodology outlined in the Licence and the Final Criteria and computed a working capital as shown in Table 8.10 below.

Table 8.10: Working Capital Historical and Forecasted Results 2014 to 2023

Working Capital (J$ millions)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Accounts Receivable	22,082	15,996	19,980	27,804	23,345	19,481	21,448	21,342	22,233	22,609
Cash and Short-Term Deposits	990	711	1,107	1,562	3,490	4,741	2,100	2,285	2,548	2,788
Tax Recoverable,	-	-	-	221	-	497	120	140	163	190
Inventory	4,307	3,931	4,114	5,300	5,129	5,356	4,690	4,753	4,890	5,020
Less:										
Accounts Payable	20,685	14,351	17,405	24,461	24,450	18,928	20,047	19,940	20,872	21,450
Customer Deposits	3,294	3,207	3,110	3,475	3,839	4,050	3,496	3,529	3,583	3,662
Bank Overdraft and Short-Term Loans	-	-	-	3,318	2,560	2,051	1,321	1,542	1,799	2,098
Total	**3,401**	**3,080**	**4,686**	**3,632**	**1,116**	**5,046**	**3,494**	**3,509**	**3,581**	**3,396**

8.34. Working capital as at year end 2018 was J$1.1 billion. This was significantly lower than in previous years. Over the last four (4) years (2014 to 2017), JPS recorded average working capital of J$3.7 billion. JPS reported that the low year end result for 2018 was due to the GOJ's decision to settle more that J$7 billion debt to the company. Consequently, JPS' accounts receivable was significantly reduced. In response, JPS did not correspondingly and simultaneously pay-down/reduce its accounts payables. In light of this, accounts receivable of US$182 million reported at year end 2018 was less the US$191 million, which was reported for accounts payable at year end. This unusual position was rectified year-ending 2019 as JPS reported US$152 million for accounts receivables and US$148 million for 2019 accounts payables year-end balances, within the expected range.

8.35. In its comments on the Draft Determination Notice, JPS asserted that J$100.6 million, representing construction advances that the OUR has removed should be added back to the working capital. JPS argued that construction advances are liabilities recorded by JPS for line extension projects where a customer bears the responsibility for the cost of the line extension until the project is completed and accepted by JPS. JPS stated that, under this process, the customer makes payment for the purchase of construction materials, design and labour that will be supplied by the company, following which the customer also pays directly to JPS' approved contractor for installation/construction of the line extension.

8.36. The OUR however, maintains the position that both ***customers' advances for construction*** and ***customers' deposit for electricity service***, which makes up total customer deposits, should be offset from working capital requirement.

8.37. JPS argues that "unlike customer deposits, construction advances are not cash in hand for JPS and not available to JPS for temporary cash management purposes." The OUR is of the view that this argument is not supported by empirical data. As evidenced in JPS' audited financial reports, (see data extracted from JPS' audited accounts 2013 to 2019 in Table 8.11 below) customers' advances for construction have been consistently retained on the company's books throughout the years and are available in a similar manner as does customers' deposit for electricity service.

Table 8.11: JPS' Customers' Deposits 2013 – 2019

Customers' Deposits 2013 - 2019 (US$'000')							
Year	2013	2014	2015	2016	2017	2018	2019
Customers' Deposit for Electricity Service	16,721	15,579	14,834	14,868	16,203	16,636	16,907
Customers'Advances for Construction	10,106	10,153	10,220	9,426	10,947	13,353	14,731
Total	26,827	25,732	25,054	24,294	27,150	29,989	31,638

8.38. Furthermore, JPS in its previous tariff review applications combined customers' advances for construction and customers' deposit for electricity service, presented them as customer deposits and treated them as an off-set to its rate base. As shown in the extracted "***Table 6-6: Rate Base***" below, which was taken from JPS' 2014 - 2019 Tariff Application, customer deposits of US$26.827 million, an off-set to JPS' 2013 rate base, is an aggregate of both US$16.721 million for customers' deposit for electricity service and US$10.106 million for customers' advances for construction.

8.39. The provisions of the Licence do not stipulate a change of treatment of customer advances and therefore, the OUR is of the view that its position, which is consistent with previous treatment is correct. Therefore the OUR maintains its treatment of customers' advances for construction as off-set to working capital and by extension the rate base.

Table 6-6: Rate Base

(US dollar thousands)	2008	2013	Change
Fixed Assets:			
Property Plants and Equipment	623,439	698,571	
Intangible Assets	4,007	9,877	
Rural Electrification Programme Assets	1,097	-	
Other Asset		4,606	
Long-Term Receivables		1,447	
Construction Work in Progress	(56,617)	(14,516)	
Exclusion of JPS managed IPP assets		(43,319)	
Net Fixed Assets	**571,926**	**656,667**	**15%**
Offsets:			
Customer Deposits	30,078	26,827	
Employee Benefits Obligations	17,706	6,908	
Deferred Expenditure (Tax)	58,418	39,917	
Deferred Revenue	-	1,654	
Total Offsets	**106,202**	**75,306**	**-29%**
Total Long Term Assets			
Current Assets:			
Cash and Short-Term Deposits	7,208	3,854	
Repurchase Agreements/ Restricted Cash	8,139	21,642	
Receivables	172,428	186,877	
Tax Recoverable	2,420	420	
Inventories	43,929	40,871	
Total Current Assets	**234,124**	**253,664**	**8%**
Current Liabilities:			
Bank Overdraft	775	1,938	
Short Term Loans + Current Maturity	66,002	37,492	
Payables	78,254	189,385	
Corporation Tax Payable	-	(1,148)	
Related Companies balances	161	698	
Total Current Liabilities	**145,192**	**228,365**	**57%**
Net Current Assets (Working Capital)			
Rate Base	**554,656**	**606,660**	**9%**

8.4. Offsets to Rate Base

8.4.1. System Benefit Fund (SBF)

8.40. Section 50 of the EA establishes the System Benefit Fund (SBF), and specifies that it should be administered and controlled by the Office. Subsections (2) and (3) of section 50 of the EA prescribes the sources of financing and the permitted usage of the SBF as follows:

> 2) *The System Benefit Fund shall be financed from-*
> a) *tariffs, as the Office may direct;*
> b) *fines collected pursuant to this Act;*
> c) *monies from the Consolidated Fund;*
> d) *any other source.*
>
> 3) *The resources of the System Benefit Fund shall be utilized –*
> a) *to increase the penetration of renewable energy or energy security;*
> b) *for the promotion of energy conservation;*
> c) *for the purpose of providing electricity to rural areas; and*

d) *for any other purpose that the Minister may prescribe by Order published in the Gazette.*

History of the System Benefit Fund

8.41. In a letter from MSET dated 2017 August 15, the OUR was informed that in light of indication that the OUR intends to discontinue the EEIF, the Minister with responsibility for energy is proposing that the SBF be established based on an annual inflow of US$5,000,000.00.

8.42. Consistent with Section 50(1) of the EA, the Office gave favourable consideration to the request from MSET to replace the EEIF with the SBF with an initial amount of US$5,000,000.00 payable into the SBF over a ten (10) month period. The EEIF was a customer-contributed fund which was introduced by the OUR in 2009 for the primary purpose of augmenting JPS' capital expenditure on system losses initiatives with the objective of accelerating loss reduction. In its 2018 Annual Rate Review Submission, JPS indicated that by the end of 2016 December, the EEIF had funded assets totaling US$60.6M.

8.43. The OUR approved the discontinuation of the EEIF and commenced the SBF in the 2017 Annual and Extraordinary Rate Review Determination Notice. The SBF was to be funded initially by transferring from the residual credit in the EEIF owed by JPS, which was provisionally assessed by auditors employed by the OUR. This preliminary audit indicated that the cumulative capital allowance tax benefits owing to the EEIF up to the end of 2016 was US$17.4M and that additional tax benefits would be due to the EEIF in 2017 and beyond.

8.44. On the basis of the results obtained from the preliminary audit, the OUR requested that JPS engage an Auditor to determine the outstanding amount due to the EEIF as at 2018 June 30 and the further amounts due from the capital tax allowances extending into future years. The OUR considered it prudent to have JPS transfer the residual funds and any outstanding obligations accruing to the EEIF to the SBF.

8.45. JPS engaged KPMG, and the results of KPMG's assessment was presented to the OUR during the 2018 Annual & Extra-Ordinary Rate Review.

8.46. The audit, conducted by KPMG on behalf of JPS, reviewed and re-computed the capital allowances to determine the accuracy of the calculation of the tax benefits due to the EEIF covering the period 2009 January – 2017 December. In addition, KPMG calculated the future tax benefits for all qualifying assets from 2018 January 1, up to the point where the assets are fully written down for tax purposes. Table 8.122 shows the summary results of the KPMG audit for tax allowance benefits up to 2027.

Table 8.12: KPMG's Assessment of Tax Allowance Benefits due to the EEIF

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
EEIF Assets in CWIP - Investment Allowance									2,924,234	
EEIF Assets Capitalised - Investment Allowances	87,948	2,364,588	990,138	3,381,013	4,747,027	65,515	278,607	830,435	1,020,700	
EEIF Assets Capitalised - Annual Allowances	13,192	770,366	1,094,138	1,973,423	3,960,463	3,968,029	4,161,282	4,834,084	5,688,409	5,570,890
Total Allowances earned to date	101,140	3,134,954	2,084,276	5,354,436	8,707,490	4,033,544	4,439,889	5,664,519	9,633,343	5,570,890
Tax Impact of Allowances	33,713	1,044,984	694,754	1,784,812	2,902,496	1,344,515	1,479,963	1,888,173	3,214,447	1,856,963

	2019	2020	2021	2022	2023	2024	2025	2026	2027
EEIF Assets in CWIP - Investment Allowance EEIF Assets Capitalised - Investmentl Allowance EEIF Assets Capitalised -Annual Allowances	4,926,435	4,653,923	3,297,069	926,994	858,020	713,912	694,341	675,539	657,218
Total Allowances earned to date	4,926,435	4,653,923	3,297,069	926,994	858,020	713,912	694,341	675,539	657,218
Tax Impact of Allowances	1,642,145	1,551,308	1,099,023	308,998	286,007	237,970	231,477	225,180	219,073

8.47. The KPMG assessment indicated that:

- the amount owing to the EEIF up to the end of 2017 December was US$14.4M and was projected to be US$16.2M up to the end of 2018;
- the future benefit beyond 2018 amounts to US$12.3M.

8.48. During the 2018 Annual Review, JPS indicated to the OUR that only 76% of the amount calculated by KPMG was owing to the EEIF as JPS had contributed to investment in system losses reduction assets. This, JPS indicated, was confirmed by the KPMG report, which indicated that up to the end of 2017, a cumulative amount of US$83.6M of investments were made for system losses reduction assets while the amount contributed by EEIF was US$63.6M.

8.49. JPS further provided its management calculation of the amount of money that it believed was due to the EEIF up to the end of 2018. The calculation is summarized in **Table 8.133** below.

Table 8.13: JPS' Management Calculation of the amount of Liabilities owing to the EEIF

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total to end of 2017	Total to end of 2018
Tax Impact of Allowances	33,713	1,044,984	694,759	1,784,812	2,902,496	1,344,515	1,479,963	1,888,173	3,214,447	1,856,963	14,387,862	16,244,825
Proportional of EEIF funding to total asset cost	76%	76%	76%	76%	76%	76%	76%	76%	76%	76%		
Tax Impact: Capital Allowance US$ - Customer funded	25,622	794,188	528,017	1,356,457	2,205,897	1,021,831	1,124,772	1,435,011	2,442,980	1,411,292	10,934,775	12,346,067

8.50. The OUR disagreed with JPS' calculations shown in Table 8.13 above as it did not factor annual variations in the proportion of investments made by JPS versus the EEIF. Additionally, the calculation did not make any adjustment for the time value of money. When costs are brought to present value using opportunity cost as the discount rate, these variations are meaningful.

8.51. Since the OUR was unable to determine the annual variations in the proportion of investments made by the EEIF versus JPS' investments, the OUR determined in its 2018 Annual & Extraordinary Rate Review Determination Notice that a further audit/assessment of the EEIF investments was to be conducted and that a decision on the amount owing to the EEIF would be made in the Determination Notice for the Rate Review Period. Once this review is conducted, the OUR would be in a position to determine if any amounts will be available to be transferred to the SBF.

Deductions from the EEIF Residual Amount

8.52. Prior to the commencement of the KPMG audit, to satisfy the Minister's request, the OUR determined that JPS was to make payments of US$500,000 per month for ten (10) months into the SBF, commencing 2017 September, for an accumulated total of US$5M by 2018 June. Following a request made by JPS, the OUR approved the delay of the commencement of the payments to SBF to 2018 January at an accelerated funding rate that would still achieve the US$5M total by 2018 June. In its 2018 Annual Tariff Adjustment, JPS proposed that rather than paying monthly payments into the SBF that the OUR considers setting off the residual amount owing to the SBF against its expenditure on the Smart Streetlight Programme (SSP), which JPS had commenced in 2016 using its own funding.

8.53. The OUR was of the view that the residual funds owing to the EEIF, representing the capital allowance tax benefits was a viable source of financing for the SSP and approved JPS' request to set off these amounts against its expenditure up to the end of 2018 on the SSP. This decision by the OUR obviated the immediate need to adjust tariffs for customers to fund the SBF to the level that is required to support the SSP. Additionally, this decision was not inconsistent with the funding mechanism prescribed in Condition 28 of the Licence, which permits the Office to either utilize the SBF or some other "Fund" to allow JPS to recover its expenditures on the SSP. The OUR's intent was that any residual monies remaining after the amount of money awarded for the SSP up to 2018 December was deducted would be transferred to the SBF, once the amount due to EEIF is calculated in the 2019 – 2023 Rate Review exercise.

8.54. JPS had indicated that its expenditure on the SSP up to the end of 2017 December was US$11.997M, and that it was projected to spend an additional US$2.523M up to the end of 2018 December. The OUR allowed JPS to recover the amount it spent in 2017 with opportunity cost to compensate JPS for using its own capital in 2017. The total amount that was to be recovered by JPS is shown in Table 8.144 below:

Table 8.14: Capital Expenditure Recoverable by JPS

	Unit	Value
Capital Spend on SSP in 2017	US$	11,997,000
WACC	%	13.22%
Opportunity Cost	US$	1,586,003
Total Amt. due to JPS for 2017 expenditure	US$	13,583,003
Total Amount projected for 2018	US$	2,523,000
Total Amount of set-off required	**US$**	**16,106,003**

JPS' Proposal for use of EEIF Funds for the Rate Review Period

8.55. Similar to its proposal in the 2018 Annual Review, JPS is proposing that the OUR approves a direct set-off of the total capital expenditure cost of the SSP against the commensurate tax allowances associated with the benefits of the EEIF assets during the Rate Review period.

8.56. JPS' forecast of capital expenditure for the SSP between 2019 and 2021 is shown in Table 8.15 below. JPS is projecting to spend a total amount of US$24.379M for the period.

Table 8.15: JPS' Forecast of Capital Expenditure for the SSP

DIVISION	Project Name	2019	2020	2021	2022	2023	Total
Technology and Inovation	Smart Streetlight	8,400	8,994	6,984	-	-	24,379

8.57. According to JPS, it relied on the review of the EEIF conducted by KPMG in the 2018 audit, which determined the future tax benefits for all qualifying assets associated with the EEIF to the point where the assets are fully written down. The company indicated that the tax benefits calculated by KPMG is shown in the Table 8.16 below.

Table 8.16: JPS' Statement of Tax Benefits calculated by KPMG

Tax Rate	33.33%					
	2018	2019	2020	2021	2022	2023
EEIF Asset in CWIP - Investment Allowances	-	-	-	-	-	-
EEIF Asset Capitalised - Investment Allowances	-	-	-	-	-	-
EEIF Asset Capitalised - Annual Allowances	5,570,890	4,926,435	4,653,923	3,297,069	926,994	858,020
Total Allowances earned to date	5,570,890	4,926,435	4,653,923	3,297,069	926,994	858,020
Tax impact of Allowances	1,856,963	2,824,220	1,551,308	1,099,023	308,998	286,007

8.58. JPS' SBF proposal is for the total tax benefit of US$6.1M due to the EEIF as at 2023 December 31, to be offset against the forecasted CAPEX for the SSP over the Rate Review period.

8.59. JPS also claimed that when the total tax benefits for the respective years as determined by the KPMG audit was added to the net book value (NBV) of the existing Smart Streetlight assets, this resulted in a cumulative offset of J$6.1B (US$47.5M) over the Rate Review period, as reflected in Table 8.17 below.

Table 8.17: JPS' Calculation of Rate Base Offset for Smart Streetlight Programme

Offsets (J$M)	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	Total 2019-2023
Smart Streetlight Program	1,299	1,220	1,141	1,062	984	905	5,312
SSP Tax Allowance Offset	-	362	199	141	40	37	777
							6,089

<u>OUR's Assessment of JPS' Proposal</u>

8.60. Before assessing the merits of JPS' proposal, the OUR, as determined in the 2018 Annual Rate Review, had to compute the actual amounts that was owing to the EEIF up to the end of 2018. As such, JPS was requested to provide information that shows the proportion of investment made into system losses reduction assets by the EEIF versus JPS for each year in the period 2009 to 2017 December. This information, which was submitted via e-mail on 2020 March 18, is presented in Table 8.18 below. Table 8.18 shows JPS' summary of the total investments into system losses reduction assets over the period, 2009-2017 and the investments that were sourced from the EEIF versus investments from JPS for each year over the period.

Table 8.18: JPS' Summary of Sources of Investment for System Losses Reduction Assets between 2009 and 2017.

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
	US$	US$	US$	US$	US$	US$	US$	US$	US$	US$
EEIF Fund revenue net of taxes	1,364,624	8,445,845	8,643,237	8,208,190	8,236,362	8,077,747	8,828,736	7,026,081	3,001,333	**61,832,156**
Investment in EEIF Related Projects										
Finalised projects	439,741	11,822,940	4,950,692	16,905,066	23,735,137	327,577	1,393,034	4,152,174	5,103,498	**68,829,859**
Capital Work in Progress as at 2017	4,996	5,260	44,702	2,586	76,829	3,603,846	1,601,174	1,672,653	7,659,124	**14,671,170**
	444,737	11,828,200	4,995,394	16,907,652	23,811,966	3,931,423	2,994,208	5,824,828	12,762,622	**83,501,029**
Difference	**919,887**	**(3,382,354)**	**3,647,842**	**(8,699,462)**	**(15,575,604)**	**4,146,324**	**5,834,528**	**1,201,254**	**(9,761,288)**	**(21,668,872)**
Net Investment in Losses projects										
Investment through EEIF tariff	444,737	9,365,733	4,995,394	11,856,032	8,236,362	3,931,423	2,994,208	5,824,828	14,183,440	**61,832,157**
Investment by JPS	-	2,462,467	-	5,051,619	14,154,786	-	-	-	-	**21,668,872**
Net Investment in EEIF related proj	444,737	11,828,200	4,995,394	16,907,651	22,391,148	3,931,423	2,994,208	5,824,828	14,183,440	**83,501,029**

8.61. The information provided by JPS was sufficient for the OUR to assess the amount that was owing to the EEIF up to 2018 December. In calculating this amount, the OUR computed the cumulative total of investments made by the EEIF and the cumulative amount made by JPS for each year of the period. The proportion of annual cumulative investment made by the EEIF was used to determine the tax benefits arising from the EEIF investments for each year.

8.62. The opportunity costs forgone was also factored by using the appropriate discount rate for each year during the period. Table 8.19 below shows the results of the OUR's calculations.

Table 8.19: The OUR's Computation of amount owing to the EEIF

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total to end of 201	Total to end of 2018
Tax Impact of Allowances	33,713	1,044,984	694,759	1,784,812	2,902,496	1,344,515	1,479,963	1,888,173	3,214,447	1,856,963	14,387,862	16,244,825
Proportional of EEIF funding to total asset cost	100%	80%	86%	78%	62%	64%	66%	69%	74%	74%		
Tax Impact: Capital Allowance US$ - Customer funded	33,713	835,316	595,686	1,392,395	1,790,652	862,948	974,880	1,297,925	2,380,284	1,375,073	10,163,799	11,538,873
Approved WACC	10.44%	10.44%	10.44%	10.44%	10.44%	10.44%	8.07%	13.22%	13.22%	13.22%		
Present Value of Tax Impact of	**84,744**	**1,901,229**	**1,227,650**	**2,598,323**	**3,025,628**	**1,320,269**	**1,350,525**	**1,663,780**	**2,694,958**	**1,375,073**	**15,867,104**	**17,242,178**

8.63. Table 8.19 shows that up to the end of 2018 December, the amount owing to the EEIF was US$17.242M.

8.64. In the 2018 Annual Review, the OUR had determined that JPS was allowed to set-off U$16.1M of its SSP expenditure against the amount owing to the EEIF up to 2018 December (although the full amount owing to the EEIF had not yet been determined). The US$16.1M was the estimated amount attributable to the EEIF at 2018 December. As it has turned out, the actual amount attributable to the EEIF was US$1.136M more than the 2018 Annual Review estimate.

8.65. Notably, the implication of the US$16.1M set-off against the SSP, meant that the smart streetlight assets are owned by customers, instead of JPS. In its Business Plan, JPS signaled its intention to invest approximately US$24M in the SSP during the Rate Review period. Even though this is perfectly normal and consistent with Condition 28(7) of the Licence, this would result in the dichotomization of the smart streetlight assets, that is, a part of the assets would be owned by customers and the rest by JPS. From the perspective of regulatory oversight, the Office considers such an arrangement to be untidy.

8.66. JPS has also indicated a preference for the full ownership of the smart streetlight assets. The OUR recognizes that full ownership of the smart streetlight assets would have a favorable effect on electricity rates in that, with ownership by the utility, the investment would be recovered over the 15-year depreciable life of the assets, instead of the 5-year period under customer ownership.

8.67. In this context, the Office approves the transfer of ownership of the smart streetlight assets which were implemented using the EEIF monies, to JPS. Accordingly, the US$16.1M allowed as a set-off against the SSP in the 2018 Annual Review, shall be treated as a loan to JPS based on an opportunity cost equivalent to the company's WACC of 11.87%.

8.68. The application of the WACC to the US$16.106M owing at 2018 December results in a balance of US$18.018M (or J$2,306.3M[5]) at the end of 2019. Therefore, if JPS is allowed to pay back a fixed amount annually to customers over the remainder of the Rate Review period, that is the 4-year period, the annual reduction in JPS' Revenue Requirement would be US$5.916M (or J$777,282M).

8.69. The OUR also computed the amount of money that would become due to the EEIF between 2019 and 2027. This is shown in Table 8.20 below.

Table 8.20: Projected Residual Funds due to the EEIF from 2019 to 2027

	2019	2020	2021	2022	2023	2024	2025	2026	2027
EEIF Assets in CWIP - Investment Allowance EEIF Assets Capitalised - Investmentl Allowance EEIF Assets Capitalised -Annual Allowances	4,926,435	4,653,923	3,297,069	926,994	858,020	713,912	694,341	675,539	657,218
Total Allowances earned to date	4,926,435	4,653,923	3,297,069	926,994	858,020	713,912	694,341	675,539	657,218
Tax Impact of Allowances	1,642,145	1,551,308	1,099,023	308,998	286,007	237,970	231,477	225,180	219,073
Proportion of Investments made by EEIF	74%	74%	74%	74%	74%	74%	74%	74%	74%
Amount due to the EEIF	1,215,187	1,147,968	813,277	228,659	211,645	176,098	171,293	166,633	162,114

8.70. The residual funds due to the EEIF from 2019 December to 2023 December will be US$3.617M. As previously noted, JPS owes an additional US$1.136M to the EEIF arising from the underestimation of the accumulated amount in the EEIF at the end of 2018. Consequently, JPS' combined (existing plus projected) liabilities to the EEIF over the period 2018-2023 amounts to US$4.753M.

[5] Assuming an exchange rate of J$128.00:US$1.00

8.71. The OUR considers that this sum may be treated in one of two (2) ways. The first is the transfer of the sums owning by JPS, as they become due, to the SBF. The second, would require the reduction in electricity rates annually by these sums, through the revenue-cap true-up mechanism as they become due. The activation of the SBF for the acquisition of the smart streetlight assets was as a result of a request made by the Minister responsible for Energy pursuant to the provisions of the Licence. Given this context, the OUR considers that it would be prudent to engage in further consultation with the Minster before making a final determination on the recovery of JPS' existing and projected liabilities to the EEIF. Therefore, the exact treatment to be accorded to the balances due to the EEIF shall be determined at the next Annual Review.

DETERMINATION: # 10

The Office determines that:

a) JPS shall be allowed ownership of all the smart streetlight assets, including those acquired under the SSP prior to the Rate Review period. The US$16.1M provided through the SBF to assist JPS in the initial phases of the SSP in the 2018 Annual & Extraordinary Rate Review Determination Notice has been deemed to be a loan to the company by customers and shall be repaid to customers via a reduction in the company's Revenue Requirement.

b) The reduction in the Revenue Requirement, which includes an opportunity cost equivalent to JPS' WACC, shall be effected via four (4) equal payments of US$5.916M over the Rate Review period.

c) The OUR after consulting with the Minister with responsibility for Energy, shall determine at the next Annual Review, whether the JPS' liabilites to the EEIF, consisting of what is currently owed and what will become due to customers, should be credited to the SBF or be used to reduce rates via the Annual Review true-up exercises.

8.5. SUMMARY OF JPS' FIXED ASSET IN SERVICE DETERMINATION

JPS' Proposal

8.72. Based on the Application, JPS' forecasted Rate Base for the Rate Review period is as follows:

- 2019: J$90.428 Billion (US$706.4 M);
- 2020: J$91.826 Billion (US$717.2 M);
- 2021: J$94.119 Billion (US$735.4 M);
- 2022: J$96.847 Billion (US$757.0 M);
- 2023: J$96.081 Billion (US$751.3 M).

8.73. The computation of the proposed Rate Base for each year is presented in Table 8.21 below.

Table 8.21: JPS' Proposed Rate Base Rate Review Period

JPS' PROPOSED RATE BASE 2019-2023 (J$ Million)						
Component	**Actual**	**Forecast**				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**
Gross Plant in Service (Opening Balance)	284,056	298,271	310,328	321,681	334,439	347,419
Additions:						
Capital Investment	14,215	19,836	12,257	11,221	10,934	10,981
Other (capital Spares)						
Disposal /Retirement(		(7,778)	(904)	1,537	2,046	(847)
Gross Plant in Service (Closing Balance)	298,271	310,328	321,681	334,439	347,419	357,552
Accumulated Depreciation (Opening Balance)	188,375	198,835	209,885	2221,060	232,212	243,507
Addition	10,459	7,371	8,780	9,666	10,243	10,513
Retirement						
Accelerated Depreciation (OH and HB)		1,606	398			
Accelerated Depreciation (Bogue, RF and HB)		689	689	689	689	689
Stranded Asset Write Off		1,385	1,309	797	364	210
Accumulated Depreciation (Closing Balance)	198,835	209,885	221,060	232,212	243,507	254,920
Net Fixed Assets Closing Balance	99,436	100,443	100,621	102,227	103,912	102,632
Working Capital	3,872	5,921	5,994	5,564	5,466	4,970
Other Offsets: SSP Tax Allowance		(206)	(146)	(112)	(81)	(80)
Other Offsets: ALRIM Tax Allowance		(150)	(127)	(109)	(48)	(47)
Offsets	(15,389)	(15,580)	(14,516)	(13,451)	(12,402)	(11,394)
RATE BASE	**87,919**	**90,428**	**91,826**	**94,119**	**96,847**	**96,081**

8.74. These Rate Base calculations were supported by, among other things, the following schedules:

- 2018 Asset Register with Depreciation Forecast 2019-2023, submitted 2020 February 14;
- Stranded Assets Summary, submitted 2020 March 12;
- Accelerated Depreciation Recovery, submitted 2020 March 12.

8.75. Consistent with the Licence and the Final Criteria, the Rate Base is the value of the net investment in the Licensed Business. It includes the assets that are in use, will be expected to be in use over the Rate Review period and are deemed useful in providing electricity services to its customers. The Rate Base shall be based on the approved NBV of the company's assets for the Rate Review period as informed by the Business Plan.

8.76. According to the Licence, the Rate Base should represent the relevant costs associated with JPS' property, plant and equipment and intangible assets and employed in the Licensed Business to carry out the activities of generation, transmission, distribution, supply and dispatch of electricity.

Fixed Assets in Service

8.77. With respect to fixed assets in service, it appears that there are discrepancies with the values proposed by JPS and the calculations in the referenced Fixed Asset Register and Depreciation Forecast.

8.78. The details of the assets included in the Fixed Asset Register and Forecast are summarized in Table 8.22 below.

Table 8.22: JPS' Fixed Assets in Service - Rate Review Period

FIXED ASSET IN SERVICE 2019-2023					
Year	**Cost (US$)**	**Depreciation (US$)**	**Depreciation Reserve (US$)**	**NBV (US$)**	**Remarks**
2018	2,192,860,019.75	79,709,942.18	1,546,904,271.26	645,955,748.49	2018 Fixed Asset
2019		64,920,438.05	1,611,824,709.43	581,035,310.32	
2020		47,334,942.61	1,659,159,652.04	533,700,367.71	
2021		41,065,748.92	1,700,225,400.96	492,634,618.79	
2022		39,358,400.94	1,739,583,801.90	453,276,217.85	
2023		36,024,612.20	1,775,608,414.10	417,251,605.65	

Review of Fixed Assets in Service

8.79. Based on the OUR's review and evaluation of the Fixed Asset Register and Depreciation Forecast, the net fixed assets in service were determined as shown in Table 8.23 below.

Table 8.23: OUR's Estimated Fixed Asset in Service - Rate Review Period

FIXED ASSET IN SERVICE - 2019-2023 FORECAST (U$ MILLIONS)						
Components	**2018 NBV**	**2019 NBV**	**2020 NBV**	**2021 NBV**	**2022 NBV**	**2023 NBV**
JPS Fixed Asset in-Service (US$M)	645.96	581.04	533.7	492.63	453.28	417.25
OUR Adjusted Fixed Assets in Service (US$M)		583.77	536.44	489.93	450.03	414.12
Fixed Assets Excluded (US$M)		36.14	27.40	24.17	21.55	19.24
NET FIXED ASSEST IN SERVICE (REGULATED)		**547.63**	**509.04**	**465.76**	**428.48**	**394.88**
Less: NON REGULATED ASSETS (US$M)						
Bogue Conversion Assets		8.63	8.23	7.83	7.43	7.03
Smart Streetlight Programme		9.60	8.99	8.37	7.76	7.14
EEIF		52.65	47.64	37.31	32.47	28.32
Estore		0.31	0.29	0.28	0.27	0.26
Munro Windfarm		6.17	5.62	5.07	4.52	3.97
Maggotty Hydro		32.14	31.25	30.36	29.47	28.59
Sub Total - Non Regulated		**109.50**	**102.02**	**89.22**	**81.92**	**75.31**
NET FIXED ASSET IN SERVICE		**438.13**	**407.02**	**376.54**	**346.57**	**319.57**

Fixed Asset Adjustment

8.80. Fixed assets were adjusted as follows:

- To account for the new OH#3 step-up transformer placed in service in 2018, which the OUR indicated in 2018 should not be retired but hold for use in the T&D system;
- Adjustments for incorrect asset lives used for depreciation calculations.

Fixed Assets Excluded

8.81. Fixed assets were excluded for the following reasons:

- OHPS and HBPS Retirements;
- Asset Write Off;
- Stranded streetlight assets;
- Stranded meter assets.

8.82. In the process of examining and evaluating the Fixed Asset Register and Depreciation Forecast the net fixed assets in service were reconciled against JPS' proposed values and the values presented in the 2018 audited financial accounts.

8.83. The results of the OUR's evaluation and analysis of the Rate Base are shown in Table 8.24 below.

Table 8.24: JPS' Proposed and OUR's Approved Rate Base (2018 – 2023)

JPS Rate Base (in millions of JA dollars)												
	2018		2019		2020		2021		2022		2023	
	JPS Actual	AFS/OUR Allowed	JPS Forecast	OUR Allowed	JPS Forecast	OUR Allowed	JPS Forecast	OUR Allowed	JPS Forecast	OUR Allowed	JPS Forecast	OUR Allowed
Gross Plant [Intangibles incl.] (Opening Balance)	**284,056**		**298,271**		**310,328**		**321,681**		**334,439**		**347,419**	
Additions:												
Capital Investment	14,215		8,403		10,376		11,221		10,934		10,981	
Other (capital Spares)			11,432		1,881		0		0		0	
Disposal /Retirement/Change in CWIP			(7,778)		(904)		1,537		2,046		(847)	
Gross Plant in Service (Closing Balance)	298,271		310,328		321,681		334,439		347,419		357,552	
Accumulated Depreciation (Opening Balance)	**188,375**		**198,835**		**209,885**		**221,060**		**232,212**		**243,507**	
Addition	10,459		7,371		8,780		9,666		10,243		10,513	
Retirement												
Accelerated Depreciation (OH and HB)			1,606		398							
Accelerated Depreciation (Bogue, Rockfort and HB)			689		689		689		689		689	
Stranded Asset Write Off			1,385		1,309		797		364		210	
Accumulated Depreciation (Closing Balance)	**198,835**		**209,885**		**221,060**		**232,212**		**243,507**		**254,920**	
Net Fixed Assets Closing Balance	**99,436**	**99,436**	**100,443**	**97,967**	**100,621**	**99,271**	**102,227**	**100,360**	**103,912**	**102,252**	**102,632**	**102,354**
Working Capital	3,872	2,163	5,921	2,915	5,994	3,953	5,564	3,522	5,466	3,424	4,970	2,929
Other Offsets: SSP Tax Allowance			(206)	0	(146)	0	(112)	0	(81)	0	(80)	0
Other Offsets: ALRIM Tax Allowance			(150)	(154)	(127)	(77)	(109)	(77)	(48)	(77)	(47)	(77)
Offsets:	**(15,389)**	**(15,389)**	**(15,580)**	**(14,551)**	**(14,516)**	**(13,564)**	**(13,451)**	**(12,586)**	**(12,402)**	**(11,588)**	**(11,394)**	**(9,988)**
Bogue Conversion Assets	1,148	1,148	1,096	1,105	1,045	1,053	994	1,002	943	951	891	900
Smart Streetlight Program	1,299	1,299	1,220	0	1,141	0	1,062	0	984	0	905	0
ALRIM	0	0	1,154	1,154	1,039	1,039	923	923	808	808	692	0
System Benefit Fund	0	0	-	0	0	0	0	0	0	0	0	0
EEIF	7,239	7,239	6,592	6,739	5,951	6,098	5,311	4,776	4,690	4,156	4,110	3,625
Capital Reserve	609	609	609	609	618	618	625	625	627	627	630	630
Estore	42	42	39	40	37	37	36	36	34	35	33	33
Munro	777	777	706	790	636	719	565	649	495	579	424	508
Maggotty	4,276	4,276	4,162	4,114	4,049	4,000	3,935	3,886	3,822	3,772	3,708	3,660
CB Hill Run DG Project		0		0		0		690		661		632
Rate Base	**87,919**	**86,210**	**90,428**	**86,178**	**91,826**	**89,582**	**94,119**	**91,219**	**96,847**	**94,011**	**96,081**	**95,217**

9. The Cost of Capital

9.1. Introduction

9.1. It is common for businesses such as JPS to source capital to finance its operations from both debt and equity. These sources of capital, however come at a cost as creditors require interest on loans and investors require a return on equity investments. It is within this context, that Condition 13 paragraph 7. of the Licence make provisions for JPS, pursuant to its duty to connect, to include in its rates charged to customers a reasonable rate of return on its capital.

9.2. The allowed return on investment, which is captured in the Weighted Average Cost of Capital (WACC) is computed by multiplying an approved rate of return to the rate base of the company. The overall rate of return or WACC is the weighted average cost of debt and the approved return on equity.

9.3. The mathematical representation of the return on investment (*ROI*) is as follows:

$$Return\ on\ Investment\ (ROI) = WACC * \ Rate\ Base$$

9.2. JPS' Return on Investment Proposal

9.4. JPS in its submission proposed a pre-tax WACC and a post-tax WACC of 12.12% and 8.08% respectively for the Rate Review period. The proposed WACC is based on the CAPM methodology and is predicated on the following parameters:

(i) Cost of debt: 7.45%;
(ii) Gearing ratio is 50%;
(iii) The CRP is 2.53%;
(iv) The return on equity is 11.20%.

9.3. OUR's Analysis of the Return on Investment Proposal

9.3.1. Cost of Debt

9.5. With respect to the cost of debt, paragraph 30 b. of Schedule 3 of the Licence states that "*[t]he interest rate will reflect the weighted average interest rate in place for the latest audited financial statements, corrected for known material changes in the funding structure related to refinancing or new PPE capital outlays…*"

9.6. Criterion 1 in the Final Criteria requires JPS to provide a schedule showing the weighted average interest rate of its long-term debt. The schedule should be based on JPS' audited financial position as at 2018 December 31 and include the following:

a) A list of all its long-term debt and their corresponding amounts;
b) The associated interest rates for each loan;
c) The computation of the weighted average interest rate;
d) Prudently incurred costs associated with the issuance of debts such as commitment fees, arrangement fees, due diligence fees, breakage costs and refinancing fees should be included in the non-fuel operating expenses.

9.7. In its submission, JPS proposed a weighted average interest rate of 7.45% based on its 2018 audited financials. In its computation, JPS excluded the interest rates on preference shares from its computation. Additionally, the outstanding balances of most of the loans were not the same as those listed in the audited financial statement.

9.8. With respect to the interest-bearing preference shares, the OUR is of the view that these should be included in the computation of the weighted average interest rate. This treatment is consistent with those of previous OUR determinations and is also in keeping with the International Accounting Standards (IAS), which recognizes preference shares as debt even though legally they are shares of the issuer.

9.9. In Determination 6 of the 2018 Annual & Extraordinary Rate Review Determination Notice, the Office approved a Refinancing Incentive Mechanism (RIM) in the amount of US$2.66M over the 2018-2019 period. Under RIM, JPS was to use the additional revenue allowed in the tariff to fund the refinancing of expensive debts so that financing benefits for the remaining tenure of the loans would flow to customers.

9.10. In JPS' 2018 December 31 Audited Financial Accounts, the company reported in its long-term loan schedule a US$177.2M Senior Note, which attracted an interest rate of 11% and repayable in 2021. This liability was refinanced under the RIM in early 2019 and was replaced by a Sagicor US$180M refinancing package with average variable interest rate of 7.18%.

9.11. Accordingly, an adjustment, "known and measurable", was made to JPS' 2018 long-term loan schedule to reflect the refinancing benefits (318 basis points lower rates) to be passed on to customers in the derivation of JPS' weighted average cost of debt.

9.12. With the 11% Senior Notes, the weighted average cost of debt would have been 8.77%. The OUR calculated the weighted average interest rate to be 7.57%. The details of the computation are shown in Table 9.1 below.

Table 9.1: JPS' Average Borrowing Cost as at 31 2018 December

JPS' Average Borrowing Cost as at December 31, 2018					
2018 Long-Term Debt Obligations	**Date of Maturity**	**Amount (US$)**		**Interest Rate**	
		JPS	**OUR**	**JPS**	**OUR**
NEXI /Citibank Japan Ltd.	27-Dec-20	16,250,000	15,478,000	4.35%	4.35%
Export Development Canada	15-Sep-20	1,529,042	1,512,000	2.01%	2.01%
PROPARCO	30-Nov-20	13,440,680	13,341,000	8.37%	8.37%
Peninsula Corporation	30-Jan-19	9,000,000	9,000,000	9.05%	9.05%
IFC US$30M Loan Facility	15-Sep-20	6,666,670	6,634,000	7.84%	7.84%
FCIB US$60.625M Loan (JMD Portion)	11-Oct-28	10,726,909	10,726,909	7.50%	7.50%
FCIB US$60.625M Loan (USD Portion)	11-Oct-28	25,000,000	24,311,000	6.00%	6.00%
Caribbean Development Bank	1-Jan-29	15,000,000	15,000,000	4.50%	4.50%
NCB Syndicated J$2.45B Loan	31-Jan-23	16,924,379	16,823,000	9.95%	9.95%
OPEC Fund for International Development	30-Nov-20	5,554,000	5,523,000	7.72%	7.72%
Citibank/ OPIC	15-Dec-26	65,000,000	20,000,000	7.63%	6.73%
Citibank/ OPIC	15-Dec-21	20,000,000	61,769,000	6.73%	7.63%
KFW Loan - DM 7M	30-Dec-30	4,270,711	4,270,711	7.00%	7.00%
Sagicor 180M Refinance (JMD Portion)	22-Feb-34	82,153,846	82,153,846	8.40%	8.40%
Sagicor 180M Refinance (USD Portion)	22-Feb-29	34,000,000	34,000,000	7.35%	7.35%
Sagicor 180M Refinance (USD Portion)	22-Feb-29	66,000,000	66,000,000	7.35%	7.35%
Preference Shares-Class B	n/a		38,000		7.00%
Preference Shares - Class C	n/a		6,000		5.00%
Preference Shares- Class D	n/a		61,000		5.00%
Preference Shares- Class E	n/a		27,000		6.00%
Preference Shares- Class F	n/a		24,556,000		9.50%
Total/Weighted Avg. Int. Rate		**391,516,237**	**411,230,466**	**7.45%**	**7.57%**

9.3.2. Return on Equity (ROE)

9.13. The cost associated with sourcing equity capital is derived by examining the return investors require for investing in JPS' business. This return is expected to be above the opportunity costs faced by risk-free investments. Theoretically, it is the excess above the risk-free rate that attracts investors to invest in JPS over alternative investments available.

9.14. Given the fact that a significant component of JPS' business operation is classified as a monopoly, the rate of return on equity is determined notionally by the industry regulator and not by market competition. Consequently, the determination of the appropriate return on equity for JPS is not a completely objective process.

9.15. Criterion 2 of the Final Criteria sets out the methodology for the computation of JPS' proposed ROE. The criterion states:

a) "*In computing the ROE, JPS shall use the CAPM methodology based on the formula below:*

$$Rate\ of\ Return\ on\ Equity\ =\ R_f\ +\ [\beta\ *\ (TMR\ -\ R_f)]\ +\ CRP$$

Where;

R_f = *Risk-free rate*
β = *Beta*
TMR = *Total Market Return*
CRP = *Country Risk Premium*

b) *In addition, the following shall be observed with regard to the data used in the ROE calculation:*

i. *R_f shall be the U.S. long-run historical average return on bonds (1998-2018);*
ii. *β shall be based on the latest information on the five (5) year beta for all U.S. electric utilities from Bloomberg database;*
iii. *The Mature Market Equity Risk Premium shall be computed indirectly by subtracting the risk free rate (R_f) from the Total Market Return (TMR)*[6].*
iv. *The TMR is the arithmetic average of long-run historical data of U.S. Market (1900-2018)*
v. *The CRP shall be derived from the 2018, one (1) year average of the bond yield spread of the ten (10) year Jamaican USD denominated sovereign bond and the US 10-year Treasury bond.*

9.16. Further, paragraph 30 c. of Schedule 3 of the Licence states, among other things, that:

"*The Bank of Jamaica will provide guidance on the ROE, which allows the Licensee the opportunity to earn a return sufficient to provide for the requirements of consumers and acquire new investments at competitive cost based on relevant market benchmarks prevailing internationally for a similar business as the Licensee and adjusted for country risk, which will be used by the Office and Licensee to calculate the WACC.*"

[6] *[NB: See *Return on Equity for Jamaica Public Service Company Limited Study*, NERA Economic Consulting, October 2017, for calculation methodology]

9.17. In keeping with this requirement, in developing the Final Criteria, the OUR consulted with the Bank of Jamaica (BOJ) on the ROE methodology. In addition, the OUR shared the results of its ROE study with the BOJ.

9.18. The ROE methodology study was conducted by NERA Economic Consulting (NERA), a globally recognised economic consulting firm in 2017. The study identified three main methodologies that are used globally for the derivation of the ROE. They are (1) the Capital Asset Pricing Model (CAPM), (2) the Dividend Growth Model and (3) Market to Asset Ratios.

9.19. The study revealed that CAPM was the most appropriate methodology for the Jamaican context, as it has very strong theoretical underpinnings that are supported by empirical evidence for explaining stock returns, even in emerging markets. Additionally, based on the nature of JPS' operations and regulatory environment, CAPM shows a clear advantage over the other models in its practicality. In this regard, both JPS and the OUR considered the use of CAPM as the most suitable approach for the computation of JPS' ROE.

9.3.3. CAPM Methodology

9.20. The CAPM is a backward-looking model that relies on historical data to estimate individual parameters. It is the most commonly used model for estimating the cost of equity in international regulation of natural monopolies. The data required for estimating the ROE under the CAPM is readily available and the application of different methods for estimating individual parameters has been extensively debated in international regulation. As such, OUR can draw on international best practice in applying the CAPM, and rely on reliable and easily accessible databases.

9.21. Notwithstanding the backward-looking nature of CAPM, the model must be applied in a manner that captures the forward-looking risk, for which an investor would require remuneration as required by the Licence. Furthermore, JPS' rates are designed on the basis of a forward-looking orientation, consequently, the OUR factors into the calculation historical data that are likely to most accurately capture expectations of the future in the regulatory period.

Risk-free rate (Rf)

9.22. The risk-free rate is the return an investor expects to receive on an investment made in safe assets, which returns do not co-vary with the market. A country's sovereign bond, such as the United States bonds, is considered safe assets, as there is little to no default risk in these bonds. Criterion 2 (b) of the Addendum to Final Criteria states that the risk-free rate shall be the U.S. long-run historical average return on bonds from 1998 to 2018.

9.23. JPS proposed to use the US 20-year Treasury bond and argued that the nature of the business involves the holding of an illiquid class of assets and that the length of bonds used in the valuation of the company's return should match the investment life of the assets. JPS therefore proposed a nominal risk-free rate of 4.24%.

9.24. As expressed in the Final Criteria on page 101, the OUR notes that the 10-year or 20-year Treasury bonds are typically used in CAPM valuations, therefore the U.S. 20-year Treasury bond is deemed as a suitable proxy for the risk-free rate. Consequently, the OUR approves the nominal risk-free rate of 4.24% and the corresponding real risk-free rate is 2.4%.

The Equity Beta (βe)

9.25. The equity beta measures the covariance between the returns of the company against that of the market. More specifically, the equity beta measures the systematic risk of the company. This is the risk that an investor faces even after diversifying his/her portfolio. In JPS' case, where the company is not publicly traded on the stock exchange, the equity beta can be derived by finding the unlevered beta for a group of similar companies, then re-levering it with JPS' tax rate and debt to equity ratio. The computation is as follows:

$$\beta_L = \beta_U * [1 + (1 - T) * \left(\frac{D}{E}\right)]$$

Where;

β_L = JPS' Re-levered Equity Beta

β_U= The unlevered beta for the group of U.S. electric companies from Bloomberg database

T= Tax Rate

D/E= JPS' Debt to Equity Ratio

9.26. The re-levered equity beta proposed by JPS is 0.75 and the unlevered beta being 0.45. However, in the supporting files provided by JPS, the equity beta computation was not based on the methodology which was outlined by JPS in the Application. Additionally, JPS used data covering the period 2012 October to 2017 September from the Bloomberg database. This, however, contravenes Criterion 2 (b) (ii) of the Addendum to Final Criteria which states that "β shall be based on the latest information on the five (5) year beta for all U.S. electric utilities from Bloomberg database."

9.27. The latest available data at the time of JPS' submission is the Bloomberg data covering the period 2014 January to 2018 December. It is more recent, and therefore represents a more appropriate five (5) year data-set for the computation of the equity beta. Furthermore, based on NERA's ROE study, the change from a price cap to a revenue cap regime would suggest that JPS should be exposed to less systematic risk, and consequently equity beta in this review should be lower than the previous review under the price cap regime.

9.28. Based on the most recently available data from the Bloomberg database, the OUR approves an equity beta of 0.68, which is derived as follows:

$$\beta_e = \beta_L = 0.407 \text{ x } [1 + (1-.3333)\text{x}.5/.5)] = 0.68$$

Mature Market Risk Premium (MMRP)

9.29. The Mature Market Risk Premium (MMRP), also known as the Equity Risk Premium (ERP), is the return in excess of the risk-free rate that an investor requires for investing in the market portfolio. It is computed indirectly by finding the difference between the Total Market Return (TMR) and the real risk-free rate. Criterion 2 (b) (iv) of the Addendum to Final Criteria states that the TMR shall be the arithmetic average of long-run historical data of the

U.S. Market from 1900 to 2018. The TMR for the 1900 to 2018 period is 8.30%[7] and the real risk-free rate of 2.4% derived above, results in an MMRP/ERP of 5.9%.

9.30. JPS argued in its submission that the ERP should be directly computed on a forward-looking basis as compared to the use of historical approach proposed by NERA. Consequently, JPS posited that it would be more appropriate to use the Discounted Cash Flow (DCF) two-stage methodology to determine the ERP since it is forward-looking in nature.

9.31. According to JPS, the DCF forward-looking methodology yielded an ERP of 6.6%. This translates to 70 basis points higher than the 5.9% using the historical arithmetical average approach recommended by NERA. However, JPS admits that the difference in the result is smaller and suggests that both approaches converge over time.

9.32. Consequently, JPS has decided to use the parameters computed by the historical approach recommended in NERA's study. NERA's study computes a TMR of 8.4% and a real risk-free rate of 2.5% for the period 1900-2016, resulting in an MMRP of 5.9%. By mere coincidence, this MMRP/ERP is the same computed by OUR because of JPS' use of the parameters from the NERA study instead of using updated data which covers 1900 to 2018.

Country Risk Premium (CRP)

9.33. The Country Risk Premium (CRP) is an additional return required by investors for investing in a specific country outside of the investor's home territory. Overseas investment options are usually associated with higher risks because of the geopolitical and macroeconomic risk factors that may affect investments.

9.34. In deriving the CRP applicable to JPS, the U.S. Treasury bond is used as a benchmark instrument as the USA is seen globally as the least risky of countries to invest in. Investors in Eurobonds[8] in countries outside the USA would seek a premium above the US Treasury bond in order to reward them for investing in a more risky country. This premium is defined as the CRP.

9.35. In the case of JPS, the Jamaican USD-denominated sovereign bond is used to derive the additional return investors are demanding for investing in a Jamaican company. Criterion 2 (b) (v) of the Addendum to Final Criteria states as follows:

> "*The CRP shall be derived from the 2018, one (1) year average of the bond yield spread of the ten (10) year Jamaican USD denominated sovereign bond and the US 10-year Treasury bond*."

9.36. JPS argues that the three-year average of the bond yield spread between the Jamaican USD-denominated 20-year sovereign bond and the U.S. 20-year Treasury bond should be used to compute the CRP. This however would contravene the provisions of Criterion 2 (b) (v) of the Addendum to Final Criteria.

9.37. Based on the results of JPS' analysis, it initially proposed a CRP of 3.90%, using a three (3) year average of the Jamaican and US 20-year bond and a nominal ROE of 12.57%. The

[7] Source: credit-suisse-global-investment-returns-yearbook-2019

[8] A Eurobond is a debt instrument that's denominated in a currency other than the home currency of the country or market in which it is issued.

company further states that the spread between the 10-year bonds have been lower than that of the spread between the 20-year bonds. Another argument raised by JPS is that by using a one-year average instead of a three-year average, it would disregard the possibility of future instability in the Jamaican economy as the "best year" if Jamaica's recently improved macroeconomic environment was chosen.

9.38. JPS mentioned in its submission that its initially… "*proposed ROE computation is actively being contested before the All Island Electricity Tribunal in the matter of an appeal against the Final Criteria, pending the outcome of a ruling; JPS in its 2019-2023 Rate Review submitted a revenue requirement as per instructions promulgated by the OUR in its Final Criteria Document for the computation of the Cost of Capital*."

9.39. In light of this, JPS proposed a CRP of 2.53%, which has been computed based on the provisions of Criterion 2: (b) (v) of the Addendum to Final Criteria.

9.40. The OUR's reasoning in response to JPS' arguments is to be found in the NERA study and the Addendum to Final Criteria. The OUR verified the CRP amount of 2.53%, which was derived from using the one (1) year average of the bond yield spread of the ten (10) year Jamaican USD denominated sovereign bond and the US 10-year Treasury bond.

9.3.4. Return on Equity Rate (ROE)

9.41. Based on the parameters that JPS has proposed, it arrived at a post-tax ROE of 11.20%. The OUR however, derives and approves a post-tax ROE of 10.78%, computed as follows:

$$\text{ROE (post tax)} = 4.24\% + [0.68 * (8.3\% - 2.40\%)] + 2.53\%$$
$$\text{ROE (post tax)} = 10.78\%$$

9.42. Table 9.2 below shows the parameters used in computing JPS' ROE under the CAPM methodology. The ROE derived by the OUR is 42 basis points lower than that which is proposed by JPS.

Table 9.2: JPS' Post-tax Return on Equity for the Rate Review Period

Return on Equity			
CAPM Parameters	**2014 OUR Determination**	**JPS' 2019 Proposal**	**2019 OUR Determination**
Nominal R_f		4.24%	4.24%
Real R_f	2.90%	2.50%	2.40%
β_U	0.49	0.45	0.41
β_L	0.88	0.75	0.68
TMR	7.90%	8.40%	8.30%
MMRP (ERP)	5.00%	5.90%	5.90%
CRP	5.58%	2.53%	2.53%
***ROE** $_{post\text{-}tax}$*	**12.25%**	**11.20%**	**10.78%**

9.3.5. Weighted Average Cost of Capital (WACC)

9.3.5.1. Capital Structure

9.43. JPS' capital structure is required for the calculation of the WACC. The weights of the WACC are comprised of both portions of the long-term debt and the shareholders' equity. The WACC is derived by finding the product of the debt to equity ratio in the capital structure and their respective rates.

9.44. In accordance with the Licence, *the WACC will be based on the actual capital structure of the Licensee corrected for planned and approved major changes (>3% absolute) in the gearing of the Licensee.*"

9.45. The capital structure of JPS consists of both 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 payable to equity shareholders are however 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 which were initially registered as collateral for the respective loans. This increases the security of such loans, consequently lowering the risk faced by lenders, and ultimately lowering the expected returns. Whereas, the cost of equity is relatively more expensive as shareholders are required to be compensated with higher returns as they face greater risks.

9.46. Table 9.3 below shows the actual capital structure and gearing ratio computed over the five-year period 2014 to 2018. Given that debt is cheaper than equity over the course of the Rate Review period, JPS plans to do further refinancing to acquire more debt. In the 2014-2019 Determination Notice, the OUR indicated that a capital structure that resulted in 50% debt and 50% equity was one that keeps parity of both customers' interest and the interest of investors.

9.47. Consistent with previous determinations on this matter, the OUR deems a gearing ratio of 50%.

Table 9.3: JPS' Gearing Ratio for the Period 2014 to 2018

Gearing Ratio, Shareholders' Equity and Long-Term debts (2014-2018)					
Year	**2018**	**2017**	**2016**	**2015**	**2014**
Gearing Ratio	**0.48**	**0.47**	**0.48**	**0.51**	**0.54**
Shareholders' Equity (US$'000)	441,084	424,147	395,411	366,891	336,220
Long Term Debts (US$'000) + CPLTD	411,230	378,733	368,892	381,905	398,765

9.3.5.2. Derivation of JPS' WACC

9.48. The overall ROR 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 9.4 below shows the comparison of the OUR determined WACC, against JPS' proposal and the 2014-2019 Determination Notice. JPS proposed a pre-tax WACC of 12.12%.

Table 9.4: JPS' Weighted Average Cost of Capital

WACC Parameters	2014 OUR Determination (Price Cap)	2019 JPS Proposal (Revenue Cap)	2019 OUR Determination (Revenue Cap)
Cost of Debt	8.07%	7.45%	7.57%
Return on Equity (ROE)	12.25%	11.20%	10.78%
Tax Rate	33.33%	33.33%	33.33%
Gearing Ratio	50%	50%	50.00%
Post-tax WACC	**8.82%**	**8.08%**	**7.91%**
Pre-tax WACC	**13.22%**	**12.12%**	**11.87%**

9.49. The pre-tax WACC computation is based on the foregoing approved parameters in Table 9.4 above:

$$WACC\ (pre-tax) = \frac{ROE}{(1-T)} * (1-\mathrm{G}) + \text{Interest Rate} * \mathrm{G}$$

$$WACC\ (pre-tax) = \frac{10.78\%}{(1-.3333)} * (100\% - 50\%) + 7.57\% * 50\%$$

$$\boldsymbol{WACC}\ (pre\ tax) = \mathbf{11.87}\%$$

Where;

WACC=Weighted Average Cost of Capital (pre-tax)

ROE= Return on Equity

T= Tax Rate

G= Gearing Ratio

Interest Rate= Cost of Debt

9.50. In light of the ROR on investment parameters calculated and endorsed by the OUR above, the Office approves a pre-tax WACC of 11.87%, which is applicable for the Rate Review period.

DETERMINATION # 11:

Consistent with the methodology outlined in the Final Criteria and Addendum to Final Criteria, the Office approves a pre-tax WACC and a post-tax WACC of 11.87% and 7.91% respectively for the Rate Review period. The approved WACC is based on the CAPM methodology and is predicated on the following parameters:

(i) Cost of debt: 7.57%
(ii) Gearing ratio is 50%
(iii) The CRP is 2.53%
(iv) The return on equity is 10.78%

10. Productivity Improvement Factor (PI-Factor)

10.1. The Productivity Improvement Factor Framework

10.1. The purpose of incentive-based regulation, within the context of an imperfect market structure, is to replicate the discipline that a competitive market would impose on the regulated firm if competition was present. Economic theory suggests that if the firm's prices are required to change at a rate equal to the difference between the rate at which input prices rise and its productivity increases, then the regulated firm would earn a normal profit, just as it would in a competitive market place. It was on this theoretical foundation that the price cap formula, which determines the annual maximum allowed change in the non-fuel electricity prices, was constructed. JPS was under a price cap framework from 2001 until 2016, at which time the maximum annual allowed change in prices (dPCI) was defined by the formula:

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

10.2. 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.

10.3. With the introduction of the Licence in 2016, JPS' tariff regime was changed from a price cap framework to one based on revenue cap. Under this new tariff regime, the maximum allowed annual change to non-fuel electricity revenues is now dictated by the following formula:

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

10.4. Thus, the revenue-cap system no longer has an explicit X-factor, as was the case under the price cap regime. Nevertheless, paragraph 11 of Schedule 3, of the Licence, indicates that productivity improvement ought to be taken into account in rate reviews. Accordingly, the Productivity Improvement Factor (PI-factor), described by the OUR in the Final Criteria, prescribes the application of an efficiency improvement path over the five years of the PBRM.

10.5. In developing the Final Criteria, the OUR engaged Consultants, DNV GL, to assist it in determining how the productivity improvement could be incorporated into the revenue cap regime. Based on the study conducted by the DNV GL, the OUR developed a methodology for incorporating the PI-factor into the revenue cap regime. This method consists of a 5-step process that may be encapsulated as follows:

1. Determination of the initial level of efficiency (E_0);
2. Determination of the efficiency target (E_T);
3. Determination of the number of years over which the efficiency target is to be achieved (Y_{ET});

4. Computation of the *PI-factor*;
5. Projection of allowed OPEX based on the *PI-factor*.

10.2. JPS' Proposed Productivity Improvement Factor

10.6. JPS' proposal for the PI-factor is summarized by the following:

1. The initial efficiency of JPS based on the DEA is 67% (E_0 = 67%);
2. The target efficiency is 74% (E_T = 74%);
3. Achievement of the target in five years (Y_{ET} = 5 years);
4. The resulting *PI-factor* is 1.9%.

10.7. The main elements of the proposal are the initial and target efficiencies proposed by JPS, which are 67% and 74% respectively. This means that JPS has proposed to move its operations from a 67% to 74% level of efficiency over the Rate Review period, which would require a 1.9% productivity improvement annually.

10.8. JPS stated that in determining the productivity factor, it applied the Data Envelop Analysis (DEA) methodology, but was mindful of its imperfections and therefore recommended other benchmarking approaches to complement the DEA analysis.

10.9. The company presented its historical O&M performance over the 2014 – 2019 period and explained the rationale for changes on a year-on-year basis. JPS explained that in some years, increases in O&M were driven by business initiatives from which customers benefitted, these included:

- Reliability improvement

Setting the Productivity Improvement Factor

Step 1: Initial efficiency level (*E_0*)

The initial level of efficiency is, as may be clear, the starting point for the setting of the *PI-factor*. To quantify the initial efficiency, the OUR prescribes a Data Envelopment Analysis (DEA) study. JPS was invited to present its counter study which includes the identification of what is its initial efficiency.

Step 2: Efficiency target (*E_T*)

The efficiency target is in principle 100%, but this is to be interpreted as a long-term target to be achieved over a time-period that exceeds the rate review period. The practical efficiency target reflects the more shorter-term expectation of what improvement can be achieved. This is, along with other considerations, determined on the basis of the results of the DEA study.

Step 3: Target achievement period (*Y_{ET}*)

The path from initial to target efficiency is to be achieved during a certain period of time. This period is denoted the target achievement period. As will be discussed later, this period is in principle equal to the duration of the Rate Review Period i.e. five years.

Step 4: Productivity improvement factor (*PI-factor*)

The *PI-factor* can be computed after the initial efficiency, target efficiency, and the achievement period have been determined. Starting with the initial efficiency E_0, the *PI-factor* should be such that:

$$E_T = E_0 \cdot (1 + PI)^{Y_{ET}}$$

From this the *PI-factor* can be easily derived:

$$PI = \left(\frac{E_T}{E_0}\right)^{\frac{1}{Y_{ET}}} - 1$$

Step 5: Annual OPEX allowances

The annual OPEX allowance in year *Y* can then be given by:

$$OPEX_Y = (1 - PI)^Y \cdot OPEX_0$$

Here, the $OPEX_0$ is the starting OPEX level which is based on the operating expenditures in the base year. The annual OPEX allowance for year *Y* can subsequently be fed into the computation of the revenue cap.

- Heat rate improvement
- Customer satisfaction improvement
- Reduction in system losses

10.10. In some years, increases in O&M resulted from an increase in payroll costs as a result of contractual obligations.

10.11. JPS summarized that performance over the period highlights the fact that O&M expenses are driven by many factors, which include:

- Foreign exchange movement;
- Local and US inflation;
- Business strategic priorities such as improving customer service, loss reduction and reliability improvement;
- One-off expense items and adjustments.

10.12. JPS opined that transmission and distribution utilities generally have a high level of fixed costs and drastic methods to reduce costs are not fully sustainable. This, it argued, is because increases in customer service, system reliability, heat rate performance and reduction in system losses, tend to lead towards increased costs. The company recommended that its business initiatives be given strong consideration when determining its O&M cost over the Rate Review period.

10.2.1. JPS' Proposed Benchmarking Methodologies

10.13. JPS recommended that more than one benchmarking methodology be employed to aid in the determination of a reasonable PI-factor. This, JPS contends, is necessary because of the weaknesses inherent in the DEA method. In its criticism of the DEA approach, JPS identified the following shortcomings:

- the results depend on the selection of the input and output factors;
- it provides no information about the statistical significance of the results;
- the results can be influenced by random errors, measurement errors or extreme values;
- companies exhibiting extreme parameters will be classified as efficient by default;
- it provides a point in time estimate.

10.14. JPS further noted that regulators in general have full discretion in the choice of benchmarking method and that one method only gives an indication, but not a confirmation of efficiency. The company pointed out that in some jurisdictions, regulators utilised more than one method before making a determination on efficiency.

10.15. Based on the forgoing, JPS conducted benchmarking studies utilising DEA, total factor productivity analysis, and univariate (partial benchmarking) analysis. The results of these studies are described below.

10.2.2. JPS' DEA Model Specification and Sample

10.16. JPS has applied the DEA model specified by OUR in the Final Criteria, that is, OPEX as an input factor and sales, customers, network length, and service area as output factors. The model specification is Variable Returns to Scale (VRS) which means that differences in the scale of companies do not drive the efficiency results.

10.17. The data that JPS used to conduct its DEA and univariate analysis is shown in Table 10.1 below.

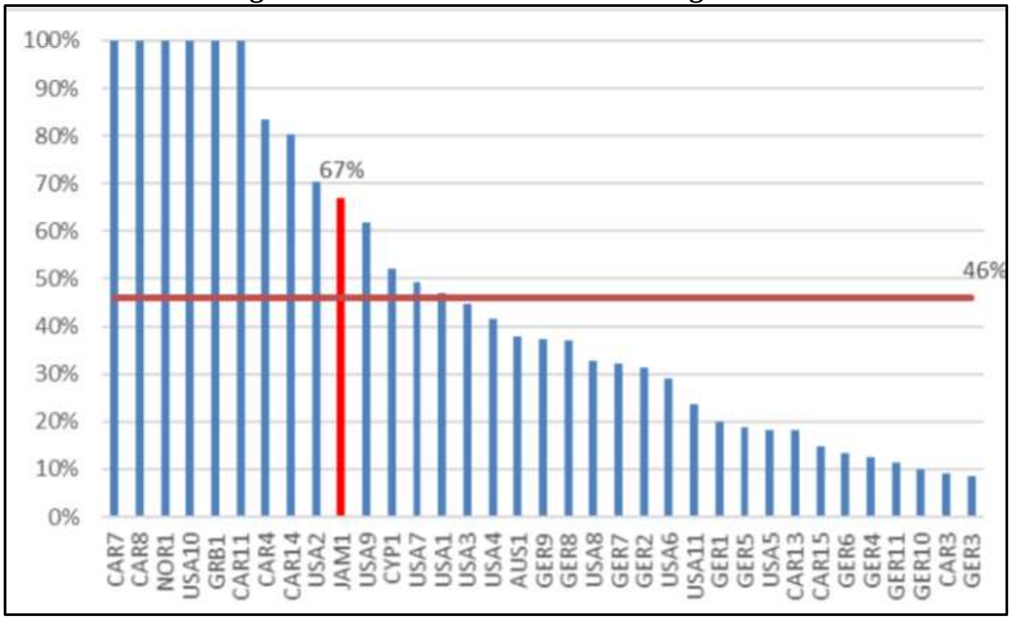
Table 10.1: Final Input-Output Data

Code	Sales (MWh)	Customers	Network	Area	Opex USD 2017
JAM1	3,207	642,944	12,538	10,991	108,541,061
USA1	3,656	263,242	25,767	15,540	183,787,932
USA2	4,516	171,834	13,174	25,900	82,716,936
USA3	4,146	263,896	19,713	19,425	155,268,384
USA4	3,241	152,601	3,318	818	85,499,517
USA5	3,868	422,163	677	3,140	265,061,751
USA6	3,873	149,828	7,863	784	141,215,293
USA7	1,539	66,554	2,562	2,712	41,168,637
USA8	3,546	159,336	8,010	3,885	117,605,046
USA9	1,105	80,927	3,472	13,987	34,255,050
USA10	1,659	96,168	5,141	38,070	35,633,152
USA11	623	67,155	2,419	1,056	50,409,095
CAR3	944	129,112	2,950	430	183,049,980
CAR4	553	94,450	3,040	553	15,470,049
CAR7	622	29,160	732	202	11,355,551
CAR8	78	36,467	1,325	754	6,567,775
CAR11	360	66,784	4,248	617	15,452,659
CAR13	219	14,746	641	427	43,125,329
CAR14	199	50,019	354	348	10,002,566
CAR15	8,565	479,687	22,829	5,128	602,164,817
GER1	19,945	737,097	44,346	948	948,484,485
GER2	9,615	427,329	19,782	274	302,439,200
GER3	23,281	799,982	51,540	1,185	2,716,049,122
GER4	8,960	994,993	31,258	938	892,971,965
GER5	12,017	1,147,000	28,998	365	820,654,127
GER6	18,467	726,219	27,549	818	1,315,272,374
GER7	6,487	353,205	3,349	78	209,577,351
GER8	9,472	393,035	5,400	92	251,216,992
GER9	12,469	448,242	6,536	105	318,357,898
GER10	13,585	1,418,705	79,085	2,294	2,652,565,691
GER11	6,700	683,000	30,165	6,433	874,820,789
CYP1	4,496	568,500	27,289	6,027	174,774,411
GRB1	37,100	3,799,848	126,457	94,204	417,277,225
NOR1	19,500	710,000	43,624	9,554	182,733,320
AUS1	7,604	667,118	13,243	1,472	227,724,520

10.18. JPS stated that in updating the database, 2017 audited information was used for most companies, but that there were cases in which only 2016 audited information was available. In such an event, the 2016 audited information was used and adjusted for inflation.

10.19. The VRS model employed by JPS yielded the results demonstrated in Figure 10.1 below. According to the results, JPS' efficiency score was 67% with average efficiency of the companies in the sample being 46%. The results indicate that JPS was the tenth most efficient firm in the sample.

Figure 10.1: JPS' DEA Benchmarking Results



10.20. JPS attempted to highlight the inherent weaknesses of the DEA methodology primarily through comparator analysis which is discussed below. According to JPS, its analysis of the DEA methodology provided the following insights:

1. The inherent weakness of the DEA methodology (skewed by outliers) was evident with the frontier companies predominantly represented by size extremes;
2. Heterogeneous nature of the sample.

10.21. The company stated that despite the weaknesses in the DEA, JPS' efficiency score has demonstrated a high level of productivity, as evidenced by:

1. JPS ranking 10th overall and therefore recording an efficiency score better than 25 utilities of the 35;
2. JPS ranking 2^{nd} when compared to utilities of similar size, whether using the number of customers or network length.

10.2.3. Total Factor Productivity

10.22. In its 2014 – 2019 Tariff Application, JPS used the Total Factor Productivity (TFP) methodology to determine the X-Factor. In its current Application, JPS updated the TFP study stating that, "[s]ince the TFP was a suitable model used by both JPS and the OUR in the past, the model was updated as a gauge to determine JPS' potential efficiency gains in the next regulatory period."

10.23. The X-Factor was calculated as the difference between the expected change in the TFP of JPS (ΔTFP_{JPS}) and that of the general economy (ΔTFP_{Gen}), which may be expressed as follows:

$$X = \triangle TFP_{JPS} - \triangle TFP_{GEN}$$

10.24. JPS indicated that it updated the TFP model used in the 2014-2019 Tariff Application to include audited information up to 2017. In deriving the TFP for JPS, the company used the input variables - O&M and capital expenditure - and the output variables - the number of customers, energy and demand. The TFP for the general economy is calculated as the weighted average of the TFP growth rates of the United States and Jamaican economies and was derived as follows:

$$\triangle TFP_{GEN} = (0.76 \times \triangle TFP_{US}) + \left(0.24 \times \triangle TFP_{Jamaica}\right)$$

10.25. The **Table 10.2** below shows the results of JPS' updated TFP study.

Table 10.2: JPS' PI-factor derived from the updated TFP Study

TFP Calculation	Results	
PI-Factor	**-0.13%**	
General TFP	**0.492%**	
JPS TFP	**0.363%**	
Total Inputs	0.91%	
O&M		-2.65%
CAPEX		3.52%
Total Output	1.28%	
Customers		1.53%
Energy		0.43%
Demand		0.96%

10.26. The result shows JPS' TFP growing at 0.363% for the Rate Review period, but that this was 0.13% below the growth of the general economy, which grew at a rate of 0.492% for the 2012 – 2017 period. This, JPS suggested, is due to a lag in the translation of the investments in efficiency and productivity gains in energy and demand growth even though the economy itself is growing at a faster rate. According to JPS, this should not be entirely surprising given the global and domestic gains in energy efficiency and the trend in Distributed Energy Resources (DER) driven load defection. The company cautioned that too aggressive a push for greater investment in efficiency may not necessarily translate into the benefit expected over a defined time period.

10.27. JPS explained that the low TFP values were mainly driven by slow output growth, as both the peak demand and total energy recorded growth rates of less than 1%, while the number of customers grew at a rate of 1.5% per year. The company further stated that while it had been able to reduce its O&M input variable, its capital expenditure had increased significantly, albeit not totally within its control. This was because the company had to be investing heavily to improve reliability, grid stability and reducing system losses.

10.28. JPS summarized the TFP results and indicated that the DEA results should be applied with caution as it provides only a point-in-time estimate of performance. The TFP is more reflective of what is happening over a longer period of time. JPS speculated, through an illustrative example, that in the 2017 sample of utilities, some of the differences in the O&M expenses may be due to the fact that certain utilities have accelerated maintenance expenses of T&D structures, while others are doing it in the regular scope, and some others may have already completed it. JPS believed that these differences should be smoothed out over time.

10.2.4. Partial Benchmarking Analysis

10.29. Partial productivity measures are the ratio of a single output to a single input across firms. According to JPS, partial productivity methods produce simple, easy to calculate straightforward indicators of performance, but it does not recognize the trade-offs between different improvement possibilities or areas. JPS pointed out that partial productivity measures should only be viewed as rough indicators as they can potentially mislead or misrepresent the performance of a firm.

10.30. JPS conducted the following partial benchmarking analysis:

- OPEX per kWh sold
- OPEX per customer

10.31. The results of these analyses are shown in Figure 10.2 and Figure 10.3 below.

Figure 10.2: Results of OPEX per kWh sold Partial Benchmarking

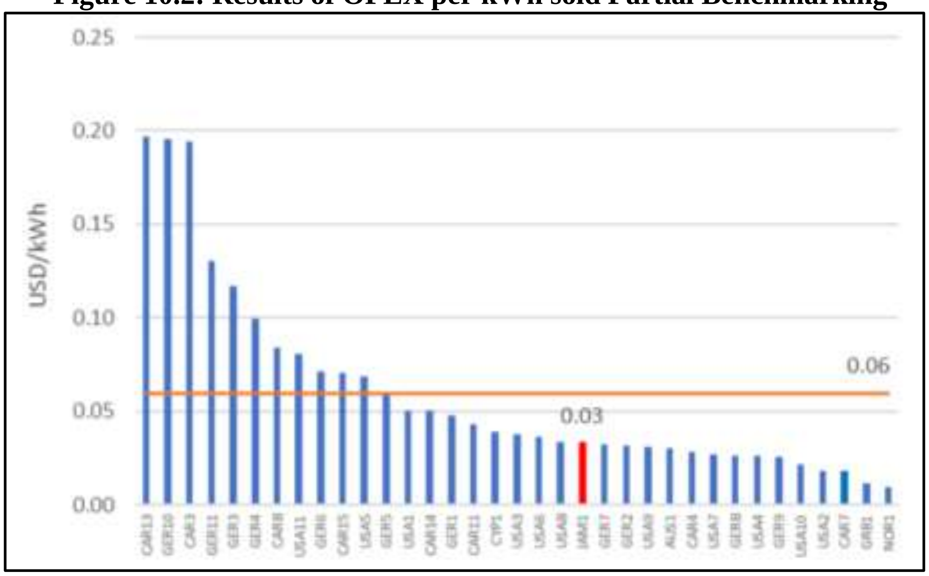
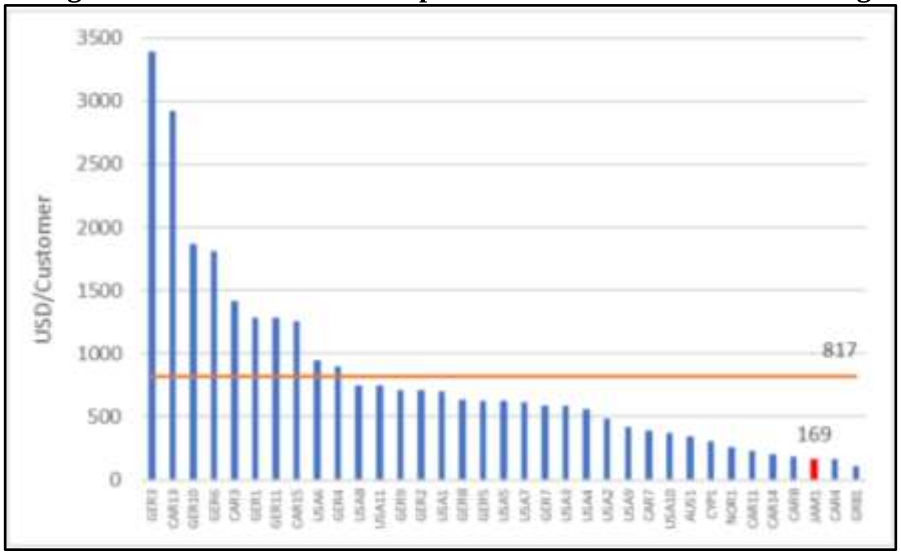


Figure 10.3: Results of OPEX per customer Partial Benchmarking



10.32. The OPEX per kWh sold partial benchmark measure, shows that JPS spends US$0.03 per kWh and ranks as the 15th most efficient utility. JPS stated that of the fourteen utilities that rank higher than it, six (6) are European, five (5) American, two (2) Caribbean and one (1) Australian. JPS pointed out that these utilities have significantly higher average consumption than JPS.

10.33. The OPEX per customer result indicates that JPS spends US$169 in OPEX per customer. JPS stated that this depicts that JPS performed extremely efficiently, ranking the 3rd most efficient utility in the sample. The company further stated that in regard to operating expenses per customer, the results demonstrated that JPS had significantly lower cost relative to utilities in developed countries such as Germany and the USA.

10.34. JPS concluded that the results from the DEA model and the partial benchmarking measures show that JPS is performing efficiently relative to the sample of comparable utilities determined from the methodology prescribed by the Final Criteria. It further stated that the results indicate that the company operates in the top quintile of the comparator group, which is representative of utilities operating in developed countries, and those within the Caribbean, that share some of the region's unique island challenges.

10.35. The company argued that aggressive productivity improvement targets in the preceding regulatory periods have been successful in inducing a strong focus and culture of improving operational efficiency. It further concluded from this that known areas of efficiency gains have already been exploited and thus, to get to the frontier will require large investments and a longer horizon given that the frontier is dynamic.

10.2.5. JPS' Comments on the DEA Methodology

10.36. JPS provided some methodological comments on the DEA model, primarily to demonstrate its weakness. These are presented below:

Sample

10.37. JPS pointed out that having a homogenous sample increases the quality of the data, as well as the robustness of the results. JPS used the DNV GL's report to support this point, as it quoted sections of the report, which state that "a key factor is to try to ensure that the operating environment of the companies is as similar as possible to be able to compare 'like with-like" and "for any efficiency analysis, a data sample consisting of as many utilities as possible that are similar to JPS is required." JPS further stated that this similarity is stated in terms of being an island utility, with comparable size (as measured by the number of customers), supply areas, and sales.

10.38. JPS' critique was that in the DNV GL sample, only one utility satisfied the two (2) criteria stated in the DNV GL report simultaneously, that is, "similar in terms of being an island utility" and "with comparable size as measured in the number of customers, supply areas, and sales."

OPEX as the only input factor

10.39. JPS noted that companies face different input and output prices such as labour and the cost of capital.[9] This, JPS argued, creates a bias towards CAPEX in more developed jurisdictions, as labour cost tends to be higher there. Ideally, therefore, a measure of CAPEX should also be included in the benchmarking. JPS also noted that due to a certain degree of substitution between productive factors, the consideration of only OPEX inputs may create perverse incentives in terms of input choice by the utility, favouring capital-intensive solutions, which may not be the most cost efficient.

10.40. Related to the previous point, JPS noted that a case in point was that JPS had chosen to lease its transport fleet, while BEL, (a company within the sample and a peer to JPS) owned its fleet, and therefore was able to capitalize this cost.

10.41. JPS noted that in response to the concerns expressed by JPS, the OUR indicated in the Final Criteria that CAPEX could be included as an input factor, but its inclusion would have to be justified by JPS. JPS stated, however, that it was unable to include CAPEX due to the lack of available data for most comparator utilities in the required sample.

Sales as an output factor

10.42. JPS stated that the use of sales (kWh) as an output factor was questionable because the distribution business is generally understood to be a pure "wires" business. JPS argued further that for a pure distribution company at least, there was no relationship between kWh sales and cost.

Frontier Utilities

10.43. JPS opined that the six (6) utilities on the frontier (that is, with 100% efficiency) was an indication of the flaws of the DEA sample that was used. JPS indicated that the firms on the frontier demonstrated extremes in size, that is, either they were much smaller than JPS or much larger. Only one (1) of these utilities was comparable in size (demonstrated by customer numbers) to JPS.

[9] JPS' Proposal, p. 91.

Comparative Analysis

10.44. JPS indicated that the DEA model identified three (3) utilities as its comparator. These are:

- DOMLEC;
- Scottish and South Eastern (SSE);
- Harfslund.

10.45. JPS highlighted the differences between itself and DOMLEC in terms of sales, number of customers, network length, supply area, level of system losses and debt to GDP ratio. The company also opined that the impact of Hurricane Maria in 2017 significantly affected the operation of the utility and therefore accounted for its low operating cost, which would be deemed efficient based on the limitations of the DEA model.

10.46. With regard to SSE, JPS opined that the large size differential between SSE and JPS contributed to the SSE ranking as being 100% efficient. JPS noted that size provides economies of scale and SSE was 10.1 times and 5.9 times larger than JPS based on the network length and number of customers respectively. JPS also noted that SSE was the largest utility in the sample and that if it were removed from the sample, JPS would be on the frontier.

10.47. JPS identified Hafslund as a comparator based on customer size. JPS argued that a combination of smaller service area and higher customer density provided a scale-advantage for Hafslund and an opportunity to lower its costs to serve. JPS also pointed out that Hafslund was an urban utility which provided a terrain which was essentially easier to serve.

10.48. Another difference that was noted between JPS and Hafslund was the stark differences in system losses. JPS noted that had there been no need to curtail system losses, JPS' efficiency score would have been 76%.

Comparable Utilities

10.49. JPS concluded that the utilities identified as comparators were not reasonable due to size and operating characteristics, and as a result conducted an assessment of itself against utilities that JPS deemed to be comparable. In this complementary analysis, a comparison was done using a sample including JPS and ten (10) US utilities of similar size as JPS (between 550,000 and 750,000 customers). This analysis was done on the basis of uni-dimensional analysis. The indicator chosen by JPS was OPEX per customer. The motivation for this was based on the findings of a study by Fares as shown in Table 10.3 below, which identified a customer number as "the main driver of cost".[10]

[10] The source mentioned by JPS is: Fares, The US Electric Grid's cost in 2 charts – Scientific American Blog Network. It should be mentioned that the table shown in Figure 1 (JPS Updated Proposal, Report 1, p. 24) is in fact not from the reference "Fares 2017", as mentioned under that Table, but from another publication: Fares, R.L. and C.W. King, Trends in transmission, distribution, and administration costs for U.S. investor-owned electric utilities, Energy Policy, Vol. 105, p. 354-362.

Table 10.3: Results of the Fares-King Study: Correlation between Cost and Outputs.

Cost Category	Cost Per Customer ($/Customer-Year)	Cost Per Peak kW ($/kW-Year)	Cost Per kWh (¢/kWh)
Transmission	119 (R^2=0.459)	21 (R^2=0.399)	0.47 (R^2=0.373)
Distribution	291 (R^2=0.901)	52 (R^2=0.775)	1.1 (R^2=0.740)
Administration	333 (R^2=0.853)	61 (R^2=0.766)	1.3 (R^2=0.734)
Total	727 (R^2=0.886)	134 (R^2=0.781)	2.9 (R^2=0.747)

***Source**: Reproduced from the JPS' Updated Proposal, Report 1, p. 24. Original Table is from Fares and King (2017).*

10.50. JPS carried out a uni-dimensional analysis of OPEX per total customers and OPEX per residential customers. In this analysis, JPS had the lowest cost per customer.

10.2.6. JPS' Recommendation for the PI-Factor

10.51. JPS proposed that the OUR considers the above described limitation of the DEA methodology and the results of the partial benchmarking analysis when determining the PI-factor. Specifically, JPS proposed that the OUR take into account the following when determining the PI-factor:

1. Observed frontier;
2. Reasonable and Achievable targets;
3. Business Plan Initiatives.

10.52. JPS argued that a fundamental principle of the Licence was the concept of reasonable and achievable targets. It pointed out that while the Licence explicitly identified target setting within the context of Reliability, Systems Losses and Heat Rate, it was clear that the principle and spirit outlined under the target setting section were universally applicable to all regulatory targets, including the PI-factor.

10.53. The company also outlined a number of business initiatives it would undertake over the Rate Review period which will have a tendency to increase costs.

10.54. Based on the aforementioned, JPS therefore proposed that the YET target be achieved over the Rate Review period. Also it proposed to reduce its "inefficiencies" by 20%, which implies an efficiency target (ET) of 1.9% annually applied to controllable OPEX.

10.3. The OUR's Assessment of JPS' Proposal

10.55. The main elements of the OUR's assessment of JPS' productivity proposal are the initial and target efficiencies proposed by JPS. More concretely, whether 67% was an appropriate initial efficiency, and 74% was an appropriate target efficiency over the Rate Review period.

10.56. JPS made several comments on the suitability of the DEA model for conducting the productivity assessment on which the OUR will also provide a response.

10.3.1. Assessment of JPS' DEA Model Specification

10.57. JPS used a somewhat different sample than what was used by DNV GL. The JPS sample contained thirty-five (35) companies compared to forty-two (42) in the DNV GL analysis. JPS excluded a total of nine (9) companies while two (2) new ones were included.

Table 10.4: Sample Composition: JPS compared with DNV GL's

Excluded companies		**Newly included companies**	
CAR1	ANGLEC (Anguilla)	CAR 4	T&TEC (Trinidad & Tobago)
CAR2	Aqualectra (Curacao)	CAR15	GRENLEC (Grenada)
CAR5	BELCO (Bermuda)		
CAR6	BVIE (British VI)		
CAR9	VIWAPA (US VI)		
CAR10	VINLEC (St. Vincent & Grenadines)		
CAR12	EBS (Suriname)		
INT1	Energy Fiji (Fiji)		
USA12	Black Hills/Colorado (USA)		

10.58. The fact that the JPS sample was smaller, will tend to produce higher efficiency scores. This was a feature of DEA whereby the discriminative power of the analysis was driven by the sample size. A smaller sample implied less probability for a given sample unit to have proper comparators, and hence the efficiency score would, on average, tend to be higher.

10.59. A sample size of thirty-five (35) companies was somewhat at the lower side of the spectrum. Nevertheless, this could still be considered acceptable, although the bias towards higher scores should be kept in mind.

10.60. With regard to excluding nine (9) companies from the sample, it was noted that the arguments provided by JPS for doing so were not very clear. JPS stated that it agreed with DNV GL that the sample should consist of companies that were "similar" to JPS. Similarity was then defined in terms of being an island utility and of similar scale as JPS. The way in which JPS then applied these criteria was however ambiguous. As shown in Table 10.44 above, JPS chose to exclude nine (9) companies, out of which seven (7) were island utilities. At the same time, the other non-island companies have been maintained in the sample. Furthermore, the criteria of scale also seemed to be applied in an ambiguous manner. For example, JPS decided to exclude EBS (130,000 customers) but maintained companies with a smaller customer base (for example LUCELEC, 65,000 customers).

Comments on JPS' Correction to OPEX

10.61. The OPEX for JPS was set at a level of US$108,541,061. The OPEX for JPS in the DNV GL study was US$116,350,464 which was 7% higher. The reason for this difference was the fact that the costs of business development are no longer included in the OPEX, as this concerns a non-regulated activity.

10.62. The adjusted OPEX for JPS of US$108.5 million was appropriate given that business development should not have been included.

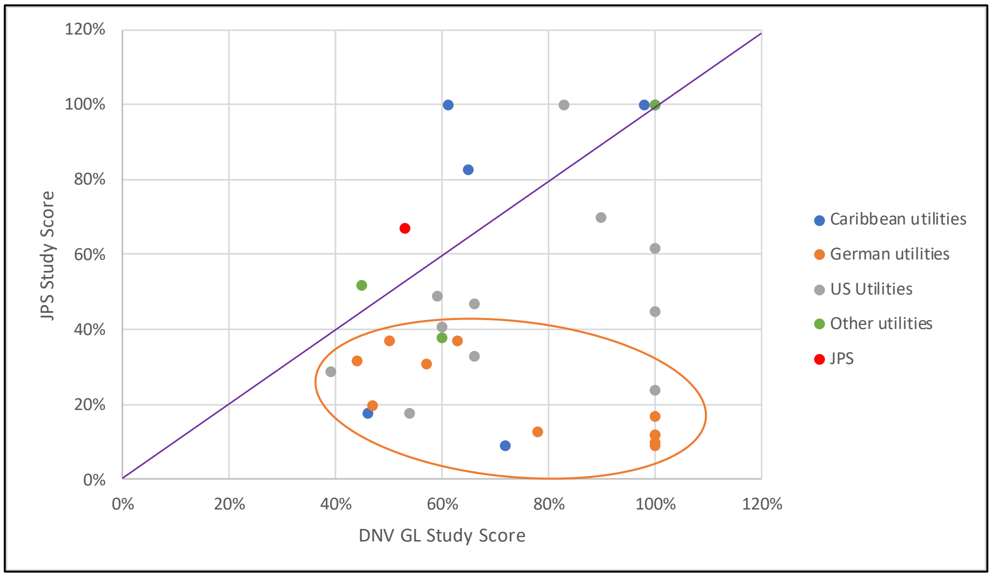
10.3.2. Efficiency Scores

Recalculation of the DEA scores on the basis of JPS' revised data and model results in the same efficiency scores as presented by JPS. A graphical comparison between the DNV GL scores and the scores from the JPS' proposal is shown in Figure 10.4 below.

10.63.

10.64. Figure 10.4, the names of the utilities are not shown, but only the regions to which the utilities belong.

Figure 10.4: Comparison of Efficiency Scores: DNV GL vs JPS' Updated Proposal



Note: *The diagonal line represents the line of equal scores.*

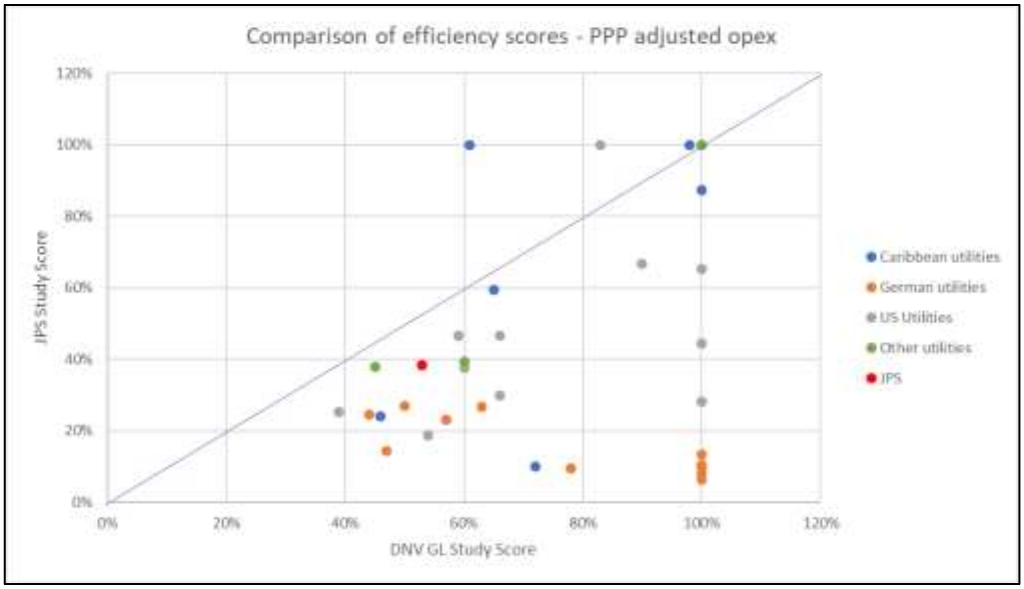
10.65. Before discussing the results, it is first helpful to explain Figure 10. 4 above. For each utility that was included in both studies, the efficiency score has been plotted. The x-axis represents the score from the DNV GL study, and the y-axis represents the score from JPS' proposal. The diagonal line represents an equal score. If a utility has a lower score under the JPS study, then this utility is located below the line, and vice versa.

10.66. It may be observed that most utilities now obtain a lower score. On average the score drops from 73% under the DNV GL study to 46% under the JPS study. Only seven (7) out of thirty-five (35) utilities obtained a higher score, including JPS.

10.67. Updating the data will inevitably result in some relatively small differences in the DEA scores. When comparing the DNV GL and JPS' proposal scores, however, very large differences appeared. The difference is particularly large for the German utilities, which have been highlighted in Figure 10.4 above. Under the DNV GL study, the average German score is 76%. Under the JPS study, the score is reduced to 21%. Some German companies that obtained a 100% efficiency score under the DNV GL report now get a score of around 10%. It would not appear very plausible that Germany utilities are, on average, less efficient than JPS' (21% versus 67%).

10.68. As can be seen in Figure 10.5 below, there are also two Caribbean utilities now obtaining a much lower efficiency score (these are Fortis from Turks and Caicos, and BLPC from Barbados). Also, most of the US companies now obtain a lower score.

Figure 10.5: Graphical comparison of efficiency scores between DNV GL and the JPS Proposal – PPP adjusted.



Note: *The diagonal line represents the line of equal scores.*

10.69. The OUR explored what contributed to the major differences in the results between the JPS and DNV GL studies. One observation was that JPS did not use purchasing power parity (PPP) to account for income differentials across countries.

10.70. Utilities in more developed countries (in this case specifically the USA and Germany) will tend to incur higher average wage costs due to the higher standard of living. As a result, the efficiency scores in jurisdictions with relatively low labour wages (such as Jamaica) will tend to be inflated. The reason is that lower labour wages result in lower OPEX and hence, a more favourable DEA evaluation.

10.71. To compensate for such differences, a method commonly applied in benchmarking is the use of PPP adjustment. This PPP adjustment offsets differences in labour input prices to a large extent. PPP adjustment was used in the DNV GL analysis but not in the JPS study.

10.72. Using the JPS data, an analysis of the efficiency score results with the OPEX adjusted for PPP was carried out. The results are shown in **Error! Reference source not found.** above.

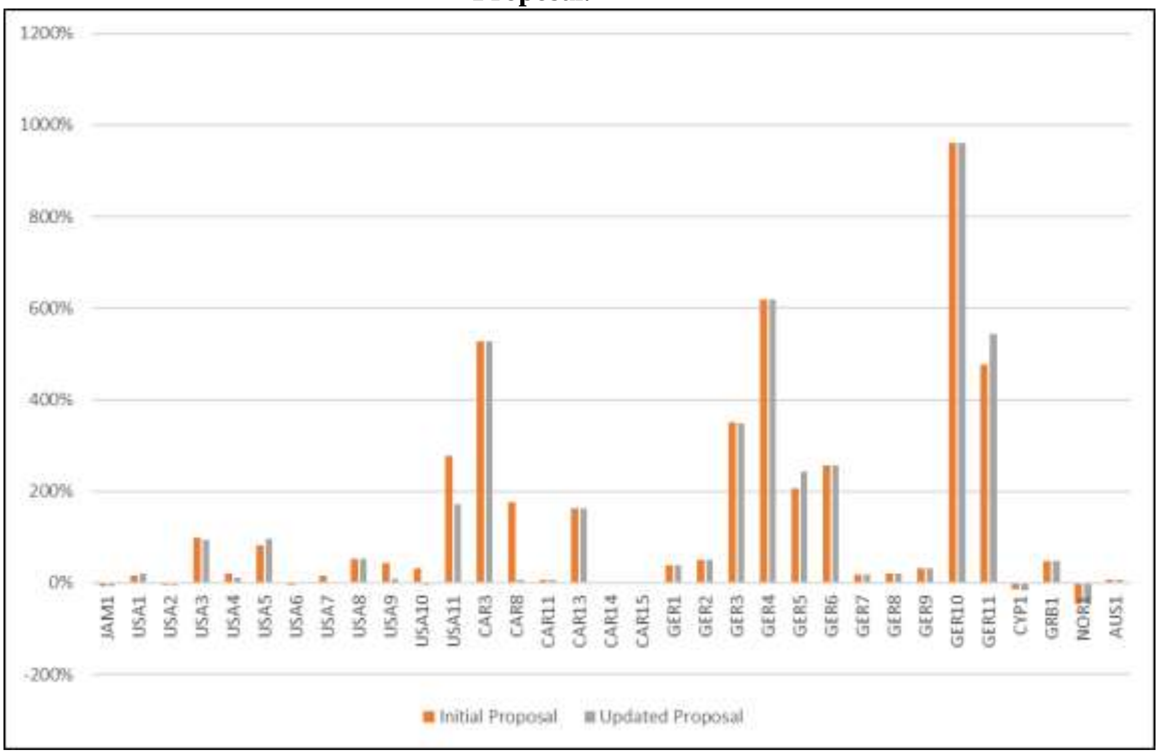
Similar as in Figure 10.4 above, the scores are compared between the DNV GL and the JPS Updated proposal – but now with PPP adjusted OPEX for the latter.

10.73. As can be seen, the PPP adjustment has minimal impact on the efficiency scores of the US and German companies. This presents a hypothesis that these efficiency scores are to a large extent driven by data errors.

10.74. As mentioned above, there are considerable and implausible differences between the DNV GL study and the JPS proposal. The observations indicate that there is an important structural issue with the data.

10.75. To illustrate the large differences between DNV GL and JPS' data, Figure 10.6 below shows the deviation between these two in percentage terms.

Figure 10.6: Percentage Difference between JPS data and DNG GL data for Initial and Updated Proposal.



10.76. **Figure 10.6** above, it is clear that the data differences are extreme. On average, the DNV GL OPEX figure is US$150M per utility. In the JPS dataset, this is US$415M. This is particularly driven by data issues with the German utilities. For example, for GER10 the difference is 1000%, which means that JPS has used an OPEX figure which is more than 10 times higher than the OPEX used by DNV GL.

Table 10.5: OPEX data for German utilities

	DNVGL	Initial Proposal	Updated Proposal
GER1	685,965,327	948,484,485	948,484,485
GER2	201,391,591	302,439,200	302,439,200
GER3	606,254,252	2,733,959,636	2,716,049,122
GER4	124,147,046	892,971,965	892,971,965
GER5	239,197,647	735,219,461	820,654,127
GER6	368,421,178	1,315,272,374	1,315,272,374
GER7	175,757,157	207,853,777	209,577,351
GER8	207,619,497	251,216,992	251,216,992
GER9	243,176,242	318,357,898	318,357,898
GER10	249,878,153	2,652,565,691	2,652,565,691
GER11	135,749,774	783,359,378	874,820,789
Average	**294,323,442**	**1,012,881,896**	**1,027,491,818**

10.77.

10.78.

10.79.

10.80. **Table 10.5**5 above shows the differences in the OPEX data between DNV GL and JPS. As can be seen, the OPEX figures for the German companies in the JPS data are significantly higher. Closer analysis revealed that this is caused by the inclusion of the purchase cost of energy in the OPEX.[11] Such purchase costs are not part of T&D expenses as this is the cost of energy purchased from generators and traders. This cost is conceptually similar to the cost that JPS incurs with respect to generation and purchases from IPPs. Including these costs as OPEX is a clear data error and has a direct impact on the efficiency score. This also explains the very low scores for these companies in the DEA results for the JPS sample.

10.81. For BLPC (CAR3) the difference between JPS data and DNV GL data is 528%, that is, the JPS OPEX is five times higher than DNV GL's. The EMERA Caribbean annual report for 2015 indicates that total operating expenses for BLPC (including generation) was BB$103M which translates into US$51.5M.[12] In JPS' sample, BLPC is shown to have an

[11] These are referred to as "Aufwendungen für Roh-, Hilfs- und Betriebsstoffe und für bezogene Waren".
[12] Emera Caribbean, 2015 Annual Report. Available at: http://www.emeracaribbean.com/site-emera/media/EmeraCaribbean/Emera%2017%20Final%20Approved%20(OPT).pdf, p. 13 and p. 22

OPEX of US$183M for that year. This figure seems similar to the total cost (fuel plus OPEX) for the whole EMERA group, i.e. BLPC, DOMLEC, and LUCELEC together. This is clearly a gross overstatement of BLPC's true OPEX. In the Excel sheet provided by JPS, no underlying data or calculations for BLPC's OPEX are shown. The figure of US$183M has been entered as "hard data" in the Excel Table.[13]

10.82. In light of the above, the results of the JPS DEA study cannot be considered robust. Consequently, no further analysis was undertaken as from the above examples it is already clear that there are serious data errors with the JPS sample.

10.3.3. Assessment of JPS' Partial Benchmarking Results

10.83. All things being equal, the results of JPS' partial benchmarking assessment would suggest that JPS is highly efficient. However, as JPS has cautioned, partial benchmarking results must be interpreted with care as they provide only a very rough indicator of performance. As a result of the unidimensional nature of these measures, they ignore the fact that there are many factors that impact efficiency.

10.84. It should also be mentioned that the analysis done by JPS did not account for PPP. Firstly, in the comparisons, JPS has a cost of US$169 per customer versus the average of US$460 per customer. If the PPP adjustment (1.74 for Jamaica) is taken into account, this would imply a result of US$294 per customer for JPS, which would however still put JPS in a position better than average. A similar argument holds for the OPEX per kWh sold.

10.3.4. OUR's Response to JPS' Comments on the DEA Methodology

10.85. The following outlines the OUR's response to JPS' critique of the DEA methodology.

10.86. The OUR has acknowleged that there are inherent weaknesses in the DEA methodology. In fact, all benchmarking methodologies suffer from inherent weaknesses. The OUR also noted that it is important to select as homogenous a sample as possible to ensure a higher quality and accuracy of the DEA results. Consequently, the OUR has taken the limitations of the DEA methodology into account when making its decisions on the PI-factor.

OPEX as an Input Factor

10.87. JPS compared itself to Belize to illustrate the point that the exclusion of CAPEX as an input factor may create perverse incentives in terms of input choice by the utility, causing it to favour capital intensive solutions. JPS' argument seems to be that BEL has different incentives due to a different OPEX/CAPEX trade-off. However, the GDP per capita in Belize and Jamaica are very close (USD 4,905 and USD 5,109 per capita, respectively). Decisions regarding OPEX/CAPEX trade-offs would therefore not be fundamentally different in these countries. Then, following JPS' argument, if it seems efficient for BEL to own its transport fleet, the question can be asked why JPS has not chosen to do so as well.

Sales as an Output Factor

10.88. It is generally true that in the 'wires' business, the true product sold by the utility is network capacity, which is measured in peak demand (kW) rather than energy (kWh) transmitted

[13] Excel file "2016 DEA Database Sources", sheet "Utilities data base", cell G14.

through the network. However, it should also be considered that there is an important relationship between these two variables. This is the load factor, which for a given company tends to be more or less fixed over time. Higher cost due to increased demand is therefore directly reflected in higher sales. Sales is thus an appropriate approximation of demand and therefore a suitable output factor.

10.89. Furthermore, sales is preferable to demand as an output factor for practical reasons. Experience shows that issues arise when using peak demand. The definition of peak demand can differ per jurisdiction, which makes it a less stable indicator to compare. Sales, on the other hand is a uniform measure in each jurisdiction. Therefore, most if not all benchmarking models for electricity distribution, use sales rather than peak demand as the output factor.

Comparative Analysis

10.90. JPS' comparative analysis focused on three (3) utilities (DOMLEC, SSE and Harfslund) that were comparators to JPS based on the DEA results. The OUR has identified that data issues significantly affected the results that JPS achieved, and thus, a conclusion cannot be drawn that these utilities are in fact comparator to JPS. Nevertheless, the OUR believed that it is prudent to respond to JPS on the points made.

10.91. JPS indicated that DOMLEC was an outlier because of the impact of Hurricane Maria in 2017, which lowered the company's operating cost because of reduced operations. Considering that DOMLEC was an anomaly due to a hurricane, it would have been reasonable that JPS remove DOMLEC from the sample, as it did with other Caribbean utilities. This point supports the fact that JPS' sample selection was somewhat arbitrary. The OUR, in the Final Criteria, gave JPS the opportunity to modify the sample as long as it could be justified.

10.92. JPS' main concern with comparisons against SSE is that the latter has a larger scale than JPS (around 6 to 10 times). As mentioned earlier, however, the use of the VRS model assures that scale differences do not affect the comparisons. More specifically, under VRS the extent to which a peer influences the score of another company depends on how similar these companies are in terms of scale. Even if SSE is a peer, it will contribute relatively little to the determination of JPS' efficiency score. The issue of differences in scale compared to SSE (or any other company for that matter) is therefore not relevant under the VRS model.

10.93. Regarding Harfslund, the OUR takes the point that this utility, while similar in size to JPS, does not operate in the same environment and may seem more efficient to JPS only because of the environment in which it operates.

Frontier Utilities

10.94. JPS argued that the frontier utilities demonstrated the extremes in scale, which showed the deficiency in the DEA approach. The OUR concurs that one of the limitations of DEA is that it will tend to over-rate the efficiency results of small and large units displaying strong dis-economy and economies of scale.

Comparable Utilities

10.95. With regard to JPS' comparable company analysis, a main disadvantage of an efficiency measure that only considers a single dimension is that this disregards the fundamental fact that efficiency has a multidimensional nature. Considering only a single output factor, as JPS has done, ignores this and can potentially provide misleading results.

10.96. In this respect, the outcome of the Fares- King study stating that customers show the highest correlation with cost should be interpreted with care. Indeed, as JPS mentioned, Jamaica has a lower average consumption per customer than US utilities. But, this implies that, by definition, the cost in JPS will be lower as well. If customers have less consumption, this implies that the necessary network capacity to be installed will be less. Subsequently, the operating cost will also be lower as O&M cost tends to be a direct function of the value of the assets installed in the system. Having less average consumption per customer, therefore automatically also implies less cost per customer.

10.97. JPS' argument is therefore circular. As observed by JPS, utilities with lower average consumption will always tend to exhibit higher cost per kWh and therefore less cost per customer. However, this is not significant and does not imply that utilities with lower average consumption are therefore more efficient. Rather, these companies will tend to incur less cost, simply because of the reason that their customers require less system capacity to be supplied.

10.98. The root of the problem is that the analysis as above considers efficiency from a uni-dimensional standpoint. If a multi-dimensional approach is taken instead, then a more elaborate and accurate measure of efficiency can be obtained.

10.99. In conclusion, the fact that the cost per customer for JPS is relatively low, is not an indication that JPS is also being efficient. A genuine measure of efficiency can be derived, only if costs are assessed in relation to other factors. Finally, it should be mentioned that JPS, after presenting the favourable cost-per-customer results, does not refer to these as a point to consider in the determination of the PI-factor.

10.3.5. The OUR's Determination on the PI-Factor

10.100. Any regulatory target imposed on the company should be reasonable and achievable. This is reflective of best-practice regulatory practices.

10.101. For the duration of time over which the improvement is to be achieved (Y_{TE}), the period of five years seems suitable. The question then is, what would constitute adequate initial and target efficiency levels. Even though the JPS' analysis cannot be used due to data errors, it is a fact that JPS has proposed a PI-factor of 1.9%.

The figure of 1.9% by definition is considered reasonable by JPS and therefore sets the lower bound for the *PI*-factor. When moving to the frontier efficiency of 100%, this would translate into a PI-factor of 13.5% per year over a period of five years if DNV GL's efficiency of 53% is used as the starting point. This then can be considered the upper bound for the PI-factor. The lower bound for the PI-factor is therefore given as 1.9%, while the upper bound is 13.5%. The choice of the PI-factor and hence the efficiency target is constrained to a number within this band.

10.102. The range from 1.9% to 13.5% is quite broad and should be narrowed down. For this, international experience can be useful. This suggests that in the earlier years, after the introduction of incentive-based regulation, the annual efficiency improvement target is typically not above 4% per year. Over time, the target will go down, reflecting the initial realization of the "low hanging fruits".

10.103. Taking into account the interrelationships with JPS' performance in other areas, this would suggest a PI-factor between 1.9% and 4%. A PI-factor of 1.9% can be considered the absolute minimum; considering that JPS itself has proposed this. A level of 4% on the other hand could be somewhat on the high side, considering that this is not the first time that JPS will be exposed to a price-control system. Overall, a range between 2% - 3% would, however appear to be realistic. Finally, it should be mentioned that setting the PI-factor is not a mathematical operation, but rather a policy decision based on analysis of comparative efficiencies. The suggested range between 2% and 3% follow from analysis and logic.

10.104. In deciding on the PI-factor for JPS, the OUR considered the Business Plan and the initiatives that JPS has proposed to improve efficiency. While JPS has suggested that it has already exhausted most of the "low hanging" fruits to improve productivity, the OUR is not convinced that that is the case. Nevertheless, a PI-factor on the lower end of the 2% - 3% range seems reasonable given JPS' own claim that it can achieve a 1.9% improvement per year, and the fact that the PI-factor in the prior regulatory period was set to 1.1%. The OUR therefore determines that the PI-factor shall be 2%.

OPEX Projections

10.105. The Final Criteria outlined the procedure for JPS to compute the projected path for its controllable OPEX over the Rate Review period. The projection consists of three main elements:

1. The proposed PI-factor;
2. The proposed adjustment factor (volume factor) consisting of a weighted average of sales, demand, and customer growth; and
3. The starting level for the OPEX, to which the PI-factor and the volume factor is applied.

10.106. The OUR has determined that the PI-factor shall be 2%. JPS proposed a volume factor which is the weighted average of the growth in sales (kWh), demand (MVA), and customer numbers. JPS has proposed to allocate weights on an equal basis, that is, $33^1/_3$% each. It is expected that OPEX will change in response to changes in output delivered by the utility. In the DEA model applied by the OUR, sales and customer numbers have been included as outputs. These are the typical output factors recognised in productivity studies in the electricity business.

10.107. Additioanlly, demand is included as an output factor. Demand is often not included in international productivity studies, because the definition of peak demand may differ from one jurisdiction to the other. However, in this specific case, the change in demand is considered relevant, particularly in its treatment in the annual adjustment component of the revenue-cap mechanism. Hence, the use of demand in the PI-Factor adjustment derivation has been accepted.

10.108. It can be argued that each of the three outputs is important from JPS' perspective. To establish the weight factors, one could do an analysis of historical correlation between OPEX and outputs. In fact, a study of US data was referred to by JPS in the Application. This indicated that customer number is the most significant driver of OPEX. The correlation between OPEX and customer number was 88.6%, while for demand this was 78.1%, and for sales 74.7%. This result would suggest a weighting of 37/32/31.

10.109. However, JPS did not refer to its analysis, but has proposed a 33/33/33 weighting. It is understood that JPS does not consider the degree of accuracy sufficiently high to adopt a specific weighting such as 37/32/31. The use of 33/33/33 then seems a pragmatic assumption, which seems appropriate for the OUR to accept.

10.110. Based on the equal weighting and the projected growth in volume, JPS has computed the annual volume adjustment factors as shown in Table 10.6**Error! Reference source not found.** below. Verification of these numbers showed that the volume factor has been computed in conformity with Annex 1 of the Final Criteria.

Table 10.6: JPS' Computation of Volume Adjustment Factors 2019-2023

Factor	Unit	2018	2019	2020	2021	2022	2023
Sales	GWh	*3,216*	*3,215*	*3,246*	*3,284*	*3,322*	*3,361*
Sales growth rate	%		*0.0%*	*1.0%*	*1.2%*	*1.2%*	*1.2%*
Customers	#	*658,016*	*668,404*	*681,893*	*695,502*	*706,963*	*718,409*
Customers growth rate	%		*1.6%*	*2.0%*	*2.0%*	*1.6%*	*1.6%*
Demand	MVA	*508*	*510*	*511*	*516*	*523*	*530*
Demand growth rate	%		*0.3%*	*0.3%*	*1.1%*	*1.3%*	*1.3%*
Overall adjustment factor	%	***0***	***0.6%***	***1.1%***	***1.4%***	***1.4%***	***1.4%***

10.111. The OUR accepts the methodology used by the JPS in calculating the volume adjustment factor. However, the OUR has revised JPS sales forecast based on new data provided by the JPS and a recognition of slowing of economic output owing to the Covid-19 pandemic. The revised forecast anticipates negative growth in 2020. Table 10.7 below shows the result of OUR's approved adjustment factor.

Table 10.7: OUR Calculated Overall Adjustment Factor

Starting OPEX and projections

10.112. JPS indicated that the Business Plan is an important factor in determining its O&M targets for 2019-2023. The company further stated that in developing the Business Plan, it has established five strategic priorities and three enablers for those strategic priorities. According to JPS, these strategic priorities are intended to deliver a number of improved outcomes for the organization, including areas of regulated performance.

10.113. Table 10.8 below shows JPS' revised projected O&M expenditure for 2019-2023, submitted after its Application. The table shows JPS' inclusion of business plan initiatives, productivity improvement and growth rate.

Table 10.8: **JPS' O&M with Business Plan, Productivity Factor at Cost Item Level & Growth Rates 2019-2023**

	2016	2019	2020	2021	2022	2023	Total
Productivity Improvement (T&D)	110.8	108.7	108.9	110.2	109.4	108.4	545.6
Generation & Shared Services	41.46	38.85	34.73	30.22	30.18	30.14	164.1
Off-Set (excluded Non-Reg)	-3.10	-3.38	-2.79	-3.27	-3.31	-3.29	(16.0)
Total O&M -Rev. Requirement (U$'M)	**149.17**	**144.16**	**140.82**	**137.20**	**136.24**	**135.30**	**693.72**
Total O&M for Rev. Requirement (J$M)	**19,094**	**18,453**	**18,024**	**17,562**	**17,439**	**17,319**	**88,796**

	Unit	2018	2019	2020	2021	2022	2023
Sales	GWh	3,212	3,219	3,068	3,197	3,237	3,287
Sales growth rate	%	-	*0.2%*	*-4.7%*	*4.2%*	*1.3%*	*1.5%*
Customer	#	659,422	674,211	690,028	706,108	720,257	734,622
Customer growth rate	%	-	*2.2%*	*2.3%*	*2.3%*	*2.0%*	*2.0%*
Demand	MVA	599	600	572	596	604	613
Demand growth rate	%	-	*0.2%*	*-4.7%*	*4.2%*	*1.3%*	*1.5%*
Overall Adjustment Factor	**%**	**-**	**0.9%**	**-2.4%**	**3.6%**	**1.5%**	**1.7%**

10.114. JPS arrived at the productivity improvement projections shown in Table 10.8 above by applying the productivity factor of 1.9% to its T&D services. The company stated that its Generation and Shared Services Costs would not be impacted by a productivity factor. The Final Criteria described the procedure for projecting the controllable OPEX.

10.115. JPS proposed that the starting OPEX be set equal to its 2017 OPEX. This proposal was based on its argument that the base year (2018) OPEX was unusual, as JPS had sought to aggressively reduce operating expenses to improve efficiency, but recognized the need to balance expenditure reduction and the achievement of other dimensions of business performance.

10.116. Figure 10.7 below shows JPS' operating expenses between 2013 and 2018. The graph shows that OPEX in 2018 was lower than in prior years. OPEX in 2018 was 7% below the average spend (US$140M) over the period and approximately 4.8% below the next lowest spend which occurred in 2014. Given the historical performance, JPS' argument that this level of spend is unsustainable may be valid, however, JPS' request that the 2017 OPEX be used as the starting level of OPEX is unreasonable given that 2017 was the year in which it had the highest level of expenditure over the period. Expenditure in 2017 was 6.2% above the average and so was quite significant. It is plausible that JPS aggressively sought to reduce its expenditure in 2018 after having observed a sharp increase in expenditure in 2017. This reduced expenditure also spilled over to 2019 where JPS reported OPEX of US$128M which is approximately 1.2% lower than 2018 audited costs.

10.117. The OUR takes the view that the 2018 expenditure is more representative of OPEX over the period as it is not significantly lower than the average neither is it a one-off occurrence. Furthermore, while the OUR recognizes that a range of 2%-3% would be a reasonable range for the PI-factor, the decision was taken to set the index at 2%, the lower end of the range. The OUR has therefore determined that the starting OPEX shall be the 2018 regulatory adjusted OPEX of US$143M[14].

Figure 10.7: JPS' Operating Expense (2013 – 2018)

Source:

[14] Even though JPS OPEX in 2018 was US$130.4M after adjustments 'known' expenses for regulatory purposes it was adjusted to US$143M.

DETERMINATION: # 12

The OUR determines that:

a) The Productivity Improvement Factor (PI-factor) for each year of the 2019-2023 period shall be 2.0%.
b) The volume for each year of the Rate Review period shall be:
   - 2019 : 0.9%
   - 2020 : -2.4%
   - 2021 : 3.6%
   - 2022 : 1.5%
   - 2023 : 1.7%
c) The starting year for OPEX projections shall be the 2018 Audited Adjusted figures.

11. Revenue Requirement

11.1. Introduction

11.1. In accordance with Schedule 3 of the Licence, the basis of JPS' rate setting is the revenue cap principle, which looks forward at five (5) year intervals and involves the decoupling of kilowatt hour sales and the approved Revenue Requirement. This new principle replaces the price cap mechanism, which governed JPS' past rate setting processes. The Licence explains that the new revenue cap principle will accelerate energy access, affordability, renewable energy, energy efficiency and other policy initiatives of the Government of Jamaica (GOJ).

11.2. Paragraphs 27 and 28 of Schedule 3 of the Licence states that the Revenue Requirement shall be recovered through the approved rates. The approved Revenue Requirement under the revenue cap principle is made up of two (2) main elements:

1) Net investments (Rate Base) in the Licensed Business multiplied by the WACC to calculate the capital recovery element; and
2) Recovery of all prudently incurred expenses of the Licensed Business.

11.3. The legal and regulatory framework sets out in Schedule 3 of the Licence further details the elements of the Revenue Requirement at paragraphs 29 to 33.

11.2. Summary of JPS' Revenue Requirement Request

11.4. JPS is seeking approval of a five-(5) year levelized Revenue Requirement as shown in Table 11.1 below.

Table 11.1: JPS' Proposed five (5) Year Revenue Requirement

Revenue Requirement	J$M	US$M
2019	63,904	499.3
2020	62,350	487.1
2021	62,493	488.2
2022	60,842	475.3
2023	60,970	476.3

11.5. The proposed Revenue Requirement includes the following key drivers of the increase:

- Decommissioning Cost: J$4.428B or US$34.6M;
- Stranded Asset Cost Recovery: J$4.064B or US$34.6M;
- Recovery of depreciation expense on capital investments made in 2016-2018: J$2.939B or US$23.0M;
- Recovery of return on investment on capital investments made in 2016-2018: J$3.522B or US$27.5M;
- Electricity Disaster Fund (EDF): J$256M or US$2.0M annually.

11.6. JPS stated that the associated average rate increase resulting from the Annual Revenue Target (ART) increase over the last approved rates, from the 2018 Annual & Extraordinary Rate Review Determination Notice, is 10.6%, adjusted for non-fuel IPP surcharge on current bills.

11.3. Proposed Revenue Caps for Rate Review Period

11.7. JPS is seeking approval of revenue caps for the Rate Review period. The company stated that these revenue caps have been adjusted to reflect revenue from special contracts and the offsetting of unregulated expenses. The proposed caps are as shown in Table 11.2 below.

Table 11.2: JPS' Proposed Revenue Caps Rate Review Period

Proposed Revenue Caps	J$M	US$M
2019	60,922	476.0
2020	61,443	480.0
2021	62,249	486.3
2022	63,012	492.3
2023	63,784	498.3

11.8. The OUR in its evaluation of JPS' Revenue Requirement was guided by the provisions of the Licence, the Final Criteria and the Addendum to Final Criteria. This chapter analyses JPS' proposed Revenue Requirement and the company's explanations for known and measureable adjustments, which are included in the calculations and OUR's response to same. The necessary adjustments made are intended to ensure that expenses reflect normal operations, and any changes in the level of expenses that will take effect within the five-year tariff period.

11.4. The OUR's Analysis and Evaluation of JPS' Non-Fuel Operating Expenses

11.9. Schedule 3, paragraph 31 of the Licence defines non-fuel operating costs as:

- All prudently incurred costs, which are not directly associated with investments in capital plant, but are costs incurred by JPS in providing electricity services and maintaining and operating its generation, transmission, distribution and general plant assets;
- Power Purchase costs and other related costs including but not limited to working capital and credit support charges incurred under approved PPAs;
- Fuel supply agreements and other related infrastructure arrangements;
- Interest and other financial costs on other borrowings and working capital requirements not associated with capital investments incurred by the JPS;
- Foreign exchange loss/(gain);
- Rent and lease on properties associated with the Licenced Business;
- Taxes which JPS is required to pay other than income taxes of the Licensee.

11.10. In evaluating JPS' operating costs, the OUR was guided by the Licence, JPS' Audited Financial Statements for 2018 and 2019 and the methodological approach outlined in Annex 1 of the Final Criteria and the OUR's responses in the Addendum to Final Criteria. Base Year values were adjusted to reflect such changes in revenues and costs as are known and measurable with reasonable accuracy at the time of the filing of the Application.

11.11. This approach is founded on the premise that JPS should achieve efficiency improvements over the Rate Review period. Criteria 8 of the Final Criteria states, "JPS' controllable OPEX for 2020-2023 shall be adjusted by the PI-factor and a factor which is the weighted average of the projected sales, demand and customer growth rates".

11.12. Thus the OUR's approved OPEX for the forecasted years includes a PI-factor and a volume adjustment factor. Table 11.3 below shows the components of the adjustment factors applied to JPS' forecasted OPEX.

Table 11.3: Forecasted Adjustment Factors

Year	PI-Adjustment Factor
2018	0.0%
2019	0.9%
2020	-2.4%
2021	3.6%
2022	1.5%
2023	1.7%
PI-Factor 2018-2023	2.0%

11.13. The derivation and explanation of the above-mentioned factors are explained in **Chapter 10, Productivity Improvement Factor (PI-Factor)** of this Determination Notice.

JPS' Historical O&M Cost Highlight for the period 2013-2018

11.14. JPS indicated that it has accomplished remarkable reductions in its operating costs over the last tariff period 2014-2019. The company said that average expenditure over that period 2014 - 2018 was US$140M per annum compared to its test year 2013 expenditures of US$143.2M. JPS' base year expenses for this Rate Review period is US$130.4M, which is approximately 8.99% less than the last tariff period base year expense. JPS considered its reduction in operating expenses as remarkable, since market forces such as US inflation and a devaluation of the Jamaican dollar could have prevented the company from achieving reduced costs.

Payroll Related Expenses (2014-2018)

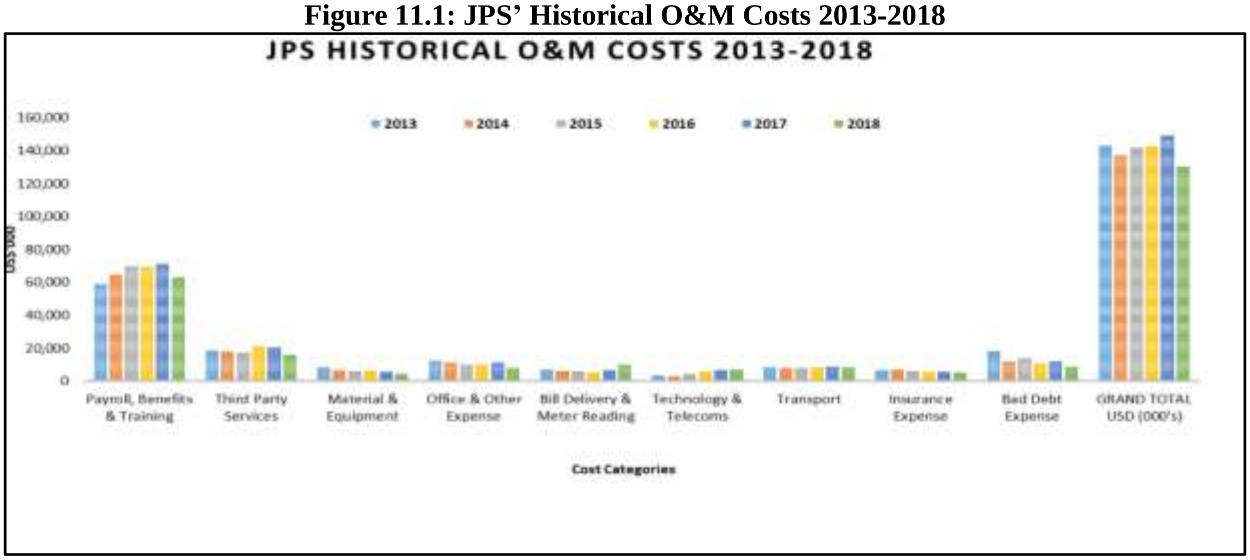
11.15. JPS' annual payroll related expenses during the period ranged between 49% and 41% of total O&M expenses. Payroll related expenses increased marginally over the period 2014-2017. In 2018, this cost category reached an all-time low of US$62.86M, which reflects a US$8.1M reduction over 2017 figures. JPS' reduced payroll expenses were caused by a reduction in staff headcount, which fell from 1,667 to 1561, and a reduction in overtime costs.

Non-Payroll Related Expenses (2014-2018)

11.16. Non-payroll related expenses trended downwards throughout the period 2014-2016, however, it marginally increased by 6.4% in 2017. This cost category reached its lowest amount in 2018, which suggests that JPS has attempted to practice meaningful cost containment strategies. The overall reduction in non-payroll expenses were attributed to a reduction in Material and Equipment expenses, Insurance expenses and Bad Debt expense.

11.17. Figure 11.1 below depicts the changes in JPS' historical O&M expenses over the period 2013-2018.

Figure 11.1: JPS' Historical O&M Costs 2013-2018



***Source**: JPS' Five Year O&M Plan (Excel Spreadsheet)*

Base Year Non-Fuel Operating Expenditure

11.18. In its Application, JPS stated that it has made significant efforts to contain O&M expenditures so that they are in alignment with the company's programme initiatives aimed at delivering value to customers. JPS also articulated that its cost containment efforts will continue through the Rate Review period. The OUR believes that cost containment is important in the day to day running of the business, as this will lead to allocative and productive efficiency necessary for system reinforcement and growth.

11.19. JPS submitted its audited financial statements for 2018 along with its submission. Based on the financials, total O&M was US$130.4M. JPS further revised the stated base year amount to US$141.1M. The company reported that the adjustments made to its audited 2018 spend included several unique isolated adjustments made to third party costs of US$2.03M, increase bad debt expenses of US$2.2M and payroll related adjustments of US$6.5M.

11.20. JPS specified that its 2018 audited expenses were lower than usual and hinted that the cost containment measures practised in 2018 cannot be sustained throughout the tariff period. The company purported that its 2016 audited amounts adjusted for inflation and exchange rate fluctuations would be a better fit for its starting base year cost.

11.21. The OUR believes that this assertion is unreasonable given that 2016 costs would have been somewhat different from current costs as the company has undergone a number of strategic initiative and changes to its business model.

11.22. Furthermore, JPS' assertions that its 2018 OPEX amount was unusually low and only occurred as a result of an aggressive OPEX reduction strategy is unfounded. JPS' 2019 Audited Financials reported a further reduction in its operating expenses.

The OUR believes that the 2018 audited OPEX is not an unusual occurrence even with the onset of the pandemic. Although the 2018 OPEX was 7% below average spend in 2013-2018, this amount was 1.15% higher than 2019 audited figures. The OUR has decided to use JPS' 2018 audited amounts as the base year costs.

11.23. Table 11.4 below depicts JPS' base year and projected operating and maintenance expenses for the period 2018-2023.

Table 11.4: JPS' Proposed Base Year and Projected Operating and Maintenance Expenditures 2018-2023

Operating Expenses by Nature:	2018	2018 Adjusted	2019 Audited	2019 Adjusted	2020	2021	2022	2023	2023 vs 2018 base year Var ($)	2023 vs 2018 Var (%)
Payroll, Benefits & Training	62,861	69,379	64,237	68,943	67,173	66,351	66,255	66,187	3,326	5.3%
Third Party Services	15,842	17,877	18,311	18,311	21,924	18,967	18,584	17,913	2,070	13.1%
Material & Equipment	4,340	4,340	4,626	4,626	4,558	4,010	4,035	3,990	(350)	-8.1%

Bill Delivery & Meter Reading	10,382	10,382	9,471	9,471	9,279	8,098	7,740	7,100	(3,282)	-31.6%
Technology & Telecoms	7,001	7,001	7,008	7,008	8,799	8,979	8,940	8,968	1,967	28.1%
Office & Other Expense	7,898	7,899	6,405	6,405	8,246	8,209	8,181	8,252	354	4.5%
Transport	8,234	8,234	8,338	8,338	8,492	9,121	9,164	9,229	995	12.1%
Insurance Expense	5,152	5,152	4,976	4,976	4,695	3,632	3,695	3,759	(1,393)	-27.0%
Bad Debt Expense	8,672	10,899	5,507	10,613	9,038	10,624	10,538	10,794	2,122	24.5%
GRAND TOTAL (US$000's)	**130,384**	**141,164**	**128,879**	**138,691**	**142,204**	**137,991**	**137,131**	**136,193**	**5,809**	**4.5%**

***Source**: JPS' 2019 - 2024 Tariff Application*

11.24. As shown in Table 11.4 above, JPS' expectation is that future O&M expenses will be reduced in the latter part of the Rate Review period. The company revealed that this reduction would be achieved by practising prudent business management strategies that are geared towards reducing payroll, insurance expenses, and material and equipment expenses. Notwithstanding the above mentioned cost reductions, JPS predicted that expenses such as Transportation, Technology and Telecoms, and Office and Other expenses will increase over time.

11.25. During the analysis of JPS' forecasted OPEX, the OUR was unclear as to how JPS incorporated the requirements outlined in Criteria 8 of the Final Criteria. That is, JPS' stated amounts did not reflect a 1.9% decline in productivity as mentioned.

It was also unclear if an annual adjustment factor was included in future cost projections. Therefore, the OUR asked that JPS provides relevant data in support of its claim that projected O&M expenses includes productivity improvement adjustments of 1.9%.

11.26. Subsequent to the OUR's request, JPS submitted a new OPEX Model ("Productivity Improvement Model") on 2020 October 01 and requested a meeting, which was held on the same day to explain the variables derived in the new model. With the aid of the OPEX Model, JPS was able to demonstrate the application of a 1.9% PI-factor in its projected O&M expenses. A volume adjustment factor was also included in the projections. Table 11.5 below depicts JPS' newly proposed O&M costs.

Table: 11.5 JPS' Revised O& M Calculation Inclusive of Productivity and Growth Factor

JPS O&M with Business Plan, Productivity Factor at Cost item level & Growth Rates							
	2016	2019	2020	2021	2022	2023	Total
Productivity Improvement (T&D)	110.8	108.8	108.9	110.2	109.4	108.4	545.7
Generation & Shared Services	41.46	38.85	34.73	30.22	30.18	30.14	164.1
Off-Set (excluded Non-Reg)	-3.10	-3.38	-2.79	-3.27	-3.31	-3.29	(16.0)
Total O&M for Rev. Requirement (U$'M)	**149.17**	**144.26**	**140.82**	**137.20**	**136.24**	**135.30**	**693.81**
Total O&M for Rev. Requirement (J$M)	19,094	18,465	18,024	17,562	17,439	17,319	**88,808**

Source: *JPS Reconsideration Request Application of the PI factor on O&M Excel Model*

11.27. JPS proposed that the starting OPEX be set equal to its 2016 OPEX adjusted for inflation and exchange rate variations. This would mean that JPS' starting OPEX of US$151.11M, is substantially higher than its 2018 audited adjusted OPEX of US$141.16M.

11.28. In JPS' Model, the Productivity Factor and Growth Factor were limited to the T&D component of O&M expenses. Cost categories such as Insurance and Bad Debt were excluded from the application of the productivity factor. JPS also stated that throughout the tariff period, a number of business initiatives will be undertaken by the company in accordance with its Business Plan. The effect that these initiatives will have on the company's forecasted costs were considered in JPS' proposal.

Unregulated Business Offsets

11.29. In its Application, JPS declared that costs incurred by the unregulated portion of the business are embedded in its proposed O&M costs. These unregulated business costs consist of costs incurred by the IPPs, Munroe Windfarm, Maggotty #1, disconnection and reconnection costs and penalties imposed for breaches of the Guaranteed Standards. Based on JPS' licensing requirement, all costs associated with the unregulated business must be deducted from the O&M costs of the Licensed Business.

11.30. Table 11.6 below shows JPS' unregulated business offsets and subsequent net O&M expenses for inclusion in the Revenue Requirement.

Table 11.6: JPS Unregulated Business Costs Offsets

Unregulated Business Offset	2019	2020	2021	2022	2023
G/S Penalties	1,110	740	977	924	890
Discon/ Recon	857	627	626	687	657
Business Development	1,237	1,152	1,383	1,412	1,441
Generation Un Reg.	176	269	280	289	298
	3,380	**2,787**	**3,267**	**3,312**	**3,287**

Source : *JPS' Reconsideration Request Application of the PI factor on O&M Excel Model*

11.31. The analysis on the components of the proposed O&M costs are examined in the subsequent subsections along with the OUR's comments, analysis and determinations.

OUR's Evaluation of Key Operating and Maintenance Expenses

Methodological Approach

11.32. JPS' O&M expenditures consist of eight (8) key expense drivers, namely; Payroll, Benefits and Training expenses, Third Party Services expenses, Material and Equipment expenses, Billing Delivery and Meter Reading expenses, Technology and Telecoms expenses, Office and Other expenses, Transportation expense, Insurance expense and Bad Debt. The details of the adjustments made by the OUR to JPS' expenditure drivers are outlined below.

11.33. In analysing and computing the projected path of these controllable expenses, the OUR adopts the methodological approached outlined in the Final Criteria. The OUR's projections for 2019-2023 OPEX consists of:

- The determined PI-factor of 2%, which is applied to JPS's total controllable OPEX, and not only its T&D cost component;
- The determined adjustment factor (Volume Factor) consisting of a weighted average of sales, demand and customer growth;
- The starting OPEX (which is determined to be 2018 Audited Adjusted figures) to which the PI-factor and Volume Factor is applied;
- Any known and measurable business initiatives that may affect OPEX negatively or positively throughout the Rate Review period.

Calculated Volume Factor

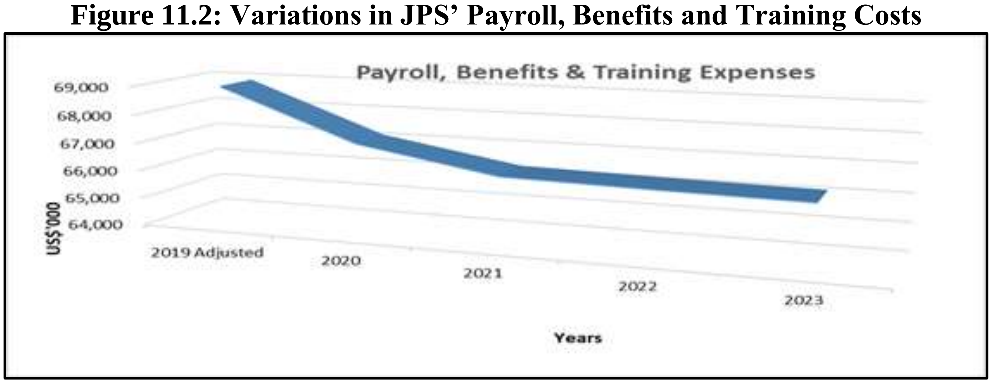
Years	2019	2020	2021	2022	2023
Volume Factor	0.9%	-2.4%	3.6%	1.5%	1.7%

Payroll, Benefits &Training

11.34. JPS stated that Payroll costs would be reduced beyond 2019 because of the planned closure of the Old Harbour and Hunts Bay Plants between 2020 and 2021 and a general decline in headcount over the Rate Review period.

11.35. Figure 11.2 below shows the movement in JPS' Payroll, Benefits and Training cost over the Rate Review period.

Figure 11.2: Variations in JPS' Payroll, Benefits and Training Costs



OUR's Review of JPS' Proposed Payroll Benefit and Training Expenses

11.36. Following JPS' submission, the OUR carried out an initial review of the proposed Payroll, Benefit and Training costs. The purpose of the review was to evaluate the reasonableness and prudency of including such costs in the controllable operating expense component of the Revenue Requirement. At the preliminary stages of the review, the OUR identified the need for additional data and schedules; a request was made to JPS for supplemental information.

To further substantiate its analysis, the OUR used JPS' 2018 and 2019 Audited Financial Statements to compare proposed amounts against actual audited figures.

Proposed Adjustment to Payroll, Benefits and Training Costs

Pension Adjustment

11.37. JPS on 2020 June 18, in responding to OUR's request for clarification and additional data on its pension adjustment, advised that its accounting for Pension is guided by International Accounting Standards on Employee Benefits (IAS 19). Among other things, IAS 19 requires an entity to recognize:

- a liability when an employee has provided service in exchange for employee benefits to be paid in the future; and
- an expense when the entity consumes the economic benefit arising from the service provided by an employee in exchange for employee benefits.[15]

11.38. Pension plans providing these benefits are the defined benefit (DB) plans and the defined contribution (DC) plans. JPS advised that the company has both a DB and a DC plan, however, the pension adjustment is applicable to the DB plan.

11.39. JPS advised that based on IFRS, the pension plan has residual obligations, and therefore is valued each year. Any surplus or deficiency arising must be recorded. JPS' DB plan is long established, and an annual valuation of this plan is usually conducted. JPS stated that in both 2018 and 2019 the valuation on its DB plan was in excess of the value on the books by US$4.2M and US$14.3M respectively.

In order to reflect this valuation, the Pension Asset account was debited by US$4.2M and US$14.3M, while the Equity and O&M accounts were credited with US$2.243M and US$1.986M respectively in 2018; and US$10.9M and US$3.4M respectively in 2019.

11.40. OUR's assessment of the adjustments are as follows:

- The IAS 19 adjustments are legitimate adjustments that are made to the financial statements (based on the actuary's own outlook, the performance of the pension plan assets, and pension obligations, and various assumptions) of an entity that has, as in this case, a defined benefit pension scheme;
- The adjustments are made to Administration Expenses via Staff Costs in arriving at net profit/loss, and further adjustments are usually made below the net profit/loss line to arrive at Total Comprehensive Income. There are balance sheet (assets/liabilities and reserves) entries that are also required for reporting purposes;

[15] https://www.ifrs.org/issued-standards/list-of-standards/ias-19-employee-benefits/

- The items that are used to make the adjustments to staff costs are actual costs (including discounted costs)/returns, e.g. Service Costs, Interest Expense on Pension Obligations, Interest Income on Pension Plan Assets, and Administration Fees.

Labour Capitalization

11.41. JPS requested US$2.3M of additional capitalization into internal resources. The company explained that labour capitalization refers to the percentage of the emoluments which are charged to capital projects. JPS employs both permanent and temporary staff and their direct labour costs are capitalized based on time spent and work done on a specific project. Both time spent and work done by these staff, varies based on the nature of the project.

JPS explained that in 2018 its capitalized labour amounts increased as a result of a revision to its capitalization practice, as well as an increase in internal labour contribution. JPS said that its capitalized labour cost for 2018 was US$13.5M, which is 11% of total project cost. Of this capitalized amount, US$2.3M represents labour costs of permanent employees who, going forward, would be involved in ongoing operations and maintenance of assets constructed.

11.42. In light of this, the OUR accepted JPS' adjustments to the audited figures for inclusion in the Revenue Requirement. JPS' adjustments reflect pension fund changes of US$4.2M and the additional US$2.3M capitalization of emoluments into resources.

11.43. Projected Payroll costs were done by applying the stated growth factor and the productivity factor for the respective years 2019-2023. An additional US$288,000 representing costs associated with business initiatives that JPS plans to undertake over the Rate Review period.

Third Party Services Expenses

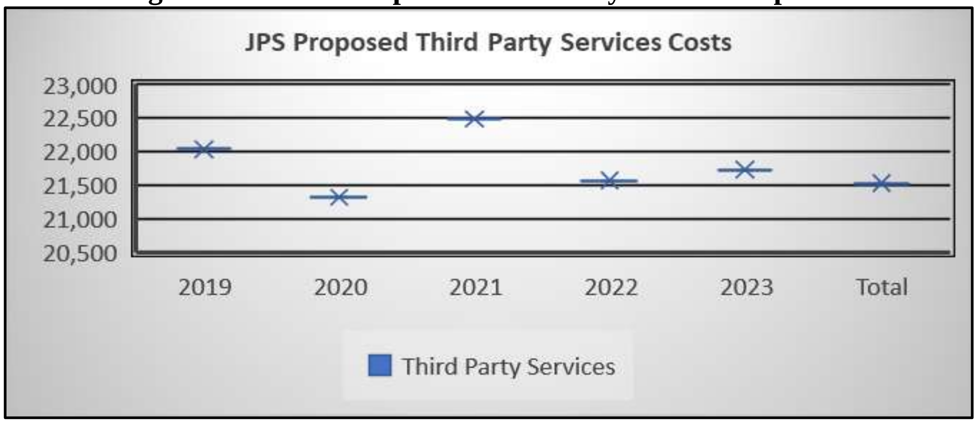
11.44. JPS' proposed Third Party Services Expenses were assessed taking into consideration the Base Year values adjusted to reflect such changes in revenues and costs as are known and measurable with reasonable accuracy at the time of the filing.

11.45. JPS' projections revealed that Third Party Services Expenses would increase in the early years of the Rate Review period. The company stated that this increase will happen as a result of a number of business initiatives that it will undertake. These initiatives include planned increase in spending on activities aimed at curtailing electricity theft and technological upgrade to key operating systems. JPS has included approximately US$3.63M for business plan initiatives throughout the Rate Review period.

11.46. Notwithstanding the proposed increase in Third Party Services Expenses, JPS stated that factors such as: a reduction in consultancy fees, reduction in generation and maintenance costs due to the retirement of Old Harbour Power Plant and Hunts Bay B6 generating unit and a reduction in T&D maintenance cost from efficiencies achieved through automation, will cushion the level of increase in this cost category.

11.47. JPS' forecasted Third Party Services expenses are shown in Figure 11.3 below.

Figure 11.3: JPS' Proposed Third Party Services Expenses



Source: *JPS 2019 - 2024 Tariff Application*

11.48. The OUR's review of JPS' Third Party Services Expenses took into consideration the proposed known and measurable adjustments incurred by the Licenced Business. The detailed cost listing was presented in Microsoft Excel format. The listing was carefully examined and adjustments made in relation to costs deemed unrelated to the regulated operations, as well as one-off costs that are not likely to be carried forward throughout the Rate Review period.

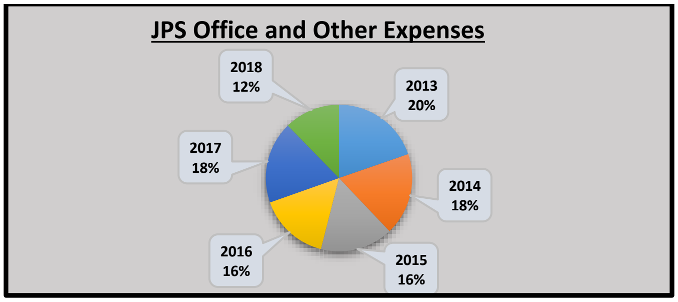
11.49. The OUR allowed the JPS proposed cost and approved Third Party Services Expense in the amount of US$89.5M for the Rate Review period for inclusion in the Revenue Requirement.

Office and Other Expenses

11.50. This expense category consists primarily of expenses incurred from maintaining JPS' physical office space, business advertising expenses, sponsorship costs, property taxes, etc.

11.51. Figure 11.4 below shows annual amounts of Office and Other Expenses incurred by JPS for the period 2013-2018. The amount for Base Year 2018 was the lowest, which augers well for JPS' efforts of controlling costs in this area. JPS indicated in the Application that it has been undertaking a number of business initiatives geared towards improving efficiencies and containing costs.

Figure 11.4: JPS' Office and Other Expenses 2013-2018



Forecasted Office and Other Expenses

11.52. The OUR's forecast for Office and Other Expenses was done in accordance with the provisions in the Final Criteria, which allows for the application of PI-factor and Volume Factor.

11.53. Office and Other Expenses approved by the OUR for inclusion in the Revenue Requirement is as shown in Table 11.7 below.

Table 11.7: OUR's Approved Office and Other Expenses

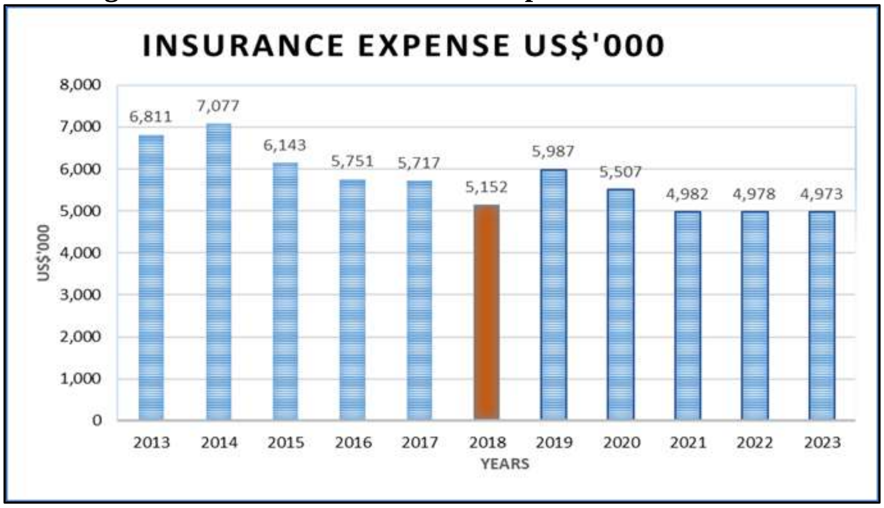
Cost Items (US$'000)	2019		2020		2021		2022		2023	
	JPS	OUR Allowed	JPS	OUR Allowed	JPS	OUR Allowed	JPS	OUR Allowed	JPS	OUR Allowed
Office & Other Expense	11,563	11,523	11,569	11,266	11,963	11,877	12,042	11,879	12,002	11,842

Insurance Expenses

11.54. According to JPS, Insurance Expenses is expected to reduce over the forecasted five-year period with the decommissioning of Old Harbour Power Plant by 2020 and the retirement of the B6 Unit at Hunts Bay by 2021. In its Business Plan, JPS stated that insurance premiums may be reduced by as much as 40% after the closure of these plants. The company further explained that insurance premium rates are expected to remain stable to mid-2020 based on existing contractual arrangements. Notwithstanding, JPS cautioned that although it will be making all efforts to procure the most competitive insurance coverage available, insurance costs incurred are usually outside of the control of the company.

11.55. The OUR examined JPS' past insurance costs with the aim of identifying any abnormalities or sudden spikes in this cost item. The data showed that insurance costs have been reducing over the period. Figure 11.5 below shows the changes in Insurance Expenses over the years.

Figure 11.5: JPS Historical and Proposed Insurance Costs



Insurance Cost for Hunts Bay and Old Harbour Power Plants

11.56. In evaluating this expense item, the OUR took into consideration insurance premiums for Bogue, Rockfort, Old Harbour, Hunts Bay, JPS' Renewables Plants, and the company's Corporate Offices. The OUR also made allowance for the decommissioning of the Old Harbour Plant and the B6 Unit at Hunts Bay. Although JPS had stated that the decommissioning exercises would have caused a reduction in insurance premiums, the company did not include as a part of its business initiatives, the cost savings that this exercise will bring when calculating its annual insurance premiums.

11.57. The OUR made allowance for this by reducing the proposed insurance costs by 14% from 2020 onwards. A 14% reduction was applied as past data revealed that the Old Harbour Power Plant on an annual basis incurred approximately 14% of total insurance costs.

11.58. The OUR's approved Insurance Expenses are shown in Table 11.8 below. The PI-factor and Volume Factor were applied in order to forecast JPS' 2020-2023 values.

Table 11.8: OUR Approved Insurance Expenses

INSURANCE EXPENSES US$' 000	2018	2019	2020	2021	2022	2023
JPS Proposed	6,274	5,987	5,507	4,982	4,978	4,973
OUR Approved	5,152	5,095	4,193	4,246	4,228	4,216

Material and Equipment

11.59. Material and Equipment cost category include purchasing safety and janitorial supplies, chemicals for water treatment, generation spares costs, lubrication costs, equipment costs,

costs for tools, meters, etc. JPS' revised base year values for Material and Equipment cost is US$4.34M. The company forecasted that this cost category will gradually reduce over the Rate Review period.

11.60. The main cost driver for the proposed increase relates to Generation Spares. The company stated that the cost of Generation Spares would increase because accounting principles require full expensing of charges associated with the decommissioning of the Old Harbour and B6 generating plants. Despite the proposed increase in this item, JPS explained that its SSP would yield some amount of cost savings. Chemicals and Lubricant costs are also expected to be reduced over the years.

11.61. The OUR's examination and analysis found that the Material and Equipment cost category included items such as Generation Spares, Transformers, Poles and Meters. These expenses could be classified as CAPEX. In light of this, the OUR sought clarification from JPS. Its explanation is as follows:

- *Generation spares covers costs attributed to Old Harbour and Hunts Bay B6 generating plant. Since these plants are to be decommissioned equipment costs that were previously charged to Capex are now expensed. Thus, JPS has increased its 2020 forecasted generation spares costs to account for this change;*
- *Costs itemized as Transformers, Meters, Poles and fittings represent accessories costs that are used in remedial situations such as pressure valves or small mechanical items, spare parts used to rectify defective poles, meter accessories such as seals, locking bands and padlocks and transformer accessories such as switches, insulators, copper rods*.

11.62. All other itemized material and equipment costs proposed by JPS were viewed as credible costs incurred by the Licensed Business.

11.63. The OUR did not identify any costs that could be classified as non-recurring, not known or not measurable. In light of JPS' explanation of the items which fall within this cost category, coupled by the fact that these costs can be considered as known and measurable, the OUR approved the proposed base year amount of US$4.34M for inclusion in the Revenue Requirement.

11.64. The OUR applied the PI-factor of 2% and a factor which is the weighted average of the projected sales, demand and customer number growth rates to the derived base year values in its projections for the Rate Review period. This forecast is in accordance with the Criterion 8, e) of the Final Criteria.

<u>Technology and Telecoms</u>

11.65. JPS stated that as the company modernizes its core technology platforms and ramps up its Smart Grid Strategies, it would incur an increase in Software and Telecommunication related costs relative to its Base Year costs. Other factors such as:

- The demand for Smart Meter/Smart Grid Technology, SCADA, CRM Microsoft EA, etc.;

- The current global trend of software as a cloud-based service, and with it the accounting treatment as an O&M expense rather than a capital cost;
- The leveraging of cutting-edge technology to enhance efficiency and outperform expectations in the area of customer service, utilizing the following software:
  1. UIQ and Operations SaaS Fees;
  2. AP Maintenance Costs and Communication;
  3. MDMS Fees.

11.66. Notwithstanding JPS' proposed increase in the Software and Technological expenses, the company envisages that savings amounting to US$650,000 will be achieved from a reduction in its telecommunication charges. JPS hopes to expand its network capabilities and decrease its dependency on third party suppliers by implementing a Field Area Network which will integrate Transformer Meters, Distribution Automation Switches and Trip Savers, thus eliminating the use of SIM cards and attendant data charges.

11.67. In response to OUR's request for additional data, JPS submitted a spreadsheet showing annual Smart Meter Operation and Maintenance Expenses, Smart Streetlight Operation and Maintenance Fees, Meter Data Management Systems costs, etc.

11.68. The proposed increase in Technology and Telecoms costs in the Base Year are considered to be just and reasonable and are approved by the OUR. Planned investment in this area should increase the accuracy and interactivity of the billing system, which will be beneficial for customers and is welcomed. The OUR applied the PI-factor and a factor which is the weighted average of the projected sales, demand and customer number growth rates to the base year values in its projections for 2020 -2023. This forecast is in accordance with the Criterion 8 e) of the Final Criteria.

Transportation Expense

11.69. JPS' proposed Base Year Transportation Expense was US$8.23M. Included in this total were amounts for gasoline expenses, distill-2 diesel oil, accident damage repairs, lease/purchase of motor vehicle, licensing and insurance of a motor vehicle and transmission expense clearing. JPS stated that currently it operates an aged fleet and therefore incurs substantial motor vehicle maintenance cost. JPS further indicated that it would improve efficiencies by undertaking an accelerated replacement program in 2020. Because of this, the company projected that transportation costs would increase by US$1M over the Rate Review period.

The proposed amount for the Base Year transportation cost was verified against that reported in JPS' audited financial statement.

Bad Debt Expenses

11.70. In accordance with IFRS 9, JPS' Bad Debt reflects the movement on the provision for aged receivables based on individual customers' payment history over a one-year period. In applying IFRS 9, JPS stated that the company is required to take three factors into account in determining the required provision for Bad Debt. These are:

- The Collection Experience;

- Accounts Receivable Age Profile;
- Economic Outlook.

11.71. In 2018, JPS recorded Bad Debt of US$8.23M, which is the lowest that it has been since the start of the tariff period. The company stated that this reduction in Bad Debt is the result of extensive amnesty initiatives and several collection campaigns which are unsustainable given the level of resources required to achieve such a reduction.

11.72. JPS' projection for the Rate Review period is for Bad Debt to increase on average to US$10.07M, even though the company holds to its Bad Debt target of 1% of revenues.

11.73. JPS indicated that since the onset of Covid-19 average collections have declined. The company claims that it also has experienced an upsurge in requests for extended payment terms, an increase in the number of accounts due for disconnection and an escalation in the arrears balance. JPS debated that in respect to the accounts receivable age profile, the categories at risk have risen sharply. The inactive accounts balance has increased by US$3.1M or 15% between 2020 January and 2020 May and accounts unpaid in excess of 12 months have grown by 5%.

11.74. The OUR is aware that job losses have travelled hand in hand with the Covid-19 pandemic. Thus, a major repercussion of Covid-19 pandemic is that customers may have cash flow strains and therefore delay or default on payments. This change in payment behaviour brought on by the pandemic, may have a crippling ripple effect on JPS' cash flow over the Rate Review period.

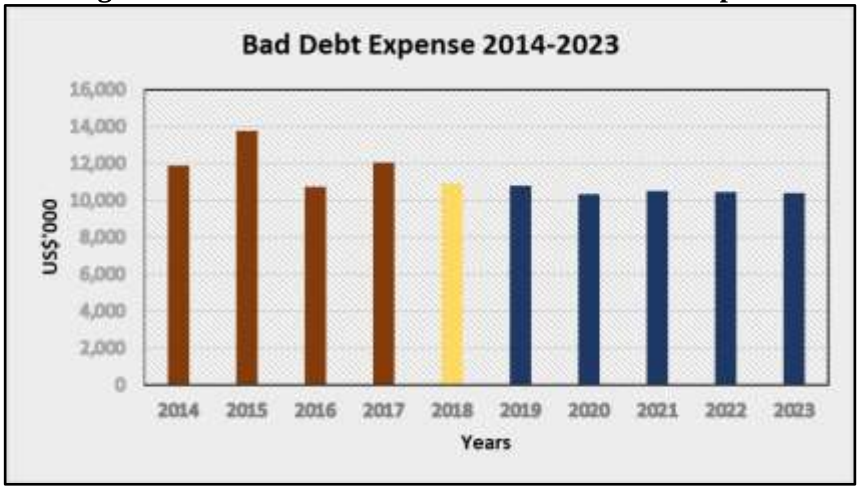
11.75. However, to minimize this risk, JPS must develop strategies to optimize accounts receivable and limit bad debt losses as much as possible. Thus, the aim of JPS should not be limited to securing an increase in bad debt provisions, but to develop best practices to assess accounts receivable portfolios, consider renegotiating payment terms with customers and streamline the accounts receivable process.

11.76. Notwithstanding the abovementioned suggestions, the OUR examined JPS' actual collection rate pre and post Covid-19 to determine the extent to which the company's collections were affected by the pandemic. The statistics show that for the period 2020 January – August, average collection rate was 99.8%. However, for the Covid-19 period 2020 March - August, collection rate reduced to 90.77%, which is even lower than the reported 105% published by JPS for the same period in 2019. The data also revealed that outstanding receivables for the year 2020 have increased.

11.77. Given the downward trend in collection rate, coupled with the increase in outstanding receivables, the OUR has decided to allow JPS the opportunity to make a provision for bad debt of US$52.4M for the Rate Review period.

11.78. Figure 11.6 below gives a pictorial indication of JPS' historical and projected bad debt expenses.

Figure 11.6: Historical and Forecasted Bad Debt Expense



11.79. In light of the above assessments, the OUR has approved the amounts for operating and maintenance costs as shown in Table 11.9 below.

Table 11.9: OUR Approved Operating and Maintenance Costs (2019 to 2023)

Cost Items (J$'millions)	2018		2019			2020		2021		2022		2023	
	Audited	OUR Base	JPS	AFS	OUR Allowed	JPS	OUR Allowed	JPS	OUR Allowed	JPS	OUR Allowed	JPS	OUR Allowed
Payroll, Benefits & Training	8,046	8,892	8,761	8,222	8,752	8,433	8,374	8,248	8,574	8,232	8,540	8,219	8,523
Third Party Services	2,028	2,288	2,728	2,344	2,256	2,879	2,282	2,761	2,308	2,781	2,312	2,755	2,298
Material & Equipment	556	555	534	592	581	503	531	470	539	468	536	466	534
Bill Delivery & Meter Reading	1,329	1,329	1,388	1,212	1,303	1,229	1,247	911	1,114	819	1,063	655	977
Technology & Telecoms	896	896	1,186	897	1,109	1,300	1,171	1,247	1,148	1,167	1,111	1,112	1,087
Office & Other Expense	1,011	1,277	1,480	820	1,475	1,481	1,442	1,531	1,520	1,541	1,520	1,536	1,516
Transport	1,054	1,054	1,071	1,067	1,042	1,066	997	1,132	1,013	1,137	1,007	1,145	1,004
Insurance Expense	660	660	766	637	652	705	537	638	544	637	541	637	540
Bad Debt Expense	1,110	1,395	1,199	705	1,380	1,157	1,320	1,360	1,340	1,349	1,333	1,382	1,329
TOTAL	**16,689**	**18,346**	**19,113**	**16,497**	**18,549**	**18,751**	**17,900**	**18,297**	**18,099**	**18,132**	**17,965**	**17,908**	**17,806**
Less Unregulated Business Costs	412	397	433	-	433	357	357	418	418	424	424	421	421
O&M for Revenue Requirement	**16,277**	**17,950**	**18,680**	**16,497**	**18,116**	**18,394**	**17,544**	**17,878**	**17,681**	**17,708**	**17,541**	**17,487**	**17,386**

Unregulated Business Offsets (2019-2023)

11.80. JPS declared in its Application that embedded in its proposed O&M costs are costs incurred by the unregulated portion of the business. These costs are related to its own IPPs, namely, Munroe Windfarm and Maggotty Hydro #1, business development cost, E-Store costs, disconnection and reconnection exercises and guaranteed standards penalties.

11.81. Table 11.10 below shows JPS' proposed unregulated business costs to be offset from the Revenue Requirement.

Table 11.10: JPS' Unregulated Business Costs Offsets

Unregulated Business Offset	2019	2020	2021	2022	2023
G/S Penalties	1,110	740	977	924	890
Discon/ Recon	857	627	626	687	657
Business Development	1,237	1,152	1,383	1,412	1,441
Generation Un Reg.	176	269	280	289	298
Total	**3,380**	**2,787**	**3,267**	**3,312**	**3,287**

11.82. The OUR accepted the proposed US dollar values in its computation of JPS' Unregulated Business Costs as an offset to the Revenue Requirement.

Financing Expenses

11.83. JPS stated that its Base Year net finance expense is J$421M. The company indicated that the main cost drivers of net financial expenses are interest on customer's deposits, debt issuance costs, and interest on short-term loans. Table11.11 below shows JPS' proposed amounts for financing expenses.

Table 11.11: JPS' Proposed Net Finance Costs

JPS Proposed Net Finance Expense 2018-2023 in Millions of Jamaican Dollars						
Description	**2018 Actual**	**2019**	**2020**	**2021**	**2022**	**2023**
Financing Expenses :	**602**	**817**	**330**	**301**	**314**	**321**
Interest on short Term Loan	76	91	0	0	0	0
Interest on Customer Deposits	103	101	99	99	96	93
Interest- Other	0	0	0	0	0	0
Debt Issuance costs and expenses	424	965	232	202	218	228
Less Bond Refinancing Costs	0	(340)	0	-355		0
Less Finance Income	**(181)**	**(186)**	**(266)**	**(335)**	**(355)**	**(358)**
Net Financing Expenses	**421**	**631**	**64**	**(34)**	**(41)**	**(37)**

11.84. JPS expects its net finance cost to fall over the Rate Review period due to lower debt issuance expenses. The unusually high amount for debt issuance expenses in 2019 is attributed to the refinancing of the Credit Suisse US$180M Bond.

11.85. For Finance Expenses, in its 2018 and 2019 audited accounts, JPS reported the total amounts of US$3.7M and US$5.2M respectively. Finance Expense includes: interest on short term loans, interest on customer deposits and debt issuance cost and expenses. The details of the amounts approved by the OUR for total Finance Expense for the period 2018 to 2023 are shown in Table 11.12 below.

Table 11.12: OUR Approved Finance Expense 2018-2023

Finance Expenses	2018	2019	2020	2021	2022	2023
Interest on short Term Loan	677	711	-	-	-	-
Interest on Customer Deposits	231	400	414	414	414	414
Debt Issuance costs and expenses	2,820	4,043	1,657	1,657	1,443	1,557
Total(US$'000')	**3,728**	**5,154**	**2,071**	**2,071**	**1,857**	**1,971**
Total(J$'000')	**477,184**	**659,704**	**265,101**	**265,106**	**237,678**	**252,306**

11.5. Depreciation Expense

11.86. In determining the depreciation allowance for establishing JPS' Revenue Requirement, the regulatory Rate Base which impacts the allowable return ROE, is one of the most important components that must be considered. In reference to the price control regime, the regulatory requirements for determining the Rate Base and depreciation charges are of critical importance, as they are key determinants of prices that will be charged for regulated electricity services in the future. Hence, decisions on the Rate Base and depreciation will most likely have the greatest impact on establishing a balance between the interest of the consumers and that of the regulated utility.

11.5.1. Depreciation Principles and Considerations

Definition

11.87. In the context of utilities regulation, depreciation generally refers to the systematic allocation of the cost of an asset over its useful life. Since the future economic benefits embodied in an asset are consumed by an entity primarily through its use, this allocation is designed to reflect the economic benefits associated with the asset over its useful life.

11.88. With respect to regulated utilities, a depreciation allowance is normally included in the revenue requirements to recoup the outlays involved in the purchase of the utility assets over their useful lives. Additionally, depreciation is necessary to ensure the build-up of funds for the replacement of the utility's fixed assets (FA).

11.89. Application of Depreciation

1) According to established accounting standards, after an asset is recognized in a utility's PPE, it should be carried at its cost and be subject to depreciation.
2) Depreciation of an asset begins when it is available for use, that is, when it is in the location and condition necessary for it to operate in the manner intended by the entity.
3) Depreciation of an asset ceases at the earlier of the date that the asset is classified as held for sale (or included in a disposal group that is classified as held for sale) and the date that the asset is derecognized (asset fully depreciated).

Depreciation Computations

11.90. In computing depreciation charges for rate determinations, consideration should be given to, among other things, the following conditions:

1) The assets included in the Rate Base should be recognized as "Plant in Service" that are used and useful in the provision of the regulated services. In line with rate setting

principles, these assets would then form the basis of the related depreciation calculations and charges;

2) Depreciation associated with any unregulated assets should not be reflected in the depreciation of utility assets used for the provision of the regulated services;

3) Depreciation is generally calculated using the straight-line depreciation methodology with pre-defined asset lives (depreciation rates). All assets should be depreciated with the exception of land and construction work-in-progress (CWIP). For CWIP, no depreciation should be recorded until the asset is placed in service;

4) A distinction should be made for the purposes of calculation between the depreciation of existing assets (those existing at the start of the new price control period) and new assets (those acquired after the start of the price controls); and

5) For determining the Rate Base and depreciation at each Rate Review interval, there should be clear guidelines on the methodology and procedures as well as the regulatory treatment of these components during the new price control period. This is necessary to ensure consistency and transparency in the regulatory process. The re-opening or re-setting of pre-agreed revenue requirement components should be avoided as this can undermine the regulatory regime.

<u>Depreciation Method</u>

11.91. Generally, the applicable depreciation method should reflect the pattern in which the asset's future economic benefits are expected to be consumed by the utility.

11.92. Based on JPS' price control mechanism, the straight-line methodology is prescribed for the calculation of depreciation charges. This method involves systematic allocations that remain constant from year to year and it is the most commonly adopted approach due to its administrative simplicity. Essentially, this approach calculates the write-down of the gross asset value to obtain the depreciated asset value, by assuming a linear relationship between accumulated depreciation and the age of the asset relative to its expected economic life.

<u>Licence Requirements for Depreciation</u>

11.93. Regarding the regulatory requirements pertaining to JPS' depreciation, Condition 15, paragraphs 4 and 5 of the Licence, provide 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 the 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; and
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 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 the property, plant and equipment stated at book value. As part of the Rate Review Process, the Office shall determine the adequacy of the depreciation rates based on a depreciation study conducted by a reputable firm of chartered accountants engaged by the Licensee. 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."

Annual Depreciation Expenses for Revenue Requirement

11.94. The basis for calculating the depreciation component of the Revenue Requirement is set out under Schedule 3, paragraph 32 of the Licence, which states as follows:

"Depreciation: The depreciation component will be calculated by applying annual depreciation rates, as provided at Schedule 4 (as may be updated from time to time in accordance with this Licence), to the gross value of the individual plant asset accounts included in the approved Rate Base."

Final Criteria – Depreciation Requirements

11.95. The relevant depreciation requirements for the 2019-2024 Rate Review are outlined in section 3.7 and Criterion 4 of the Final Criteria.

Review Objective

11.96. In the Application, JPS indicated that in accordance with the Licence conditions and the OUR's 2017 Annual & Extraordinary Rate Review Determination Notice, the company undertook a deprecation study in 2018 (2018 PwC Depreciation Study), which was conducted by PricewaterhouseCoopers (PwC), an international audit and consulting firm.

11.97. Further, there has been major system developments recently, including generation assets displacement, grid modernization projects, energy efficiency (EE) initiatives, and planned investments. Consequently, this Rate Review is critical for ensuring that the proposed depreciation expenses associated with the existing fixed assets in-service and CAPEX transferred in service from the CWIP, are justified and reasonable and do not impose any undue burden on rate payers.

11.5.2. JPS Depreciation Proposal

Depreciation Forecast

11.98. Based on the Application, JPS' forecasted Depreciation Expenses for the Rate Review period are as follows:

- 2019: J$13.027 billion (US$101.77 M)
- 2020: J$10.102 billion (US$78.92 M)
- 2021: J$10.080 billion (US$78.75 M)
- 2022: J$10.243 billion (US$80.02 M)
- 2023: J$10.402 billion (US$81.27 M)

11.99. The breakdown of the proposed annual depreciation expenses is presented in Table 11.13 below.

Table 11.13: JPS' 2019-2023 Depreciation Breakdown

JPS DEPRECIATION FORECAST 2019-2023					
Depreciation	**Depreciation Forecast (J$ Millions)**				
	2019	**2020**	**2021**	**2022**	**2023**
DEPRECIATION	**13,027**	**10,102**	**10,080**	**10,243**	**10,402**
Gross Fixed Asset in-Service Depreciation	6,740	6,825	6,327	6,108	5,680
CAPEX Depreciation	631	1,955	3,339	4,134	4,833
Accelerated Depreciation (OH and HB)	1,606	398			
Accelerated Depreciation (Bogue, RF and HB)	689	689	689	689	689
Stranded Asset Costs:					
Recovery of Asset Write-Offs	414	414	414	0	0
Meter Replacements	459	383	383	364	210
Streetlight Replacement	512	512	0	0	0
2016-2018 Depreciation Recovery	2,939	0	0	0	0
LESS: Customer Contribution Depreciation					
Bogue Conversion Assets	(51)	(51)	(51)	(51)	(51)
Smart LED Streetlight Programme	(79)	(79)	(79)	(79)	(79)
ALRIM	0	(115)	(115)	(115)	(115)
EEIF	(646)	(641)	(641)	(621)	(579)
JPS Estore	(2)	(2)	(1)	(1)	(1)
JPS Munro Windfarm	(70)	(70)	(70)	(70)	(70)
JPS Maggotty Hydro (6.3MW)	(114)	(114)	(114)	(114)	(114)

11.100. According to JPS, this depreciation forecast is mainly driven by the growth in the fixed asset base, reflecting the capital projects to be implemented in the Rate Review period.

PROPOSED DEPRECIATION EXPENSES COMPONENTS

11.101. As represented in Table 11.13 above, the proposed depreciation projections comprise the following components:

<u>Fixed Assets in-Service and CAPEX Depreciation Expenses</u>

11.102. In the Application, JPS indicated that this component of expenses refers to the depreciation expense derived by applying annual depreciation rates to the gross value of the individual plant asset accounts included in the proposed Rate Base after rolling through CWIP, which details the CAPEX component. The company also indicated that the annual depreciation rates are based on the asset lives as recommended in the 2018 PwC Depreciation Study, which generated depreciation expense for fixed assets in-service and CAPEX of J$7,371M (US$57.58M) in 2019.

Accelerated Depreciation for Decommissioning Assets

11.103. This component involves accelerated depreciation in relation to generation plant assets addressed below.

Capitalized Maintenance Cost - OHPS & HB B6

11.104. JPS is requesting accelerated depreciation for capital maintenance expenditures pertaining to the OHPS and HB B6 unit, which, according to the company, was originally discussed in the 2018 Annual Review Filing. The requested accelerated depreciation provision is J$1,606 million (US$12.5M) for 2019 and J$398M(US$3.1M) for 2020.

Scheduled Plant Retirements

11.105. As indicated in the Application, JPS is requesting accelerated depreciation of the Bogue and Rockfort plants as well as HB B6, in the amount of J$689M (US$5.38M), per year. However, the reference to HB B6 may be incorrect as the OUR in the 2018 Annual & Extraordinary Rate Review Determination Notice, already approved accelerated depreciation for that generating unit.

11.106. Regarding the OHPS and HB B6 unit, JPS asserted that in the 2018 Annual Review Filing, it requested accelerated depreciation of these plants which would be retired consequent on the commissioning of the new SJPC CCGT (194MW) and NFE CHP (94MW) facility in 2019 and June 2020 respectively. The company emphasized that its accelerated depreciation request regarding the OHPS and the HB B6 unit had two (2) components:

1) Incremental depreciation charges for the assets in-service, reflecting modification of the depreciation rates applying to these steam assets to achieve a full write-off of their carrying values over the period to their projected retirement dates. The effect of the accelerated depreciation of these assets resulted in incremental charges of US$9.157 million over the period 2017 to 2020.
2) Incremental depreciation related to future maintenance expenditure of the OHPS and the HB B6 unit totaling US$13.184M.

11.107. Further, as the company noted, in the 2018 Annual & Extraordinary Rate Review Determination Notice, the OUR approved the incremental depreciation charges of US$7.946 million for the assets in-service, after factoring Rate Base reduction due to the accelerated depreciation of the assets (US$9.157M less return on rate base reduction of US$1.211M).

11.108. As it relates to the incremental depreciation involving future maintenance expenditure of the OH and HB plants, the company indicated that the OUR concluded that based on International Accounting Standard (IAS) 16, the forecast capital expenditure for maintenance activities over the 2018-2020 period, cannot be recognized as assets, until they are incurred and thus depreciation charges cannot be applied. Further, the company indicated that the OUR also noted that necessary plant maintenance expenditure incurred by JPS in the future that is determined to be reasonable and prudent, will be considered for recovery. Referencing those decisions, JPS submitted updated depreciation calculations for the OHPS and HB B6 unit, including actual 2018 capitalized maintenance expenditure, as presented in Table 11.14 below.

Table 11.14: Accelerated Depreciation – OHPS and HB B6 Capitalized O&M

ACCELERATED DEPRECIATION - OHPS & HB B6 CAPILALIZED O&M						
Description	**NBV**	**2019**	**2020**	**2021**	**2022**	**2023**
OH & HB Assets in Service prior to 2018	10,624	8,023	2,151			
OH & HB Assets in Service added in 2018	5,793	4,520	958			
Annual Provision	**15,652**	**12,543**	**3,109**	-	-	-

11.109. JPS contends that the requested accelerated depreciation of these plant maintenance expenditures, is consistent with the IFRS requirements, in that depreciation is to be determined as the systematic allocation of the cost or carrying value of an asset over its useful life. The company also argued that the requested accelerated depreciation also satisfies the regulatory principle that "the cost causer pays the cost" and in that context, the asset costs are recovered from customers who derive benefit from their operation.

Stranded Assets Costs

11.110. JPS has requested the recovery of the stranded costs related to the implementation of the 2018 PwC Depreciation Study results, meter replacements, and streetlight replacements as part of the Depreciation Expense. The proposed recovery of stranded assets cost for 2019 is J$1,385M (US$10.8M).

11.111. JPS posited that, consistent with paragraphs 27 b. and 32 of Schedule 3 of the Licence, any stranded costs occasioned by the implementation of strategic initiatives approved by the OUR, whether as part of the Business Plan or initiatives presented in filings to the Regulator, should be fully and completely recovered through the tariff on a timely basis.

11.112. As described in the Application, two (2) major initiatives, the SSP and the Smart Metering programme, will generate approximately US$21.3M of stranded asset costs that will create a charge on income. The company asserted that it cannot absorb the impact of these costs, therefore regulatory relief must be provided to ensure fairness and integrity in the regulatory regime.

Asset Write-off Requirements

11.113. With respect to asset write-offs, JPS indicated that based on the 2018 PwC Depreciation Study to update the useful lives used in Schedule 4 of the Licence, the existing lives of certain assets are higher than the recommended useful asset lives. As such, JPS, asserted that adjustments would need to be made for these assets within the following categories:

1) *Hydraulic Production Plant*: Adjustment primarily relates to the group of assets acquired between 1950 and 1960. Current life parameters in the fixed asset register,

is between 57 and 71 years. The 2018 PwC Depreciation Study recommended life parameters between 20 to 50 years;

2) *Distribution Plant:* Adjustment primarily relates to group of assets acquired in the early 1970s. Life in the fixed asset register is 57 years. The 2018 PwC Depreciation Study recommended life parameters between 15 and 30 years;

3) *Other Production Plant:* (including Wind and Solar): Adjustment primarily relates to assets acquired in 1993. Existing life in the fixed asset register is 32 years on average. The 2018 PwC Depreciation Study recommended a life parameter of approximately 24 years;

4) *Transmission Plant*: Adjustment primarily relates to assets acquired in 1987. Existing life in the Fixed Asset Register is 35 years. The 2018 PwC Depreciation Study recommended a life of approximately 30 years;

5) *Steam Production Plant and General Plant:* the adjustments identified for these component of the plant were relatively small in comparison to the other categories.

11.114. The proposed asset write-off cost due to the recommended useful asset live is US$9.703M, which is broken out by asset category as shown in Table 11.15 below.

Table 11.15: Asset Write-off Cost

ASSET WRITE OFF COST DUE TO RECOMMENDED USEFUL ASSET LIVES		
Asset Category	**Write-Off Cost (US$M)**	**Remarks**
Steam Production Plant	(477)	
Hydraulic Production Plant	(2,432)	Existing Asset Lives deviated from Schedule 4 of the 2001, 2011 and 2016 Licence
Other Production Plant	2,855)	Existing Asset Lives deviated from Schedule 4 of the 2001, 2011 and 2016 Licence
Transmission Plant	(973)	Existing Asset Lives deviated from Schedule 4 of the 2001, 2011 and 2016 Licence
Distribution Plant	(2,858)	Existing Asset Lives deviated from Schedule 4 of the 2001, 2011 and 2016 Licence
General Plant	(108)	
TOTAL	**(9.703)**	Deviation from the 2018 NBV

11.115. Regarding the asset write-off cost recovery, the company indicated that in order to mitigate the rate impact to the customers, it is requesting that these costs be systematically written off over the 2019-2021 period at the annual write-off of US$3.235M in 2019, and US$3.234M in each of 2020 and 2021, respectively.

Meter Replacements

11.116. JPS indicated that the replacement of existing revenue meters necessitated by the Smart Metering programme has generated stranded costs of US$14.0M. According to the company, this programme is expected to have multiple future benefits, and on that basis, it proposed that the resulting stranded asset costs be shared among the entire customer base. Also, the company proffered that since the programme is scheduled to be implemented over a five-year period, it proposed that the recovery of the stranded asset costs be initiated in line with the timing when costs are incurred, as detailed in Table 11.16 below.

Smart Streetlight Programme

11.117. As described by JPS, the implementation of the SSP resulted in stranded streetlight asset costs of US$8M. This the company proposes to recover as part of the annual depreciation expense in equal amounts of US$4M per year in 2019 and 2020.

Proposed Recovery of Stranded Asset Costs

11.118. The proposed cost recovery schedule for the described asset write-offs and stranded assets is presented in Table 11.16 below.

Table 11.16: JPS' Proposed Recovery of Stranded Asset Costs

STRANDED COSTS (US$M) – METER REPLACEMENTS					
Description	**2019**	**2020**	**2021**	**2022**	**2023**
Assets Write-Off	3.235	3.234	3.234	-	-
Meter Replacement Stranded Cost Recovery	3.587	2.989	2.989	2.840	1.644
Smart Streetlight Programme	4.000	4.000	-	-	-

2016 – 2018 Incremental Depreciation Recovery

11.119. JPS has requested the recovery of depreciation charges related to regulatory assets placed in service during the fiscal years 2016 to 2018, amounting to J$2.939 billion (US$22.96M), as shown in Table 11.17 below.

Table 11.17: JPS' Proposed Excess Depreciation Charges 2016-2018

JPS' EXCESS DEPRECIATION CHARGES (US$M) 2016-2018		
Year Ending	**Excess Depreciation Charge**	**Remarks**
31-Dec-16	1.02	Cost reported in the supporting schedule appears to deviate from this value
31-Dec-17	9.69	
31-Dec-18	12.25	
TOTAL	**22.96**	

11.120. The arguments presented by JPS to support the proposed recovery of these incremental depreciation expenses are as follows:

1) JPS asserted that in accordance with paragraph 27 b. of Schedule 3 of the Licence, recovery of all prudently incurred expenses of the Licensed Business is one of the two main elements of the Revenue Requirement under the revenue cap principle. Accordingly, it is proposed that consistent with paragraph 27 b. of Schedule 3 of the Licence, provision be included in the Revenue Requirement for the depreciation charges related to regulatory assets incurred during the fiscal years 2016 - 2018 over and above the approved depreciation charge determined in the 2014-2019

Determination Notice and modified by the 2017 Annual & Extraordinary Rate Review Determination Notice.

2) JPS stated that it first addressed the recovery of these costs in a discussion paper presented to the OUR during mid 2016 with a formal request being made in the 2017 Annual Adjustment filing. In the 2017 Extraordinary Rate Review, the OUR looked at the approach involving an adjustment to the approved 2014 Rate Base to include JPS' investments in 2017 and 2018 on a forecast basis. Accordingly, in the 2017 Annual & Extraordinary Rate Review Determination Notice, the OUR determined that JPS should: *"...provide details on each project in its investment plan for 2017 and 2018. The information provided shall include the purpose, a break-out of the cost into its components, the implementation schedule and the benefit to be derived from the specific investment, including any supporting return on investment projections"*

3) According to the company, it responded to the OUR's determination via letter dated 2017 April 27, in which it proposed to defer the recovery of additional revenues on investments in fixed asset additions during 2017 and 2018 tariff periods until after the expenditure is incurred, as the company was not yet in a position to implement the business processes and procedures necessary to sufficiently forecast the capital investment with the level of precision and granularity within the timeframe stipulated by the OUR.

4) Additionally, the company referenced the Addendum to the Final Criteria, indicating that the OUR in response to its comment regarding the recovery of the incurred capital expenditures, stated that it would encourage JPS to make a submission on these investments in its Application for the Office's consideration.

11.121. Based on these conditions, JPS has requested the recovery of such prudent costs as accommodated under paragraph 27 b. of Schedule 3 of the Licence. The total cost recovery requested by JPS is US$22.9 million, and the details of the additions to the fixed assets during the period will be made available to facilitate the evaluation of this request.

JPS Non-Regulated and Customer Funded Assets Depreciation

11.122. This component represents depreciation charges associated with JPS' non-regulated assets, with a majority funded by customer contributions. As represented by JPS, these are applied as an offset to the annual forecasted depreciation expenses for the Rate Review period, with the 2019 depreciation charges calculated to be J$963M (US$7.5M).

11.123. As indicated by JPS, this asset category includes the following components:

- Bogue Conversion Assets;
- SSP;
- ALRIM;
- EEIF;
- JPS eStore;
- JPS Munro Windfarm;
- JPS Maggotty Hydro (6.3MW).

Depreciation Study

11.124. As previously indicated, JPS undertook a deprecation study in 2018 (2018 PwC Depreciation Study), which was conducted by PricewaterhouseCoopers (PwC). The scope of the study included a review of Schedule 4 of the Licence to determine the appropriateness of the depreciation rates for all asset categories.

11.125. The major recommendations of the study as outlined in the Application, are as follows:

- The regulatory useful lives of seventy (70) asset categories were recommended to be increased. This included thirty-seven (37) Generation asset categories, twenty-one (21) Distribution asset categories and one (1) other asset category. The associated impact of these changes will be a reduction of approximately US$8.9 million on the depreciation expense for 2018. These categories of assets will also continue to have reductions in the depreciation charges in the future relative to the currently approved depreciation rates in Schedule 4 of the Licence.
- The regulatory useful lives of thirty-five (35) asset categories were recommended to be reduced. This included eleven (11) Generation asset categories, eleven (11) Distribution asset categories and six (6) other asset categories. The associated impact of these changes will be an increase of approximately US$4.8 million on the depreciation expense for 2018. These categories of assets will continue to have higher depreciation charges in the future relative to the currently approved depreciation rates in Schedule 4 of the Licence.
- For the remaining asset categories, retention of the useful lives specified in the Amended and Restated All-Island Electric Licence, 2011 was recommended. These categories of assets will continue to experience the same level of depreciation charges.

11.126. Based on these recommendations, JPS conveyed that the aggregate impact due to the increased useful life for some assets and reduction in useful life of other assets (not impaired) represents an overall reduction of US$4.1M in the annual depreciation expense for 2018. This impact is demonstrated in Table 11.18 below.

Table 11.18: Depreciation Expense Changes for 2018 by Asset Category

DEPRECIATION EXPENSE CHANGES FOR 2018 BY ASSET CATEGORY (US$M)				
Asset Category	**Net Book Value**	**Increased Depreciation due to reduced Asset Life**	**Reduced Depreciation due to increased Asset Life**	**Total Estimated Adjustment to Annual Depreciation Charge**
Steam Production Plant	37,700	(178)	707	529
Hydraulic production Plant	44,200	(16)	322	306
Other Production Plant (incl. Wind and Solar)	100,505	(840)	2,974	2,134
Transmission Plant	54,154	(1,139)	1,110	(30)
Distribution Plant	311,077	(2,597)	3,195	598
General Plant	80,290	(8)	583	575
TOTAL	**627,931**	**(4,779)**	**8,892**	**4,112**

11.127. According to JPS, while the 2018 PwC Depreciation Study recommendations would result in an overall reduction in annual depreciation charges, there are certain asset classes that would become impaired as a result of the reduced useful lives. In that regard, the company indicated that there will be a need to recognize the financial effect of writing off these assets in the regulatory accounting records.

11.128. Additionally, JPS requested that the OUR approve the revised depreciation rates as per recommendations of the 2018 PwC Depreciation Study presented as an Annex to the Application.

11.5.3. OUR's Review of JPS' Depreciation Proposals

11.129. The focus of the OUR's depreciation review entails the following:

1) Examination of the depreciation rates, plant in-service and future CAPEX flows used to compute the depreciation expenses reflected in the Application, and validation as to whether they are justified and reasonable based on the depreciation principles described herein;
2) Verification that the depreciation rates in use are in accordance with the requirements of the Licence and has been approved by the Office;
3) Evaluation of changes in the accumulated depreciation reserve and to ensure alignment with the annual depreciation expense and plant in service balances (NBV);
4) Evaluation of plant retirements to ensure that asset balances are removed from plant in-service and depreciation charge ceases as of plant retirement date;
5) Evaluation on the basis of any stranded/write-off assets and the reasonableness of the associated costs; and
6) Verification of depreciation expense associated with Non-Regulated assets reflected in the depreciation forecast.

11.5.4. OUR's Evaluation, Findings and Position

11.130. Details of the OUR's evaluation of JPS' proposed Depreciation Expenses, findings and position are delineated in the sections below:

Fixed Asset In-service Depreciation

11.131. For the proposed gross fixed asset in-service depreciation expenses, the company provided its 2018 "Fixed Asset Register and Depreciation Forecast 2019-2023" in MS Excel format, to substantiate the calculated charges. This depreciation forecast includes JPS' fixed assets in service at the end of 2018 and contained the projected depreciation charges for individual assets and related calculations used to derive the proposed annual depreciation expenses for the Rate Review period.

11.132. The referenced "Fixed Register and Depreciation Forecast" was central to the OUR's assessment and as such, it was subjected to a comprehensive review. During this review, the OUR identified several issues with the depreciation data, requiring adjustments to the proposed Fixed Asset In-service depreciation. These issues are outlined below.

<u>Fixed Asset In-Service Depreciation Evaluation</u>

11.133. The depreciation charges for assets in the Fixed Asset and Depreciation Forecast were examined and found to be equal to the annual depreciation amount stated for each year in the forecast. However, significant variations were observed with the fixed asset in-service depreciation presented in the Application and the Fixed Asset Register & Depreciation Forecast 2019-2023, as shown in Table 11.19 below.

Table 11.19: Discrepancy with JPS' Fixed Asset In-Service Depreciation

FIXED ASSET IN-SERVICE DEPRECIATION (US$M)						
Description	**2019**	**2020**	**2021**	**2022**	**2023**	**Remarks**
Fixed Asset In-Service Depreciation (Rate Review Application)	52.66	53.32	49.43	47.72	44.38	
Fixed Asset In-Service Depreciation (Fixed Asset Register & Depreciation Forecast)	64.92	47.33	41.07	39.36	36.02	2019: Include OH&B6 Depreciation.
Variance	**-12.26**	**5.99**	**8.36**	**8.36**	**8.36**	

11.134. Based on the OUR's observations and findings, this wide disparity in costs was largely due to information gaps in the Application, capital cost reconciliation issues, as well as many instances of aggregated cost data, particularly, with respect to the "2018 CWIP transferred into Service" and Capital Spares.

11.135. In the Application, the company included a document entitled "Fixed Asset Depreciation Reconciliation with Financial Model", which contained depreciation projections for "2018 CWIP transferred into Service" and Capital Spares, over the Rate Review period. However, no specific details and/or cost breakdown by projects were provided by the company to substantiate these capital items and basis of their associated depreciation charges.

11.136. With these observations, the OUR noted that if these components are included in the depreciation calculations without reasonable clarity and corroboration, it could be problematic for the following reasons:

1) Based on the requirements of the Licence and the Final Criteria, CAPEX to be recognized as Fixed Assets after the end of 2018 should flow through the CWIP schedule then transferred in service, on project completion. After CWIP is transitioned to Fixed Assets, then depreciation commences. Accordingly, all CWIP costs and projected CAPEX should be reflected in the "CWIP Schedule with CAPEX" to avoid distortion and duplication of costs;
2) The proposed annual depreciation expenses for the Rate Review period include CAPEX depreciation charges, which according to JPS were derived by applying the relevant depreciation rates to CAPEX transferred in Service after rolling through CWIP. However, it is not clear whether depreciation associated with the

indicated Capital Spares and CWIP transferred in Service, were included in the projected CAPEX depreciation expenses. This may require explanation from JPS; and

3) The referenced "2018 CWIP transferred in Service" and Capital Spares could not be specifically identified in JPS' "CWIP Schedule with CAPEX" data file.

11.137. As demonstrated, these issues did not permit sufficient clarity and access to all the relevant data to facilitate a fulsome evaluation. In recognition, the OUR deduced that there may be need for clarity and additional information, as well as some degree of cost disaggregation. Also, it was conveyed that the "burden of proof" is on the company.

11.138. Under the circumstances, the OUR acknowledged that there was no clear basis to include these unsubstantiated depreciation components in the 2019-2023 Fixed Asset In-service depreciation forecast. Accordingly, the OUR initially recognized the fixed assets depreciation projections obtained from the Fixed Asset Register and Depreciation Forecast, as represented in Table 11.19 above, as the gross Fixed Asset In-service depreciation expenses for the Rate Review period. Additionally, the OUR made minor adjustments to the annual depreciation charges to account for OH#3 GSU transformer as a useful asset, as well as corrections to some EEIF asset lives.

JPS' Reconsideration Request – Fixed Asset In-service Depreciation

11.139. In JPS' comments (dated 2020 September 8) on the Draft Determination Notice (2020 July 31), the company requested a reconsideration of the Office's decision on its proposed Fixed Asset In-service depreciation forecasted for Rate Review period. The reconsideration request entails the following aspects:

- Depreciation charges from 2018 CWIP transferred into Service - US$33.05M; and
- Depreciation charges derived from Capital Spares – US$0.28M per year for the Rate Review period.

Reconsideration Review – 2018 CWIP to Assets In-service and Capital Spares Depreciation

11.140. In response to the issues raised by JPS in this reconsideration request, the OUR by way of letter (dated 2020 September 15) to the company, requested the following information, to support its evaluation:

1) The full breakdown of the capital works in progress (CWIP) as at 2018 December 31, on a project-by-project basis including capital cost, forecasted to enter service and become "PPE", over the Rate Review period.
2) Schedule of depreciation computations specifically related to the 2018 CWIP transferred into service.

11.141. In response to this information request, the company on 2020 September 23, submitted a schedule in MS Excel, entitled "2018 CWIP transferred to FA Depreciation Forecast". This schedule was reviewed by the OUR in conjunction with JPS' 2018 Financial Statements and was found to satisfy the information request.

11.142. The main indications from this review are as follows:

- According to the 2018 Financial Statements, the CWIP balance as at 2018 December 31 was US$113.1M;
- The "2018 CWIP transferred to Fixed Asset Depreciation Forecast" indicates that a CWIP balance of US$108.29 will be transferred into service over the Rate Review period, with a total depreciation charge of US$33.27M over the period;
- US$85.43M of this CWIP balance will be transferred into service in 2019 January, while US$22.86M will be transferred in 2021 January;
- Capital projects with aggregate cost of US$1.98M were cancelled;
- Capital projects with aggregate cost of US$2.87M were placed on hold; and
- Depreciation from Capital Spares – US$0.28M per year for 2019-2023.

11.143. To validate these costs, the details of the associated projects were subjected to a rigorous evaluation by the OUR, including cross-checks and corroboration with other project information and cost data reported by the company. The findings from this evaluation, indicate that the relevant investment costs and charges are prudent and reasonable. On that basis, the proposed "2018 CWIP transferred into Service" (US$108.29M) and the corresponding depreciation charges (US$33.27M), were included in the Fixed Asset In-service deprecation calculations and forecast for the Rate Review period. The breakdown of the approved asset costs and depreciation charges are provided in Table 11.20 below.

Table 11.20: OUR Determined Fixed Asset In-service Depreciation Charges (2019-2023)

FIXED ASSET IN-SERVICE DEPRECIATION CHARGES 2019-2023 (US$M)							
Depreciation Component	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**	**Remarks**
Fixed Assets in-Service	64.92	47.34	46.32	39.78	35.69		
2018 CWIP transferred in Service	5.13	6.15	7.33	7.33	7.33	**33.27**	"2018 CWIP transferred to FA Depreciation"
Capital Spares	0.28	0.28	0.28	0.28	0.28		
TOTAL (US$M)	**70.33**	**53.77**	**53.93**	**47.39**	**43.30**		

OHPS & HB B6 Issues - Adjustment to Fixed Assets In-Service Depreciation

11.144. Due to the retirement of the OHPS and HB B6 Unit and other issues, there was need for adjustments to the Fixed Asset In-Service depreciation. These adjustments are delineated below.

Excluded Depreciation Charges for OHPS and HB B6 Unit

11.145. The closure of the OHPS in 2019 and the scheduled retirement of the HB B6 unit in 2020, means that these plants will no longer be considered "used and useful" in the provision of electricity service. In the 2018 Annual & Extraordinary Rate Review Determination Notice, the Office approved accelerated depreciation for these generation facilities to allow JPS to recover the remaining asset costs. Based on general accounting practices and regulatory requirements, these assets should be removed from "Plant in Service" or the Rate Base and related depreciation charges discontinued. Consequently, the annual depreciation charges applied by JPS for these assets are excluded from the forecasted annual depreciation expenses for the Rate Review period. The various issues and related adjustments are described below.

2018 Fixed Asset Register - Generation Decommissioning Costs (OHPS & HB B6)

11.146. In reviewing the company's "2018 Fixed Asset Register and Depreciation Forecast", the OUR identified a category of assets described as "Generation Decommissioning Cost", which was captured in the fixed asset details for both the OHPS and HB B6 plant. It is important to note that the company failed to provide any clear basis or justification to substantiate the inclusion of these cost components. The specific details of these cost items are set out below.

2018 Fixed Asset Register - Generation Decommissioning Costs (OHPS & HB B6)

11.147. As represented in the 2018 Fixed Asset Register, items described as "Generation Hunts Bay Decommissioning Cost" and "Generation Old Harbour Bay Decommissioning Cost", were recognized as assets in 2017 June, with costs of US$2.33M and US$6.72M, respectively. Correspondingly, these defined assets generated annual depreciation charges of US$2,239,021.66 and US$581,262.00, respectively for OHPS and HB B6. The respective costs and depreciation details for these defined assets are summarized in Table 11.21 below.

Table 11.21: Details of Assets - Decommissioning Costs in 2018 FA Register and Depreciation Forecast

OHPS & HB B6 ASSETS DEFINED AS DECOMMISSIONING COST													
Asset #	Cost Centre	Asset Description	FERC #	Date In Service	DEP Method	Asset Life (Yrs)	Asset Cost (US$)	DEP Amount (US$)	YTD DEP (US$)	2018 NBV (US$)	2019 DEP (US$)	2020 DEP (US$)	2021 DEP (US$)
255634	4316	Generation Hunts Bay Decommissioning Cost	31611	30-Jun-2017	STL	4	**2,325,048**	48,438	581,262	1,453,155	581,262	581,262	290,631
255635	4400	Generation Old Harbour Decommissioning Cost	31611	30-Jun-2017	STL	3	**6,717,065**	186,585	2,239,021	3,358,532	2,239,021	1,119,510	-

11.148. Given that asset Decommissioning Costs primarily relate to a plant's post retirement activities, the addition of these costs in the Fixed Asset register would not conform with the asset recognition criteria of the relevant IFRS. Consequently, the defined decommissioning cost should be derecognized and removed from the fixed assets in-service costs, with the associated depreciation charges also excluded. Further, there is no provision in the existing legal and regulatory framework to support the qualification of plant Decommissioning Cost as a fixed asset.

11.149. In its comments on the Draft Determination Notice, JPS suggested that if the "2017 Decommissioning Costs" as defined in the 2018 Fixed Asset Register are excluded from the Rate Base then they should be included in its O&M expenses. The OUR categorically rejects this proposition, as these unsubstantiated "2017 Decommissioning Costs" do not intrinsically reflect an O&M orientation, and were NOT approved by the Office in 2017 or any other time. Also, they were NOT confirmed in the Draft Determination Notice. To be clear, the Office has determined the level of decommissioning cost to be recovered in the Revenue Requirement based on its review of JPS' plant decommissioning proposal included in the Application, and not on any assumed costs in 2017. Notably, if the assumed "2017 Decommissioning Costs" along with the decommissioning costs were approved at this 2019 - 2024 Rate Review, that would be considered double counting, and deviate from prudent and reasonable standard.

11.150. Therefore, subject to the requirements of the Licence, established accounting standards and prudent utility practice, the recognition of these costs as fixed assets by JPS is not deemed prudent and justified. Additionally, this revelation also raises serious questions as to the reliability and accuracy of the annual Fixed Asset Register and the depreciation computations presented by the company.

11.151. In light of this finding, to be clear, the Office had NOT approved any plant Decommissioning Costs for JPS at any time prior to this 2019-2024 Rate Review. Therefore, having regard to the issues described and the relevant legal and regulatory provisions, these capitalized Decommissioning Costs are NOT allowed. As a result, the related depreciation charges of US$0.81M and US$2.23M for HB B6 and OHPS respectively, are NOT APPROVED. By extension, the existing cost balances of these capitalized items were also excluded from the Rate Base forecast.

JPS' Comments – Exclusion of Decommissioning Cost (OHPS & HB B6)

11.152. In JPS' comments on the Draft Determination Notice, the company indicated that the OUR excluded decommissioning costs which had been capitalized and included in the overall value of the OHPS and HBB6 assets. However, the company indicated that it agrees that the recovery of these costs would be addressed within the overall decommissioning discussion, even though the capitalization of these costs are specifically required based on IFRS.

11.153. With respect to the treatment of the referenced decommissioning costs, the OUR maintains its position that for regulatory accounting and rate setting purposes, the inclusion of these costs in the Rate Base and annual depreciation expenses is not prudent and must be disallowed. Therefore, in keeping with the regulatory principles and reasoning delineated above, the Office's decision to disallow these capitalized Decommissioning Cost is appropriate and justified, and remains unchanged.

Continuation of Depreciation Charges after Plant Retirement Dates

11.154. Despite the approved accelerated depreciation allowance for the OHPS and HB B6 Unit in 2018 and the established plant retirement schedule, the OUR's review identified that JPS continues to carry depreciation charges for a number of component assets connected to these plants after the stated retirement dates. Based on the relevant depreciation standards and principles, and the provisions of the Licence, these charges are not considered reasonable and prudent, and as such are not allowed in the forecasted Fixed Asset In-service depreciation. Therefore, in keeping with the regulatory requirements, these depreciation charges were excluded from the proposed annual depreciation projections for the Rate Review period.

JPS' OHPS Raw Water Facilities used to Support SJPC Operations

11.155. The OUR's review also found that despite the closure of the OHPS in 2019 December, some raw water assets have been carried beyond the plant retirement date. This observation raises the question of whether these JPS assets are being utilized to facilitate SJPC's operations, given its proximity and need for raw water supply in the steam production process. While no specific details have been provided in that regard, the company would be aware that the cost structure and operation of SJPC is independent of the Licensed Business. Therefore, any use of JPS' assets to provide other services should be transparent and provided for proper accounting of attendant costs. As such, JPS is required to demonstrate that any and all costs associated with any such operations are not reflected in JPS' costs.

11.156. In its comments on the Draft Determination Notice, JPS indicated that it would require additional information from the OUR regarding the facilities in question, as SJPC's operations are fully self-sufficient and independent of JPS. Subject to the contractual arrangements and licence conditions governing SJPC's commercial operations, it is a requirement that there is complete separation and independence from the Licensed Business. To be clear, the JPS assets in question involve the existing raw water pumping equipment, pipeline infrastructure, and other related facilities located in Old Harbour, which now supplies bulk raw water to the SJPC Complex. The issue is that no documentation to confirm whether these assets have been transferred to SJPC or if there are other arrangements to account for the utilization and commensurate costs of these raw water facilities, has been provided by the JPS. In that context, the company is required show that any and all costs associated with these raw water assets are completely separated from JPS' regulated utility costs. This information shall be submitted to the Office within one (1) month of the effective date of this Determination Notice.

Summary of Excluded Depreciation Charges for OHPS and HB B6 Unit

11.157. Having regard to the described depreciation issues related to the subject generation facilities, the associated depreciation charges excluded from the proposed gross fixed asset in-service depreciation expenses, for the Rate Review period, are summarized in Table 11.22 below.

Table 11.22: Excluded Depreciation Charges – OHPS & HB B6 Retirement

DEPRECIATION EXCLUDED (US$M) – OHPS & HB B6 RETIREMENT						
Description	**2019**	**2020**	**2021**	**2022**	**2023**	**Remarks**
Total Excluded Depreciation Charges	12.64	3.18	0.58	0.19	0.14	Includes Depreciation Charges for disallowed Decommissioning Costs

Other Exclusions to Fixed Asset In-Service Depreciation

11.158. These exclusions from the fixed asset in-service depreciation expenses relate to the asset write-offs, stranded meter assets and stranded streetlight assets described herein which, according to JPS, have become impaired/stranded at the end of 2018. Generally, in rate review proceedings, when a utility's assets are declared impaired or stranded, the treatment based on established accounting standards and regulatory depreciation principles, is that such assets should be removed from 'Plant in Service' and not included in the Rate Base determined for the new regulatory period. This means that related depreciation charges should cease and not continue during the new regulatory period.

11.159. With respect to the reported asset write-off/stranded asset situation, this principle underscores that no depreciation charges for these assets should apply for the Rate Review period. However, as represented in the Fixed Asset Register and Depreciation Forecast, despite the designated status of these assets, related depreciation charges were forecasted throughout the Rate Review period. Based on the OUR's assessment, this approach by JPS was not considered to be consistent with the regulatory and accounting requirements. As such, these depreciation related costs are not deemed prudent and reasonable, and therefore, are NOT allowed. Consequently, they were excluded from the proposed gross fixed asset in-service depreciation expenses and their respective asset costs also removed from the Rate Base.

11.160. Additionally, there are other minor depreciation charges that were identified in the Fixed Asset Register and Depreciation Forecast, including, among other things, depreciation related to T&D Codes. These depreciation charges were excluded on the basis that the defined assets do not satisfy the asset recognition principle as per the IFRS, but rather appear to depict an OPEX orientation.

11.161. Based on the OUR's assessment of the highlighted depreciation issues, it was determined by the Office that the referenced depreciation charges forecasted by JPS are not prudent and reasonable, and as such were excluded from the proposed gross fixed asset in-service depreciation expenses projected for the Rate Review period. The excluded depreciation charges are summarized in Table 11.23 below.

Table 11.23: Other Excluded Depreciation Charges– Impaired/Stranded Assets

DEPRECIATION EXCLUDED (US$M) – IMPAIRED/STRANDED ASSETS					
Description	**2019**	**2020**	**2021**	**2022**	**2023**
Stranded Meter Assets Depreciation Carried Forward	0.89	0.89	0.89	0.89	0.89
Stranded Streetlight Assets Depreciation Carried Forward	0.80	0.80	0.78	0.74	0.69
Write-off Assets Depreciation Carried Forward	1.34	1.32	1.10	0.93	0.76
Other Excluded Depreciation Charges	0.26	0.06	0.01	0.01	0.01
TOTAL (Other Excluded Depreciation Charges)	**3.29**	**3.07**	**2.78**	**2.57**	**2.35**

CAPEX Depreciation

11.162. This CAPEX depreciation component relates to the OUR's estimated CWIP Schedule and resulting CAPEX transferred in service, based on the OUR's approved capital projects to be implemented by JPS over the Rate Review period. The annual depreciation charges were derived by:

- Applying the defined annual depreciation rate to the approved CAPEX transferred into service for each project component listed under the major project categories (Generation, Transmission, Distribution, Losses, General Plant and IT), in each year of the stated period; and
- Aggregating the individual depreciation charges to determine the annual CAPEX depreciation expense for each year over the Rate Review period.

11.163. Based on this computation, the CAPEX depreciation forecast for Rate Review period, was determined by the OUR as shown in Table 11.24 below.

Table 11.24: OUR Determined CAPEX Depreciation Forecast 2019-2023

OUR DETERMINED CAPEX DEPRECIATION CHARGES (US$M) 2019-2023						
Description	**2019**	**2020**	**2021**	**2022**	**2023**	**Remarks**
Approved CAPEX Transferred into Service	63.87	70.17	75.31	67.93	87.53	SSP Costs Included
OUR APPROVED CAPEX DEPRECIATION	**4.84**	**13.79**	**23.59**	**29.29**	**35.24**	

11.164. Notably, the CAPEX depreciation forecast includes the relevant depreciation charges flowing from the capital cost of the LED smart streetlight programme (SSP), which was incorporated in JPS' Rate Base.

Accelerated Depreciation - Capitalized Maintenance Cost (OHPS & HB B6)

11.165. As previously indicated, this aspect of the depreciation proposal involves the recovery of capitalized maintenance expenditure of US$15.65M (refer to Table 11.21 above) associated with the OHPS and HB B6 unit through accelerated depreciation. To justify this request, JPS provided a supporting MS Excel document entitled "GENERATION CAPEX JUSTIFICATION – OUR NOV 5". The contents included a schedule of plant maintenance activities involving the HB B6 unit and the generating units at the OHPS. Based on this schedule, the respective maintenance items were classified as assets, with each item defined by asset number, cost centre number, FERC accounting number, date in service, asset cost, imputed asset life, and depreciation charges. However, the OUR's review of the proposed maintenance costs revealed that the total cost of the assets included in the schedule was US$9.48M and not US$15.65M as presented by JPS in the Application. Furthermore, no explanation, justification or supporting documentation to substantiate the proposed US$15.65M, was provided. As such, the OUR's evaluation was premised on the total maintenance cost of US$9.48M obtained from the "GENERATION CAPEX JUSTIFICATION – OUR NOV 5" document.

OH#3 New GSU Transformer

11.166. With respect to the specific capital maintenance expenditures, in 2018 January, JPS placed in service a new GSU transformer (13.8kV/138kV, 60/80MVA, 3-Phase) on the OH#3 unit (asset # 257433), at a cost of US$3.09M. Based on JPS' depreciation proposal and supporting data, the company is requesting accelerated depreciation for this transformer after being in service for less than two (2) years. According to the Licence and the 2018 PwC Depreciation Study, the useful life of a GSU transformer is defined as 25-30 years. Given the depreciable life relative to the reported period of use, the OUR recognizes this transformer as a useful plant asset that should be carried as a spare or integrated within the T&D system.

At the 2018 Annual Review, in respect of the impending OHPS decommissioning, the treatment of this transformer was discussed with JPS, and the OUR indicated that it will not be considered as part of the OHPS retired assets but should be carried in the fixed assets in-service (component of the Rate Base), with continued application of normal depreciation charges until the asset is fully depreciated.

In translation, this position would require the subtraction of the transformer asset cost (US$3.09M) from the total capitalized maintenance (US$9.48M) proposed for accelerated depreciation recovery, with the 2018 annual depreciation charge for the transformer allowed. This computation resulted in a net capital cost of US$6.51M.

11.167. Based on the OUR's evaluation of this accelerated depreciation proposal, the Office determined that the OHPS and HB B6 capitalized maintenance cost to be recovered by JPS during the Rate Review period is US$6.51M.

JPS' Reconsideration Request - Generation Maintenance Cost Recovery (US$15.65M)

11.168. In its comments on the Draft Determination Notice, JPS requested a reconsideration of the Office's determination on its proposal for accelerated depreciation of capitalized generation maintenance cost (US$15.65M), incurred during the period 2017-2018, in relation to the OHPS and HB B6 Unit. The reconsideration request involves the following:

- The disallowance of capitalized generation maintenance cost (US$15.65M); and
- The exclusion of the OH#3 GSU transformer cost from generation maintenance cost (US$9.48M) reported in the "GENERATION CAPEX JUSTIFICATION – OUR NOV 5" document.

OUR's Reconsideration Review - OHPS & HB B6 Capitalized Maintenance Cost

11.169. In response to JPS' queries and issues raised in this reconsideration request, the OUR in its 2020 September 15 letter to the company, requested additional information, including a full breakdown of the capitalized generation maintenance expenditures (US$15.65M), connected to the OHPS and HB B6 Unit and related depreciation calculations, to support its evaluation. However, despite several reminders to the company by the OUR, the requested information was not provided.

11.170. However, since the cost under consideration relates to generation maintenance projects/activities executed by JPS during the 2017-2018 period, the OUR performed a detailed search of the 2018 Fixed Asset Register in order to identify the relevant maintenance projects and to provide corroboration of the respective costs. This search produced the following results:

- Evidence that the total capitalized O&M cost of US$15.65M encapsulates maintenance costs associated with the OHPS & HB B6 unit (plants subject to decommissioning) and also HB GT5 & HB GT10 units (not being evaluated for decommissioning).
- Verification that generation maintenance activities carried out at the OHPS and on HB B6 Unit (decommissioning plants) over the period 2017-2018, amounted to approximately US$9.5M, which is consistent with the O&M expenditure of

US$9.48M reported in the "GENERATION CAPEX JUSTIFICATION – OUR NOV 5" document and not the US$15.65M being claimed by JPS.

- Validation that generation maintenance expenditures of approximately US$6.00M in aggregate during 2017-2018 is linked to the HB GT5 & GT10 Units, which would account for the differential between the proposed maintenance cost of US$15.65M and the expenditure reported in "GENERATION CAPEX JUSTIFICATION – OUR NOV 5" document (US$9.48M).

11.171. JPS would be aware that the HB GT5 & GT10 Units are not part of the generation plant retirements that were scheduled to occur within the 2019-2020 timeframe. Further, it is important to note, that in 2018, the OUR only gave consideration for the execution of critical maintenance activities to the OH generating units (OH#2, OH#3 and OH#4) and the HB B6 unit. In that regard, the portion of the capitalized generation maintenance linked to HB GT5 & GT10, will not be allowed. Based on the 2014-2019 Tariff Review process which was concluded in 2015, the estimated maintenance costs for these plants were included in the determined 2014 Revenue Requirement. Therefore, the allowance of these costs would not be prudent and may be tantamount to double counting.

Regulatory Treatment of the OH#3 GSU Transformer Cost

11.172. In relation to the OH#3 GSU transformer, JPS contended that even though the asset was brought into service in 2018 January as part of the major maintenance activities on the generating unit, the transformer would still be subject to accelerated depreciation as part of the assets for retirement. While this position is understandable in accounting terms, from a regulatory perspective, the question is whether the consumer would have reasonably benefitted from the acquisition and use of this asset. Moreover, the OUR's initial regulatory treatment would not have inhibited JPS from recovering the full cost of the transformer. The differentiation is that the OUR took the position that the asset should depreciate systematically over its useful life, given the nature of the plant and scope for system applications.

11.173. JPS also indicated that it undertook an assessment of whether the transformer could be utilized elsewhere within its existing generation fleet and T&D network, but found it unsuitable for further application.

11.174. After reviewing JPS' arguments and revisiting its assessment of the entire interconnected electricity system configuration, the OUR accepts JPS' position.

OUR's Position – Generation Maintenance Cost Recovery

11.175. Taking all the relevant factors into consideration, the OUR's revised position on this accelerated depreciation proposal is as follows:

1) The 2017-2018 capitalized generation maintenance cost of US$15.65M associated with the OHPS and the entire HBPS (B6, GT5 and GT10) is NOT APPROVED.
2) The 2017-2018 capitalized generation maintenance cost of US$9.48M associated with the OHPS (including the cost of OH#3 GSU transformer) and HB B6 Unit is APPROVED.

11.176. Based on these considerations, the OUR determined that the OHPS and HB B6 capitalized generation maintenance cost to be recovered by JPS during the Rate Review period is US$9.48M, with the total amount allocated to 2019, as shown in Table 11.25 below.

Table 11.25: OUR Determined - OHPS & HB B6 Capitalized Maintenance Cost Recovery (2019-2024)

JPS OHPS & HB B6 CAPITALIZED MAINTENANCE COST RECOVERY (US$M)				
Description	**JPS Proposed Cost**	**Cost - Generation Capex Justification**	**OUR APPROVED**	**Remarks**
JPS Capitalized Gen Maintenance Cost - 2017-2018	15.65	9.48		
OUR VERIFIED – OHPS & HB B6 Cost		9.48	9.48	Includes OH3 GSU Transformer Cost
NET ASSET COST			**9.48**	**Allocated to 2019**

Accelerated Depreciation – Plant Retirement (Bogue, RF and HB GTs)

11.177. In the Application, JPS asserted that due to the scheduled retirement of the Bogue (ADO GTs), Rockfort plant (SSD) and HB GTs, at the end of 2023, it is requesting the recovery of its remaining aggregate asset cost of J$3.445 billion (US$26.91M), through accelerated depreciation. In its proposal, JPS requested that this cost balance be applied evenly over the Rate Review period, with the allocation of J$689M or US$5.38M, per year.

11.178. From the OUR's perspective, while the scheduled plant retirements are recognized, such projections do not necessarily mean immediate regulatory treatment of post retirement activities, including decommissioning and the related cost requirements. Moreover, as a practical matter, due to factors, such as: load/generation uncertainties; non-firm commitments and timetable for new capacity additions; potential generation procurement isues; IRP project implementation issues; and meeting system security requirements, the projected retirement dates may likely be staggered by up to 12 to 24 months or even greater, which could push plant retirements to 2025 and beyond.

With respect to timing, the 2024-2029 Rate Review application will also be due by 2024 April, and at that juncture, there should be greater certainty regarding planned system developments, which undoubtedly impact plant retirement scheduling. Based on all the influential factors described, the OUR believes that it would be more appropriate to evaluate all relevant costs associated with these plants during the 2024-2029 Rate Review Process. On that basis, these generating plants shall continue to be depreciated at the existing rates of depreciation prescribed by the Licence, and complemented by the useful asset lives recommended by the 2018 PwC Depreciation Study, until the 2024-2029 Rate Review Process, when the existing and future operating status of all plants in service will be comprehensively assessed.

11.179. Having regard to these considerations, the OUR in keeping with the requirements of the Licence, determines that JPS' proposed accelerated depreciation of J$3.445 billion (US$26.91M), for these plants over the Rate Review period, is NOT approved.

11.180. Therefore, in regard to the company's reconsideration request, the Office's decision remains unchanged.

Recovery of Stranded Meter Asset Costs

11.181. In the Application, JPS claimed that as a consequence of the implementation of the Smart Meter Programme, up to the end 2018, a number of meter related assets have become stranded, with accumulated stranded asset cost of US$14M. With reference to this development, the company requested the recovery of this stranded asset cost as an adjustment to the annual depreciation expenses over the Rate Review period. To substantiate this request, JPS provided a "Stranded Asset Summary" in MS Excel format, containing a schedule of meter assets declared stranded.

OUR's Evaluation of JPS' Stranded Meter Assets Cost

11.182. In evaluating this proposal, the OUR reviewed the "Stranded Asset Summary", the Fixed Asset Register and smart meter project information, which recognized the subject assets as being stranded.

11.183. Due to the large-scale deployment of advanced revenue meters in the electricity network (Smart Meter Programme), this situation was anticipated as existing meter assets are being replaced by new AMI assets, and in most cases, before being fully depreciated. In context, this stranded asset situation under consideration means that after 2018 December 31, the relevant meter assets are no longer "Plant-in-Service" and must be excluded from JPS' Fixed Asset In-service (a component of the Rate Base) projected for the Rate Review period. Consequently, depreciation charges should be discontinued and the related assets cost balances removed from the Rate Base.

Regulatory Treatment of Stranded Meter Assets Cost

11.184. Regarding the stranded meter assets cost, the proposed total of US$14M was found to be consistent with the aggregated 2018 NBV (US$14.05M) for the respective meter assets, carried in the 2014-2019 Rate Base. In principle, this amount represents the total cost to be recovered as at 2018 December 31, since the assets would have been taken out of service up to end of the year. However, due to the time gap from the end of 2018 to the effective date of this Determination Notice, the existing non-fuel rates remained in effect, resulting in significant depreciation accruals in relation to these stranded meter assets. It is important to note that this accumulated depreciation is not attributable to the utilization of the subject meter assets, as they have been completely replaced by other assets and are no longer in operation.

11.185. Since the utility would have recovered a portion of the 2018 stranded meter assets cost through these depreciation charges accumulated in advance, to ensure reasonable and prudent cost recovery, it is necessary for the accrued depreciation to be treated as an offset to 2018 NBV of these assets.

11.186. Using the monthly depreciation charges computed by JPS for these assets, the accumulated depreciation from 2019 January – 2020 October was estimated to be US$1.63M. Based on the principle outlined above, this amount was applied as an offset to stranded meter assets cost of US$14.05M, resulting in a net value of US$12.42M.

11.187. Based on the relevant factors and considerations, the OUR determined that the stranded meter asset cost to be recovered by JPS during the Rate Review period is US$12.42M, with equal allocations of US$2.48M per year over the Rate Review period, as represented in Table 11.26 below.

Table 11.26: OUR Determined Stranded Meter Assets Cost for Recovery (2019-2024)

OUR APPROVED - STRANDED METER ASSET COST RECOVERY 2019-2024 (US$M)							
Description	**2018 NBV (US$M)**	**OUR Determined Stranded Cost (US$M)**	**Stranded Cost Allocation (US$M)**				
			2019	**2020**	**2022**	**2023**	**2024**
JPS 2018 Stranded Cost - [Stranded Assets Summary]	14.05	-					
OUR VERIFIED – Stranded Meter Assets Cost	14.05	14.05					
OUR ADJUSTMENT – Stranded Cost Recovered	-	(1.63)					
OUR APPROVED – Stranded Meter Cost	**-**	**12.42**	**2.48**	**2.48**	**2.48**	**2.48**	**2.48**

Recovery of Stranded Streetlight Asset Costs

11.188. In the Application, JPS claimed that as a consequence of the implementation of the SSP, up to the end of 2018, a number of streetlight related assets have become stranded, with stranded assets cost amounting to US$7.3M (2018 NBV– Fixed Asset Register). Citing this development, the company requested the recovery of this stranded cost as an adjustment to the annual depreciation expenses over the Rate Review period. To support this request, a schedule of the streetlight assets declared stranded was included in the referenced "Stranded Asset Summary". This means that as of the end of 2018, these assets are no longer in service, and consequently, they should be removed from the Rate Base and the related depreciation charges discontinued.

OUR's Evaluation of JPS' Stranded Streetlight Assets Cost

11.189. Based on the OUR's review of the Stranded Asset Summary, the Fixed Asset Register and other relevant streetlight information, it was found that a portion of these streetlight assets was recognized as being stranded. However, for some of the assets denoted as stranded by JPS, no clear basis or demonstrable evidence was provided to support that status.

Stranded Streetlight Asset Issues

11.190. As observed, some of the salient issues, include the following:

- A total of 160 streetlight assets were listed as being stranded but there are several questionable cases. Furthermore, no clear basis or justification was provided by JPS to demonstrate how some of these assets became stranded;
- These questionable assets are mainly associated with JPS' Cost Centres (1310, 4211, 5000, 5305, 5310, 5315, 5690, 5730 and 5770);

- Some of these assets are described as LED streetlight installations and GOJ streetlight project, which also raise concerns as to why they would have become stranded, given that the SSP is predicated on an LED street lighting strategy;
- Some of the assets appear to have no clear connection to street lighting;
- Some of these questionable assets were largely placed in service during 2016-2018. That is, during the period of SSP implementation, with several added in 2018 December. It therefore raises concerns as to why a streetlight asset placed in service in 2018 December under a grid modernization/EE programme has already become stranded; and
- The associated assets cost balance is US$1.91M (their aggregated 2018 NBV).

11.191. Given these observations and the absence of adequate justification to designate these assets as being stranded is not acceptable. In this regard, the OUR is of the view that the purported stranded cost associated with these assets is considered not prudent and reasonable at this time, on the grounds that there is no sound basis to substantiate the recovery of such stranded cost.

JPS' Reconsideration Request – Stranded Streetlight Cost Recovery

11.192. In its response to the OUR's Draft Determination Notice, JPS requested reconsideration of the Office's determination involving the exclusion of a component of the stranded streetlight asset cost recovery of US$7.3M, proposed for recovery.

11.193. JPS sought to justify its reconsideration request by arguing that stranded costs arise from prudent "PPE" and that the company has not fully depreciated these prudent assets, and although they are no longer "used and useful", it must still be compensated for their remaining costs.

11.194. However, to be clear, the OUR did not disallow the total stranded streetlight assets cost (US$7.3) proposed by JPS. The portion that was deemed prudent and reasonable is approved while the portion that was not justified was rejected.

Regulatory Treatment of Stranded Streetlight Assets Cost

11.195. In reviewing the referenced reconsideration request, the OUR identified the need for JPS to provide reasonable justification for streetlight assets listed in the "Stranded Asset Summary" under Cost Centres – 1310, 4211, 5000, 5305, 5310, 5315, 5690, 5730 and 5770, declared as stranded. This information was requested in the OUR's 2020 September 15 letter to JPS. In response, the company on 2020 October 5, submitted a schedule in MS Excel, entitled "Stranded Assets – Accelerated Depreciation Revised".

11.196. The OUR's review of this schedule found that the contents were a straight replication of the assets captured under the named Cost Centres in the "Stranded Asset Summary". However, no justification for declaring the respective streetlight assets as stranded was provided as requested by the OUR.

11.197. Although the JPS did not provide the requisite justification, based on discussions with the company on the streetlight issues following its comments on the Draft Determination Notice, it was asserted that some of the questionable streetlights assets may have been installed as part of an earlier GOJ streetlight project but have been replaced under the present SSP. Based on this understanding, the OUR revisited its stranded streetlight evaluation and during the process, it was determined that a number of the assets that were initially regarded as questionable could be recognized as stranded. Due to this alteration, there was need to adjust the stranded streetlight cost that was initially allowed.

11.198. Accordingly, the total stranded streetlight cost, according to the 'Stranded Assets Summary" and the 2018 Fixed Asset Register, was adjusted upwards from US$5.39M to US$6.77M. In principle, this amount would represent the total cost to be recovered as at 2018 December 31, since the assets would have been taken out of service up to end of the year.

Streetlight Assets Not Justified as Stranded

11.199. While the OUR made adjustments to some aspects of stranded streetlight assets after re-examining its initial position following JPS' comments, there are still 24 out of the total number (160) of streetlight assets reported as being stranded, with an aggregated cost balance of US$0.53M for which no justification was provided by JPS to support its claim. As it stands, there is no clear basis for the OUR to allow JPS to recover this component of stranded streetlight assets cost. As such, this amount was NOT APPROVED by the Office at this Rate Review.

11.200. In the event that these stranded assets are found to be legitimate after the completion of the SSP audit to be performed at the end of the programme, then the OUR will ensure that the associated costs are recovered by the company.

Stranded Street Asset Cost Fully Recovered Through Depreciation

11.201. Due to the extended time span from the submission of the Application and the effective date of this Determination Notice, the existing non-fuel rates remained in effect during this period. As a result, the Fixed Asset Register and Depreciation Forecast indicates that a portion of the streetlight assets recognized as stranded would be fully depreciated during this time period. This means that their aggregated 2018 NBV (US$0.097), would be recovered by JPS through the accumulated depreciation charges over the period 2019 January – 2020 October. Accordingly, in keeping with the principles of reasonable prudence, and to avoid double counting, the OUR has determined that no additional cost will be allowed for recovery in relation to this particular group of stranded streetlight assets.

Recovery of Stranded Streetlight Assets Cost Outstanding

11.202. Due to the extended application of the existing non-fuel rates during this Rate Review process, there have been significant depreciation accruals related to the recognized stranded streetlight assets not yet fully depreciated. This means that the utility would have recovered a portion of the 2018 stranded streetlight assets cost through these accumulated depreciation charges. Therefore, to ensure reasonable and prudent cost recovery, it is necessary for this accrued depreciation to be treated as an offset to 2018 NBV of these stranded streetlight assets. Using the monthly depreciation charges computed by JPS for these assets, the accumulated depreciation from 2019 January – 2020 October was estimated to be US$1.46M.

OUR Determined Stranded Streetlight Assets Cost

11.203. In keeping with the principles and calculations outlined above, a total offset of US$1.56M was applied to the recognized stranded meter assets cost of US$6.77M, resulting in a net amount of US$5.21M.

11.204. Based on the relevant factors and considerations, the OUR determined that the stranded streetlight asset cost to be recovered by JPS during the Rate Review period, is US$5.21M, with equal allocations of US$2.61M per year in 2019 and 2020 as represented in Table 11.27 below.

Table 11.27: OUR Determined Stranded Streetlight Assets Cost for Recovery (2019-2024)

OUR APPROVED - STRANDED STREETLIGHT ASSET COST RECOVERY 2019-2024 (US$M)							
Description	**2018 NBV (US$M)**	**OUR Determined Stranded Cost (US$M)**	**SL Stranded Cost Allocation (US$M)**				
			2019	**2020**	**2022**	**2023**	**2024**
JPS Stranded Streetlight Asset Cost (US$M)	7.30	-					
Stranded Streetlight Cost Disallowed by OUR (US$M)	-0.53	-					
OUR VERIFIED – Stranded Streetlight Cost (US$M)	6.77	6.77					
Stranded SL Asset Cost Fully Depreciated up to 2020 OCT		-0.097					
Stranded SL Cost Partially Recovered – DEP Charges up to 2020 OCT	-	-1.46					
OUR APPROVED – Stranded Streetlight Cost (US$M)	**-**	**5.21**	**2.61**	**2.61**	**-**	**-**	**-**

Recovery of Write-Off Asset Costs

11.205. As previously mentioned, JPS is requesting the recovery of asset write-off cost of US$9.7M (2018), which it claims is due to the effect of reduced "Useful Life" of some assets recommended by the 2018 PwC Depreciation Study. To support this request, a schedule of the assets identified for write-off was included in the referenced "Stranded Asset Summary". According to the price control provisions of the Licence, this infers that after 2018 December 31, these write-off assets should no longer be considered Plant-in-Service and must be excluded from JPS' Fixed Assets In-Service (a component of the Rate Base) projected for the Rate Review period. Concomitantly, depreciation charges should be discontinued and the related assets cost balances removed from the Rate Base.

OUR's Evaluation of JPS' Write-off Assets Cost

11.206. In evaluating this proposal, the OUR reviewed the "Stranded Asset Summary", the 2018 Fixed Asset Register, the 2018 PwC Depreciation Study, Schedule 4 of the Licence and other relevant fixed asset information. This review identified a number of problematic issues, which are described as follows:

a) The review revealed that since 2001, the company has deviated from the requirements of the Licence in applying the depreciation rates prescribed by the 2001 Electricity Licence, and the 2011 and 2016 amended versions;

b) Improper accounting involving the application of asset lives, not in conformance with Schedule 4 of the Licence for the calculation of applicable depreciation charges, permeated the entire spectrum of asset categories;

c) A significant number of assets with in-service dates and useful lives that would render them retired prior to the 2001 Electricity Licence, were carried by the company for periods extending beyond 50 years (maximum depreciable life set out under Schedule 4 of the 2001 Electricity Licence, and the 2011 and 2016 amended versions);

d) In some cases, assets that were placed in service in 1952, with useful lives as low as 15 years were carried on the books for 71 years. This means that the company continued to receive a return on these assets along with the accrued depreciation, although they should have been retired from service decades ago. This is not acceptable;

e) Based on the useful asset lives established in the Licence, some of the assets for which write-off is being requested, should have been off the books prior to the launch of the 2018 PwC Depreciation Study;

f) Numerous inconsistencies and discrepancies were detected with the depreciation (calculations, costs, asset life, etc.) of the subject assets and the fixed assets in general;

g) Component assets linked to the OHPS and the HB B6 unit, for which accelerated depreciation was approved in 2018, were featured as part of this asset write-off schedule, which is NOT prudent;

h) The unrecovered cost of some of the assets identified for write-off, were fully recovered in 2019 or early 2020;

i) The proposed total asset write-off cost (US$9.7M) shows significant variance with the aggregated 2018 NBV (US$8.94M) of the subject assets captured in the 2018 Fixed Asset Register, but no explanation was provided by JPS;

j) Other assets included in the Fixed Asset Register and Depreciation Forecast which were assigned incorrect useful lives were not included in the write-off schedule; and

k) There was partial application of the depreciation rates prescribed in the Licence and those recommended by the 2018 PwC Depreciation Study.

11.207. In the Application, JPS highlighted that in its review of certain individual assets, numerous depreciation rates were found to be not in line with other assets within their respective categories. According to JPS, the majority of these assets related to items which were added to the Fixed Asset Register several decades prior to the issuance of the Licence, and in some instances the depreciation rates at the time, may have been considered to be appropriate, but subsequently were not adjusted to reflect the changes in circumstances. JPS also admitted that these assets are considered anomalies within their respective categories. Further, JPS claimed that these defects are isolated instances that would not have had an impact on the overall reasonableness of the annual depreciation charges over the prior periods, and that the useful lives of these items have been updated to ensure that they were systematically removed from the Fixed Asset Register in an orderly manner. However, the OUR observations and findings proved otherwise, as there have been major deviations in the application of the useful asset lives prescribed under Schedule 4 of each approved version of Electricity Licences from 2001 to 2016. Given the extent of the deficiencies identified. Going forward, JPS is required to employ reasonable efforts to regularize its Fixed Asset Register by the end of 2021.

Regulatory Treatment of Write-off Asset Costs

11.208. Regarding the asset impairment cost, the OUR recognized the aggregated 2018 NBV (US$8.94M) of the relevant assets, as the baseline value for regulatory treatment and not the US$9.7M proposed by JPS, which has not been justified.

11.209. In principle, this amount represents the total cost to be recovered as at 2018 December 31, since the reduced "Useful Life" in the case of these assets would require them to be out of service up to the end of the year. However, despite these assets being subject to write-off, given that the 2014-2019 Rate Base has not yet been adjusted, the company continues to recover depreciation charges for the said assets up to present.

Write-off Asset Cost - OHPS and HB B6 Depreciated Assets

11.210. The OUR's evaluation identified two (2) plant assets in the Write-off Asset Schedule which are linked to the OHPS and HB B6 unit, with a total cost of US$0.26M. However, these plant assets were already approved for accelerated depreciation by the OUR at the 2018-2019 Annual Review. Therefore, the Office has determined that these costs are Not Allowed as part of the write-off of ? assets costs.

Write-off Asset Cost Fully Recovered Through Depreciation

11.211. Due to the extended time span from the submission of the Application and the effective date of this Determination Notice, the existing non-fuel rates remained in effect during this period. As a result, the Fixed Asset Register and Depreciation Forecast indicate that a portion of these recognized Write-off assets would be fully depreciated during this period. This means that their aggregated 2018 NBV (US$0.21M) would be recovered by JPS through the accumulated depreciation charges over the period 2019 January – 2020 October. Accordingly, in keeping with the principles of reasonableness and prudence, and to avoid double counting, the OUR has determined that no additional cost will be allowed for recovery in relation to this particular group of stranded streetlight assets.

Recovery of Write-off Asset Cost Outstanding

11.212. Due to the extended application of the existing non-fuel rates during this Rate Review process, there have been significant depreciation accruals related to the recognized Write-off assets not yet fully depreciated.

11.213. This means that the utility would have recovered a portion of the 2018 Write-asset cost through these accumulated depreciation charges. Therefore, to ensure reasonable and prudent cost recovery, it is necessary for this accrued depreciation to be treated as an offset to 2018 NBV (US$8.47M) of these Write-off assets. Using the monthly depreciation charges computed by JPS for these assets, the accumulated depreciation from 2019 January – 2020 October was estimated to be US$2.33M.

Treatment of Other Write-off Assets

11.214. In reviewing the Write-off assets proposal, the OUR identified other categories of assets in the 2018 Fixed Asset Register with "Useful Lives" that are higher than the depreciable lives prescribed by the Licence or recommended by the 2018 Depreciation Study. Based on the in-service date for each of these assets, the application of the prescribed/recommended "Useful Life" indicates that these assets would be fully depreciated prior to the end of 2018. This means that these assets should be written off and removed from the Fixed Assets In-Service, which is in keeping with established accounting standards and regulatory principles in the rate setting process.

11.215. Taking into account the rate of depreciation for these assets up to 2018 December 31 (2018 Fixed Asset Register), this correction would result in unrecovered asset costs by the utility. These unrecovered costs were considered reasonable and were allowed for recovery by the company. The details of these assets and cost to be recovered are provided in Table 11.28 below.

Table 11.28: Details of Other Assets Written Off due to Corrected Useful Lives

DETAILS OF OTHER WRITE-OFF ASSETS												
Asset No.	**Cost Centre**	**Asset Description**	**FERC No.**	**Date In Service**	**DEP Method**	**Asset Life (Years)**	**Applicable Asset Life (Years)**	**Cost (US$)**	**DEP Amount (US$)**	**YTD DEP (US$)**	**2018 NBV (US$)**	**2019 DEP (US$)**
185738	4126	Major Engine Overhaul GT#6 A11 Free Turbine & Gas Generator	34311	31-Aug-2015	STL	24	**3**	1,170,762	3,463	41,558	**858,864**	41,558
181305	4241	Major Overhaul of Maggotty Hydro JAN 2013)	33311	31-Dec-2013	STL	25	**5**	533,813	1,694.64	20,336	**406,715**	20,336
117287	1250	Information Security Enhancement	39011	29-Dec-2009	STL	50	**5**	136,770	228	2,735	**112,152**	2,735
OTHER WRITE-OFF ASSET COST											**1,377,731**	
ADJUSTMENT - Write-off Asset Cost Partially Recovered – DEP Charges up to 2020 OCT											-118,486	
OUR APPROVED – Other Write-off Assets Cost											**1,259,245**	

OUR Determined Write-off Assets Cost

11.216. In keeping with the principles and calculations outlined above, a total offset of US$2.45M was applied to the recognized Write-off assets cost of US$9.85M, resulting in a net amount of US$7.40M. Based on the relevant factors and considerations, the OUR determined that the write-off assets cost to be recovered by JPS during the Rate Review period is US$7.40M, with equal allocations of US$2.47M per year in 2019, 2020 and 2021, as represented in Table 11.29 below.

Table 11.29: OUR Determined Write-off Asset Cost for Recovery (2019-2024)

OUR APPROVED - WRITE-OFF ASSETS COST RECOVERY 2019-2024 (US$M)								
Description	**JPS Cost (US$M)**	**2018 NBV (US$M)**	**OUR Determined Write-off Cost**	**Stranded Cost Allocation (US$M)**				
				2019	2020	2022	2023	2024
JPS proposed Asset Write-off Cost (US$M)	9.703	8.94	-					
Write-off Disallowed (ACC DEP – OHPS & HB B6)		-0.26	-					
OUR VERIFIED: Asset Write-off Cost (JPS Proposal)		8.47	8.47					
Other Write-off Assets Cost		1.38	1.38					
TOTAL - Write-off Assets Cost		**9.85**	**9.85**					
Write-off Asset Cost Fully Depreciated up to 2020 OCT		-	-0.21					
Write-off Asset Cost Partially Recovered – DEP Charges up to 2020 OCT		-	-2.45					
OUR APPROVED – Write-off Assets Cost	**-**	**-**	**7.62**	**2.54**	**2.54**	**2.54**		

11.217. According to the price control provisions of the Licence, after 2018 December 31, these Write-off assets should no longer be considered "Plant-in-Service" and must be excluded from JPS' Fixed Assets In-Service (a component of the Rate Base) projected for the Rate Review period. Concomitantly, depreciation charges should be discontinued and the related assets cost balances removed from the Rate Base.

Incremental Depreciation Recovery (2016-2018)

11.218. As articulated by JPS, this aspect of the proposal involves the recovery of annual depreciation charges related to "Regulatory Assets", that were incurred during the fiscal years 2016 to 2018, over and above the depreciation charge approved in the 2014-2019 Tariff Determination Notice and modified by the 2017 Annual & Extraordinary Rate Review Determination Notice.

11.219. The OUR having reviewed JPS' proposal and supporting documentation, sets out its position and rationale as follows:

1) While JPS has sought to chronicle its representations and sequence of interactions with the OUR on this matter, the company was not responsive to the OUR's conditions specified in the 2017 Annual & Extraordinary Rate Review Determination Notice. Moreover, in a related correspondence dated 2017 April 27 from JPS, the company had proposed to defer the recovery of additional revenues on investments in fixed asset additions during the 2017 and 2018 tariff periods until after the expenditures were incurred, admitting that at that point it was not in a position to implement the business processes and procedures necessary to sufficiently forecast the capital investment with the level of precision and granularity within the timeframe stipulated by the OUR. This meant that the

company had not satisfied the requirements to facilitate consideration and determination of the matter by the Office;

2) JPS has cited Schedule 3, paragraph 27 b. of the Licence to substantiate its request. However, having full regard to the regulatory context, this provision cannot be construed as an all-encompassing criterion without reference to established regulatory principles and conditions. That is, the issue of cost recovery has to be grounded on established price control principles and procedures that satisfy "prudent and reasonable" standard;
3) Based on the price-cap mechanism that preceded the revenue cap principle which came into effect in 2016, the Rate Base, determined at the 2014-2019 Tariff Review on the basis of reasonable and prudent asset costs, was expected to remain fixed throughout the price control period. Adjustment to the Rate Base, all other things remaining equal, at the 2019-2024 Rate Review. So in essence, the OUR at the 2014 Tariff Review would have estimated and allowed reasonable CAPEX levels in the company's cost structure for the ensuing 5-year regulatory period;
4) In that regard, the contemplation of a re-setting or adjusting to the pre-established Rate Base during the 2014-2019 regulatory period to accommodate incremental depreciation and other cost items emanating from additional capital expenditures, without prior approval by the Office, would essentially undermine or compromise the price control regime, and the regulatory process. Furthermore, implicit in JPS' proposal are features of "Rate-of-Return Regulation", which would contravene the price control provisions prescribed by the Licence for both the previous price-cap mechanism and present revenue-cap principle;
5) Notably, to facilitate the transition from the price-cap mechanism to the "revenue cap principle" due to the Licence amendment in 2016, it was agreed that subject to the requirements of the Licence, the 2014 Revenue Requirement which includes cost components derived from the approved 2014-2019 Rate Base, would be used as the basis for implementing the revenue cap system;
6) According to Schedule 3 of the Licence, under the existing "revenue cap principle", any CAPEX to be recognized as "PPE" and/or Intangible Assets must be channeled through the Business Plan or a Project Plan, which must be approved by the Office. The necessity for the Business Plan or a Project Plan is so that the regulator can determine whether JPS' proposals/projects are prudent and reasonable both in terms of necessity and costs for implementation. However, JPS failed to submit the plan as requested during the 2016-2018 timeframe for assessment for the Annual Reviews or Extraordinary Rate Reviews;
7) Importantly, in performance-based price regulation, where the Revenue Requirement is fixed for a pre-determined time period, attempting to increase depreciation charges due to the addition of Fixed Assets/Intangible Assets during the regulatory period, would also open the door for reciprocity. That is, the claw back of depreciation charges in excess of the depreciable amount (asset cost), recovered by the company for assets that have been fully depreciated prior to the end of the 5-year review period;

8) It is also acknowledged that the depreciation allowed in the Revenue Requirement is critical for accumulating funds to facilitate the replacement of the company's Fixed Assets/Intangible Assets. Therefore, the request for incremental depreciation (2016-2018) could involve some level of circularity and duplication in some aspects, as some of the new assets added during the period would have been procured with capital recovered through depreciation; and
9) Additionally, while no sound justification was provided by the company, there is also no supporting regulatory rationale to countenance the re-opening of the Rate Base and to adjust the depreciation charges established in the previous regulatory period to determine rates, without prior approval by the Office.

11.220. Having regard to these considerations, among other things, the OUR's position is that the proposed recovery of the incremental depreciation expenses of US$22.96M for 2016-2018, are not in alignment with the legal and regulatory requirements. Therefore, on that basis, these depreciation charges are not approved.

JPS' Reconsideration Request – Incremental Depreciation Recovery (2016-2018)

11.221. In JPS' comments on the OUR's Draft Determination Notice, the company requested a reconsideration of the Office's decision that rejects the proposed recovery of the 2016-2018 incremental depreciation charges.

JPS' Justification of "Request for Reconsideration" - Incremental Depreciation Decision

11.222. To justify this reconsideration request, the company made the arguments set out below.

11.223. The company asserted that it continued with plant investment in the interim years of 2016-2018 after the Licence became effective in 2016 as part of its prime obligation and mandate to provide safe and reliable power supply to consumers in Jamaica. The company claimed that this investment was not reflected in the 2014-2019 Revenue Requirement under the 2011 Licence, and the 2016-2018 depreciation was substantially higher than the depreciation level recognized in the current tariffs. JPS further indicated that the proposed Revenue Requirement recognizes this 2016-2018 investment through three (3) elements:

- 2016-2018 incremental depreciation expense not reflected in the current tariffs;
- 2016-2018 incremental ROI not reflected in the current tariffs; and
- Inclusion of the 2016-2018 net investment (original value less 2016-2018 depreciation) in the Rate Base for the 2019-2024 Rate Review Determination.

11.224. However, the company then claims that there were no solid regulatory reasons supporting the OUR's rejection of the 2016-2018 incremental depreciation expense and ROI.

11.225. The company also posited that the 2011 Licence and the subsequent 2016 Licence recognize a sustainability objective, that is, tariffs should generate enough revenue to cover efficient economic costs. JPS argued that economic sustainability is a condition that has to be met by all regulatory regimes and therefore, no "price control principles" can limit that objective. This means that all prudent investments by JPS have to be recovered either through ex-ante inclusion in the Rate Base or through an ex-post mechanism as the one requested by JPS.

11.226. JPS also claimed that the 2011 Licence explicitly contemplated the inclusion of future investments in the Rate Base where it is stated that "the Rate Base shall include appropriate rate-making adjustments to take into account known and measurable changes in the plant investment base".

11.227. On the OUR's position regarding the recognition of CAPEX through the Business Plan/Investment Plan, which the company did not satisfy during the 2016-2018 timeframe, the company noted that the 2011 Licence on which the 2014-2019 tariff was established, had no Business Plan provisions. The company also noted that the Business Plan as defined and contemplated in the Licence suggests that this condition was specific to the 2019-2024 Rate Review Process.

OUR's Response to JPS' Arguments

11.228. The arguments presented by JPS in relation to this reconsideration request are noted. However, it is important to note that while rates should be set to reflect the cost of service, these costs must be prudent and reasonable and be subject to regulatory scrutiny and approval. As it relates to cost recovery, JPS would also be aware that under the existing legal and regulatory framework, the test of prudence and reasonableness is within the regulatory remit of the OUR, not JPS.

Further, the conceived approach for the recovery of investment cost through an ex-post mechanism, in respect to this particular matter, is not tenable, and show some semblance of a "Capital Cost Tracker" mechanism, which is not applicable under the price control regime prescribed by the Licence.

11.229. Regarding JPS' reference to determination of the "Rate Base" derivation as defined in the 2011 Licence, which was cited by the company to support its arguments for the inclusion of future investments in Rate Base, the OUR finds this reasoning to be a misrepresentation and distortion of the provisions of the 2011 Licence. Contrary to JPS' interpretation, the Rate Base definition as set out under Schedule 3 (1) of the 2011 Licence, states as follows:

> *""Rate Base" means the value of the net investment in the Licensed Business. The Rate Base shall be calculated on the net electric system investment made by the Licensee at the time the rates are being set and shall include the net investment made in generation, transmission and distribution and general plant assets. The Rate Base shall include appropriate rate-making adjustments to take into account known and measurable changes in the plant investment base…"*

11.230. As indicated, the Rate Base shall be determined at the time the rates are being set, which means at the 5-year Rate Reviews. Therefore, the argument proffered by JPS is without merit.

11.231. On the matter of the CAPEX being channelled through the Business Plan, the arguments presented by JPS clearly reinforce the OUR's position that following the amendments to the Licence in 2016, all capital investments have to be addressed through the Business Plan. However, since the Business Plan would not be ready until the 2019-2024 Rate

Review process, it means that any and all additional capital investments, above the capital cost approved at the 2014 Tariff Review would have to be approved by the Office, in order to be recognised for incremental depreciation and ROI.

Major Projects Approved for Implementation during 2016-2018

11.232. During the 2016-2018 timeframe, the OUR had approved four strategic projects to be implemented by JPS. These projects include:

- Hybrid Energy Storage Project
- SJPC Transmission Interconnection
- Bogue GT#11 Repowering Project
- Smart Meter Programme

11.233. Since the Office had given prior approval for JPS to undertake these projects, it has determined that the associated incremental depreciation and ROI (2016-2018), which are deemed reasonable and prudent, are to be recovered by the company.

11.234. To determine the actual amounts to be recovered, the OUR on 2020 October 21 requested information from JPS related to CAPEX, Depreciation and ROI in respect of the cost and timing of the capitalization of these projects. On the same day, JPS submitted an MS Excel document entitled "2016-2018 Capital Investment by Projects" with a schedule representing the requested information. According to this schedule, JPS is requesting the recovery of US$1.86M and US$7.8M for incremental depreciation and ROI respectively, for these projects.

Smart LED Streetlight Programme – Incremental Depreciation & ROI (2017-2018)

11.235. Based on the shift in the funding arrangement for the SSP as described herein, the OUR also requested information from JPS regarding incremental depreciation and ROI associated with this capital programme. This information was submitted to the OUR on 2020 October 29, in a MS Excel document, entitled "Streetlight Analysis". This document indicates that JPS is requesting the recovery of incremental depreciation charges of US$0.7M.

OUR's Determined Incremental Depreciation & ROI for Approved Projects (2016-2018)

11.236. Based on the OUR's evaluation of the project costs and calculation in referenced project schedules in conjunction with the 2018 Fixed Asset Register, the incremental depreciation and ROI associated with referenced projects were determined to be US$1.57 and US$6.15M, respectively, which were included in the Revenue Requirement. The details of the projects and amounts to be recovered are summarized in Table 11.30 below.

Table: 11.30: OUR's Determined Depreciation & ROI Recovery for Approved Projects (2016-2018)

2016-2018 APPROVED CAPITAL PROJECTS – INCREMENTAL DEPRECIATION & ROI RECOVERY (US$K)										
PROJECT DESCRIPTION	ASSET No.	Cost CENTRE	CATEGORY	Amount Invested (US$K)	JPS INCR DEP (US$K)	JPS ROI (US$K)	JPS ROI with Opport. Cost (US$K)	OUR INCR DEP (US$K)	OUR ROI (US$K)	REMARKS
2016 SMART METERS PROJECT (ID184100)	254851	1200	Non-Regulated (EEIF)	2,981	-	-	-	**0**	**0**	NOT APPROVED - EEIF ASSETS
2016 SMART METERS PROJECT (ID184100)	254852	1200	Regulated	1,406	914	1,245	1,382	**269**	**270**	
GT#11 RE-POWERING to NG FIRED UNIT (Project # IG022700)	257421	4131	Regulated	15,146	404	2,114	2,164	**404**	**1,761**	
2017 SMART METERS PROJECT (ID206000)	258037	1200	Non-Regulated (EEIF)	4,476	447	686	704	**0**	**0**	NOT APPROVED - EEIF ASSETS
OLD HARBOUR, 190MW INTERCONNECTION PROJECT (# IT009800)	258476	5730	Regulated	8,111	98	975	995	**98**	**835**	
2018 SMART METERS PROJECT (ID225200)			-	19,562	0	1,513	1,523	**0**	**1,459**	
24.5MW HYBRID ENERGY STORAGE SYSTEM (Project # ID217200)			Regulated	15,581	0	1,037	1,037	**0**	**1,035**	
SUBTOTAL (4 Projects)					1863	7,569	7,805	**771**	**5,359**	
SMART SL PROGRAMME				13,625	695	-	-	**798**	**788**	
TOTAL					**2,558**	**7,569**	**7,805**	**1,569**	**6,147**	

11.237. As indicated, JPS has requested the recovery of incremental depreciation and ROI for the 2016 and 2017 Smart Meter Projects. However, the 2018 Fixed Asset Register shows that these projects were financed by the EEIF (customer funded), which means that these assets are not owned by JPS. On that basis, the proposed depreciation and ROI, were Not Approved by the Office.

Customer Funded and Non-Regulated Assets Depreciation

11.238. During the OUR's evaluation of JPS' depreciation proposal, the annual depreciation charges for these assets were included in the Fixed Asset Register and Depreciation Forecast for the following assets:

- Bogue Conversion Assets;
- JPS eStore;
- JPS Munro Wind Farm;
- JPS Maggotty Hydro Plant (6.4MW); and
- ALRIM Assets.

11.239. The annual depreciation charges were evaluated by the OUR and found to be largely accurate and representative. Since these assets are not covered under the "Licensed Business", their associated depreciation charges were applied as offsets to the forecasted gross depreciation for the Rate Review period.

EEIF Assets

11.240. In the case of the EEIF assets (customer funded), a few issues were identified, which include the following:

1) A significant number of EEIF funded electronic meters were identified with useful asset lives that were not consistent with the asset lives applied to similar metering devices in JPS' regulated asset category. As such, appropriate adjustments were made by the OUR to accurately reflect the depreciation charges for these assets;
2) Some metering assets had useful lives of 30 years, which is inconsistent with the Licence and the 2018 PwC Depreciation Study. This needs to be reviewed by the company.
3) The adjusted annual depreciation charges were applied as offsets to the forecasted gross depreciation for the Rate Review period.

Smart LED Streetlight Programme

11.241. In response to the issues raised by JPS pertaining to the capitalization of the SSP assets in its comments on the Draft Determination Notice, the OUR determined that the total capital cost approved for the programme will be allowed as part of the company's planned investment costs, instead of utilizing the SBF. As a result, the total SSP capital cost incurred from 2017 to 2019 and the projections for 2020 and 2021 were included in the Rate Base for the Rate Review period.

SSP Depreciation Charges

11.242. Based on the indicated modification to the SSP funding arrangement and Rate Base treatment of the capital cost, the ownership of relevant streetlight assets will shift from the customer to the utility, and classified as "Regulated Assets". For these "Regulated Assets", the utility is permitted to recover the applicable depreciation charges as part of the costs of its "Licensed Business", which are reflected in the approved depreciation expenses for the Rate Review period.

SSP Depreciation Offset

11.243. Based on changes in the SSP funding arrangement, the SSP depreciation offsets included in 2019-2023 depreciation forecast would no longer apply, and therefore were deleted from the calculations, as shown in Table 11.32 below. From this adjustment, the applicable depreciation charges for the SSP assets are automatically recognized in the Fixed Asset In-service deprecation and CAPEX depreciation forecast, represented in Table 11.33 [CJ2]below.

JPS/CB Hill Run DG Project

11.244. The "2018 CWIP Transferred to FA Depreciation Forecast" (submitted 2020 September 23), included the JPS/CB Hill Run Distributed Generation Project (Hill Run Project), which was scheduled to be placed in-service and added to the Fixed Asset Register in 2021 January, with asset cost of US$5.61M. Based on this projection, the company forecasted depreciation charges of US$224,552.50 for each year during the period 2021-2023, as shown in Table 11.31 [CJ3]below. However, the OUR's evaluation found that depreciation charges were not applied as offsets to JPS' gross depreciation forecast.

Table: 11.31[CJ4]: JPS/CB Hill Run DG Project Cost and Depreciation

2018 CWIP TRANSFERRED IINTO SERVICE: JPS/CB HILL RUN DG PROJECT – ASSET COST & DEPRECIATION								
Description	CAPEX Transferred US$	Asset Life (Years)	DEP Start Date	Annual Depreciation Charges (US$)				
				2019	**2020**	**2021**	**2022**	**2023**
PROJECT# IG023300: JPS/CB Hill Run DG Project – Install and Commission a 8MW DG with Heat and Power Cogeneration at CB's Hill Run, St Catherine Facility.	**5,613,813**	25	2020 JAN 1	-	-	**224,553**	**224,553**	**224,553**

11.245. JPS would be aware that the Office had given approval for the Hill Run Project to be implemented under a "Virtual IPP" arrangement, and not a Rate Base asset. This means, the company is NOT allowed to recover the associated depreciation charges as part of the costs of its "Licensed Business". Based on this position, these depreciation charges were applied as offsets to the forecasted gross depreciation for the Rate Review period, as shown in Table 11.32 below.

11.5.5. OUR Determined Depreciation Expenses for 2019 - 2023

11.246. Based on the OUR's review and evaluation of the Depreciation Expenses, the annual depreciation expenses determined for JPS during the Rate Review period, are as represented in Table 11.33 below.

Table 11.32: OUR Determined Depreciation Forecast for 2019-2023

OUR's DEPRECIATION FORECAST 2019-2023 (US$ Millions)						
Depreciation Components	**Depreciation Forecast (US$M)**					**Remarks**
	2019	**2020**	**2021**	**2022**	**2023**	
FIXED ASSET IN-SERVICE DEPRECIATION FORECAST:						
2018 FA Register: Asset In-Service Depreciation	64.92	47.34	46.32	39.78	35.69	
2018 CWIP Transferred into Service	5.13	6.15	7.33	7.33	7.33	Total – US$33.27M
Capital Spares from 2018	0.28	0.28	0.28	0.28	0.28	
Fixed Assets from 2018	**70.33**	**53.77**	**53.93**	**47.39**	**43.30**	
ACC DEP (OHPS & HBB6 Maintenance) - 2017-2018	9.48	0.00	0.00	0.00	0.00	
ACC DEP (Bogue GTs, RF1&2 and HB GTs)	0.00	0.00	0.00	0.00	0.00	NOT APPROVED
EXCLUSION - OHPS & HBB6 Depreciation	**-12.64**	**-3.18**	**-0.58**	**-0.19**	**-0.14**	Plants Retired – No DEP
2018 FIXED ASSET IN-SERVICE DEPRECIATION	**67.17**	**50.59**	**53.35**	**47.20**	**43.16**	
CAPEX DEPRECIATION (2019-2023 Capital Projects)	4.84	13.79	23.59	29.29	35.24	Include SSP (US$24M)
SUB-TOTAL: FA In-Service & CAPEX DEPRECIATION	**72.01**	**64.38**	**76.94**	**76.49**	**78.40**	
APPROVED STRANDED/WRITE-OFF ASSET COSTS:						
Write-off Assets Cost	2.47	2.47	2.47	0.00	0.00	US$7.4M Approved
Stranded Meter Assets Cost	2.48	2.48	2.48	2.48	2.48	US$12.42M Approved
Stranded Streetlight Asset Cost	2.61	2.61	0.00	0.00	0.00	US$5.21M Approved
SUB-TOTAL: STRANDED/WRITE-OFF ASSETS COST	**7.56**	**7.56**	**4.95**	**2.48**	**2.48**	
APPROVED Incremental Depreciation (2016-2018)	**1.57**	**0.00**	**0.00**	**0.00**	**0.00**	Included SSP Assets Cost
CUSTOMER FUNDED/NON-REGULATED ASSETS DEP						
Bogue Conversion Assets	-0.40	-0.40	-0.40	-0.40	-0.40	
Smart LED Streetlight Programme	0.00	0.00	0.00	0.00	0.00	Transferred to Rate Base
EEIF	-5.05	-5.01	-9.95	-5.23	-4.15	
JPS Estore	-0.02	-0.02	-0.01	-0.01	-0.01	
JPS Munro Windfarm	-0.55	-0.55	-0.55	-0.55	-0.55	
JPS Maggotty Hydro (6.3MW)	-0.89	-0.89	-0.89	-0.89	-0.89	
JPS/CB Hill Run DG Project	0.00	0.00	-0.22	-0.22	-0.22	Included in 2018 CWIP
ALRIM	0.00	-0.90	-0.90	-0.90	-0.90	
SUB-TOTAL: CUSTOMER FUNDED/NON-REGULATED	**-6.91**	**-7.77**	**-12.93**	**-8.21**	**-7.13**	
EXCLUDED - Stranded/Write-off Assets DEP	**-3.29**	**-3.07**	**-2.78**	**-2.57**	**-2.35**	
NET DEPRECIATION (2019-2023) – US$M	**70.94**	**61.10**	**66.19**	**68.20**	**71.40**	
NET DEPRECIATION (2019-2023) – J$M	**9,080**	**7,821**	**8,472**	**8,729**	**9,139**	

11.247. A comparison of the OUR's approved annual depreciation expenses relative to those forecasted by JPS for the Rate Review period are shown in Table 11.33 below.

Table 11.33: OUR's Determined Depreciation Forecast vs. JPS' Application for [CJ5]2019-2023

PROJECTED DEPRECIATION EXPENSES 2019-2023 (J$M)										
Depreciation Components	**2019**		**2020**		**2021**		**2022**		**2023**	
	JPS	**OUR**	**JPS**	**OUR**	**JPS**	**OUR**	**JPS**	**OUR**	**JPS**	**OUR**
FIXED ASSET IN-SERVICE DEPRECIATION	9,035	8,598	7,912	6,476	7,016	6,829	6,797	6,042	6,369	5,524
CAPEX DEPRECIATION - CAPITAL PROJECTS	631	619	1,955	1,766	3,339	3,020	4,134	3,749	4,833	4,511
SUB-TOTAL: Fixed ASSETS IN-SERVICE & CAPEX DEPRECIATION	**9,666**	**9,217**	**9,867**	**8,241**	**10,355**	**9,849**	**10,931**	**9,791**	**11,202**	**10,035**
STRANDED/WRITE-OFF ASSETS COST	1,385	968	1,309	968	797	634	364	317	210	317
2016-2018 INREMENATAL DEPRECIATION	2,939	201	0	0	0	0	0	0	0	0
CUSTOMER FUNDED/NON-REGULATED ASSETS DEPRECIATION	-962	-884	-1,072	-995	-1,071	-1,655	-1,051	-1,050	-1,009	-912
EXCLUDED - STRANDED/WRITE-OFF ASSETS DEPRECIATION	0	-421	0	-393	0	-356	0	-329	0	-301
NET DEPRECIATION (J$M)	**13,028**	**9,080**	**10,104**	**7,821**	**10,081**	**8,472**	**10,244**	**8,729**	**10,403**	**9,139**

11.5.6. Office Determinations – Depreciation

11.248. Based on the OUR's review, the Office determinations on Depreciation expenses are as follows:

DETERMINATION 13

JPS' proposed annual Depreciation Expenses for the Rate Review period are not approved, on the basis that they are not deemed prudent and reasonable. The Office therefore directs as follows:

a) The approved annual Depreciation Expenses for the Rate Review period are set out in Table 11.33 of this Determination Notice.

b) The company is required to conduct a detailed review of its Fixed Asset Register to eliminate any existing errors and anomalies and to ensure that all the useful asset lives, depreciation rates, and depreciation calculations are consistent with the requirements of the Licence and useful lives recommended by the 2018 PwC Depreciation Study. The review shall be completed by the end of 2021, and a report including the improved Fixed Asset Register shall be submitted to the Office.

c) The company shall submit to the Office a complete, accurate and representative Fixed Asset Register of its Fixed Asset In-service, with depreciation calculations, each year following the completion of its Annual Financial Report.

11.6. Determinations: Other Adjustments to the Revenue Requirement

11.6.1. Stranded Asset Cost Recovery

11.249. JPS' proposal is to recover a total of US$31.8M in costs for Stranded Assets over the Rate Review period. The OUR approved an amount of US$24.3M, which is to be recovered over the period. The full treatment of the Stranded Assets has been dealt with as a part of depreciation analysis above.

11.6.2. 2016-2018 Incremental Depreciation

11.250. JPS requested the recovery of J$2.939 billion (US$23.0M) for what it claimed to be depreciation expense on capital investments made in 2016-2018. The Office has approved J$200.8M in relation to five (5) specific projects. All five (5) projects had received the endorsement of the OUR prior to implementation. The projects are as follows:

- The Smart Meter project
- The re-powering of GT11 (to natural gas)
- The Old Harbour, 190MW Interconnection project
- The 24.5MW Hybrid Energy Storage System
- The Smart Streetlight Project

11.6.3. 2016-2018 Incremental Return on Investment (ROI)

11.251. JPS requested the recovery of return on investment on capital investments made in 2016-2018 of J$3.522 billion or US$27.5M. Consistent with the five (5) projects identified above the OUR analysis indicated the J$786.8M in incremental ROI was warranted. Hence, the J$786.8M was allowed in the revenue requirement.

11.252. JPS stated that the line item 'other income' was predominantly comprised of proceeds from the sale of scrap, rental income, and other miscellaneous settlements. The company forecasted that on average other income and expenses for the Rate Review period would range between J$163M and J$168M annually. The proposed values are follows:

- 2019 – US$1.148M;
- 2020 – US$1.297M;
- 2021 – US$1.312M;
- 2022 – US$1.281M;
- 2023 – US$1.273M.

11.253. The OUR accepted the proposed US dollar values in its computation of JPS' Other Income and Expense costs as an off-set to the Revenue Requirement.

11.6.4. Finance Income

11.254. JPS reported in its 2018 and 2019 audited accounts the amounts of US$11.2M and US$8.1M respectively, for finance income. Finance Income includes interest income and interest capitalized during construction. The Licence allows inclusion of CWIP as part of

PPE in the Rate Base. Consequently, interest capitalized during construction shall be an offset to the Revenue Requirement. The details of the total Finance Income for the period 2018 to 2023 is shown in Table 11.34 below.

Table 11.34: OUR Approved Finance Income 2018-2023

Finance Income	2018	2019	2020	2021	2022	2023
Interest Income	(6,792)	(5,638)	(2,482)	(2,482)	(2,482)	(2,482)
Interest Capitalised During Construction	(4,387)	(2,499)	(3,819)	(3,819)	(3,819)	(3,819)
US$'000'	**(11,179)**	**(8,137)**	**(6,301)**	**(6,301)**	**(6,301)**	**(6,301)**
J$'000'	**(1,430,912)**	**(1,041,536)**	**(806,528)**	**(806,528)**	**(806,528)**	**(806,528)**

11.6.5. Bond Refinancing Costs

11.255. JPS presented as offset to its 2019 Revenue Requirement, the amount of J$340M in relation to the Revenue Incentive Mechanism (RIM), which was developed and approved by the OUR in the 2018 Annual & Extraordinary Rate Review Determination Notice, to assist the company with the refinancing of a high interest bearing bond in the amount of US$179.1M. The proposed offset of J$340M reflects the benefit to customers from the refinancing of a portion of JPS' long term loan. The J$340M off-set has been approved by the OUR and is recognized in the revenue requirement.

11.6.6. Required Revenue for Decommissioning Costs

11.256. JPS' proposal is to recover a net total of US$43.8M in Phase I decommissioning costs over the Rate Review period. The OUR approved an amount of US$14.1M, which is to be recovered over four (4) years. The full treatment of the decommissioning cost is dealt with at **Chapter 19 – Decommissioning Cost**.

11.6.7. Special Energy Supply Contracts

11.257. In 1999, JPS entered into a long-standing contractual agreement with the Caribbean Cement Company Limited (CCCL) for the supply of electricity to its facility at Rockfort. JPS stated that it will continue to supply CCCL with power during the Rate Review period. The contractual arrangement with CCCL requires that the revenues from CCCL be an off-set to the Revenue Requirement. The amounts proposed by JPS were approved by the OUR and are shown in Table 11.35 below.

Table 11.35: CCCL Revenue Offset

Revenue Requirement (J$'000')	2019		2020		2021		2022		2023	
	JPS Proposed	OUR Allowed	JPS Proposed	OUR Allowed	JPS Proposed	OUR Allowed	JPS Proposed	OUR Allowed	JPS Proposed	OUR Allowed
Adjustment for Cement Company Rev	670,098	670,098	688,993	688,993	725,659	725,659	750,982	750,982	777,282	777,282

11.6.8. Specialized Funds – Electricity Disaster Fund (Sinking Fund)

11.258. The electricity sector is of vital importance to the national economy and any disruptions to the supply of electricity, whether through natural disaster or otherwise, can have a significant impact on economic activity. It was with this in mind that the Electricity Disaster Fund (EDF), was established by the OUR in 2004 to reduce the financial exposure of JPS for damages to its transmission and distribution (T&D) assets caused by natural disasters, in the absence of traditional insurance coverage from firms that specialize in this business.

11.259. The objectives of the EDF are to:

1. reduce uncertainty with respect to the funding of restoration activities in the event of a natural disaster;
2. establish a framework within which restoration activities may be effected efficiently and in the shortest possible time;
3. minimise the financial impact on rate-payers since they may be required to pay higher rates in the aftermath of a natural disaster.

11.260. Since its inception, the EDF has funded restoration activities following Hurricane Maria and Hurricane Sandy.

11.261. Since 2009, the annual funding rate of the EDF has been set at US$3M. JPS is responsible for setting aside the monthly provision designated in the tariff for the EDF and depositing the sums in the approved investment instruments for the EDF. According to JPS, as of 2018 December 31, the value of the EDF is US$40.3M.

11.262. The Rules of Procedure for Operation and Administration of the EDF (Operational Rules of Procedure), which was published by the OUR in 2008 following a public consultation exercise, set out the following:

- Scope and purpose of the Fund
- Circumstances under which the EDF may be applied
- Utility record-keeping and data requirements for claims verification
- Procedure for the submission of claims
- Process for investigating claims
- Principles for settling claims
- Principles for the investment of the EDF
- Procedures for approvals and withdrawals from the EDF

JPS' Proposal for the EDF for the Rate Review Period

11.263. JPS proposed that the annual funding rate for the EDF remain at the current US$3M during the Rate Review period. The company argued that this funding rate should continue until a more comprehensive alternative insurance structure is developed and agreed upon with the OUR.

11.264. The company stated that as at 2018 December 31, the NBV of JPS' fixed assets was US$777M, with an amount of US$390.6M specifically in relation to T&D assets. According to JPS, the T&D assets are quite susceptible to natural disasters and the company is unable to obtain conventional insurance coverage for these assets.

11.265. JPS stated that the EDF now only covers 10.24% of the uninsured value of the fixed assets and pointed out that as per the Operational Rules of Procedure, Section 1.9(a) which states, "The Fund shall normally be capped at fifteen percent (15%) of the NBV of JPS' T&D assets. Notwithstanding, the Office has the right to increase this fifteen percent (15%) ceiling if it determines that JPS' T&D system is, for whatever reason, over exposed." The company argued that the EDF will require an annual funding rate of US$4M over the next five years to reach a level of US$60M, representing fifteen percent (15%) of the NBV of JPS' T&D assets after factoring future CAPEX. JPS suggested that the current level of funds in the EDF may not be adequate to cover a major natural disaster. Notwithstanding this, JPS maintained that it is proposing to keep the current funding rate to mitigate further increase to current tariffs.

11.266. JPS further argued that the existing EDF arrangements have a number of limitations. JPS stated that while the EDF balances for JPS have proven beneficial in the past in the recovery of hurricane damages, the current construct of the EDF is inefficient from a strategic risk analysis perspective. The company opined that the EDF is constrained by the Fund Limits as outlined in the Operational Rules and Procedures, for example, the OUR by way of policy, imposes a 3% lower limit on the Fund. Furthermore the company argued that "the lower and upper limits of the EDF are determined by the OUR using financial estimates of NBV as opposed to risk modelling and return periods". JPS stated that these are considerations it would like to see addressed in the design of a comprehensive alternative insurance mechanism.

11.267. In light of the perceived limitations, JPS proposed that the OUR considers parametric insurance as an alternative risk transfer solution for the company. JPS indicated that it has approached a reputable insurance company in the exploration of this option. According to JPS, the terms of reference for this engagement include a review of JPS' Captive Insurer application, which outlines the captive planning, capital requirements and adequacy, reinsurance and retention planning. The insurance consultant will also conduct risk modelling of the adequacy of the EDF in respect of indemnity and benefit. JPS opined that it will need to have significant engagement with the OUR as it relates to a revision of the Operational Rules of Procedure and authorization of the release of the funds in the EDF for alternative insurance solutions.

The OUR's Assessment of JPS' Proposal

Assessment of Monthly Allocations to the EDF

11.268. As a prelude to assessing JPS' proposal, the OUR conducted a review of the monthly accrual calculations done by JPS to determine whether the company is correctly allocating monies to the EDF. There was also an assessment as to whether JPS was making its lodgments on time, and if interest charges were being applied to outstanding balances in instances where lodgments were not made within the stipulated time.

11.269. In accordance with the Operational Rules of Procedure, JPS is required to submit a quarterly report to the OUR detailing the allocation made to the EDF over the quarter. The quarterly report also includes any interest that may have been earned over the period. The EDF report prepared by JPS also provides details on any drawdowns from the fund and shows the opening and closing balances of the EDF for the quarter.

11.270. The OUR's review of JPS' monthly allocation calculations indicated that JPS correctly applied this calculation between 2015 January and 2016 July and funds were appropriately applied to the EDF. An example of this is demonstrated in Table **11.** 11.36 below, which shows the calculations done by JPS for 2015.

Table 11.36: JPS' EDF Calculations for 2015

	Jan-15 J$'000	Feb-15 J$'000	Mar-15 J$'000	Apr-15 J$'000	May-15 J$'000	Jun-15 J$'000	Jul-15 J$'000	Aug-15 J$'000	Sep-15 J$'000	Oct-15 J$'000	Nov-15 J$'000	Dec-15 J$'000
- Billed sales (MWH)	239,293	223,758	247,386	244,226	261,452	259,964	272,382	272,360	268,505	268,790	261,246	253,370
- Base rate per MWH	158.6005	158.6005	112.7591	112.7591	112.7591	112.7591	112.7591	112.7591	112.7591	115.3526	115.3526	115.3526
- Applicable rate	184.6218	186.4796	132.3860	115.8232	116.4360	116.9094	117.7761	118.2177	118.6541	118.9033	119.6813	119.7789
- Collection factor	97.5%	97.5%	97.5%	97.5%	97.5%	97.5%	97.5%	97.5%	97.5%	97.5%	97.5%	97.5%
Sinking fund reserve amount (J$)	43,074,228.18	40,683,181.18	31,931,661.06	27,579,883.26	29,681,379.20	29,632,447.78	31,278,129.34	31,392,854.27	31,062,763.05	31,161,073.22	30,484,668.83	**29,589,682.87**
Sinking fund reserve amount (US$)	375,666.89	351,278.82	276,118.20	239,734.39	256,643.67	255,183.09	267,372.83	267,351.16	263,566.96	261,736.13	254,390.18	246,720.50
Cumulative total US$ (excludes int	375,667	726,946	1,003,064	1,242,798	1,499,442	1,754,625	2,021,998	2,289,349	2,552,916	2,814,652	3,069,042	3,315,763

11.271. When the Operational Rules of Procedure was established, JPS operated under a price cap regime. Under the price cap regime, prices are adjusted annually by an annual adjustment factor and revenue collected is determined by kWh sales multiplied by the adjusted price. The mechanism that was developed to determine the allocation to the EDF was based on this principle. The monthly accrual calculations were therefore determined by the rate per MWh assigned to the EDF, times the monthly MWh sales, times the bad debt collection factor.

11.272. The OUR's review of JPS' monthly allocation calculations indicated that JPS correctly applied this calculation between 2015 January and 2016 July and funds were appropriately applied to the EDF.

11.273. In 2016, with the introduction of the Licence, which changed the regulatory regime from price cap to revenue cap, there were a number of significant changes pertaining to the allocation of funds to the EDF. These included:

- The annual adjustment is made to revenues, not price;
- The annual adjustment factor no longer represents a year-to-year annual adjustment, but an adjustment between the base year (year in which tariffs are reset) and the current adjustment;
- Revenues are capped in real terms.

11.274. As a result of these changes in the Licence, the mechanism for calculating the EDF allocations should have been reviewed. The review of JPS' Quarterly EDF Reports indicates that JPS continued to apply the accrual calculation outlined in section 1.5, 1.6 and 1.8 of the Operational Rules of Procedure up to 2017 October even though these were no longer appropriate.

11.275. Post 2017 October, JPS no longer applied the accrual calculation outlined in the Operational Rules of Procedure. Instead, revenues for the EDF were stated without any clear indications of how these revenues were derived. Table 11.37 below shows that a shift in the methodology occurred in 2017 October. This was done without any explanation for the change.

Table 11.37: JPS' EDF Calculations for 2017

	Jan-17 J$'000	Feb-17 J$'000	Mar-17 J$'000	Apr-17 J$'000	May-17 J$'000	Jun-17 J$'000	Jul-17 J$'000	Aug-17 J$'000	Sep-17 J$'000	Oct-17 J$'000	Nov-17 J$'000	Dec-17 J$'000
- Billed sales (MWH)	257,846	240,250	256,447	265,997	268,093	273,697	286,151	284,790	279,556	280,017	258,775	257,330
- Base rate per MWH	126.3457	126.3457	126.3457	126.3457	126.3457	126.3457	126.3457	126.3457	126.3457			
- Applicable rate	132.4726	132.2856	132.1270	132.7065	133.4634	134.2300	132.2447	132.2447	133.7166			
- Collection factor	97.5%	97.5%	97.5%	97.5%	97.5%	97.5%	97.5%	97.5%	97.5%	97.5%	97.5%	97.5%
Sinking fund reserve amount (J$)	33,303,641	30,987,056	33,036,418.72	34,417,088.07	34,886,034.52	35,819,847.19	36,895,916.89	36,720,480.73	36,446,744.08	37,148,409.48	36,219,699.24	**36,219,699.24**
Late Fee/Interest						131,352.18	215,310.42					
Sinking fund reserve amount (US$)	259,292.57	241,597.33	257,884.87	267,489.21	269,596.12	276,241.06	289,435.13	286,387.65	281,123.79	285,949.02	284,551.89	287,278.50
Cumulative total US$ (excludes int	259,293	500,890	758,775	1,026,264	1,295,860	1,572,101	1,861,536	2,147,924	2,429,048	2,714,997	2,999,549	3,286,827

11.276. In a letter to the OUR dated 2018 June 29, JPS advised of adjustments to the deposit schedule following on a review of the calculation of the monthly obligation due to the EDF. JPS stated that it had not factored taxation in its calculation of the allocation to the EDF, so rather than depositing $24.7M monthly, it had deposited $37M instead. As a result of this, JPS indicated that it overfunded the EDF by $74M and as such, to ensure that the total deposit for the tariff period remains consistent with the $247M targeted, it would suspend payments to the EDF until 2018 July, when it would resume payments at the level of $24.7M until the end of the regulatory period. The OUR however, was unable to ascertain whether payments resumed in 2018 July as JPS did not provide a detailed quarterly report for the quarter ending 2018 September. Also, while JPS provided a summary report for the quarter ending 2018 December, it did not provide a detailed report showing how the allocations were done for the quarter. It will therefore be necessary to commission an audit of the EDF for the period in question. It is determined, therefore, that the OUR shall, within six (6) months of the effective date of this Determination Notice, commission an audit of the EDF for the three (3) year period 2018 - 2020.

KMPG's Assessment of EDF Agreed-upon Procedures for the Year 2017

11.277. In 2018, JPS engaged accounting firm KPMG to, among other things, assess whether JPS had accurately calculated the accrual to the EDF based on the precautionary provision, annual sales in kWh and the bad debt adjustment factor for the twelve (12) months in 2017. KPMG concluded that its review of the twelve (12) months accrual calculations revealed that sections 1.5, 1.6 and 1.8 of the Operational Rules of Procedure were appropriately adhered to, during the 2017 January 1 to 2017 December 31 period.

11.278. KPMG also indicated that based on its review of monthly lodgments, JPS made late lodgments in four (4) months. These were for monthly allocations for the months of 2017 March, July and September. KPMG's report seems to suggest that JPS, in accordance with section 1.7 of the Operational Rules of Procedure, made the appropriate interest payments to the EDF arising from the late lodgments. This would suggest that JPS is adhering to the Operational Rules of Procedure, when it comes to lodgments and interest payments.

Summary of the OUR's Assessment of the Monthly Allocations to the EDF

11.279. The OUR is unable to determine the accuracy of the calculations of the monthly allocation to the EDF between 2017 October and 2018 December, and as such, is unable to determine whether the stated value of US$40.34M in the EDF is correct.

Therefore, the OUR has determined that within three (3) months of the effective date of this Determination Notice, JPS shall provide a detailed report on how the calculations of the monthly allocations to the EDF were conducted for the period 2017 October to 2018 December. In the report, JPS should clearly indicate the basis of its calculations and the rationale for any changes in the calculation methodology.

Assessment of JPS' Proposed Funding Level and Alternative Insurance Structure

11.280. Given the level of tariff increase that is being proposed by JPS, the OUR agrees that it would be inappropriate at this time to increase the annual funding to the EDF beyond the US$3M that currently obtains. This level of funding will still ensure that the EDF remains within the 3% and 15% lower and upper limits respectively, of the NBV of the T&D assets as prescribed in the Operational Rules of Procedure.

11.281. Regarding JPS' proposal for parametric insurance as an alternative risk management solution for its T&D assets, the OUR is not averse to considering this as an option, but is unable to approve this based on the information that JPS has presented. JPS has clearly indicated that its proposal is conceptual at this stage, as it is still exploring the idea with a reputable insurance firm. Additionally, the OUR is of the view that any changes to the insurance mechanism will require a public consultation exercise to understand the views of stakeholders on this matter.

11.282. While JPS has stated it is unable to obtain conventional insurance to cover the risk of damage to its T&D assets, parametric insurance may be available to fill this gap. Parametric insurance is coverage that protects a customer against certain losses based on a verifiable event that causes the indefinite loss. According to NS Insurance, an international insurance company, "the key difference between this type of coverage and any other, is that it doesn't cover the extent of a loss – known as indemnifying the insured – but pays out an agreed-upon sum based on the expected loss resulting from a trigger event". One of the key advantages of parametric insurance is the increased speed that cash is made available to customers after an event, however, a major limitation is that if the triggering event does not occur, there will be no pay-out even if there are verifiable losses.

11.283. The Journal of Insurance states that parametric insurance is a highly customized product with uniquely tailored index and pay-out provisions. This is based on each client's specific needs, ideally aligned with its risk management game plan and the single or multi-trigger nature of the risk. This indicates that the parametric insurance product must be clearly designed based on the modelling and the nature of the risk presented to JPS. Thus, the OUR is unable to approve a proposal which does not clearly identify the specific needs of JPS' T&D network and the nature of the risks that may be presented based on the historical record of natural disaster events. The OUR will, however, give JPS the opportunity to present a detailed proposal of the parametric insurance options that are available to the company within six (6) months of the effective date of this Determination Notice. The proposal should include and detail the following:

- Modelling of the natural disaster risks presented to the T&D network;
- An assessment of the value of losses suffered based on various triggering event scenarios and the calculation of the amount of pay-out that will be made based on the modelled triggering event;
- An assessment of the expected level of pay-outs based on the model of risks for the T&D network under various scenarios;
- All contractual terms and conditions.

11.284. In addition, the proposal should include the strategy for the treatment of the EDF if parametric insurance is adopted.

DETERMINATION: # 14

The Office determines that:

a) Within six (6) months of the effective date of this Determination Notice, the OUR shall commission an audit of the EDF for the three (3) year period, 2018 - 2020.

b) The annual level of funding to the EDF for the Rate Review period shall remain at US$3M.

c) Within six (6) months of the effective date of this Determination Notice, JPS shall present a detailed proposal of the parametric insurance option available to the company and the strategy for the treatment of the EDF should parametric insurance be introduced.

d) Within three (3) months of the effective date of this Determination Notice, JPS shall provide a detailed report on how the calculations of the monthly allocations to the EDF were conducted for the period 2017 October to 2018 December. In the report, JPS should clearly indicate the basis of its calculations and the rationale for any changes in the calculation methodology.

11.6.9. JPS Managed IPP/Unregulated Expenses

11.285. JPS reported that total expenses on its unregulated assets for the base year is J$30.2M. The OUR accepts that these costs should be treated as an offset from the derived Revenue Requirement. Table 11.38 below shows the itemized amounts which are to be offset from the approved Revenue Requirement.

Table 11.38: JPS Managed IPP/Unregulated Expenses (2018 -2023)

JPS Managed IPP /Unregulated Expense (in Millions of JA Dollars)						
Description	**2018 Forecasted**	**2019**	**2020**	**2021**	**2022**	**2023**
Magotty Hydro	15	7.3	22	23.2	24	25.20
Munroe Wind Farm	15.2	15.3	12.5	12.6	13	12.90
TOTAL	**30.2**	**22.6**	**34.5**	**35.8**	**37**	**38.1**

11.286. JPS presented base year power purchase costs of US$141,480M, which is said to represent the total amount paid to IPPs for power delivered to the grid. IPP payments are made in accordance with the IPPs' respective PPAs. Currently, the non-fuel power purchase costs is an embedded component in JPS' non-fuel tariff and monthly fluctuations are addressed through adjustments to the fuel rate. However, this mechanism has a number of disadvantages and has not proven to be in sync with the various PPAs. This has led to under and over recovery of power purchase costs.

11.287. In light of the disadvantages that exist with the current treatment of power purchase costs, the OUR in section 3.7.8 of the Final Criteria specified that the non-fuel power purchase cost be decoupled from other non-fuel costs and be treated as a direct pass through on customers' monthly bills. The treatment of the IPP revenues is dealt with under **Chapter 18 – Rate Design**, of this Determination Notice.

11.288. JPS' proposed amounts and the OUR approved values are shown in Table 11.39 below.

Table 11.39: JPS Proposed Amounts and OUR's Approved IPP Payments

Revenue Requirement (J$'000')	2019		2020		2021		2022		2023	
	JPS Proposed	OUR Allowed	JPS Proposed	OUR Allowed	JPS Proposed	OUR Allowed	JPS Proposed	OUR Allowed	JPS Proposed	OUR Allowed
Purchase Power Cost (Excl. Fuel)	17,962,416	17,962,416	22,358,077	22,358,077	22,567,967	22,567,967	22,462,430	22,462,430	21,949,088	21,949,088

Annual True-Up Amounts for Foreign Exchange and Interest Charges (SFX and SIC)

11.289. Schedule 3, paragraph 55 of the Licence provides for an adjustment to JPS' non-fuel rate on an annual basis based on the anticipated foreign exchange (FX) result loss/(gain) in the Revenue Cap for the previous year, and the actual FX result incurred in the prior year related to Working Capital and Debt Service is driven by the Jamaican dollar to United States dollar foreign exchange results.

11.290. The approved amount included in the Revenue Requirement for anticipated FX result loss is J$280 million, which is an addition to the 2020 – 2023 Annual Revenue Target.

11.7. OUR Approved Revenue Requirement

11.291. After diligent analysis, the OUR approved annual Revenue Requirements for the Rate Review period are as follows:

- 2019: J$55.533 billion (US$433.9 M);
- 2020: J$57.536 billion (US$449.5 M);
- 2021: J$59.046 billion (US$461.3 M);
- 2022: J$59.024 billion (US$461.1 M);

- 2023: J$58.992 billion (US$460.9 M).

11.292. Table 11.40 shows the details of the OUR's approved Revenue Requirement for the Rate Review period.

Table 11.40: OUR's Approved Revenue Requirement (Rate Review Period)

Revenue Requirement (J$'000')	2019		2020		2021		2022		2023	
	JPS Proposed	OUR Allowed	JPS Proposed	OUR Allowed	JPS Proposed	OUR Allowed	JPS Proposed	OUR Allowed	JPS Proposed	OUR Allowed
Total Net Expenses:	**26,931,190**	**19,227,934**	**20,573,099**	**17,893,652**	**19,877,693**	**17,909,411**	**17,377,357**	**17,157,632**	**17,483,910**	**16,990,476**
Operating & Maintenance	18,679,969	18,116,424	18,394,121	17,543,569	17,878,394	17,680,822	17,708,044	17,540,980	17,487,377	17,385,666
Electric Vehicle O&M	13,803	13,803	17,544	17,544	24,252	24,252	24,252	24,252	24,252	24,252
	18,693,772	**18,130,227**	**18,411,665**	**17,561,113**	**17,902,646**	**17,705,074**	**17,732,296**	**17,565,232**	**17,511,629**	**17,409,918**
Interest Expense and Related Income:										
Interest on Short Term Loans	99,646	91,000	-	-	-	-	-	-	-	-
Interest on Customer Deposit	109,246	51,200	96,866	52,986	95,491	52,992	93,132	52,992	90,948	52,992
Interest Bank Overdraft and Late Payment	(58,660)	-	(111,859)	-	(85,250)	-	(81,123)	-	(79,501)	-
Debt Issuance Costs and Expenses	947,933	517,504	231,340	212,114	202,569	212,114	218,735	184,686	227,860	199,314
	1,098,166	**659,704**	**216,347**	**265,101**	**212,810**	**265,106**	**230,743**	**237,678**	**239,307**	**252,306**
FX Losses and Other Income and Expenses:										
Foreign Exchange Result Loss/(Gain) (TFX)	-	-	-	280,000	-	280,000	-	280,000	-	280,000
SI/EDF Contribution	256,000	384,000	256,000	384,000	256,000	384,000	256,000	384,000	256,000	384,000
Separation Costs	267,063	-	191,432	-	223,526	245,897	-	-	390,142	-
Net Stranded Assets	1,385,130	967,680	1,308,587	967,680	796,586	633,600	363,520	317,440	210,432	317,440
2016-2018 Increm Depreciation	2,939,044	98,729	-	-	-	-	-	-	-	-
2016-2018 Increm Depreciation (Smart Streetlights)		102,144								
2016-2018 Increm ROI	3,522,079	685,923	-	-	-	-	-	-	-	-
2016-2018 Increm ROI (Smart Streetlights)		100,864								
Decommissioning Cost	77,243	-	1,230,494	450,157	1,663,020	450,157	19,505	450,157	131,306	450,157
	8,446,560	**2,339,340**	**2,986,513**	**2,081,837**	**2,939,132**	**1,993,653**	**639,025**	**1,431,597**	**987,879**	**1,431,597**
Other Offsets:										
	1,307,308	**1,901,337**	**1,041,426**	**2,014,398**	**1,176,894**	**2,054,423**	**1,224,707**	**2,076,875**	**1,254,905**	**2,103,346**
Depreciation & Amortization	**8,702,464**	**8,112,452**	**8,793,872**	**6,853,463**	**9,283,492**	**7,838,354**	**9,879,834**	**8,411,636**	**10,192,056**	**8,822,039**
Income Tax	**3,730,987**	**2,322,018**	**3,809,909**	**2,367,440**	**3,884,466**	**2,435,353**	**3,985,900**	**2,495,018**	**4,025,542**	**2,548,869**
Return on Debt	**2,214,479**	**3,263,773**	**2,262,986**	**3,327,617**	**2,308,811**	**3,423,075**	**2,371,154**	**3,506,938**	**2,395,519**	**3,582,629**
Return on Equity	**4,991,494**	**4,644,732**	**5,100,831**	**4,735,590**	**5,204,122**	**4,871,437**	**5,344,646**	**4,990,784**	**5,399,565**	**5,098,502**
2018 Revenue True-Up	**636,060**	**-**								
REQUIRED REVENUE	**47,206,674**	**37,570,909**	**40,540,697**	**35,177,762**	**40,558,584**	**36,477,629**	**38,958,891**	**36,562,009**	**39,496,592**	**37,042,515**
Purchase Power Cost (Excl. Fuel)	**17,962,416**	**17,962,416**	**22,358,077**	**22,358,077**	**22,567,967**	**22,567,967**	**22,462,430**	**22,462,430**	**21,949,088**	**21,949,088**
TOTAL REVENUE REQUIREMENT	**65,169,090**	**55,533,326**	**62,898,775**	**57,535,839**	**63,126,551**	**59,045,596**	**61,421,321**	**59,024,438**	**61,445,680**	**58,991,602**

12. 2019 Revenue Target Adjustment for Annual Review

12.1. Introduction

12.1. In the 2018 Annual Review & Extraordinary Rate Review of 2018, a number of adjustments were made to JPS' tariff that went beyond the typical yearly review. These adjustments included:

- *The Accelerated Loss Reduction Incentive Mechanism (ALRIM)* - aimed at increasing the pace of JPS' loss reduction programme.
- *The Refinancing Incentive Mechanism (RIM)* - directed at supporting JPS' drive to reduce the cost of debt.
- *A Z-Factor payout* - associated with the accelerated depreciation cost incurred prior to 2018 in relation to JPS' Old Harbour Power Station and the Hunts Bay B6 plant that were slated for decommissioning by the end of 2020.
- *Accelerated Depreciation costs* - expected to be incurred by JPS over 2018-2020 as a result of the decommissioning exercise.
- *Separation costs* - expected to be incurred by the company arising from the retrenchment of staff caused by the decommissioning events.

12.2. All of these revenue adjustments were projected to take place over a one (1) year period culminating in the Rate Review exercise and the publication of new rates in 2019. However, this has not occurred. Hence, the rates approved in 2018 have remained in effect for approximately two (2) years, leading to JPS' over-recovery of the approved costs associated with each of the adjustments above.

12.3. On the other hand, the 2017 Revenue True-up was deemed to be $3.306 billion dollars, arising from system losses penalty and sales volumes in excess of the target for that year. Consequently, customers have over-recovered in their electricity rates because of the extension of the tariff regime for approximately one (1) year more than what had been intended.

12.4. In light of this, the sum over-recovered by JPS must be set-off against its under-recovery to settle the collective account of customers against JPS' account. The various components of the settling of accounts or "true-up" as it is sometimes called are discussed below.

12.2. The Accelerated Loss Reduction Mechanism (ALRIM)

<u>Background</u>

12.5. The Accelerated Loss Reduction Mechanism (ALRIM) was a special loss reduction initiative developed by the OUR, following a request by JPS in its 2018 Annual Review submission for capital support in the roll out of its SSP.

12.6. JPS indicated that it had budgeted for the installation of 100,000 smart meters in 2019, but projected that it could achieve greater loss reduction with 200,000 smart meters instead. Further, JPS suggested a reduction in the losses penalty to provide some relief that would enable it to achieve this aim.

12.7. The OUR assessed the potential for system losses over a 2-year period based on data provided by JPS and concluded that the company could achieve a loss reduction in the range of 0.84 – 1.20 percentage points if 200,000 rather 100,000 smart meters were put into service. See Table 12.1 below.

Table 12.1: Loss Reduction Projections for Smart Meter Installation

	Base 100K per year			150K per year			200K per year		
Year\Period	1st half	2nd half	**Full year**	1st	2nd	**Full year**	1st	2nd	**Full year**
2017-2018		757	**757**		757	**757**		757	**757**
2018 -2019	8,376	15,555	**23,932**	8,945	16,611	**25,556**	9,513	17,667	**27,180**
2019 -2020	9,500	13,119	**22,618**	10,351	14,294	**24,646**	12,054	16,646	**28,701**
Total (MWh)	**17,876**	**29,431**	**47,307**	**19,296**	**31 ,663**	**50,959**	**21,567**	**35,070**	**56,638**
Max %	0.38%	0.62%	**1.00%**	0.41%	0.67%	**1.08%**	0.46%	0.74%	**1.20%**
Min %	0.26%	0.44%	**0.70%**	0.29%	0.47%	**0.75%**	0.32%	0.52%	**0.84%**

12.8. It was against that background that JPS was given the option of selecting one of the two ALRIM programmes described below:

- ALRIM-1: under this option, JPS would be allowed additional revenues amounting to US$13.87M annually before tax (US$9.25M net of tax) for the 2018-2019 and 2019-2020 review periods. This was to facilitate the procurement and installation of 50,000 additional smart meters per annum. JPS' JNTL would be set at 3.60% considering the projected impact of the smart meters; or

- ALRIM-2: under this option, JPS would be allowed additional revenues amounting to US$13.87M annually before tax (US$9.25M net of tax) for 2018-2019 for the procurement of 50,000 smart meters. However, for 2019-2020, JPS could choose to spend the additional revenues in whatever way it deemed fit in its loss reduction drive and not necessarily on smart meters.

  The option also provided that in consideration of the imperative to lower system losses and for flexibility of the company to focus its attention on loss reduction, theJPS' 2019-2020 JNTL system losses target exclusively under this incentive mechanism, would be increased from 3.60% to 5.75%. This adjustment to the allowed target under ALRIM-2 would be independent of any future system losses target and should not be construed as a normal component of the system losses target process. Based on JPS' performance in 2017-2018, all other things remaining constant, the revenue effect, in this case, translated to US$9.25M before tax.

12.9. Further, it was determined that at JPS' request:

- It would be allowed to transfer the smart meter assets acquired under ALRIM to the regulatory rate base, consistent with the asset discount system established **provided that** the company achieves the system losses target established by the OUR under ALRIM over the 2018-2019 and 2019-2020 period.

- It would transfer smart meter assets acquired under ALRIM to the regulatory rate base at their NBVs if the company fails to achieve the system losses target of 1.2 percentage points established by the OUR under ALRIM over the 2018-2019 and 2019-2020 period.

12.10. In a letter dated, 2018 October 26, JPS indicated that it had opted for the ALRIM-2 package. Accordingly, the ensuing analysis is predicated on this approach.

JPS' ALRIM Proposal

12.11. Notably, even though JPS had the opportunity to transfer assets to its rate base to ALRIM-2 in exchange for a commensurate monetary reduction in its revenue requirement, this offer was not taken up.

12.12. Determination 11 of the 2018 Annual & Extraordinary Rate Review Determination Notice stipulates that even if JPS fails to achieve the system losses target, it would be allowed the "*transfer of smart meters assets acquired under ALRIM to the regulatory rate base at their net book values.*"

12.13. Having not taken up the option of having the ALRIM-2 assets included in its rate base, JPS presented the rate base off-set for the incentive programme as shown in Table 12.2 below.

Table 12.2: ALRIM-2 Rate Base Offset

JAMAICA PUBLIC SERVICE COMPANY 2019-2023 RATE REVIEW FILING ALRIM II REGULATORY OFFSET *Expressed in (USD'000)*	Total as at Dec. 31, 2018	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
ALRIM Contributions	3,468	10,403	-	-	-	-
Net Collection (Bad Debt Factor 97.5%)	3,381	10,142	-	-	-	-
Applicable Taxes 33.33%	(1,127)	(3,380)	-	-	-	-
Net ALRIM Contributions	2,254	6,762	-	-	-	-
Annual Depreciation (Straight-line 10-year life)	-	-	901.6	901.6	901.6	901.6
NBV ALRIM Assets Offset	2,254	6,762	8,114	7,213	6,311	5,410

12.14. As shown Table12.2 above, JPS' revenue forecast of ALRIM funds indicates that a total of US$9.016M was collected over the period. Hence, an equivalent amount should be removed from the rate base and the company's depreciation expense reduced by US$901,600 per annum over the 2020-2024 horizon. The smart meter has a depreciable life of 10 years, consequently the annual depreciation expense is 10% of the forecasted ALRIM funds.

12.15. Additionally, given that the ALRIM-2 expenses represent capital expenditures, JPS correctly pointed out that it attracts two types of tax benefits: a one-time investment allowance and an annual allowance. JPS computed these tax benefits to accumulate to US$1.202M over the Rate Review period as shown in Table 12.3 below.

Table 12.3: ALRIM-2 Tax Allowance Offset

	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
ALRIM Investment	9,016				
Tax Allowances:					
20% Investment Allowance	601				
20% Annual Allowance	601	601	601	601	601
ALRIM Tax Allowance Offset	1,202	601	601	601	601

The OUR's Position

12.16. As previously stated, the ALRIM programme was established to incentivize JPS in its loss reduction efforts. However, while the programme supported JPS in its acquisition of smart meters, it would appear that it had little or no effect on the actual reduction in losses. Over the period 2018 October to 2020 June, the 12-month rolling average losses indicator fell marginally from 26.48% to 26.16%, a mere 0.32% percentage point. This is well below the 1.2 percentage point target set for the 2018-2020 period.

12.17. The OUR takes the view that the advanced capabilities of the smart meters were not employed optimally to aid loss reduction activities. It is important that the functionality of smart meters be harnessed in a way that complements the use of data analytics in the development of effective strategies that will boost its system losses operations.

ALRIM Over-Recovery

12.18. The OUR's analysis of the funds collected by JPS under ALRIM-2 indicates that over the period 2018 October to 2019 the inflow amounted to US$9.263M and it is projected that the total inflows up to 2020 September was US$18.164M as shown in Table 12.4 below.

12.19. It therefore means that if JPS' ALRIM-2 collection proposal of US$9.016M is accepted, then the company would have over-recovered US$9.148M, which should be returned to customers.

Table 12.4: ALRIM-2 Inflows & Over-recovery

Month	Billed Sales	Approved ALRIM Factor	Exch. Rate		ALRIM Revenues				
			Base	Billed	Before Fx. Adj	After Fx. Adj	After Fx. Adj.	After Fx & Tax Adj.	ALRIM Inflow (97.5%)
	MWh	J$/kWh	US$/J$	US$/J$	J$'000	J$'000	US$'000	US$'000	US$'000
Sep-18	261,369	0.0000	131.00	134.65	-	-	-	-	-
Oct-18	261,697	0.5702	128.00	128.59	149,223	149,773	1,165	776	757
Nov-18	254,306	0.5702	128.00	127.79	145,009	144,818	1,133	756	737
Dec-18	251,670	0.5702	128.00	127.72	143,505	143,251	1,122	748	729
Jan-19	259,411	0.5702	128.00	136.10	147,919	155,408	1,142	761	742
Feb-19	244,540	0.5702	128.00	128.81	139,440	140,143	1,088	725	707
Mar-19	265,563	0.5702	128.00	126.47	151,427	149,976	1,186	791	771
Apr-19	258,430	0.5702	128.00	134.96	147,360	153,771	1,139	760	741
May-19	280,987	0.5702	128.00	132.82	160,222	165,050	1,243	828	808
Jun-19	277,492	0.5702	128.00	136.06	158,229	166,203	1,222	814	794
Jul-19	298,629	0.5702	128.00	136.63	170,282	179,468	1,314	876	854
Aug-19	286,235	0.5702	128.00	136.70	163,215	172,086	1,259	839	818
Sep-19	281,076	0.5702	128.00	135.16	160,273	167,444	1,239	826	805
Oct-19	281,392	0.5702	128.00	140.12	160,453	172,609	1,232	821	801
Nov-19	268,665	0.5702	128.00	135.82	153,196	160,683	1,183	789	769
Dec-19	273,512	0.5702	128.00	132.57	155,960	160,415	1,210	807	787
Jan-20	269,367	0.5702	128.00	141.22	153,597	166,288	1,178	785	765
Feb-20	254,699	0.5702	128.00	137.00	145,232	153,402	1,120	746	728
Mar-20	255,554	0.5702	128.00	135.39	145,720	152,451	1,126	751	732
Apr-20	241,179	0.5702	128.00	142.95	137,523	150,373	1,052	701	684
May-20	241,392	0.5702	128.00	143.49	137,645	150,971	1,052	701	684
Jun-20	249,807	0.5702	128.00	140.01	142,443	153,135	1,094	729	711
Jul-20	270,938	0.5702	128.00	148.01	154,492	173,813	1,174	783	763
Aug-20	266,523	0.5702	128.00	149.29	151,975	172,197	1,153	769	750
Sep-20	256,500	0.5702	128.00	142.10	146,260	159,149	1,120	747	728
Oct-18 to Sep-19	**3,220,036**				**1,836,105**	**1,887,391**	**14,250**	**9,500**	**9,263**
Oct-18 to Sep-20	**6,349,564**				**3,620,602**	**3,812,877**	**27,944**	**18,629**	**18,164**
Approved Recovery									**9,016**
Over-recovery									**9,148**
								Equivalent J$'000	**1,170,890**

Parameter/Variable	Unit	Value
Approved ALRIM	US$M	13.87
Rev.	J$M	1,775.36
2018 Sales Target	MWh	3,113,505
ALRIM Rate	J$/kWh	0.5702
Collection Factor	%	97.5%
Base Exch. Rate	J$/US$	128.00

System Losses under ALRIM

12.20. Determination 11 of the 2018 Annual & Extraordinary Rate Review Determination Notice sets out the system losses target applicable for 2019-2020. Unlike the other targets in the PBRM which are normally set one year ahead, the ALRIM-2 was set as a part of a 2-year programme. Consequently, owing to the one year delay in conducting this 2019-2024 Rate Review, the system losses targets were the only ones set.

12.21. The ALRIM-2 system losses targets established are as follows:

- Technical Losses (TL) Target: **8.00%**
- Non-Technical Losses within the control of JPS (JNTL) Target: **5.75%**
- Non-Technical Losses not fully within the control of JPS (GNTL)Target: **9.70%**
- Responsibility Factor (RF) for Non-Technical Losses to JPS' NTL that are not totally within its control: **20%**.

12.22. The system losses adjustment ($TULos_{2019}$) applicable is derived by using the formula below:

$$TULos_{y-1} = Y_{y-1} \times ART_{y-1}$$

Where;

ART_{y-1} is the Annual Revenue Target for Year 'y',
Y_{y-1} is the previous year's system losses deviation from the target.

And, $Y_{y-1} = TL + JNTL + GNTL*RF$

12.23. Given that no Annual Revenue Target was established for 2019 in performing the system losses adjustment calculation, it is assumed that the target in 2019 is exactly the same as that of 2018. Hence ART_{2019} = $48,863,083,638.

12.24. Table 12.5 shows the system losses adjustment calculation for which adjustment to JPS' Revenue Requirement is -$736,855,301. However, after adding the WACC as specified in the Licence, the adjustment required is -$834,267,572. This means that given that the JNTL target in the previous year was 3.6%, JPS has benefitted in the amount of a $1,286,852,112 reduction in system losses adjustments from ALRIM-2.

Table 12.5: ALRIM-2 System Losses Adjustment)

Variables	Unit	Target	Actual	Variance	Responsibility Factor (RF)	Applicable Adjustment Factor	Value
ART_{2019}	**$**						**48,863,083,638**
TL	%	8.00%	8.24%	-0.24%	1.0	-0.24%	(117,271,401)
JNTL	%	5.75%	6.69%	-0.94%	1.0	-0.94%	(459,312,986)
GNTL	%	9.70%	11.34%	-1.64%	0.2	-0.33%	(160,270,914)
System Losses	$						**(736,855,301)**
WACC @ 13.22%	$						**(97,412,271)**
Total Adjustment	**$**						**(834,267,572)**

DETERMINATION # 15

Based on its assessment of JPS' performance under ALRIM-2, the Office:

a) Accepts JPS' proposal with respect to its calculation of the rate base, depreciation and tax allowance off-set for the smart meters acquired under the incentive mechanism. In this regard, the following off-sets shall be applied in the derivation of the company's Revenue Requirement:

- Rate base off-set: US$9.016M
- Depreciation off-set: US$901,600 per annum over 10 years
- Tax allowance off-set: US$1.202M in 2019 and US$0.601M for the 4-year period 2020 -2023

b) Approves the reduction of JPS' Revenue Requirement by US$9.148M (or J$1,170.9M) due to its over-recovery of ALRIM-2 funds over the period 2019 October – 2020 September.

c) Approves the reduction of JPS' Revenue Requirement by J$834.267M (US$6.518M) arising from the special system losses targets that were established under ALRIM-2.

12.3. Refinancing Incentive Mechanism

Background

12.25. JPS, in its application for an Extraordinary Rate Review in 2018, requested approval for the recovery of net refinancing costs amounting to US$5.312M. The refinancing cost it proposed to recover was intended to secure a bond that it intends to use to replace US$179.19M of relatively more expensive long term debt in its portfolio.

12.26. In its response, the Office argued that the refinancing plan outlined by JPS did not qualify for an Extraordinary Rate Review. However, it took the view *"that any plausible plan that will lower cost and yield savings to customers should be encouraged"*. It was in that context that the OUR developed the RIM to assist JPS with the refinancing of the US$179.19M Bond.

12.27. Under the RIM approved by the Office, JPS was to receive an amount of US$2.66M (J$340.48M) over the 2018-2019 period. However, given that the Rate Review Process did not occur in 2019 as planned, JPS would have recovered more than the US$2.66M it was allowed under the mechanism. Consequently, to the extent to which the over-recovery occurred, the excess should be returned to customers.

The OUR's Position

12.28. Given that under the RIM mechanism JPS was allowed US$2.66M at a base exchange rate of J$128.00: US$1 and an annual sales target of 3,113,504,786 kWh, the recovery rate was J$0.10936 per kWh.

Table 12.6: Over-recovered Revenues from the Refinancing Incentive Mechanism

Month	Billed Sales	Approved Unit Refinancing Cost	Exch. Rate		Refinancing Revenues				
			Base	Billed	Before Fx. Adj	After Fx. Adj	After Fx. Adj.	After Fx & Tax Adj.	Net Inflows (97.5%)
	MWh	J$/kWh	US$/J$	US$/J$	J$'000	J$'000	US$'000	US$'000	US$'000
Sep-18	261,369		131.00	134.65	-	-	-	-	-
Oct-18	261,697	0.1094	128.00	128.59	28,618	28,724	223	149	145
Nov-18	254,306	0.1094	128.00	127.79	27,810	27,773	217	145	141
Dec-18	251,670	0.1094	128.00	127.72	27,522	27,473	215	143	140
Jan-19	259,411	0.1094	128.00	136.10	28,368	29,804	219	146	142
Feb-19	244,540	0.1094	128.00	128.81	26,742	26,877	209	139	136
Mar-19	265,563	0.1094	128.00	126.47	29,041	28,763	227	152	148
Apr-19	258,430	0.1094	128.00	134.96	28,261	29,490	219	146	142
May-19	280,987	0.1094	128.00	132.82	30,728	31,653	238	159	155
Jun-19	277,492	0.1094	128.00	136.06	30,345	31,875	234	156	152
Jul-19	298,629	0.1094	128.00	136.63	32,657	34,418	252	168	164
Aug-19	286,235	0.1094	128.00	136.70	31,301	33,003	241	161	157
Sep-19	281,076	0.1094	128.00	135.16	30,737	32,113	238	158	154
Oct-19	281,392	0.1094	128.00	140.12	30,772	33,103	236	157	154
Nov-19	268,665	0.1094	128.00	135.82	29,380	30,816	227	151	147
Dec-19	273,512	0.1094	128.00	132.57	29,910	30,764	232	155	151
Jan-20	269,367	0.1094	128.00	141.22	29,457	31,891	226	151	147
Feb-20	254,699	0.1094	128.00	137.00	27,853	29,419	215	143	140
Mar-20	255,554	0.1094	128.00	135.39	27,946	29,237	216	144	140
Apr-20	241,179	0.1094	128.00	142.95	26,374	28,839	202	134	131
May-20	241,392	0.1094	128.00	143.49	26,398	28,953	202	135	131
Jun-20	249,807	0.1094	128.00	140.01	27,318	29,368	210	140	136
Jul-20	270,938	0.1094	128.00	148.01	29,629	33,334	225	150	146
Aug-20	266,523	0.1094	128.00	149.29	29,146	33,024	221	147	144
Sep-20	256,500	0.1094	128.00	142.10	28,050	30,522	215	143	140
Oct-18 to Sep-19	**3,220,036**				**352,130**	**361,965**	**2,733**	**1,822**	**1,776**
Oct-18 to Jul-20	**6,349,564**				**694,362**	**731,237**	**5,359**	**3,573**	**3,483**
Approved Recovery									**2,660**
Over-recovery									**823**
								Equivalent J$'000	**105,399**

Parameter/Variable	Unit	Value
Approved RIM Rev.	US$M	2.66
	J$M	340.48
2018 Sales Target	MWh	3,113,505
Refinancing Rate	J$/kWh	0.1094
Collection Factor	%	97.5%
Base Exch. Rate	J$/US$	128.00

12.29. As shown in Table 12.6 above, after taking account of monthly exchange rate movements, the effect of a 33.3% income tax rate and a collection factor of 97.5%[16], the OUR's analysis indicates that over the 12-month period 2018 October to 2019 September JPS would have collected revenues amounting to US$1.77M (J$226.56M).

12.30. Additionally, it is estimated that over the 24-month period 2018 October to 2020 September, JPS would have collected US$3.48M (J$445.88M). This would represent an over-recovery of US$0.823M (J$105.4M) over the period. Accordingly, this excess of US$0.823M correctly belongs to customers and the company's revenues should be adjusted to capture the effect of the over-recovery.

DETERMINATION 16

Given that JPS over-recovered an estimated US$0.823M (J$105.4M) over the period 2018 October to the end of 2020 September in respect of the Refinancing Incentive Mechanism, the Office has determined that the company's Revenue Requirement shall be reduced by the over-recovered amount over the 2020-2021 review period.

12.4. Decommission True-Ups

12.31. Arising from the planned decommissioning of the OHPS and HB B6 generating plant, the OUR recognized that additional costs ought to be recovered by JPS in relation to:

- *Prior accelerated depreciation (Z-Factor)* - amounting to US$1,524,097 (or J$224.8M) which had been booked by JPS in 2017. This was deemed to be a Z-Factor payout.
- *Projected accelerated depreciation* - amounting to US$6,422,078 (or J$882.M) which would have been booked by JPS over the period 2018-2020. This is considered to be an Extraordinary Rate Review payout.
- *Separation costs* - approved in the amount of US$2.318M (or J$296.7M) to pay a portion of the expense that would be incurred in respect of redundant workers at the Old Harbour power station. This was also considered to be an Extraordinary Rate Review payout.

12.32. As previously pointed out, the tariff period which should have ended around 2019 June, has ran twice as long as was expected. The result is that there has been over-recoveries on the part of JPS in all three (3) areas: prior accelerated depreciation, projected accelerated depreciation and separation costs as shown in Table 12.7 below.

[16] The collection factor of 97.5% was derived from an assumed bad debt factor of 2.5%

Table 12.7: Over-recovered Revenues from Z-Factor, Accelerated Depreciation & Separation Cost

Month	Billed Sales	Adjustment Factor			Exch. Rate		Adjustment Revenue (J$)			
		Z-Factor	Accelerated Depreciation	Seperation Cost	Base	Billed	Prior Accelerated Depreciation (Z-Factor)	Projected Accelerated Depreciation	Seperation Cost	**Total**
	MWh	J$/kWh	J$/kWh	J$/kWh	US$/J$	US$/J$	J$'000	J$'000	J$'000	**J$'000**
Sep-18	261,369				131.00	134.65	-			
Oct-18	261,697	0.0627	0.2640	0.0953	128.00	128.59	16,458	69,348	25,031	**110,836**
Nov-18	254,306	0.0627	0.2640	0.0953	128.00	127.79	15,913	67,054	24,203	**107,169**
Dec-18	251,670	0.0627	0.2640	0.0953	128.00	127.72	15,741	66,328	23,941	**106,009**
Jan-19	259,411	0.0627	0.2640	0.0953	128.00	136.10	17,077	71,957	25,972	**115,006**
Feb-19	244,540	0.0627	0.2640	0.0953	128.00	128.81	15,399	64,889	23,421	**103,709**
Mar-19	265,563	0.0627	0.2640	0.0953	128.00	126.47	16,480	69,442	25,065	**110,986**
Apr-19	258,430	0.0627	0.2640	0.0953	128.00	134.96	16,897	71,199	25,699	**113,795**
May-19	280,987	0.0627	0.2640	0.0953	128.00	132.82	18,136	76,421	27,584	**122,141**
Jun-19	277,492	0.0627	0.2640	0.0953	128.00	136.06	18,263	76,955	27,776	**122,995**
Jul-19	298,629	0.0627	0.2640	0.0953	128.00	136.63	19,721	83,097	29,993	**132,811**
Aug-19	286,235	0.0627	0.2640	0.0953	128.00	136.70	18,910	79,679	28,760	**127,349**
Sep-19	281,076	0.0627	0.2640	0.0953	128.00	135.16	18,400	77,530	27,984	**123,913**
Oct-19	281,392	0.0627	0.2640	0.0953	128.00	140.12	18,967	79,921	28,847	**127,735**
Nov-19	268,665	0.0627	0.2640	0.0953	128.00	135.82	17,657	74,400	26,854	**118,910**
Dec-19	273,512	0.0627	0.2640	0.0953	128.00	132.57	17,627	74,275	26,809	**118,711**
Jan-20	269,367	0.0627	0.2640	0.0953	128.00	141.22	18,272	76,994	27,791	**123,057**
Feb-20	254,699	0.0627	0.2640	0.0953	128.00	137.00	16,856	71,028	25,637	**113,521**
Mar-20	255,554	0.0627	0.2640	0.0953	128.00	135.39	16,752	70,588	25,478	**112,818**
Apr-20	241,179	0.0627	0.2640	0.0953	128.00	142.95	16,524	69,626	25,131	**111,280**
May-20	241,392	0.0627	0.2640	0.0953	128.00	143.49	16,589	69,902	25,231	**111,722**
Jun-20	249,807	0.0627	0.2640	0.0953	128.00	140.01	16,827	70,905	25,592	**113,324**
Jul-20	270,938	0.0627	0.2640	0.0953	128.00	148.01	19,099	80,479	29,048	**128,627**
Aug-20	266,523	0.0627	0.2640	0.0953	128.00	149.29	18,922	79,731	28,778	**127,430**
Sep-20	256,500	0.0627	0.2640	0.0953	128.00	142.10	17,488	73,689	26,597	**117,774**
Oct-18 to Sep-19	**3,220,036**						**207,395**	**873,899**	**315,427**	**1,396,721**
Oct-18 to Sep-20	**6,349,564**						**418,976**	**1,765,436**	**637,221**	**2,821,632**
JPS Forecast 2019-2019							**195,084**	**822,026**	**296,704**	**1,313,814**
Over-Recovery							**223,891**	**943,410**	**340,517**	**1,507,818**
									Eqivalent US$'000	**11,780**

	Unit	**Z-Factor**	**Accelerated Depreciation**	**Seperation Cost**
Approved Amount	US$M	1.52	6.422078	2.32
	J$M	195.08	822.03	296.70
2018 Sales Target	MWh	3,113,505	3,113,505	3,113,505
Adjustment Rate	J$/kWh	0.0627	0.2640	0.0953
Base Exch. Rate	J$/US$	128.00	128.00	128.00

12.33. As shown in Table 12.7, approved amounts that JPS should have received were US$1.52M, US$6.42M and US$2.32M respectively for the Z-Factor, projected accelerated depreciation and separation costs. This translates in Jamaican dollar terms to a total of J$1,313.8M.

12.34. However, over the 24-month period, 2018 October -2020 September, the total amount received by JPS was J$2,821.6M. Hence, an over-recovery by JPS of J$1,507.8M (or US$1.78M).

12.5. 2018 True-Up Adjustment

12.35. The Licence allows for annual revenue true-ups consistent with the revenue-cap regime. The annual true-up is based on the company's performance in the previous year. The metrics used in evaluating its performance are:

- Volumes: measured in terms of number of customers, kWh sold and MVA billed.
- System losses level.
- Foreign exchange losses net of interest income.

12.36. Consequently, if the sum of the revenue linked to the factors above exceeds the revenue target in the previous year, then JPS is required to reduce the revenue allowed in the year of the review. Further, should the sum of the revenue linked to the factors above fall short of the revenue target in the previous year, then JPS is allowed revenue to increase its revenues to recover the gap. The True-up mechanism also takes the opportunity cost into account. In this regard, the final revenue True-up includes the effect of the prevailing WACC.

12.37. Based on JPS' performance in 2017, it was determined in the 2018 Annual & Extraordinary Rate Review Determination Notice that the annual true-up adjustment to JPS' 2018 revenues cap was -J$3,305.7M or -US$25.83M, inclusive of WACC. JPS' rates were therefore adjusted to facilitate the recovery of this amount over a 12-month period.

12.38. Given that the implementation of the 5-year Rate Review did not take place mid 2019 as was expected, the revenue cap mechanism has allowed customers to be compensated beyond the J$3,305.7M due.

12.39. As shown in Table 12.8 below, the total amount recovered by customers through the rates over the 24-month period, 2018 October – 2020 September was J$7,099M or US$55.46M. This means that customers collectively over-recovered J$3,793.8M (or US$29.6M) in their rates, which should be returned to JPS.

DETERMINATION 17

The Office has determined that given the delay in the implementation of the 2019-2024 Rate Review, the 2018 Revenue true-up embedded in the tariff went beyond the intended J$3,305.6M and over-compensated JPS customers in the amount of J$3,793.8M (or US$29.6M). Accordingly, this sum should be set off against JPS' Revenue Requirement to facilitate the return of the J$3,793.8M excess to the company.

Table 12.8: Customer 2018 True-up Over-recovery

Month	Billed Sales	True-up Adj.	Exch. Rate		True-up Revenues (Excl. Sys. Losses)	
			Base	Billed	Before Fx. Adj	After Fx. Adj
	MWh	J$/kWh	US$/J$	US$/J$	J$'000	J$'000
Sep-18	261,369		131.00	134.65	-	-
Oct-18	261,697	(1.0617)	128.00	128.59	(277,849)	(278,874)
Nov-18	254,306	(1.0617)	128.00	127.79	(270,002)	(269,648)
Dec-18	251,670	(1.0617)	128.00	127.72	(267,203)	(266,729)
Jan-19	259,411	(1.0617)	128.00	136.10	(275,422)	(289,365)
Feb-19	244,540	(1.0617)	128.00	128.81	(259,633)	(260,942)
Mar-19	265,563	(1.0617)	128.00	126.47	(281,954)	(279,252)
Apr-19	258,430	(1.0617)	128.00	134.96	(274,380)	(286,317)
May-19	280,987	(1.0617)	128.00	132.82	(298,330)	(307,318)
Jun-19	277,492	(1.0617)	128.00	136.06	(294,619)	(309,466)
Jul-19	298,629	(1.0617)	128.00	136.63	(317,061)	(334,164)
Aug-19	286,235	(1.0617)	128.00	136.70	(303,901)	(320,421)
Sep-19	281,076	(1.0617)	128.00	135.16	(298,424)	(311,777)
Oct-19	281,392	(1.0617)	128.00	140.12	(298,760)	(321,393)
Nov-19	268,665	(1.0617)	128.00	135.82	(285,247)	(299,188)
Dec-19	273,512	(1.0617)	128.00	132.57	(290,394)	(298,688)
Jan-20	269,367	(1.0617)	128.00	141.22	(285,993)	(309,623)
Feb-20	254,699	(1.0617)	128.00	137.00	(270,419)	(285,630)
Mar-20	255,554	(1.0617)	128.00	135.39	(271,327)	(283,859)
Apr-20	241,179	(1.0617)	128.00	142.95	(256,065)	(279,991)
May-20	241,392	(1.0617)	128.00	143.49	(256,291)	(281,103)
Jun-20	249,807	(1.0617)	128.00	140.01	(265,225)	(285,134)
Jul-20	270,938	(1.0617)	128.00	148.01	(287,661)	(323,636)
Aug-20	266,523	(1.0617)	128.00	149.29	(282,973)	(320,626)
Sep-20	256,500	(1.0617)	128.00	142.10	(272,331)	(296,331)
Oct-18 to Sep-19	**3,220,036**				**(3,418,780)**	**(3,514,274)**
Oct-18 to Sep-20	**6,349,564**				**(6,741,467)**	**(7,099,478)**
	Approved Recovery					**(3,305,674)**
	Over-recovery					**(3,793,803)**
					Equivalent US$'000	**(29,639)**

Parameter/Variabl	**Unit**	**Value**
Approved True-up	US$M	(25.83)
Rev.	J$M	(3,305.67)
2018 Sales Target	MWh	3,113,505
Volumetric Adj. Ra	J$/kWh	(1.0617)
Base Exch. Rate	J$/US$	128.00

12.6. 2019 True-Up Adjustment

12.40. In accordance with its interpretation of the targets established in the 2018 Annual & Extraordinary Rate Review Determination Notice, JPS submitted its annual revenue adjustment for 2019.

12.41. In 2016, the provisions of the Licence changed the company's performance-based ratemaking (PBRM) system from a price cap regime to one based on revenue decoupling. Consequently, for 2017 and 2018, the regulator has made annual revenue true-ups predicated on targets that were set in the previous year.

12.42. The revenue true-up mechanism may be broken down into four main components:

1. *Revenue Surcharge* (RS_{y-1}): which is comprised of:
   i. The Volumetric Adjuster ($TUVol_{y-1}$)
   ii. The System Losses Adjuster ($TULos_{y-1}$)
2. *Foreign Exchange (FX) Surcharge* (SFX_{y-1})
3. *Interest Expense Surcharge* (SIC_{y-1}); and
4. *Opportunity Cost Adjuster* (1+WACC)

Taken all together, the revenue true-up component of the PBRM may be expressed as:

$$Revenue\ True\ Up = \left(\mathrm{RS_{y-1}} + \mathrm{SFX_{y-1}} - \mathrm{SIC_{y-1}}\right) * (1 + \mathrm{WACC})$$

Where, $\mathrm{RS_{y-1}} = TUVol_{y-1} + TULos_{y-1}$

12.43. Should in any given year the actual revenue registered by JPS exceed the established revenue target, then the 'Revenue True-up', which is the difference in revenue, would be negative. As such, the company's Revenue Requirement in the following year would have to be adjusted downward by the difference. On the other hand, if the 'Revenue True-up' is positive, JPS' Revenue Requirement would have to be increased the following year to recover the revenue difference.

<u>JPS' Annual Review Proposal</u>

12.44. In its Application, JPS contends that the Licence does not explicitly prescribe an annual revenue adjustment in the fifth year of the rate review period. However, JPS stated that it had elected to make a submission given that the OUR had set performance targets in the previous year that would have been applicable in 2018. Additionally, JPS noted that presumably in the interest of regulatory efficiency, it had included the Annual Review as a part of the Application instead of placing it in a separate application.

12.45. JPS' proposal for the Annual Review adjustment indicates that a positive revenue surcharge was registered in 2018, which would require an increase of J$636.1 million (US$5.0M) in the Annual Revenue Target (ART) for 2019. The increase is explained as follows:

a) Volumetric performance adjustment of **negative J$234.6M** (US$1.8M);
b) System losses performance adjustment of **positive J$346. M** (US$2.7M);
c) Foreign exchange surcharge of **positive J$459.9M** (US$3.6M);
d) Net interest expense surcharge of **negative J$9.5M** (US$0.074M).

12.46. In an effort to incentivize JPS' loss reduction effort, the ALRIM-2 mechanism was implemented. Under this mechanism, JPS was allowed funding of capital investment in smart meters by way of an increase of the system losses target *from 3.60% to 5.75%* in

2019. In calculating its revenue adjustment for system losses in 2018, JPS assumed that this benefit was redeemable in the 2019 Annual Review.

The OUR's Position

12.47. The PBRM allows for adjustments to the Actual Revenue Target (ART_y) in the current year based on JPS' performance against targets approved by the OUR in the previous year Annual Review.

12.48. Price cap tariff regimes establish the average price of the product at the beginning of the Annual Review and there is no need for reconciliation at the end. However, under revenue decoupling the approach is different. An ART is set at the beginning of the Annual Review period and it must be compared with the actual revenue generated by the utility at the end to determine the direction and magnitude of the difference. If revenue is over-recovered, it must be returned to customers and if it is under-recovered, it ought to be recouped by the utility.

In light of this, it is only logical that there is an annual review of JPS' performance in the fifth year of a five-year rate review cycle. The decision to have an Annual Review, although not explicitly stated in the Licence is not optional, since the ART is literally the actual revenue to which the utility is entitled to in any given year.

True-Up Volumetric Adjustment ($TUVol_{2018}$)

12.49. The volumetric adjustment for any year is dependent on the variance between the target billing determinants and those that were actually achieved during that year.

12.50. For the Volumetric Adjuster ($TUVol_{y-1}$), the true-up is based on JPS' performance in the previous year against energy (kWh), demand (kVA) and number of customers. In this regard:

$$(\mathbf{TUVol_{y-1}}) = \textbf{Energy True-up + Demand True-up + Customer True-up}$$

Where:

$$\boldsymbol{Energy\ True\ Up} = \left(\frac{kWh\,Target_{y-1} - kWh\,Sold_{y-1}}{kWh\,Target_{y-1}}\right) * Non\,Fuel\,Rev\,Target\,for\,Energy$$

$$\boldsymbol{Demand\ True\ Up} = \left(\frac{kVA\,Target_{y-1} - kVA\,Sold_{y-1}}{kVA\,Target_{y-1}}\right) * Non\,Fuel\,Rev\,Target\,for\,Demand$$

$$\boldsymbol{Customer\ True\ Up} = \left(\frac{Cust.Ch.Target_{y-1} - Cust.Billed_{y-1}}{Target_{y-1}}\right) * Non\,Fuel\,Rev\,Target\,for\,Cust.Ch.$$

12.51. It was established in transitioning from the price-cap regime to the revenue-cap mechanism in the 2016 Annual Tariff Adjustment Determination Notice that the current year target for each billing determinant would be the actual billing determinant in the previous year. Hence the billing targets for 2018 are given as follows:

$kWhTarget_{2018} = kWhSold_{2017}$
$kVATarget_{2018} = kVASold_{2017}$
$\#\ Customers\ ChargesTarget_{2018} = \#\ Customers\ ChargesBilled_{2017}$

Where:

$kWhSold_{2017}$ = kWh billed in 2017

$kVASold_{2017}$ = kVA billed in 2017

Customers Charges $Billed_{2017}$= # Customers Charges Billed in 2017

12.52. The non-fuel revenue targets for energy demand and customer charge are matched to the respective components of the target billing determinants. The billing determinant targets for 2018 are the actual billing determinants for 2017. The non-fuel revenue targets for energy demand and customer charge is the product of the 2018 approved prices and the 2017 quantities for each revenue category.

12.53. Table 12.9 below shows the details of the approved ART for 2018. Consequently, the overall total ART was $48,863,083,638 and the assignment based on the tariff type was as follows:

- Energy Revenue target - $37,789,201,640
- Demand Revenue Target - $7,057,064,482
- Customer Charge Revenue Target - $4,016,817,517

Table 12.9 – Approved Annual Revenue Target: 2018[17]

		Block/ Rate	Customer Charge	Energy Rate	Demand Charge				Total Revenue
					Std.	Off-Peak	Part Peak	On-Peak	
		$'	$'	$'	$'	$'	$'	$'	$'
Rate 10	LV	--100	1,238,502,651	5,108,763,179	-				6,347,265,830
Rate 10	LV	> 100	1,816,204,152	12,146,809,442					13,963,013,594
Rate 20	LV		781,923,541	11,830,048,136	-	-	-		12,611,971,677
Rate 40	LV - Std		142,458,752	3,864,330,748	4,018,069,688	-	-	-	8,024,859,188
Rate 40	LV - TOU		9,556,439	654,822,795	-	23,037,275	234,907,848	237,141,577	1,159,465,935
Rate 50	MV - Std		9,745,191	1,127,870,157	1,124,435,611	-	-	-	2,262,050,959
Rate 50	MV - TOU		1,964,418	290,755,475	-	14,224,078	129,183,166	122,628,993	558,756,130
Rate 70	MV - Std		1,593,905	951,038,704	976,593,382	-	-	-	1,929,225,991
Rate 70	MV - TOU		314,587	162,298,583	-	8,312,110	80,535,459	87,995,293	339,456,032
Rate 60	LV		14,553,880	1,652,464,422	-	-	-	-	1,667,018,302
TOTAL			**4,016,817,516**	**37,789,201,641**	**6,119,098,681**	**45,573,463**	**444,626,473**	**447,765,863**	**48,863,083,638**

12.54. As shown in Table 12.10 below, the volumetric adjustment required based on 2018 billing performance is $234.6 million (i.e. US$1.8M). This is attributable to surcharge adjustments for Energy, Demand and Customer charge of $107.2 million, $54.1 million and $73.3 million.

[17] See *Jamaica Public Service Company Limited Annual Review 2018 & Extraordinary Rate Review Determination Notice* Doc. No: 2018/ELE/018/DET.004.

Table 12.10 – Computation of the Volumetric Adjustment

Volumetric Adjustment $TUVol_{2018}$			
Line	**Description**	**Formula**	**Value**
	Energy Surcharge		
L1	kWh $Target_{2018}$		**3,113,504,786**
L2	kWh $Sold_{2018}$		3,122,336,893
L3	Revenue Target for Energy		**37,789,201,640**
L4	kWh Surcharge	(L1-L2)/L1*L3	(107,196,964)
	Demand Surcharge		
L5	kVA $Target_{2018}$		**5,288,413**
L6	kVA $Sold_{2018}$		5,328,991
L7	Revenue Target for Demand		**7,057,064,482**
L8	kVA Surcharge	(L5-L6)/L5*L7	(54,148,714)
	Customer Count Surcharge		
L9	#Customer Charges Billed $Target_{2018}$		**639,615**
L10	#Customer Charges $Billed_{2018}$		651,280
L11	Revenue Target for Customer Charges		**4,016,817,517**
L12	Customer Charges Surcharge	(L9-L10)/L9*L11	(73,254,732)
L13	**$TUVol_{2018}$**	**L4+L8+L12**	**(234,600,410)**

True-Up System Losses Adjustment ($TULos_{2018}$)

12.55. In computing the system losses true-up ($TULos_{2018}$), the disaggregation of the system losses into its three (3) established components (i.e. TL, JNTL and GNTL) is required.

Where:

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

12.56. Each component of system loss is measured against a target that is established by the OUR as shown in the following equations:

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

Where:

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

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

$Yy\text{-}1 = Ya_{y-1} + Yb_{y-1} + Yc_{y-1}$

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

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

12.59. As mentioned earlier, the ALRIM mechanism was introduced by the 2018 Annual & Extraordinary Rate Review Determination Notice to (i) facilitate the funding of capital investment in smart meters, (ii) provide an incentive for JPS to effectively use the smart meters to reduce losses, and (iii) reward the company for positive results. ALRIM was programmed to span a two (2) year period.

12.60. Under ALRIM, JPS was allowed to select one (1) of two (2) versions of the incentive mechanism:

> ***ALRIM-1****: would provide JPS with additional revenues amounting to US$13.87M annually before tax (US$9.25M net of tax) for the 2018-2019 and 2019-2020 review periods. This was to facilitate the procurement and installation of 50,000 additional smart meters per annum.*
> ***ALRIM-2****: is identical to ALRIM-1 for the 2018-2019 review periods. However, for the* ***2019-2020 review period*** *[Emphasis Added] instead of being specifically allowed additional revenues of US$13.87M annually before tax (US$9.25M net of tax), JPS' non-technical* ***(JNTL)*** *target losses over which it is deemed to have control would be increased from 3.60% to 5.75%.*

12.61. It is important to note that in a letter to the OUR dated 2018 October 26, JPS indicated that it had opted for ALRIM-2. In this regard, the system losses targets applicable in the ***2018-2019 Annual Review period*** *[Emphasis Added]* are:

- *Technical Losses (TL) Target: 8.00%;*
- *Non-Technical Losses within the control of JPS (JNTL) Target: 5.75%;*
- *Non-Technical Losses not fully within the control of JPS (GNTL)Target: 9.70%;*
- *Responsibility Factor (RF) for Non-Technical Losses to JPS's NTL that are not totally within its control: 20%.*

12.62. However, in JPS' Annual Review submission the company assumed that the JNTL target for 2018 should have been 5.75% instead of 3.6%.

12.63. Apparently, the source of this incorrect application of the target in JPS' submission may have been the company's interpretation of the 2018 Annual & Extraordinary Rate Review Determination Notice. In paragraph 7.3.3 item b) of the 2018 Annual & Extraordinary Rate Review Determination Notice, the OUR inadvertently referenced the 2018-2019 JPS' JNTL to be increased from 3.6% to 5.75% instead of the 2019-2020 JNTL target. However, this was correctly stated in Determination 11. Also, the reference to "*the 2018-2019 Annual Review period*" in Determination 11 item (v) should instead be "**the 2019-2020 Annual Review period.**"

12.64. This anomaly was picked up by JPS and was communicated to the OUR by way of email dated 2018 October 04 stating that "*The JPS team have been reviewing the Annual Determination and from a quick review have identified one anomaly. Determination 11 part V on Page 83 has indicated that the targets are for the 2018-19 Review period. We believe this should be for the 2019-20 review period.*

12.65. In response the OUR on 2018 October 08 confirmed JPS' observations and emphasized that; "*This means that those targets will be applied at the '2019-2020' rate adjustment exercise which coincides with the 5-year Rate Review. Accordingly, this would provide the additional funding by way of the True-up over 2019-2020 to put into place the system losses strategies required to achieve the target at the end of 2020.*"

Table 12.11– JPS System Losses Spectrum as at 2018 December 31 (Submitted 2019 April 29)

JPS ENERGY LOSS SPECTRUM

December 2018
(All figures in MWh unless otherwise stated)

Transmission Network	2.24%
Primary Distribution Network	3.10%
Secondary Distribution Network	2.90%
Technical Losses	8.24%
Billed Customers & Internal Losses	8.01%
Illegal Users	10.02%
Non-Technical Losses	18.03%
Technical Losses	8.24%
Non-Technical Losses	18.03%
System Losses	26.27%

Category		Average Monthly Cust./Cons.	Net Generation	Billed Sales	Energy Loss	
					Loss	Total %
Billed Customers	Streetlight/Stoplight (R60)	476	-	96,925	325	0.01%
	Wholesale Tariff (R70)	23	-	272,117	-	-
	Large C&I (R50)	133	-	414,411	3,178	0.07%
	Large C&I (R40)	1,839	-	763,723	15,812	0.36%
	Medium C&I (rate 20)	6,536	-	371,023	17,110	0.39%
	Small C&I (rate 20)	60,497	-	227,115	9,812	0.23%
	Residential (rate 10)	581,524	-	1,066,228	266,745	6.12%
SUBTOTAL BILLED CUSTOMERS		651,028	-	3,211,542	312,983	7.19%
Other Non-Technical	Illegal Users (Non-Customers)	180,000	-	-	436,333	10.02%
	Internal Losses	-	-	-	35,913	0.82%
SUBTOTAL NON-TECHNICAL		831,028		3,211,542	785,229	18.03%
Technical Losses		-	-	-	358,764	8.24%
GRAND TOTALS		831,028	4,355,535	3,211,542	1,143,993	26.27%

Source: *JPS 2019 April 29 Submission to OUR*

12.66. Notwithstanding, JPS proposed an increase in the JNTL target from 3.60% to 5.75% for the 2018-2019 Annual Review period. The OUR therefore has corrected the JNTL target in JPS' submission to 3.60% for the 2018-2019 Annual Review period as was intended in the 2018 Annual & Extraordinary Rate Review Determination Notice.

12.67. It was established in the 2014-2019 Tariff Review that the Electricity Losses Spectrum (ELS) at December of subsequent years would be the foundation for assessment of system losses. This position was maintained even after the Licence became effective. It therefore holds that for the 2019-2020 Annual Review period, system losses would be evaluated with the utilization of the 2018 December ELS.

12.68. In keeping with the required periodic regulatory reporting practice, JPS submitted its 2018 December ELS via email on 2019 April 29 as represented in Table 12.11 above.

12.69. However, in its Application, JPS presented a revised 2018 December ELS, which it used as the basis to compute its proposed System Losses Adjustment ($TULoss_{2018}$). In the revised ELS, JPS altered the allocations for TL, JNTL and GNTL (See revised ELS in Table 12.12 below). The adjustments were made without prior consultation or approval of the OUR.

Table 12.12 – Revised JPS System Losses Spectrum as at 2018 December 31 (Submitted 2019 December 30)

JPS ENERGY LOSS SPECTRUM

December 2018

(All figures in MWh unless otherwise stated)

Transmission Network	2.24%
Primary Distribution Network	2.80%
Secondary Distribution Network	2.90%
Technical Losses	7.94%
Billed Customers & Internal Losses	8.01%
Illegal Users	10.32%
Non-Technical Losses	18.33%
Technical Losses	7.94%
Non-Technical Losses	18.33%
System Losses	26.27%

Category		Average Monthly Cust./Cons.	Net Generation	Billed Sales	Energy Loss	
					Loss	Total %
Billed Customers	Streetlight/Stoplight (R60)	476	-	96,925	325	0.01%
	Wholesale Tariff (R70)	23	-	272,117	-	-
	Large C&I (R50)	133	-	414,411	3,178	0.07%
	Large C&I (R40)	1,839	-	763,723	15,812	0.36%
	Medium C&I (rate 20)	6,536	-	371,023	17,110	0.39%
	Small C&I (rate 20)	60,497	-	227,115	9,812	0.23%
	Residential (rate 10)	581,524	-	1,066,228	266,745	6.12%
SUBTOTAL BILLED CUSTOMERS		**651,028**	-	**3,211,542**	**312,983**	**7.19%**
Other Non-Technical	Illegal Users (Non-Customers)	180,000	-	-	449,400	10.32%
	Internal Losses	-	-	-	35,913	0.82%
SUBTOTAL NON-TECHNICAL		**831,028**		**3,211,542**	**785,229**	**18.33%**
Technical Losses		-	-	-	354,698	7.94%
GRAND TOTALS		**831,028**	**4,355,535**	**3,211,542**	**1,143,993**	**26.27%**

Source: *JPS 2019 December 30 Submission to OUR*

12.70. Notably, the overall system losses in both spectrums remained constant at 26.27%. However, as shown in Table 12.13 below, the allocations in the categories TL, JNTL and GNTL in the revised ELS were changed, shifting more of the losses away from the category that JPS is totally responsible for (JNTL) to the category for which it has partial responsibility (GNTL).

12.71. Given that the target for the reduction of system losses was set on the basis of how the allocations in the 2018 December ELS submitted on 2019 April 29 was derived, the OUR rejects the revised 2018 December ELS submitted on 2019 December 30 for use in the computation of $TULos_{2018}$. Consequently, with the use of the ELS, which was submitted on 2019 April 29, the OUR's computation of the 2019 system losses adjustment as shown in Table 12.4 below is -$1,787.4 million (-US$14.0 million).

Table 12.13 – Comparison of 2018 December ELS submitted 2019 April 29 and 2019 December 30

System Losses for JPS 2019 Annual Adjustment					
Component	JPS Loss Performance as at December 2018		Target	Achievement	
	ELS Submitted 2019 Dec. 30	ELS Submitted 2019 April 29	Set using JPS 2018 data	OUR	JPS
TL	7.94%	8.24%	8.00%	-0.24%	0.06%
JNTL	4.22%	6.69%	3.60%	-3.09%	-0.62%
GNTL	14.11%	11.34%	9.70%	-1.64%	-4.41%
RF			20%		

Table 12.14 – Computation of the 2019 System Losses Adjustment

System Losses Adjustment ($TULos_{2018}$)			
Line	**Description**	**Formula**	**Value**
L14	Actual TL_{2018}		**8.24%**
L15	Target TL_{2018}		**8.00%**
L16	Ya_{2018}	(L15-L14)	-0.24%
L17	Actual $JNTL_{2018}$		**6.69%**
L18	Target $JNTL_{2018}$		**3.60%**
L19	Yb_{2018}	(L18-L17)	-3.09%
L20	Actual $GNTL_{2018}$		**11.34%**
L21	Target $GNTL_{2018}$		**9.70%**
L22	RF		**20.00%**
L23	Yc_{2018}	(L21-L20)*L22	-0.3280%
L24	Y_{2018}	L16+L19+L23	-3.66%
L25	ART_{2018}		48,863,083,638
L25	**$TULos_{2018}$**	**L24*L25**	**(1,787,411,599)**

<u>Foreign Exchange and Interest Surcharges (SFX_{2018} - SIC_{2018})</u>

12.72. Paragraph 31, Schedule 3 of the Licence makes provision for JPS to make adjustments to the revenue requirement for foreign exchange (FX) loss/ gain), provided they are deemed to be prudently incurred costs which are not directly associated with investments in capital plant and other operating costs.

12.73. The Annual Adjustment mechanism described in Exhibit 1 of the Licence, includes the true-up for FX losses (FX surcharge), which is offset by an interest surcharge on customer arrears. No provisions were made in the revenue requirement of the 2014-2019 Determination Notice for FX losses. Hence, the true-up to the 2018 revenue requirement is computed as though the target was set at zero.

12.74. For the 2019 Annual Adjustment computation, the FX surcharge is computed as the actual FX loss incurred during the year 2018. Similarly, the interest surcharge is calculated as the actual net interest expense/(income) (including net late payment fee).

12.75. In its 2018 Audited Financial Report, JPS stated that it suffered FX losses in the amount of $459.9 million. Actual net interest income based on the distribution of the payments made and credit balances applied to the interest charge for commercial and government accounts was reported as $123.3 million and net late payment fee for 2018 was reported as $132.8 million.

12.76. Based on the foregoing assumptions, the OUR's computation for the 2018 true-up for FX and Interest Surcharge is J$450.4 million (US$3.5 million). The computation is shown in Table 12.15 below.

Table 12.15 – Computation of the FX and Interest Surcharge

FX and Interest Surcharge for 2018 (SFX_{2018} - SIC_{2018})			
Line	**Description**	**Formula**	**Value**
	FX Surcharge		
L1	TFX_{2018}		-
L2	AFX_{2018}		459,901,824
L3	**SFX_{2018}**	**L2-L1**	**459,901,824**
	Interest Surcharge		
L4	Actual net interest expense/(income) in relation to interest charged to customers for 2018		(123,326,720)
L5	Actual Net Late Payment fees for 2018		132,803,712
L6	AIC_{2018}	L4+L5	9,476,992
L7	TIC_{2018}		-
L8	**SIC_{2018}**	**L6-L7**	**9,476,992**
L9	**SFX_{2018} - SIC_{2018}**	**L3-L8**	**450,424,832**

12.77. In accordance with the Licence the WACC is to be applied as an opportunity cost adjustment to the 2018 true-ups. The applicable WACC for the 2019 Annual Adjustment is 13.22%, which is the WACC that was set by the OUR in the 2014-2019 Determination Notice. As shown in Table 12.16 below the total revenue true-up amount for 2018, adjusted for the opportunity cost, is $1,779.4 million. This represents a net reduction to the overall 2019 ART instead of the $636.06 million increase proposed by JPS.

Table 12.16 – Computation of the 2018 Revenue True-Up

2018 Revenue True-Up				
Line	**Description**	**Formula**	**JPS Value**	**OUR Value**
L1	Revenue Surcharge 2018 (RS_{2018} = $TUVol_{2018}$ +$TULos_{2018}$)		111,366,123	(2,022,012,009)
L2	FX and Interest Surcharge (SFX_{2018} - SIC_{2018})		450,424,832	450,424,832
L3	WACC		13.22%	13.22%
L4	**2018 Revenue True-Up**	**(L1+L2)x(1+L3)**	**636,059,720**	**(1,779,351,002)**

DETERMINATION # 18

Consistent with the methodology outlined in the Licence, the Office has determined that JPS' Revenue true-up for 2018 shall be:

a) -$1,571,587,177 before the application of the opportunity cost (or WACC)

b) -$1,779,351,002 inclusive of the opportunity cost (or WACC)

Consequently, the 2018 Revenue True-up will result in **a reduction of $1,779,351,002 in JPS' Annual Revenue Target for 2019.**

12.7. 2020 Overall Revenue True-up

12.78. An examination of the various items that necessitates adjustment to JPS' 2020 Revenue Requirement reveals that JPS over-recovered a total of J$3,618.4M. However, on the other hand, when the $3,793.8M overcompensation to customers from the 2018 true-up is netted against the 2019 Revenue True-up of -J$1,779.4M, the result shows that JPS has under-recovered J$2,014.5M as shown in Table 12.17 below.

12.79. Given that JPS registered an over-recovery of J$3,618.4M (based on items in the *2018 Annual & Extraordinary Rate Review Determination Notice)* and an under-recovery of J$2,014.5M from its 2018 and 2019 annual true-ups, the net effect is that the company has over-recovered J$1,603.9M.

Table 12.17 – Computation of the 2018 Revenue True-Up

Over/Under-Recovery	J$'000
ALRIM: Payment Over-recovery	1,170,890
AlRIM: System Losses Adjustment	834,268
Bond Refinancing Incentive Mechanism	105,399
Z-Factor	223,891
Accelerated Depreciation (2018-2020)	943,410
Separation Cost	340,517
Total Over-recovery (JPS)	**3,618,375**
2018 Revnue True-up Under-recovery	3,793,803.00
2019 Revene True-up	(1,779,351.00)
Total Under-recovery (JPS)	**2,014,452.00**
Net Over-recovery	**1,603,923**
2002 Sales Target (MWh)	3,067,886
2020 True-up Rate ($/kWh)	**0.523**

12.80. Therefore, JPS' 2020 Revenue Requirement should be reduced by J$1,603.9M to clear the balance due to customers. Given that the forecasted sales for 2020 is 3,067,886 MWh, then JPS' average tariff should be adjusted by J$0.523 per kWh.

DETERMINATION # 19

The Office has determined that given that the net over-recovery by JPS with respect to the decisions in the 2018 Annual & Extraordinary Rate Review Determination Notice and the 2019 Annual True-up is J$1,603.9M, JPS' average Non-fuel tariff shall be reduced by J$0.0523 per kWh in the 2020 review period to restore the balance.

13. Fuel Recovery Heat Rate Target

13.1. Introduction

13.1. A significant portion of JPS' operating expenses is related to the cost of fuel consumed by JPS and IPPs power generating plants for the production of electricity, which JPS supplies to its consumers subject to its obligations under the Licence.

13.2. The total monthly fuel cost is largely dependent on the following factors:

1) The price of fuel consumed by JPS' and IPPs' generating plants;
2) The fuel conversion efficiencies (Heat Rates) of JPS' and IPPs' generating plants;
3) The total net generation (MWh) for the month;
4) The proportion of electricity generation from the various generating plants utilized in the production process; and
5) The efficacy of the generation dispatch process.

13.3. The total fuel cost therefore varies from month to month based on changes in the above factors. The monthly total fuel costs incurred by JPS are used to derive the monthly Fuel Rates (J$/kWh) in accordance with the Fuel Cost Adjustment Mechanism (FCAM) as defined by the Licence. For a given billing period, the derived Fuel Rate is used to bill customers to allow JPS to recover the total fuel cost (net of efficiency adjustment), incurred for that period.

13.1.1. Fuel Cost Adjustment Mechanism

The advantage of the FCAM is that it permits the utility to recover major costs over which it has little control.

<u>JPS' FCAM</u>

13.4. The FCAM (mathematically represented below) has been in effect since 2016 July 1. The mechanism includes a Heat Rate Factor (H-Factor) which allows the efficient pass-through of fuel expenses. As designed, the FCAM also provides a reasonable incentive to JPS to improve its operational efficiency and minimize generation cost through optimal merit order practices and economic generation dispatch, subject to the relevant provisions of the EA, the Licence and the Electricity Sector Codes.

$$\textit{Pass Through Costs} = \textit{IPPs Fuel Cost} + \left(\textit{JPS Fuel Cost} \times \overbrace{\frac{\textit{JPS Heat Rate Target\_Thermal}}{\textit{JPS Heat Rate Actual\_Thermal}}}^{\textit{Heat Rate Factor}} \right)$$

[OUR Approved FCAM: (2015 February – 2020 Determination Notice)]

13.5. This fuel cost adjustment formula allows JPS to recover its monthly fuel costs on a dollar-for-dollar basis, subject to efficiency adjustments by the Heat Rate Factor, through the monthly Fuel Rates. With respect to Heat Rate performance, the embedded incentive mechanism innately delivers financial benefits or penalties to the extent that there is any over-achievement or under-achievement of the determined Heat Rate target, respectively.

13.1.2. Heat Rate - Definition

13.6. The Heat Rate parameter is a function of the operation of the generation plants connected to the grid, but can be impacted by constraints on the transmission network in the generation dispatch process.

13.7. In general, Heat Rate is a common measure of the technical efficiency of a thermal power plant or generating unit. Specifically, it involves the amount of fuel energy input used by a generating unit or power plant to generate one (1) kWh of electricity, which is represented in the equation below.

$$\boldsymbol{Heat\ Rate}(\boldsymbol{KJ}|\boldsymbol{kWh}) = \frac{\boldsymbol{Energy\ Input}\ (\boldsymbol{KJ}|\boldsymbol{h})}{\boldsymbol{Power\ Output}\ (\boldsymbol{kW})}$$

13.8. The average Heat Rate of a generating unit is determined based on its operation, subject to its "Input – Output" curve.

13.9. The System Heat Rate relates to the average Heat Rate of the generation system for a specified period of operation, and is dependent on the average Heat Rate and Net Energy Output (NEO) of each generating unit dispatched.

13.1.3. Methodology for Determining Heat Rate Parameters for H-Factor

13.10. At the 2014-2019 Tariff Review, the OUR's assessment of the system Heat Rate (applicable for the previous 5-year rate period), revealed that the construct based on the System Heat Rate resulted in unwarranted benefits flowing to JPS due to the inclusion of the net generation from IPPs' thermal plants and renewable energy (RE) generation in the calculation. As a result, the 2014-2019 Determination Notice discontinued the System Heat Rate approach and established Heat Rate targets based exclusively on JPS' combined thermal generation plants. This approach was codified in the Licence at paragraph 40, Schedule 3, which provides as follows:

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

13.1.4. H-Factor

13.11. As defined under paragraph 46 b., Schedule 3 of the Licence, the H-Factor, if applicable, will reflect the Heat Rate as defined by the Office, of power generated by the generating system versus a pre-established yearly target in the 5-year rate setting determination by the Office. From this definition, the mathematical translation is as follows:

$$\boldsymbol{H - Factor} = \frac{\boldsymbol{Heat\ Rate\ Target}}{\boldsymbol{Heat\ Rate\ Actual}}$$

13.1.5. Regulatory Objectives and Approach

13.12. In light of the major developments in the generation system in 2019 and early 2020, as well as generation developments expected during the Rate Review period, a comprehensive regulatory review of the fuel component of JPS' rate structure is merited. Accordingly, the OUR's review encompasses the evaluation of the existing FCAM, JPS' historical/projected Heat Rate performance, and proposed H-Factor targets. This assessment is considered critical for ensuring that fuel costs to be recovered due to electricity production from JPS' and IPPs' generation facilities during the Rate Review period, are prudent, reasonable and achievable.

<u>Review Scope</u>

13.13. To achieve this goal, the following approaches have been adopted by the OUR:

1) Determine the regulatory objectives and priorities;
2) Select the Heat Rate methodology to be applied;
3) Evaluate JPS' historical Heat Rate Performance;
4) Evaluate JPS' Heat Rate proposals;
5) Determine the FCAM to be applied;
6) Set the Heat Rate targets for the application of H-Factor; and
7) Establish the framework for monitoring and reviewing performance.

13.2. Regulatory Principles for Setting Heat Rate Targets

13.14. The Heat Rate target is an essential efficiency measure to permit the efficient pass-through of fuel costs incurred by JPS, to its customers. The target is set by the OUR on a periodic basis to ensure that ratepayers are provided with reasonable, prudent and efficient Fuel Rates. In addition to the efficiency improvement goals, another strategic objective of the Heat Rate target is to encourage JPS to consistently optimize its generation operations to ensure the minimization of total operating costs.

13.15. In recognition of these objectives, the OUR has adopted the following principles to guide the setting of the Heat Rate targets for JPS:

1) The targets should hold JPS accountable for the factors which are under its direct control;
2) The targets should encourage optimal generation dispatch of the available generating units to minimize the total cost of electricity generation;
3) The targets should take into account legitimate system constraints provided that JPS is taking reasonable action to mitigate these constraints;
4) The targets should normally be set at the Rate Review and reviewed at each Annual Review, and adjusted as applicable, to reflect changes in system configuration and on-going efficiency improvements; and
5) The targets should be reasonable and achievable and consistent with the configuration and capability of the system during the target period.

13.2.1. Final Criteria: H-Factor

13.16. Regarding JPS' Heat Rate requirements for this 2019-2024 Rate Review, Criterion 14 of the Final Criteria provides as follows:

Criterion 14

In the 2019 – 2024 Rate Review application, JPS shall submit the following:

a) The projected annual Heat Rate performance, and proposed annual targets for each 12-month period (June – May) of the Rate Review period**.**

b) Supporting documentation, calculations and relevant data to substantiate its Heat Rate projections and proposed targets.

13.17. Additionally, the specific information requirements pertaining to the Heat Rate for this 2019-2024 Rate Review, are specified in Annex 4 of the said Final Criteria.

13.3. Overview of Generation System Performance (2015-2020)

13.3.1. Energy Supply Mix

13.18. Based on the generating system's energy statistics, the primary energy sources being used for the production of electricity, are:

1) Natural Gas (NG);
2) Heavy Fuel Oil (HFO);
3) Automotive Diesel Oil (ADO);
4) Renewable Energy (RE) sources.

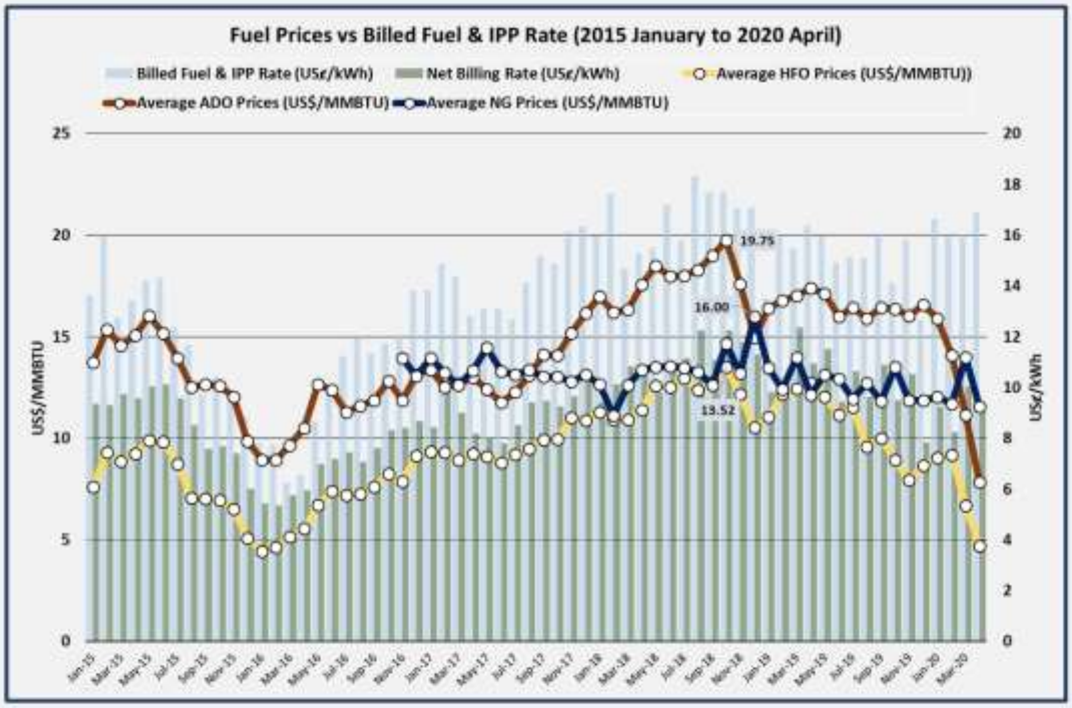
13.3.2. Fuel Price Dynamics

13.19. Despite the energy diversification strategy, the electricity sector remains largely dependent on imported fossil fuels (fuel oil and NG) for electricity production. Although the exposure to fuel price volatility may be lower with the fuel mix, the risk is still high. With the recent introduction of NG, the pricing mechanisms in the gas supply agreements (GSAs) appear to provide for more stable prices. Nevertheless, based on the fuel supply logistics and market conditions, the prices of these fuels are largely outside the control of JPS and the IPPs.

13.20. As shown in Figure 13.1 below, fuel oil prices have exhibited significant fluctuations during the 2015-2019 timeframe. In the case of HFO supplied to JPS' generating plants, its average prices over the period have fluctuated between US$42.54/Barrel and US$75.41/Barrel. During the same period, ADO prices also varied widely between a low of US$65.84/Barrel and a high of US$102.52/Barrel. In contrast, plant gate prices for NG (US$/MMBTU) since its introduction to the energy mix in 2016, have been fairly steady, at around US$13/MMBTU. For illustration, the plot in Figure 13.1 below, shows the relative movement in the monthly fuel prices over the period, with the highest recorded average monthly price for each fuel type indicated.

Figure 13.1: Average Price of Fuels used for Electricity Generation (2015-2019)

Year	Avg. HFO Prices		Avg. ADO Prices		Avg. NG Prices	Avg. Fuel & IPP Charge	Avg. Net Billing Rate
	US$/BBL	US$/MMBTU	US$/BBL	US$/MMBTU	US$/MMBTU	US¢/kWh	US¢/kWh
2015	50.36	8.01	79.39	13.63	-	12.26	8.74
2016	42.54	6.77	65.84	11.30	13.50	9.94	7.02
2017	60.35	9.60	78.45	13.39	13.28	14.28	8.99
2018	75.41	12.00	102.52	17.60	13.34	16.66	10.96
2019	67.19	10.69	96.35	16.54	12.65	15.10	10.28
2020 (Jan – Apr)	46.54	7.40	71.31	12.24	12.33	16.39	9.16



13.3.3. System Fuel Cost

13.21. JPS' Fuel Reports indicate that the total fuel cost attributable to the use of HFO, ADO and NG, for grid electricity generation during the period 2015 January – 2020 April, was approximately J$272.9 billion, with each fuel type accounting for J$187.6 billion, J$32 billion and J$53.3 billion, respectively as shown in Table 13.1 below.

Table 13.1: System Fuel Cost by Fuel Type (2015-2020 April)

SYSTEM FUEL COST BY FUEL TYPE 2015 – 2020 APRIL					
Year	HFO (J$'000)	ADO (J$'000)	NG (J$'000)	Total (J$'000)	NG Cost % of Total
2015	29,983,086	13,088,050	-	43,071,137	-
2016	28,090,363	9,066,075	1,772,394	38,928,832	**4.6%**
2017	38,040,655	2,751,564	9,389,357	50,181,577	**18.7%**
2018	45,572,946	3,187,005	13,291,431	62,051,382	**21.4%**
2019	40,937,349	3,658,726	16,352,974	60,949,050	**26.8%**
2020 Jan-Apr	5,005,858	294,503	12,453,183	17,753,544	**70.1%**

13.22. The data indicates that total NG cost relative to the total fuel cost has progressively increased from less than 10% in 2016 (inception) to over 70% at present reflecting the increased usage of the fuel type.

Contribution of JPS' and IPPs' Generation to Total Fuel Cost

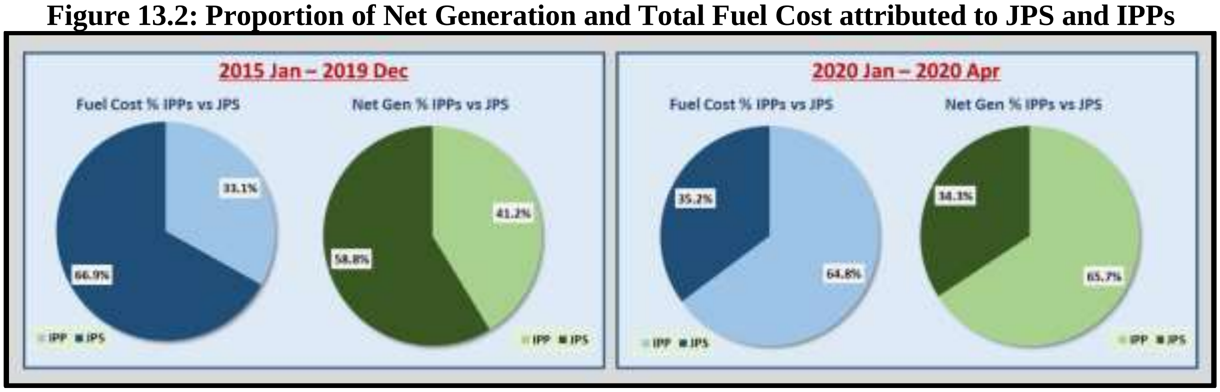
13.23. The historical generation data indicates that during the 2015-2019 period, the relative contributions of JPS and IPPs net generation to the annual total fuel costs remained fairly constant at around 67% and 33% respectively, as shown in Table 13.2 below. However, there has been almost a complete reversal of these proportions during the first four (4) months of 2020. This reversal has been explained by the introduction of new IPP capacity since late 2019.

Table 13.2: Contribution of JPS and IPP Generation to Total Fuel Cost

YEAR	FUEL COST				NET GENERATION			
	IPP (J$'000)	JPS (J$'000)	IPP %	JPS %	IPP (MWh)	JPS (MWh)	IPP %	JPS %
2015	13,667,164	29,403,973	31.7%	68.3%	1,679,413	2,529,909	39.9%	60.1%
2016	12,083,181	26,845,651	31.0%	69.0%	1,592,028	2,469,233	39.2%	60.8%
2017	16,635,376	33,546,200	33.2%	66.8%	1,698,830	2,477,695	40.7%	59.3%
2018	20,527,609	41,523,774	33.1%	66.9%	1,795,132	2,560,404	41.2%	58.8%
2019	21,541,407	39,407,643	35.3%	64.7%	1,990,338	2,439,493	44.9%	55.1%
2020 (Jan-Apr)	11,507,539	6,246,005	64.8%	35.2%	916,184	477,672	65.7%	34.3%

13.24. In terms of costs, this net generation allocation translates to average annual fuel costs of approximately US$268 million and US$132M, apportioned to JPS and IPPs, respectively. However, with the addition of new IPP generation capacity to the system since late 2019 to early 2020, coinciding with the closure of the OHPS, this orientation has dramatically shifted as illustrated in Figure 13.2 below.

Figure 13.2: Proportion of Net Generation and Total Fuel Cost attributed to JPS and IPPs



13.25. For system annual net generation reported for 2015-2019, although the IPPs accounted for approximately 33% of the annual total fuel cost, their corresponding contribution to total net generation was just over 41% on average. This suggests that the utilization of IPP generation facilities during the period, delivered some economic value to the system.

13.3.4. Fuel & IPP Charge

13.26. The Fuel & IPP Charge is calculated each month on a US¢/kWh basis by JPS and represents the total cost of fuel (JPS and IPPs fuel cost) required for producing and supplying each kWh of electricity to the system. It also includes an amount for the difference between the IPP costs included in the base non-fuel charges, and the actual IPP non-fuel costs payable and/or paid by JPS. The annual average Fuel & IPP Charges reported by JPS for the period 2015 January - 2020 April, are presented in Figure 13.1 above.

13.27. As shown in Figure 13.1 above, the monthly Fuel & IPP Charge varied significantly from month to month during the 64-month period, with a profile that appears to track the movement in fuel prices. The variations in the Fuel Rate were mainly due to fluctuations in input fuel prices, generation dispatch profile, and electricity sales volumes recorded for each billing month. The highest and lowest Fuel & IPP Charges applied over the period, were 18.3 US¢/kWh (2018 August) and 6.2 US¢/kWh (2016 March), respectively. To put things into perspective, the current Fuel & IPP Charge represents approximately 56% of the average residential customer's electricity bill.

Net Billing Rate

13.28. Similar to the Fuel & IPP Charge, the average Net Billing Rate used for energy payments to Net Billing customers/Self-generators, for excess energy supplied to the grid (governed by Standard Offer Contracts (SOCs), exhibited a similar trend over the same period. Since the Net Billing Rates are based on the short-run marginal cost of generation (mainly fuel cost), they are also largely influenced by the factors impacting the monthly Fuel Rates.

13.3.5. Introduction of Natural Gas (NG) in the Electricity Sector

13.29. The use of NG for power generation in the electricity sector was initiated with the JPS Bogue 120MW Combined Cycle Gas Turbine (CCGT) unit located at the Bogue Power Station in Montego Bay, St. James. The ensuing events are outlined below.

Reconfiguration of JPS Bogue CCGT

13.30. At the 2014-2019 Tariff Review, the operating performance of the Bogue CCGT was deemed uneconomic due to excessive fuel costs driven by escalating ADO prices, compounded by deteriorating plant efficiency, at the time. This, in conjunction with the plant's must-run status practised by JPS, resulted in persistent suboptimal generation dispatch, which adversely impacted the total system generation cost. In recognition of this issue, the OUR in the 2014-2019 Determination Notice, determined that JPS should reconfigure the Bogue CCGT unit for dual fuel (ADO/NG) operation.

This decision was in alignment with the National Energy Policy's (NEP's) energy diversification objective, and the goals of improving operational efficiency and the lowering of electricity rates. Accordingly, the OUR approved a Bogue Plant Reconfiguration Fund (BPRF) of US$15M, which was collected through the monthly Fuel Rates for a period of 12 months, to finance the project.

Gas Supply Arrangements

13.31. The materialization of the plant conversion and operation on gas was anchored on an NG supply arrangement, which was established through a GSA executed between New Fortress

Energy (NFE) and JPS in 2016 August. The Bogue CCGT unit is now able to operate on either ADO or NG, subject to fuel availability and price levels.

Commercial Operations on NG

13.32. The reconfiguration of the Bogue plant was completed in 2016 April. However, due to delays in the completion of the NG infrastructure, full commissioning was actually achieved on 2016 December 26. As reported by JPS, the total project cost amounted to US$23.23 million, exceeding the OUR's approved cost by 55%.

Repowering of JPS Bogue GT11

13.33. In an effort to mitigate operational risks of capacity shortfall due to major mechanical problems with the JPS OH unit#2 in 2017, the OUR approved the repowering of JPS' Bogue GT11 (20MW). This project involved the installation of a new turbine that operates on NG. The unit was successfully commissioned on NG in the third quarter of 2018, resulting in the expanded use of NG for grid-electricity. In terms of performance, generation reports from JPS indicate that the unit has operated satisfactorily since commissioning.

13.3.6. Net Generation by Fuel Source

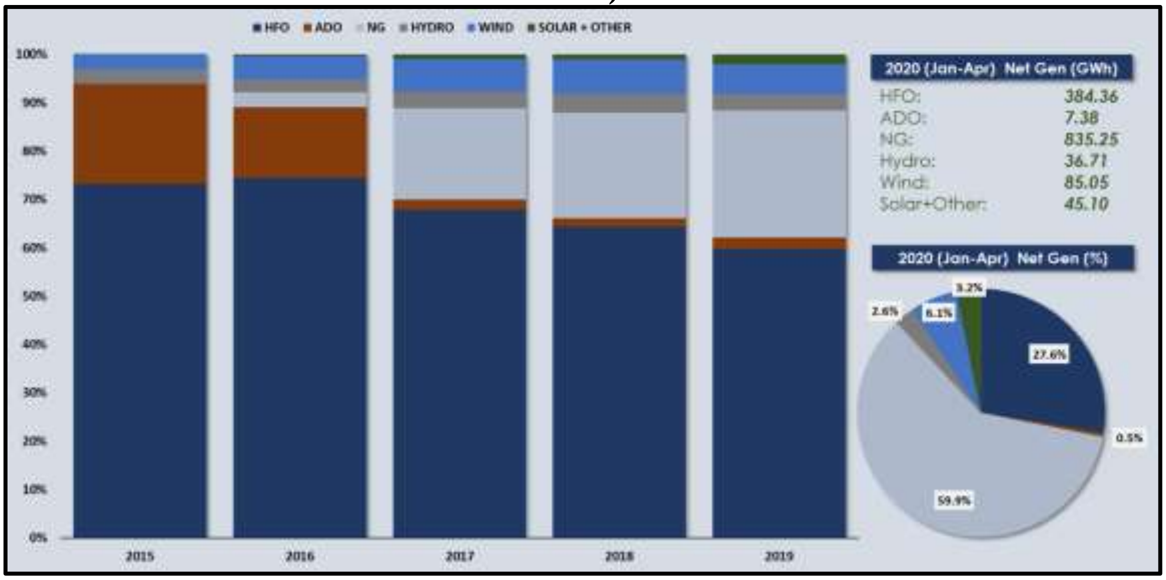
13.34. A breakdown of the system's annual net generation by primary energy sources for 2015-2019, is provided in Table 13.3 below.

Table 13.3: System Annual Net Generation by Primary Energy Source (2015-2019)

NET GENERATION BY FUEL TYPE (GWh)									
YEAR	HFO	ADO	NG	HYDRO	WIND	SOLAR & OTHER	TOTAL	HFO % of TOTAL NET GEN	NG % of TOTAL NET GEN
2015	3,082.59	870.93		125.10	128.94	1.75	4,209.32	73.2%	-
2016	3,232.49	639.83	131.19	114.93	211.14	14.66	4,343.81	74.4%	3.0%
2017	2,960.57	90.44	820.47	150.39	292.98	43.88	4,359.12	67.9%	18.8%
2018	2,801.51	80.15	946.50	176.12	304.98	45.89	4,355.54	64.3%	21.7%
2019	2,647.27	103.04	1,162.36	152.71	274.51	89.94	4,429.83	59.8%	26.2%
2020 (JAN-APR)	384.36	7.38	835.25	36.71	85.05	45.1	1,393.85	27.6%	59.9%

13.35. As indicated, developments in the generation segment of the electricity sector since 2016 have served to accelerate the transition from the use of HFO (the dominant primary energy source) for electricity generation, to NG. Based on this data, it is evident that the National Energy Policy's (NEP's) fuel diversification targets with respect to NG have been surpassed. The distribution of annual total net generation by primary energy source for the 2015-2019 period is represented in Figure 13.3 below, with the breakdown for 2020 January – April, included for comparison.

Figure 13.3: Breakdown of System Annual Net Generation by Primary Energy Source (2015 – 2019)

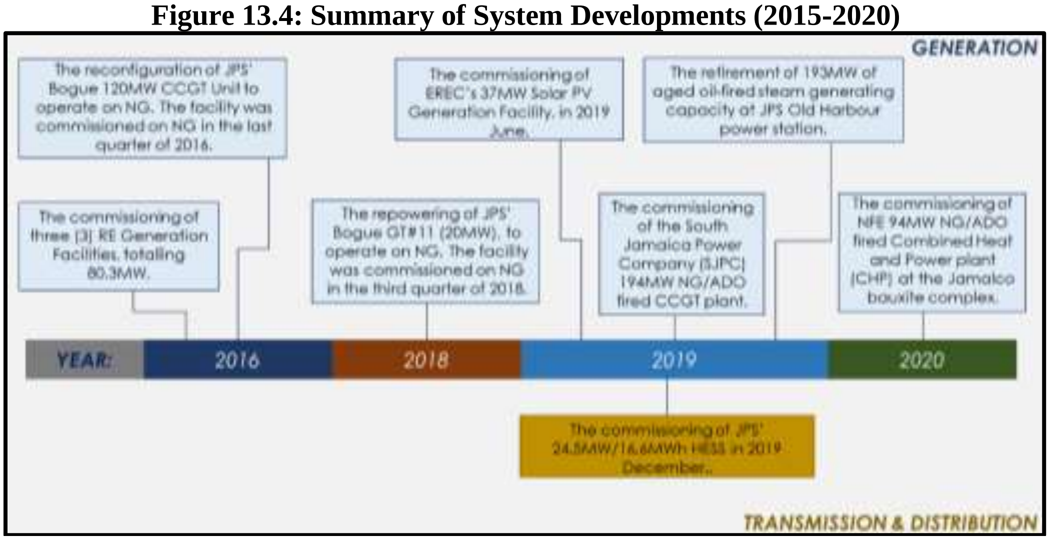


13.36. As shown in Figure 13.3 above, RE annual net generation accounted for approximately 12% of system total net generation at the end of 2019. This proportion is expected to be higher at the end of 2020 with the full annual net generation contribution from Eight Rivers Energy Company's (EREC) 37MW solar PV facility.

13.3.7. System Developments Impacting Heat Rate Performance (2015-2020)

13.37. During the 2014-2019 price control period, a number of power sector projects were implemented, resulting in alterations to the system configuration, with varying impacts on system operational efficiency. These system developments are summarized in Figure 13.4 below.

Figure 13.4: Summary of System Developments (2015-2020)



13.38. Based on system performance reports submitted by JPS, there are indications that the projects implemented in 2019 and 2020 have enhanced generation system efficiency and JPS Heat Rate performance. With respect to T&D developments in 2019 December, the Hybrid Energy Storage System (HESS) was commissioned into service. Despite the HESS' primary functional uses, it is also expected to enhance generation system efficiency, going forward.

Retirement of JPS' Steam Generation Plants

13.39. The addition of the new dual-fuel generation plants (288MW) to the system in 2019 and 2020, paved the way for the retirement of 193.5MW of JPS' Old Harbour steam generating capacity at the end of 2019. This capacity replacement strategy was predicated on the Minister's Retirement Schedule. As per the referenced Retirement Schedule, some of the remaining plants are also set to retire over the 2020-2024 period.

13.4. Analysis of JPS' Heat Rate Performance (2015-2020 April)

13.4.1. Heat Rate Target: 2014-2019 Tariff Review Period

13.40. Based on JPS' thermal generating system, the OUR determined a Heat Rate target of 12,010 kJ/kWh for the period 2015 February to June, subject to review at each Annual Tariff Adjustment during the regulatory period. The OUR subsequently made two (2) adjustments to the Heat Rate target during the five-year Rate Review period.

- *For the 2015-2016 period*: the target was held at 12,010 kJ/kWh
- *For the 2016-2017 period*: the target was revised downward from 12,010 kJ/kWh to 11,620 kJ/kWh
- *For the 2017-2018 period*: the target was further revised downwards from 11,620 kJ/kWh to 11,450 kJ/kWh
- *For the 2018-2019 period*: the target was kept at 11,450 kJ/kWh

13.4.2. Heat Rate Improvement

13.41. During the 2014-2019 price control period, the total reduction in the annual Heat Rate target was 560 kJ/kWh, which was related to the company's generation efficiency improvement initiatives. The comparison of the Heat Rate targets proposed by JPS against those set by the OUR during the 2014-2019 period indicating the adjustments made, is shown in Table 13.4 below.

Table 13.4: JPS' Proposed Heat Rate Targets versus OUR's Determined Targets 2015-2019

JPS PROPOSED HEAT RATE TARGETS VERSUS OUR DETERMINED TARGETS (2015-2019)				
Tariff Period	JPS Proposed Heat Rate Target (kJ/kWh)	OUR Determined Heat Rate Target (kJ/kWh)	Variance (JPS/OUR Targets) (kJ/kWh)	Change in OUR Target (kJ/kWh)
2015 Feb - Jun	-	12,010	-	-
2015-2016	-	12,010	-	-
2016-2017	10,710	11,620	N/A	390
2017-2018	11,720	11,450	270	170
2018-2019	11,482	11,450	32	

13.4.3. Historical Heat Rate Performance

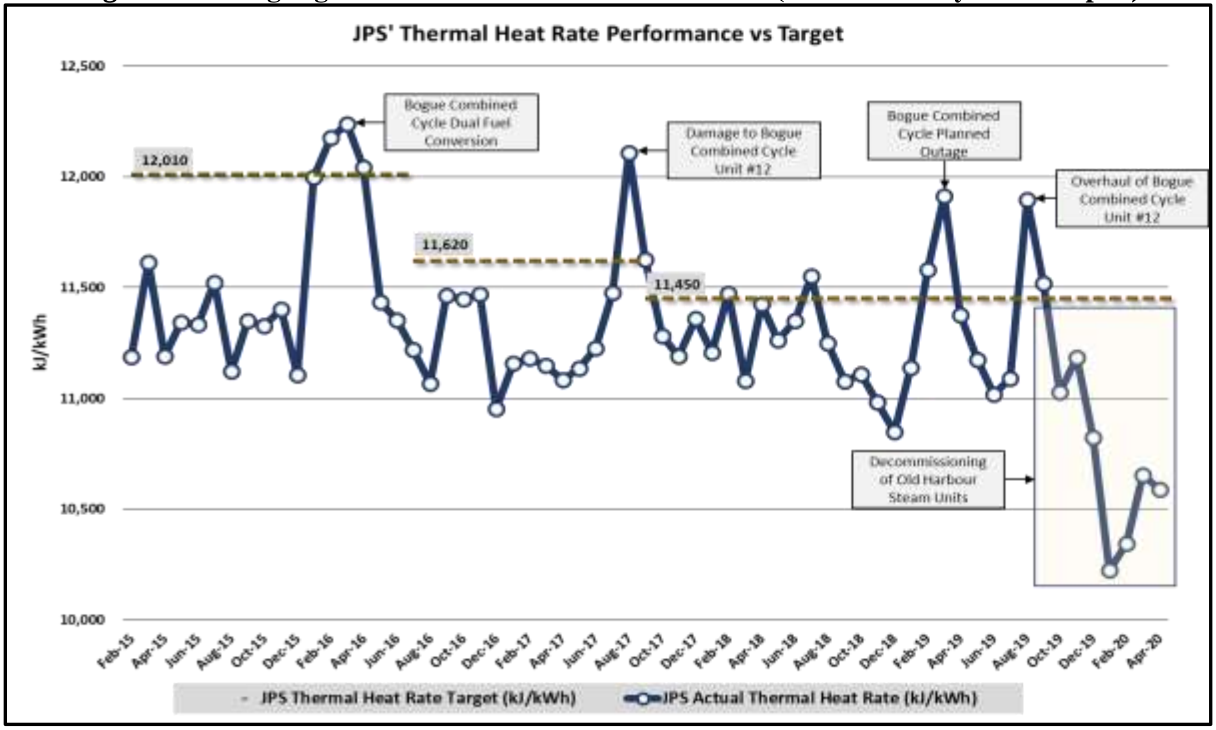
13.42. The monthly Heat Rate performance reported by JPS for the period 2015 February – 2020 April, is presented in Table 13.5 below.

Table 13.5: JPS' Heat Rate Performance versus Targets (2015-2020)

JPS ACTUAL HEAT RATE VERSUS TARGET												
	2014 – 2015 Heat Rate (kJ/kWh)		2015-2016 Heat Rate (kJ/kWh)		2016-2017 Heat Rate (kJ/kWh)		2017-2018 Heat Rate (kJ/kWh)		2018-2019 Heat Rate (kJ/kWh)		2019-2020 Heat Rate (kJ/kWh	
DATE	Actual Heat Rate	Heat Rate Target	Actual Heat Rate	Heat Rate Target	Actual Heat Rate	Heat Rate Target	Actual Heat Rate	Heat Rate Target	Actual Heat Rate	Heat Rate Target	Actual Heat Rate	Heat Rate Target
Jul			11,523	12,010	11,218	11,620	11,475	11,620	11,551	11,450	11,088	11,450
Aug			11,124	12,010	11,065	11,620	12,109	11,620	11,249	11,450	11,897	11,450
Sep			11,351	12,010	11,463	11,620	11,628	11,450	11,075	11,450	11,519	11,450
Oct			11,327	12,010	11,448	11,620	11,281	11,450	11,107	11,450	11,028	11,450
Nov			11,403	12,010	11,469	11,620	11,191	11,450	10,980	11,450	11,184	11,450
Dec			11,107	12,010	10,953	11,620	11,360	11,450	10,850	11,450	10,823	11,450
Jan			11,996	12,010	11,158	11,620	11,208	11,450	11,137	11,450	10,223	11,450
Feb	11,186	12,010	12,175	12,010	11,181	11,620	11,472	11,450	11,579	11,450	10,346	11,450
Mar	11,615	12,010	12,240	12,010	11,148	11,620	11,079	11,450	11,914	11,450	10,652	11,450
Apr	11,190	12,010	12,044	12,010	11,081	11,620	11,425	11,450	11,375	11,450	10,450	11,450
May	11,343	12,010	11,436	12,010	11,134	11,620	11,261	11,450	11,173	11,450		11,450
Jun	11,335	12,010	11,352	12,010	11,227	11,620	11,349	11,450	11,019	11,450		11,450
AVG.	**11,334**	**12,010**	**11,590**	**12,010**	**11,212**	**11,620**	**11,403**	**11,478**	**11,251**	**11,450**	**10,973**	**11,450**

13.43. As shown in Table 13.5 above, the average Heat Rate reported by JPS for each billing month during the 63-month period, was compared against the relevant target. Additionally, the highlights and major events that impacted the Heat Rate performance during the period are represented graphically in Figure 13.5 below.

Figure 13.5: Highlights of JPS' Heat Rate Performance (2015 February – 2020 April)



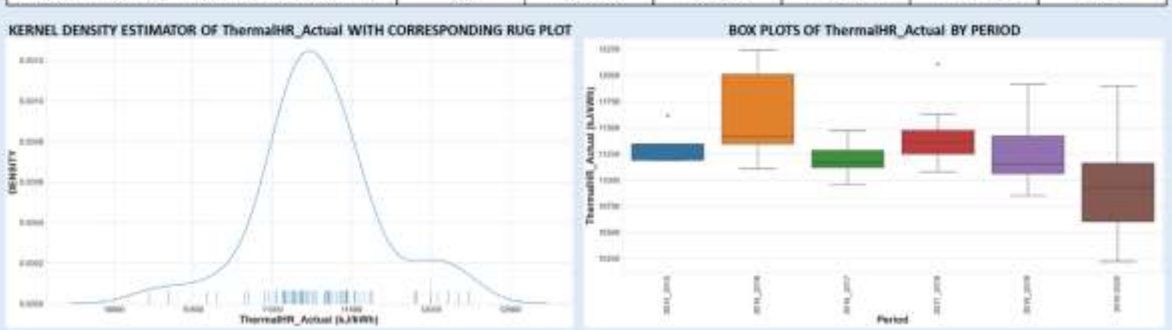
13.44. As demonstrated, there were wide variations in the monthly Heat Rates achieved over the period.

Statistical Analysis – Historical Heat Rate Data

13.45. A statistical analysis of the historical Heat Rate data was conducted. The resulting summary statistics are presented in Figure 13.6 below, along with illustrations of the variation in the data, in aggregate, and per period, respectively.

Figure 13.6: Summary Statistics - JPS' Heat Rate Performance (2015 Feb to 2020 Apr)

SUMMARY STATISTICS – JPS ACTUAL THERMAL HEAT RATE (2015 FEB TO 2020 APR)						
	COUNT	MIN	MAX	MEAN	MEDIAN	STD. DEV
Actual Thermal Heat Rate (kJ/kWh)	63	10,222.9	12,239.7	11,293.4	11,248.8	382.7



13.46. As indicated in Figure 13.6 above, the mean and the median statistics for the Heat Rate distribution show close convergence, suggesting a symmetrical structure, which infers that the orientation of Heat Rate data depicts a near-normal distribution. While the mean Heat Rate over the period was 11,293 kJ/kWh, the standard deviation was 383 kJ/kWh, which means that 68% of the monthly average Heat Rate values ranged between 10,910 kJ/kWh and 11,676 kJ/kWh. This confirms that the targets set by the OUR during the period were reasonable, and were above the upper limit on average.

Heat Rate Performance Summary

13.47. Highlights from the Heat Rate performance over the period, include:

1) The targets were reasonably achieved, except for ten (10) out of sixty-three (63) billing months, as highlighted in yellow in Table 13.5 above;
2) The under-achievement of the target during three (3) months in the 2015-2016 adjustment period was primarily due to reconfiguration activities on the Bogue CCGT unit, which was ongoing at the time;
3) During the 2017-2018 Annual Review period, JPS was unable to achieve the target in two (2) consecutive months due mainly to major damage to Bogue GT#12, a component of the Bogue CCGT unit;
4) There were five (5) other instances between 2018 and 2019 where JPS failed to achieve the Heat Rate target due primarily to issues that were associated with the Bogue CCGT unit;
5) Since 2020, the operation of the new SJPC CCGT plant and the NFE CHP generation facility, and the subsequent retirement of the JPS OH power plant, resulted in a drastic decline in JPS' monthly average Heat Rates, bettering the target of 11,450 kJ/kWh (not adjusted since 2017 September) by a margin of 1,032 kJ/KWh per month on average. This is demonstrated in the time-series plot in Figure 13.5 above and the box plot included in Figure 13.6 above.

13.48. According to JPS, improved efficiency was largely attributed to the efforts of the company improving and maintaining its generation fleet through the employment of an Enterprise Asset Management (EAM) approach, supported by prudent maintenance practices.

13.4.4. Generation Performance Indicators (Efficiency & Reliability)

13.49. In the Application, JPS asserted that the investments made by the company over the 2014-2019 price control period paid off with continued improvements in its generation efficiency & reliability metrics, namely, the Equivalent Availability Factor (EAF), Equivalent Forced Outage Rate (EFOR), and average Heat Rate of its generating units. The reported indicators for 2015-2019 are presented in Table 13.6 below.

Table 13.6: Generation Performance Indicators (Efficiency & Reliability)

METRIC	2015	2016	2017	2018	2019
JPS EAF	78%	81%	87%	89%	-
JPS EFOR	15%	12%	8%	5%	-
JPS Heat Rate (kJ/kWh)	11,332	11,570	11,341	11,214	11,311

13.50. As shown in Table 13.6 above:

1) The EAF improved from 78% in 2015 to 89% in 2018. This, according to JPS, represents the best reliability performance in more than a decade, which is debatable.

2) The reported EFOR was 5% in 2018 representing a 67% improvement over the 2015 level.

13.51. JPS has indicated that the improvements in the EAF and EFOR were major contributors to its Heat Rate performance over the 2014-2019 price control period.

13.5. JPS' Heat Rate Proposals

13.52. JPS submitted its Heat Rate proposals with supporting data and schedules. The considerations and inputs into JPS' Heat Rate Proposals for the Rate Review period are summarized below.

13.5.1. Heat Rate Proposal Considerations

13.53. In its Application, JPS argued that:

1) At the time of its submission, it was constrained in developing the Heat Rate forecast by the absence of an IRP as required by the Licence. JPS was concerned that its Heat Rate assumptions and analysis may not accord with the IRP when it is published. Accordingly, the company believes that this situation must be viewed as an exceptional circumstance meriting a potential change to the pre-established Heat Rate targets at some interim point during the Rate Review period;
2) Some of the effects caused by operation of IPPs' generation facilities which are beyond its control, are presently reflected in the Fuel Rate; however, the H-Factor is not presently adjusted for these IPP effects, and requested that this situation be addressed in the 2019-2024 Rate Review;
3) The proposed Heat Rate targets for the new regulatory period are based on the known operational status of JPS' thermal plants, and as such, are likely to change materially and frequently over the subject timeframe. Therefore, the annualized targets represent just a rough summation of discrete twelve (12) months Heat Rate data;
4) There should be periodic reviews of the Heat Rate target, no less than annually, over the Rate Review period to appropriately account for the impact of deviations, as they become known. According to JPS, this would include issues such as changes in planned commissioning dates or adverse performance of IPP assets outside of JPS' control;
5) The addition of the new IPP generating capacity (SJPC and NFE facilities), and the resulting retirement of the JPS OH power station, will result in greater than 70% of system net generation being provided by the IPPs, causing JPS' remaining generation capacity to be relegated to intermediate and peak load operation. According to JPS, this shift in operating profile will create difficulties for the company to achieve the Heat Rate targets.

6) The existing JPS thermal Heat Rate model should be continued in the Rate Review period in light of its demonstrated success in setting targets that have been reasonable and achievable;
7) Behind-the-meter RE facilities or GOJ policy objectives may adversely impact the fuel efficiency of JPS and could burden the spinning reserve of JPS' thermal plants to address variations in power output over which JPS has no control;
8) Even though the IPPs may be penalized through liquidated damages (LDs), for higher than allowed forced outages, these penalty payments are passed on to the customers and do not offset the adverse impact on JPS' Heat Rate performance, causing the company to suffer from a reduced H-Factor;
9) The Heat Rate targets should consider the mix of JPS' generating plants. That is, after the retirement of HB B6, the main units left will be the Bogue CCGT unit and the Rockfort plant with a combined average efficiency of approximately 40%, and aggregation of the other units having a combined average efficiency of 23%. This, according to JPS, poses inherent risks;
10) There are potential issues associated with the use of alternate fuels in the dual-fuel power plants, where the primary fuel becomes unavailable. According to JPS, this could be problematic in cases where there is extended operation on the alternate fuel, as this impacts plant maintenance routine, EAF, and related operating cost. JPS has proposed that this impact should be incorporated in the periodic review of the targets.

13.5.2. JPS' Heat Rate Forecast

13.54. Details relating to JPS' Heat Rate forecasting approach and projections are provided in the sections below.

<u>JPS' Heat Rate Model</u>

13.55. JPS indicated that it employed the use of the PLEXOS software to model its generation system operations and forecast its Heat Rate performance for the Rate Review period. According to JPS, the Heat Rate modelling process took into account the following aspects:

1) The maximum capacity rating (MCR) of each generating unit/facility in the system;
2) The capacity factor (CF) for each generating unit/facility based on simulated dispatch;
3) The forecasted NEO of each generating unit over the Rate Review period; and
4) Fuel price forecasts for ADO, HFO and NG for the Rate Review period.

<u>JPS' Fuel Price Forecast</u>

13.56. To support its Heat Rate proposals, JPS submitted a fuel price forecast for each of the relevant fuel types for the Rate Review period. According to the data, the fuel price forecast for NG was developed based on Henry Hub (HH) NG Futures forecast in conjunction with the respective NFE/JPS GSAs. For HFO and ADO, the price forecasts were based on Gulf Coast (Platts) futures settlement and the respective JPS/Petrojam FSAs. The fuel price forecasts also incorporated transportation cost variations and fuel quality premium. The respective fuel price forecasts are shown in Table 13.7 below.

Table 13.7: JPS' Fuel Price Forecast (2020-2024)

JPS FUEL PRICE FORECAST (2020-2024)													
PLANT	**FUEL**	**2020**		**2021**		**2022**		**2023**		**2024**		**AVERAGE**	
		US$/ BBL	US$/ MMBTU	US$/ BBL	US$/ MMBTU	US$/ BBL	US$/ MMBTU	US$/ BBL	US$/ MMBTU	US$/ BBL	US$/ MMBTU	US$/ BBL	US$/ MMBTU
JPS OH	HFO	64.89	9.50	59.46	9.88	62.94	9.59	60.16	9.70	60.760	9.80	61.64	9.75
JPS HB	HFO	65.52	9.60	60.08	9.97	63.56	9.69	60.79	9.81	61.380	9.90	62.27	9.85
JPS RF	HFO	66.23	9.71	60.79	10.08	64.27	9.80	61.50	9.92	62.090	10.02	62.97	9.96
JPS HB	ADO	87.24	13.65	80.12	14.25	85.20	13.79	81.09	13.96	81.920	14.10	83.11	14.10
JPS BO	ADO	93.35	14.70	86.23	15.25	91.31	14.82	87.20	15.01	88.030	15.15	89.22	15.14
JPS BO	NG	-	9.97	-	9.67	-	9.97	-	9.97	-	9.97	-	9.91
IPPs	HFO	65.59	11.12	59.81	10.09	60.25	9.96	60.78	10.31	61.230	10.13	61.53	10.07
SJPC CCGT	NG	-	7.97	-	7.97	-	7.97	-	7.97	-	7.97	-	7.97
NFE (CHP)	NG	-	7.97	-	7.97	-	7.97	-	7.97	-	7.97	-	7.97

13.57. The basis for converting the prices for the liquid fuels (ADO & HFO) from US$/Barrel to US$/MMBTU, is not clear, as the translations show significant variations in the conversion factors (the heating values of the respective fuels).

JPS' Generating Units Capacity Factors and Heat Rates (2020-2024)

13.58. Contributory factors to JPS' 2020-2024 annual Heat Rate forecast, specifically the individual generating unit's CF and average Heat Rate, are summarized in Table 13.8 below.

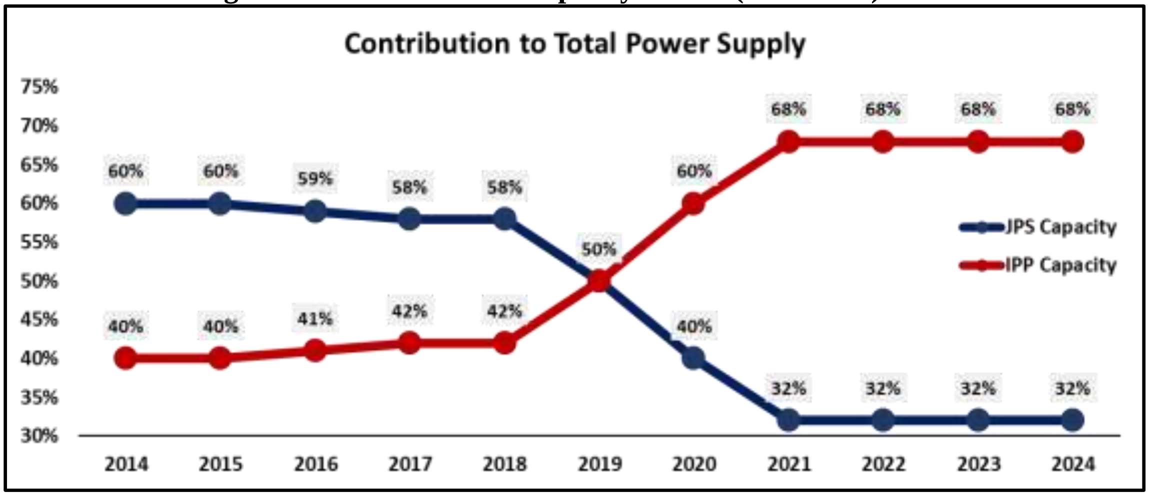
Table 13.8: JPS' Forecasted Plant Capacity and Heat Rates (2020-2024)

FORECASTED PLANT CAPACITY FACTORS AND HEAT RATES											
Category		**2020**		**2021**		**2022**		**2023**		**2024**	
Plant	**MCR (MW) [2020-2024]**	**CF (%)**	**Heat Rate (kJ/kWh)**	**CF (%)**	**Heat Rate (kJ/kWh)**	**CF (%)**	**Heat Rate (kJ/kWh)**	**CF (%)**	**Heat Rate (kJ/kWh)**	**CF (%)**	**Heat Rate (kJ/kWh)**
RF-B1	20.00	73.49%	9,086	83.89%	9,076	84.05%	9,077	83.05%	9,075	83.13%	9,075
RF-B2	20.00	65.64%	9,087	76.17%	9,076	76.25%	9,077	75.39%	9,076	75.56%	9,076
HB-B6	68.50	45.35%	13,584	*Retired*							
HBGT5	21.50	4.11%	14,965	4.12%	14,971	4.37%	15,045	4.33%	14,996	4.12%	14,976
HBGT10	32.50	7.34%	13,180	7.28%	13,178	7.85%	13,253	7.56%	13,195	7.34%	13,188
BOGT3	21.50	2.96%	15,384	2.97%	15,387	2.98%	15,402	2.97%	15,386	2.97%	15,387
BOGT6	18.00	-	-	0.01%	17,845	0.02%	17,845	0.01%	17,809	0.01%	17,809
BOGT7	18.00	0.00%	18,255	0.06%	18,213	0.11%	18,197	0.05%	18,188	0.03%	18,151
BOGT9	20.00	2.97%	14,781	3.03%	14,781	3.12%	14,781	3.10%	14,782	3.01%	14,781
BOGT11	20.00	49.65%	11,991	49.62%	11,990	49.62%	11,990	49.62%	11,990	49.62%	11,990
BOCCGT	120.00	81.85%	9,167	85.34%	8,939	81.37%	9,326	84.14%	8,940	84.39%	8,942
JPS THERMAL	**≤380.00**	**45.14%**	**10,246**	**47.79%**	**9,327**	**46.36%**	**9,613**	**47.27%**	**9,337**	**47.33%**	**9,333**
JEP	124.50	11.35%	8,616	10.81%	8,616	14.44%	8,616	11.70%	8,616	11.29%	8,616
JPPC	60.00	45.05%	8,165	58.14%	8,146	60.30%	8,152	57.49%	8,153	57.84%	8,143
WKPP	65.50	36.44%	8,569	37.64%	8,569	43.04%	8,569	37.96%	8,569	38.91%	8,569
SJPC	190.00	83.17%	8,941	81.97%	8,854	78.68%	8,818	82.43%	8,863	81.69%	8,854
NFE	94.00	43.32%	10,966	56.46%	10,963	56.82%	10,964	56.60%	10,964	56.72%	10,964
WIGTON I	20.00	31.73%		31.78%		31.78%		31.78%		31.73%	
WIGTON II	18.00	35.34%		35.36%		35.36%		35.36%		35.34%	
WIGTON III	24.00	25.61%		25.62%		25.62%		25.62%		25.61%	
BMRJW	34.00	37.53%		37.58%		37.58%		37.58%		37.53%	
CSL	20.00	24.14%		24.14%		24.14%		24.14%		24.14%	
EREC	37.00	19.57%		19.57%		19.57%		19.57%		19.57%	
JPS MUNRO	3.00	12.76%		12.74%		12.74%		12.74%		12.76%	
MAGGTY B	7.20	69.78%		69.91%		69.91%		69.91%		69.78%	
JPS HYDRO	22.40	49.49%		49.50%		49.50%		49.50%		49.49%	
JPS DG	14.00	5.62%		67.86%		91.85%		95.00%		95.00%	

<u>Impact of New Generation on Economic Dispatch and Heat Rate</u>

13.59. Based on the new IPP generating capacity addition and committed projects, JPS' projection of the system's generation capacity allocated over the Rate Review period, is shown in Figure 13.7 below.

Figure 13.7: JPS and IPP Capacity Profile (2014-2024)



JPS' Forecasted Heat Rate Performance

13.60. JPS' Heat Rate forecast for 2020-2024 is summarized in Table 13.9 below.

Table 13.9: JPS' Heat Rate Performance Forecast (2020-2024) By Plant

JPS HEAT RATE PERFORMANCE FORECAST (2020-2024) BY PLANT							
CATEGORY	**UNIT**	**CAPACITY**	**2020**	**2021**	**2022**	**2023**	**2024**
		MCR (MW)	Heat Rate (kJ/kWh)	Heat Rate (kJ/kWh)	Heat Rate (kJ/kWh)	Heat Rate (kJ/kWh)	Heat Rate (kJ/kWh)
HUNTS BAY	HB6	68.50	13,584	Retired	Retired	Retired	Retired
	GTs	54.00	13,663	13,666	13,736	13,690	13,672
ROCKFORT	RF1	20.00	9,087	9,076	9,077	9,076	9,076
	RF2	20.00	9,087	9,076	9,077	9,076	9,076
OPEN CYCLE GTs	GT3 - GT11	89.50	12,333	12,342	12,353	12,344	12,338
BOGUE	Bogue CCGT	120.00	9,167	8,939	9,326	8,940	8,942
IPPs	IPP Units	539.36	9,123	9,128	9,098	9,132	9,127
JPS THERMAL			**10,246**	**9,327**	**9,613**	**9,337**	**9,333**
SYSTEM THERMAL			**9,565**	**9,197**	**9,271**	**9,202**	**9,198**

13.61. As indicated, the JPS HB B6 unit is scheduled to retire from service by the end of 2020. From the projected Heat Rates, the corresponding average annual Heat Rate for all JPS thermal plants combined, were estimated to be in the range from 10,246 kJ/kWh to 9,333 kJ/KWh. However, the average value of 10,246 kJ/kWh for 2020 does not appear to be representative and reflective of economic generation dispatch.

JPS' Monthly Average Heat Rate Projections (2020-2024)

13.62. In the Application, JPS posited that its generation system modelling and analysis, which are based on the factors described above, yielded the monthly Heat Rate forecast shown in Table 13.10 below.

Table 13.10: JPS' Thermal Plants Monthly Average Heat Rate Projections (2019-2024)

JPS' FORECASTED MONTHLY HEAT RATES (2019-2024)													
PERIOD	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**AVG**
2020-2021	10,157	10,241	10,152	10,184	10,222	10,272	9,334	9,329	9,317	9,411	9,322	9,306	9,771
2021-2022	9,304	9,309	9,287	9,346	9,327	9,343	9,357	10,516	12,056	9,411	9,322	9,306	9,657
2022-2023	9,304	9,332	9,351	9,344	9,326	9,343	9,332	9,496	9,324	9,412	9,319	9,305	9,349
2023-2024	9,302	9,308	9,286	9,345	9,325	9,333	9,398	9,356	9,319	9,410	9,318	9,305	9,334

13.63. Given the current generation system configuration, the Heat Rate values for 2020 July – December and 2022 February–March, highlighted in yellow in Table 13.10 above, are questionable, and signals that the related generation dispatch scenarios are likely to be sub-optimal.

13.5.3. JPS' Proposed Heat Rate Targets (2019-2024)

13.64. With reference to its generation system analysis and resulting Heat Rate forecast, JPS proposed the Heat Rate targets for 2020-2024, shown in Table 13.11 below.

Table 13.11: JPS' Proposed Heat Rate Targets

JPS PROPOSED HEAT RATE TARGETS					
Heat Rate Methodology	**Tariff Period**	**Heat Rate Forecast (kJ/kWh)**	**JPS Targets (kJ/kWh)**	**Buffer (%)**	**Remarks**
JPS Thermal Plants	July 2020 - June 2021	9,771	**9,976**	2.1	Basis of buffer not clear
	July 2021 - June 2022	9,657	**9,860**	2.1	
	July 2022 - June 2023	9,349	**9,545**	2.1	
	July 2023 - June 2024	9,334	**9,530**	2.1	

13.65. With respect to the proposed targets, JPS noted that its Heat Rate performance over the 2020-2024 period will depend on several factors, including the following:

1) Growth in system demand;
2) The addition of new generating units and the installed reserve margin;
3) Heat rate improvements made to existing generating units;
4) Availability and reliability of JPS' generators;
5) Availability and reliability of IPP generators;
6) Absolute and relative fuel prices for JPS and the IPPs and the impact on economic dispatch;
7) Spinning reserve policy;
8) Network constraints and contingencies; and
9) Forced outage of Bogue CCGT of up to one month

13.66. Against this background, JPS argued that while the above factors are likely to influence the Heat Rate performance outcome, it has direct control over only a few. In that regard, the company requested that the Heat Rate methodology be continued to be based on its thermal generating plants, on the premise that it encourages the optimization of its generation operations, and mitigates certain risk elements. Citing the outlined conditions, among other factors, the company indicated that in anticipation of risk conditions outside of its control, it added a contingency buffer of 2.1% to the forecasted Heat Rates to derive the relevant targets.

13.67. Additionally, JPS proposed that the annual Heat Rate targets be revised at each Annual Review to address changes in generation system configuration and operational uncertainties.

13.6. OUR's Review of JPS' Heat Rate Proposals

13.6.1. OUR's Review Approach

13.68. With the regulatory principles in mind, the approach used to determine the Heat Rate targets to be applied during the Rate Review period, entailed two (2) main aspects:

1) A technical evaluation of JPS' Heat Rate proposals (including all the available supporting data after receipt of additional information & clarifications), using the OUR's Heat Rate model;
2) A scenario analysis to assess the effects of potential variations or uncertainties on JPS' Heat Rate (thermal plants) performance during the subject period.

13.69. This approach was adopted to enable the OUR to set Heat Rate targets that are reasonable and representative.

13.6.2. Technical Evaluation of JPS' Heat Rate Proposals

13.70. To facilitate the review of JPS' Heat Rate forecast and proposed targets, the OUR carried out a comprehensive Heat Rate evaluation. In evaluating the Heat Rate proposals, the OUR assessed the operation of the entire generation system over the Rate Review period.

Inputs/Assumptions for Heat Rate Evaluation

13.71. Consistent with the Heat Rate requirements outlined in the Final Criteria, the OUR's evaluation took into consideration, among other things, the following assumptions and parameters:

1) Chronological load data for the period 2009-2019; and
2) The system net generation and peak demand for the Rate Review period, obtained from JPS' Demand Forecast submitted with its Application.

The system net generation (GWh) and peak demand (MW) data from JPS, which was used in the OUR's Heat Rate evaluation is provided in Table 13.12 below. This load data indicates that system annual net generation and peak demand are expected to be flat during the 2020-2024 timeframe.

Table 13.12: JPS' Forecasted Net Generation and System Peak Demand (2020-2024)

Year	Net Gen (GWh)	Net Gen Growth (%)	Peak Demand (MW)	Peak Demand Growth (%)	Load Factor (%)	Remarks
2018	4,356	-	654.5	-	75.97	Actual
2019	4,430	1.70%	660.9	0.98%	76.51	Actual
2020	4,359	-1.60%	657.0	-0.59%	75.73	JPS Projection
2021	4,384	0.57%	659.0	0.30%	75.94	JPS Projection
2022	4,404	0.46%	661.0	0.30%	76.06	JPS Projection
2023	4,420	0.36%	662.0	0.15%	76.22	JPS Projection
2024	4,425	0.11%	661.0	-0.15%	76.42	JPS Projection
CUMULATIVE		**-0.10%**		**0.02%**		

13.72. Additionally, the OUR's analysis took the following into account:

a) Existing Generation System (Conventional & RE) – JPS and IPPs;
b) New Generation Capacity Additions (2019-2020);
c) Net Billing Data;
d) Committed Generation Projects Due for Commissioning during the Rate Review period;
e) Transmission System Data;
f) Annual Generation Maintenance Schedule;
g) Generation Dispatch Files.

Heat Rate Test Data

13.73. JPS also submitted its 2018 Heat Rate Test data, which was integral to the OUR's Heat Rate evaluation. Notably, Heat Rate Tests are critical for validating the current efficiency level of a generating unit relative to established limits, and are necessary for the recalibration of the Heat Rate models. The 2018 Heat Rate Test data for JPS' thermal plants is presented in Table 13.13 below.

Variable O&M Cost

13.74. In accordance with the Final Criteria, JPS provided the variable O&M (VOM) costs for the generating units owned and operated by the company, which were reportedly computed from actual O&M expenditures. For the IPPs, the VOM costs were computed according to their respective PPAs. These VOM cost assumptions are provided in Table 13.13 below, and were used in the OUR's Heat Rate evaluation.

Table 13.13: JPS' Generating Units Technical Characteristics and Costs Assumptions

GENERATING UNITS VARIABLE O&M COST									
Source	**Unit**	**Fuel Type**	**MCR (MW)**	**HEAT RATE TEST DATA**				**VOM (US$/ MWh)**	**Planned Retirement**
				Min Net Capacity (MW)	Max Net Capacity (MW)	Net Heat Rate at Min Cap. (kJ/kWh)	Net Heat Rate at Max Cap. (kJ/kWh)		
JPS	OH2	HFO	60.00	35.00	50.00	15,027	13.675	0.132	2019 Dec
	OH3	HFO	65.00	35.50	60.00	13,212	12,814	0.132	2019 Dec
	OH4	HFO	68.50	35.00	63.00	12,581	12,330	0.132	2019 Dec
	HB6	HFO	68.50	35.52	64.32	12,118	12,733	0.078	2020 Dec
	RF1	HFO	20.00	10.20	19.20	9,565	8,975	0.404	
	RF2	HFO	20.00	10.30	20.10	9,395	8,887	0.323	
	GT5	ADO	21.50	10.87	21.75	18,757	14,657	0.036	
	GT10	ADO	32.50	10.49	31.20	20,810	13,791	0.036	
	GT3	ADO	21.50	10.00	21.00	20,783	15,868	0.087	
	GT6	ADO	18.00	5.88	14.88	22,303	16448	0.087	
	GT7	ADO	18.00	5.00	18.00	23,011	15,716	0.087	
	GT9	ADO	20.00	5.18	19.73	27,540	14,515	0.087	
	GT11	NG	20.00	5.00	20.00	18,272	11,568	0.087	
	BOCC GT	NG	120.00	83.18	115.96	9,384	8,789	0.779	
IPPs	JPPC	HFO	60.00					12.92	
	JEP	HFO	124.36					23.060	
	WKP P	HFO	65.50					15.010	
	SJPC	NG/ADO	194.00					0.30	
	NFE	NG/ADO	94.00					0.10	
	Jamal	HFO	2.00					-	

13.75. It is notable that the OUR's review of JPS' generation dispatch simulations found that the VOM costs for the company's owned units were not included in the total variable cost for the 2019-2024 dispatch scenarios presented. This again raises questions regarding JPS' merit order system and dispatch process.

Fuel Price Forecast

13.76. The fuel prices used in the OUR's Heat Rate evaluation are provided in Table 13.14 below.

Table 13.14: Fuel Price Forecasts Used in OUR's Heat Rate Evaluation

JPS FUEL PRICE FORECAST (2020-2024)													
PLANT	FUEL	2020		2021		2022		2023		2024		AVERAGE	
		US$/ BBL	US$/ MMBTU	US$/ BBL	US$/ MMBTU	US$/ BBL	US$/ MMBTU	US$/ BBL	US$/ MMBTU	US$/ BBL	US$/ MMBTU	US$/ BBL	US$/ MMBTU
JPS OH	HFO	64.89	10.32	59.46	9.46	62.94	10.01	60.16	9.57	60.760	9.66	**61.64**	**9.80**
JPS HB	HFO	65.52	10.42	60.08	9.56	63.56	10.11	60.79	9.67	61.380	9.76	**62.27**	**9.90**
JPS RF	HFO	66.23	10.53	60.79	9.67	64.27	10.22	61.50	9.78	62.090	9.88	**62.97**	**10.02**
JPS HB	ADO	87.24	14.98	80.12	13.75	85.20	14.63	81.09	13.92	81.920	14.06	**83.11**	**14.27**
JPS BO	ADO	93.35	16.03	86.23	14.80	91.31	15.68	87.20	14.97	88.030	15.11	**89.22**	**15.32**
JPS BO	NG	-	9.21	-		-		-				**-**	**9.97**
IPPs (JPPC, JEP, WKPP)	HFO	65.59	10.43	59.81	9.51	60.25	9.58	60.78	9.67	61.230	9.74	**61.53**	**9.79**
SJPC CCGT	NG	-	7.97	-	7.97	-	7.97	-	7.97		7.97	**-**	**7.97**
NFE (CHP)	NG	-	7.97	-	7.97	-	7.97	-	7.97		7.97	**-**	**7.97**

13.77. For consistency, JPS' fuel prices denominated on a US$/MMBTU basis were adjusted to reflect the nominal HHVs for HFO and ADO.

Verification Check – JPS' Heat Rate Data

13.78. The OUR simulated the base year (2018) generation operations, using the actual historical data and generation system performance parameters, using its Heat Rate evaluation model. It was deduced from this verification test that JPS' Heat Rate data overall was fairly representative. Following this calibration process, the OUR forecasted the relevant Heat Rate values for the Rate Review period.

13.7. OUR's Heat Rate Evaluation Results

13.79. The OUR's Heat Rate evaluation generated different categories of results, including annual Heat Rate projections for JPS' thermal plants, system Heat Rates, plant dispatch levels (CF), and net generation, for the Rate Review period.

13.7.1. OUR's Generation Dispatch Projections

13.80. During system operations, the utilization levels of each available generating unit, resulting from the economic generation dispatch process, largely influences the unit's average Heat Rate performance in a given billing period. In line with this principle, OUR's evaluation made projections of the annual average CF of the generation plants in the system during the 2020-2024 period. The OUR's projected CF compared to those forecasted by JPS, are presented in Table 13.15 below.

Table 13.15: Generating Plants Utilization Levels Projected by OUR (2020-2024)

OWNER	Unit	Gross Capacity (MW)	2020		2021		2022		2023		2024	
			JPS	OUR	JPS	OUR	JPS	OUR	JPS	OUR	JPS	OUR
JPS	HB6	68.5	45%	2.7%	-	-	-	-	-		-	
	RF1	20.0	73%	70.7%	84%	81.8%	84%	37.3%	83%	84.0%	83%	82.5%
	RF2	20.0	66%	57.0%	76%	89.4%	76%	31.9%	75%	90.2%	76%	89.4%
	HBGT5	21.5	4%	0.7%	4%	1.0%	4%	0.7%	4%	0.6%	4%	0.5%
	HBGT10	32.5	7%	1.1%	7%	1.6%	8%	1.1%	8%	0.9%	7%	0.8%
	BOGT3	21.5	3%	0.5%	3%	0.7%	3%	0.4%	3%	0.4%	3%	0.3%
	BOGT6	18.0	0%	0.3%	0%	0.5%	0%	0.3%	0%	0.3%	0%	0.2%
	BOGT7	18.0	0%	0.2%	0%	0.2%	0%	0.1%	0%	0.1%	0%	0.1%
	BOGT9	20.0	3%	0.2%	3%	0.4%	3%	0.2%	3%	0.2%	3%	0.2%
	BOGT11	20.0	50%	3.4%	50%	2.6%	50%	1.9%	50%	1.5%	50%	1.4%
	BOCCGT	120.0	82%	92.4%	85%	79.7%	81%	93.1%	84%	76.0%	84%	77.8%
IPPs	JPPC	60.0	45%	46.9%	58%	40.6%	60%	52.8%	57%	36.9%	58%	37.6%
	JEP	124.36	11%	10.2%	11%	5.8%	14%	4.6%	12%	3.9%	11%	4.0%
	WKPP	65.5	36%	29.3%	38%	19.3%	43%	18.5%	38%	15.8%	39%	16.4%
	SJPC	190.0	83%	91.9%	82%	93.5%	79%	90.5%	82%	96.5%	82%	94.8%
	NFE/ JAMALCO	94.0	43%	70.5%	56%	93.5%	57%	91.4%	57%	92.4%	57%	92.4%
	JPS DG	14.0	6%	0.0%	68%	0.0%	92%	95.4%	95%	95.6%	95%	95.6%

13.81. With regard to plant utilization levels, the OUR's review identified a major discrepancy with the NFE CHP plant in JPS' Heat Rate model outputs. The issue is:

- JPS' dispatch of the plant did not conform to the "as-available" designation stipulated in the PPA. This situation will have to be discussed with JPS.

13.82. While the issues uncovered cannot be ignored, overall, the OUR's results show a fair comparison with JPS' forecasted values.

13.7.2. OUR's Annual Heat Rate Projections

13.83. Based on the available Heat Rate data, the OUR's evaluation also estimated the annual average Heat Rates for JPS' thermal generation plants for the Rate Review period. The OUR's projected Heat Rates compared to those forecasted by JPS, are presented in Table 13.16.

Table 13.16: Comparison of JPS' and OUR's Heat Rate Projections (2020-2024)

Year	Heat Rate Mode	Heat Rate in kJ/KWh			Remarks
		JPS Forecast	OUR Projection	Variance	
2020 - 2021	JPS Thermal Plants	**9,771**	9,133	638	Not optimal
2021 – 2022	JPS Thermal Plants	9,657	9,327	330	
2022 – 2023	JPS Thermal Plants	9,349	9,144	205	
2023 – 2024	JPS Thermal Plants	9,334	9,185	149	

Indications from OUR's Heat Rate Evaluation

1) The results suggest that there are significant variances between JPS' 2020-2024 annual Heat Rate values and those derived by the OUR.
2) During the Rate Review period, the H-Factor will be predominantly based on JPS' BOCCGT and its RF#1 & RF#2 units.
3) The recent addition of 288MW of new IPP generating capacity, the closure of the JPS OH steam units (193MW), and the impending retirement of the HB B6 unit, should result in an increased system reserve margin, during the Rate Review period. Consequently, JPS' open cycle gas turbine (OCGT) units (peak load units), are expected to operate at very low average CF (less than 3%), with minuscule contribution to JPS' Heat Rate performance.

13.7.3. Statistical Analysis

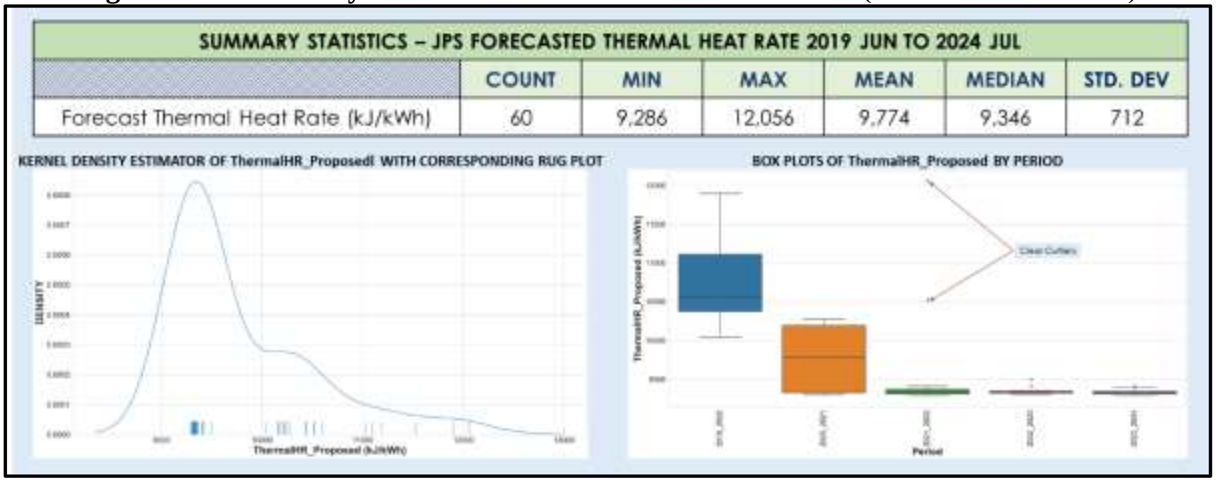
13.84. To test the soundness of JPS' forecasted monthly Heat Rates used to derive the proposed targets, they were subjected to statistical analysis by the OUR. The summary statistics, which was generated, is presented in Figure 13.8 below, which also shows the variation in the data, in aggregate, and per period, respectively.

Key Observation and Deduction

13.85. The key observations and deductions were as follows:

1) The analysis indicates that the centre of the distribution (the median) is at 9,346 kJ/KWh;
2) The mean value diverged from the median due to the Heat Rate values, flagged by the OUR as being questionable;
3) The arithmetic average of the proposed targets converged to the statistical mean of the distribution, but is not a robust statistical representation due to the influence of the outliers;
4) Heat Rate targets within the vicinity of the median value would be statistically representative.

Figure 13.8: Summary Statistics - JPS' Forecasted Heat Rates (2019 Jul to 2024 Jun)



SUMMARY STATISTICS – JPS FORECASTED THERMAL HEAT RATE 2019 JUN TO 2024 JUL						
	COUNT	MIN	MAX	MEAN	MEDIAN	STD. DEV
Forecast Thermal Heat Rate (kJ/kWh)	60	9,286	12,056	9,774	9,346	712

13.7.4. Scenario Analysis

13.86. It was established from the evaluation that the OUR's projections shown in Table 13.16 above, basically represent indicative average Heat Rates for the Rate Review period, and not the established targets. Therefore, to set the relevant targets, the OUR elevated these baseline Heat Rate values with an uplift factor (buffer), estimated from scenario analysis using the historical/forecasted data and statistical methods, (Refer to Table 13.17 below).

13.8. OUR's Determined Heat Rate Targets (2020-2024)

13.87. Based on the OUR's Heat Rate evaluation and analysis, the Office determined that JPS' Heat Rate targets based on its thermal generation plants, for the Rate Review period, shall be as set out in Table 13.17 below.

Table 13.17: OUR's Determined Heat Rate Targets for JPS (2020-2024)

OUR DETERMINED HEAT RATE TARGETS FOR JPS (2019-2024)						
Rate Adjustment Period	**Heat Rate Modality**	**JPS Proposed Heat Rate Target (kJ/kWh)**	**OUR Projection (kJ/kWh)**	**OUR Buffer (%)**	**OUR Determined Targets (kJ/kWh)**	**Target Variance (kJ/kWh)**
2020-2021 Annual Review	JPS Thermal Plants	9,976	9,133	5.9%	**9,675**	301
2021-2022 Annual Review	JPS Thermal Plants	9,860	9,327	3.6%	**9,667**	193
2022-2023 Annual Review	JPS Thermal Plants	9,545	9,144	3.8%	**9,495**	50
2023-2024 Annual Review	JPS Thermal Plants	9,530	9,185	3.1%	**9,470**	60

13.88. Paradoxically, while JPS has argued that the determination of the Heat Rate targets should consider the mix of JPS' generating plants, the OUR's evaluation reveals that some of the company's proposed targets and forecasted values were high and inconsistent with the optimal mix of generation assets assumed to be available during the new regulatory period.

13.89. Nevertheless, based on known system conditions and the Heat Rate assumptions made by JPS, it is expected that, on average, the determined Heat Rate targets will be achieved by the company during the respective rate adjustment periods. Factors that should enable target achievement, over the subject period include, among other things, the following:

1) The retirement of the HB B6 unit with relatively low efficiency at the end of 2020;
2) Major maintenance on the RF#1, RF#2, BOGT#11, and BOCCGT units, with expected efficiency improvements that should be sustained during the period;
3) Recent efficiency improvements on other existing JPS generating units;
4) Expected benefits from other ongoing and planned efficiency improvement programmes;
5) Effective management of the generation dispatch process and system operating constraints;
6) The impact of the 24.5MW HESS on system operations, particularly, to mitigate intermittency effects caused by VRE generation, with potential adverse effects on Heat Rate performance;
7) The existing predominance of IPP-based capacity, effectively relieving the system of low-efficiency and degraded oil-fired steam plants;
8) The expected addition of the committed JPS 14MW DGs, and resulting efficiency enhancement;
9) The upgrading of the transmission system to facilitate optimal power flows and mitigate network constraints; and
10) The consideration of the effects of exceptional IPPs forced outages on the targets.

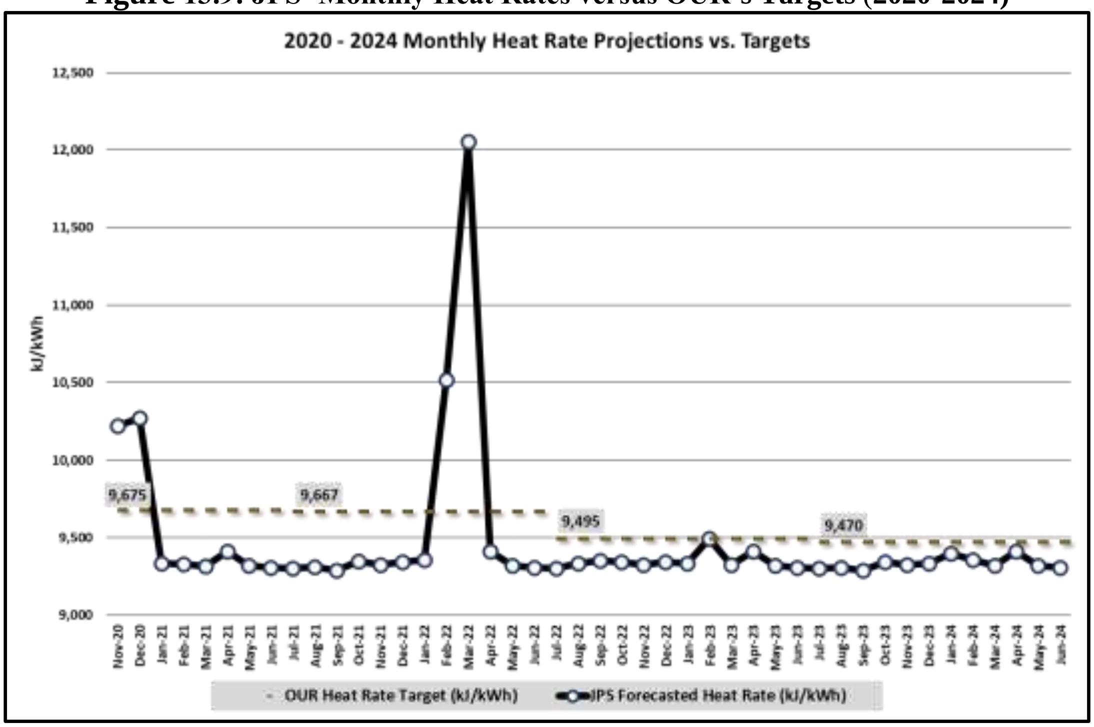
13.8.1. JPS' Heat Rate Projections versus OUR's Targets

13.90. A fundamental principle associated with the H-Factor construct is that the Heat Rate Target is an annual average value applied on a monthly basis. This means that JPS' Heat Rate performance in each billing month relative to the applicable target, is not inherently discrete but operates within a continuum subject to the time limits of the respective rate adjustment periods. That is, an under achievement of the target in one or two billing months, may not necessarily lead to penalties to the company on aggregate, at the end of the rate adjustment period. This construct is demonstrated in Table 13.18 and Figure 13.9 below, which shows a comparison of JPS' 2020-2024 monthly Heat Rate projections against the OUR's targets.

Table 13.18: JPS' 2020-2024 Forecasted Heat Rates versus OUR's Targets

PERIOD	2020-2021 Rate Adjustment			2021-2022 Rate Adjustment			2022-2023 Rate Adjustment			2023-2024 Rate Adjustment		
	(kJ/kWh)			(kJ/kWh)			(kJ/kWh)			(kJ/kWh)		
	JPS HEAT RATE	OUR TARGET	VAR	JPS HEAT RATE	OUR TARGET	VAR	JPS HEAT RATE	OUR TARGET	VAR	JPS HEAT RATE	OUR TARGET	VAR
JUL				9,304	9,667	-363	9,304	9,495	-191	9,302	9,470	-168
AUG				9,309	9,667	-358	9,332	9,495	-163	9,308	9,470	-162
SEP				9,287	9,667	-380	9,351	9,495	-144	9,286	9,470	-184
OCT				9,346	9,667	-321	9,344	9,495	-151	9,345	9,470	-125
NOV	10,222	9,675	547	9,327	9,667	-340	9,326	9,495	-169	9,325	9,470	-145
DEC	10,272	9,675	597	9,343	9,667	-324	9,343	9,495	-152	9,333	9,470	-137
JAN	9,334	9,675	-341	9,357	9,667	-310	9,332	9,495	-163	9,398	9,470	-72
FEB	9,329	9,675	-346	10,516	9,667	849	9,496	9,495	1	9,356	9,470	-114
MAR	9,317	9,675	-358	12,056	9,667	2,389	9,324	9,495	-171	9,319	9,470	-151
APR	9,411	9,675	-264	9,411	9,667	-256	9,412	9,495	-83	9,410	9,470	-60
MAY	9,322	9,675	-353	9,322	9,667	-345	9,319	9,495	-176	9,318	9,470	-152
JUN	9,306	9,675	-369	9,306	9,667	-361	9,305	9,495	-190	9,305	9,470	-165
AVG	**9,564**	**9,675**	**-111**	**9,657**	**9,667**	**-10**	**9,349**	**9,495**	**-146**	**9,334**	**9,470**	**-136**

Figure 13.9: JPS' Monthly Heat Rates versus OUR's Targets (2020-2024)



Forecasted Performance Projections and Targets

13.91. Arising from the OUR's analysis of JPS' projected performance, the following were deduced:

1) JPS would achieve the targets on average, for each rate adjustment period, except for four (4) billing months (2020 November-December and 2022 February-March), with questionable Heat Rate values;
2) For 2020-2021, the forecasted Heat Rate performance relative to the target would result in a variance of -111 kJ/kWh (-1.15%). However, the Heat Rates for 2020 November–December are relatively high and the supporting data suggests sub-optimal generation dispatch, as exhibited in Figure 13.10 below. This means that JPS' generation dispatch process/activities will require further review;
3) For 2022 March, JPS projected an average Heat Rate of 12,056 kJ/kWh, which appears to be excessively high and does not reflect economic generation dispatch operation. On close examination of the data, it was found that the main components of the Bogue CCGT unit (GT#12, GT#13, HRSG#12, HRSG#13, and Steam#14), are scheduled to be on major maintenance for almost the entire month, which would have some impact on JPS' Heat Rate performance. However, JPS' 2022 CF projections show that the same CCGT unit, which should be out of service for maintenance, was projected to be utilized at a CF of about 60%, while in the same month, the utilization of efficient IPP generation facilities was significantly restricted, as shown in Figure 13.10 below.

Figure 13.10: JPS' 2020/2022 CF Projections and Bogue CCGT Scheduled Maintenance

CAPACITY FACTOR PROJECTIONS (2020 JUL – DEC)

	Capacity	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
Old Harbour Steam	68.5						
OH-4	68.5						
Hunts Bay Steam	68.5	47%	47%	47%	47%	47%	47%
HB-B6	68.5	47%	47%	47%	47%	47%	47%
Rockfort	40	83%	51%	80%	75%	65%	56%
RF-B1	20	83%	52%	80%	81%	59%	56%
RF-B2	20	83%	51%	80%	68%	71%	56%
Hunts Bay Gas Turbines	54	6%	6%	6%	6%	6%	6%
HBGT10	32.5	7%	7%	7%	7%	7%	7%
HBGT5	21.5	4%	4%	4%	4%	4%	4%
HB-Combined	122.5	29%	29%	29%	29%	29%	29%
Bogue Gas Turbines	97.5	11%	12%	10%	12%	12%	12%
BOGT3	21.5	3%	3%	3%	3%	3%	3%
BOGT9	20	2%	3%	3%	3%	3%	3%
BOGT7	18			0%	0%		0%
BOGT6	18						
BOGT11	20	50%	50%	45%	50%	50%	50%
BOG-Combined Cycle	120	88%	87%	88%	88%	86%	85%
	217.5						
Private Power	548.00	52%	48%	51%	48%	49%	43%
JEP (Plant Total)	124.50	9%	3%	9%	12%	11%	7%
JPPC	60	67%	63%	51%	44%	52%	28%
WKPP	65.5	36%	22%	41%	33%	25%	14%
SJPC 194	190.0	82%	80%	81%	79%	83%	78%
JPS DG	14.0						66%
JAMALCO 94	94.0	58%	58%	58%	58%	57%	56%

PLANNED OUTAGES (2022 FEB 1 – MAR 4)

STATION	Rated Capacit	Outage Days	Derated Capacit	From	To	REASON
Steam #14	40.0	40	40.0	Tuesday, 01 February, 2022	Sunday, 13 March, 2022	Steam Turbine Overhaul
HRSG12 - Bogue	18	3.0	18.0	Saturday, 12 February, 2022	Wednesday, 02 March, 2022	HRSG12 - Bogue Statutory 2021
GT12 - Bogue	38	3.0	38.0	Saturday, 12 February, 2022	Tuesday, 22 March, 2022	GT12 - Bogue - Hot Gas Path Inspection
HRSG13 - Bogue	18	3.0	18.0	Thursday, 17 February, 2022	Monday, 07 March, 2022	HRSG13 - Bogue Statutory 2021
GT13 - Bogue	38	3.0	38.0	Thursday, 17 February, 2022	Sunday, 27 March, 2022	GT13 - Bogue - Hot Gas Path Inspection
GT8 - Bogue	20	3.0	20.0	Tuesday, 22 February, 2022	Monday, 14 March, 2022	GT8 - Bogue - Hot section Inspection
Wartsila	50.2	25	16.7	Tuesday, 01 March, 2022	Friday, 25 March, 2022	DG #9 Generator Inspection
JPPC	30.7	3	30.7	Tuesday, 01 March, 2022	Thursday, 03 March, 2022	Engine #2 on maintenance outage
Wartsila	50.2	1	50.2	Friday, 04 March, 2022	Friday, 04 March, 2022	Total Plant Outage

CAPACITY FACTOR PROJECTIONS (2022 FEB – APR)

	Capacity	Feb-22	Mar-22	Apr-22
Rockfort	40	70%	86%	82%
RF-B1	20	90%	86%	82%
RF-B2	20	49%	86%	82%
Hunts Bay Gas Turbines	54	9%	6%	6%
HBGT10	32.5	12%	8%	7%
HBGT5	21.5	6%	4%	4%
Bogue Gas Turbines	97.5	12%	12%	12%
BOGT3	21.5	3%	3%	3%
BOGT9	20	4%	3%	3%
BOGT7	18	0%	0%	
BOGT6	18	0%		
BOGT11	20	50%	50%	50%
BOG-Combined Cycle	120	73%	59%	79%
	217.5			
Private Power	548.00	59%	54%	51%
JEP (Plant Total)	124.50	34%	21%	10%
JPPC	60	48%	29%	53%
WKPP	65.5	76%	60%	38%
SJPC 194	190.0	77%	84%	83%
JPS DG	14.0	84%	96%	96%
JAMALCO 94	94.0	58%	58%	56%

NOTES

- Projected Capacity Factor for some IPP plants significantly lower than some JPS facilities of lower efficiency.
- JEP capacity factor at 12% or lower during 2020 Jul – Dec, while GT11 and B6 at or close to 50% during the same period.
- JEP capacity factor at 34% or lower during 2022 Feb – Mar, while Bogue CCGT at 50% throughout, despite the steam turbine being out of service for a significant portion of that period

13.92. Notwithstanding these issues, a reasonable buffer was incorporated in the determined targets to provide JPS with sufficient latitude and flexibility to withstand the effects of potential forced outages (infrequent) or other operational constraints that may be encountered during the period. Even with some dispatch deviation ($\leq 2\%$), the company is still incentivized to achieve the targets during the respective rate adjustment periods.

13.93. Further, the OUR recognizes that there is merit in JPS' argument that the absence of the IRP at the time of this Rate Review may result in its Heat Rate assumptions and analysis being out of sync with the IRP when it is published. However, an assessment of whether an Extraordinary Rate Review is warranted would have to await the publication and evaluation of the IRP against actual performance in the sector, particularly given the possible effect of Covid-19 on the demand for electricity.

13.94. The OUR also acknowledges that some of the effects caused by IPP issues are beyond JPS' control. However, even though the H-Factor mechanism does not automatically adjusts for such IPP effects, the OUR includes these considerations in the setting of the Heat Rate targets.

13.95. Contrary to JPS' position, the OUR does not share the view that "heat rates are likely to change materially and frequently over the subject timeframe therefore, the annualized targets represent just a coarse summation of discrete 12 months Heat Rate data". The condition of the generation system is known and the Heat Rate performance is predictable within an acceptable statistical range. Therefore, the use of annual targets set over a five (5) year period is reasonable and serves as an incentive for generation efficiency.

13.96. JPS also argues that the potential exists for the extended use of alternate fuels in the dual-fuel power plants, which may distort the company's Heat Rate performance. In principle, the OUR considers this a tangential issue of setting the Heat Rate target. The use of the alternative fuel was conceived as a contingency arrangement, which excluded extended or continuous use. Therefore, based on the existing primary fuel supply logistics, the OUR's probabilistic analysis, and other factors, the utilization of the secondary fuel is expected to be marginal, with immaterial impact on JPS' Heat Rate performance.

13.97. Overall, the Office believes that the determined Heat Rate targets are reasonable and achievable, and consistent with the legal and regulatory framework, and good regulatory practice.

13.9. OUR's Comments and Position

13.98. While there have been recognizable improvements in generation efficiency during the 2014-2019 regulatory period, a number of issues have emerged during this 2019-2024 Rate Review process, that have implications for the operation of the generation system going forward. These issues are delineated below.

System Heat Rate

13.99. Since 2015, the basis for determining the relevant H-Factor parameters was shifted from a System Heat Rate approach to a thermal plant methodology. While there have been incremental improvements in the System Heat Rate as the grid evolves, this efficiency indicator is now dominated by IPPs' contracted Heat Rates, which are not necessarily representative of the generating plants' actual design Heat Rates, and therefore do not convey the true efficiency effect.

Despite the change in methodology, the System Heat Rate, nonetheless, provides an indication of the overall fuel conversion efficiency of the entire generation system. On that basis, the OUR has determined that in accordance with prudent utility practice, JPS should continue to calculate the System Heat Rate on a monthly basis and include it as a key performance indicator (KPI) in the monthly Fuel Rate Calculation Reports.

Merit Order and Economic Generation Dispatch

13.100. The EA, the Licence and the Electricity Sector Codes include specific provisions, requiring that the System Operator (JPS) schedule and dispatch all available generating units in the system, in accordance with a merit order system. The established merit order/generation dispatch framework stipulates that the generating units shall be dispatched in ascending order of marginal costs based on "Equal Incremental Cost-System" principles, to the extent allowed by transmission system operating constraints. While the defined legal and regulatory framework provides clear guidance on this process, certain issues continue to arise. Some of which include:

1) Lack of clarity in the reporting structure of the System Operator in relation to the generation dispatch process;
2) IPPs concern regarding the transparency of the merit order calculations and the dissemination of dispatch information;
3) Concerns about fairness in the dispatch process due to apparent disparities in the utilization of IPP generation facilities versus plants owned and operated by JPS;
4) Out-of-merit dispatch without adequate explanation or report;
5) VOM cost for JPS plants not included in dispatch inputs and assumptions, despite the relevant legal and regulatory requirements; and
6) The mode of dispatch of certain IPP facilities. In the case of the NFE CHP facility, the PPA provisions specify an "as available" supply arrangement. Moreover, the Electricity Sector Codes make special provision for plants with an "as available" contract. Specifically, section DSC 5(k) of the Electricity Sector Codes, states as follows:

   "Units that have been declared based on their contract, as Take-As-Available, are not influenced by the merit order and equal incremental cost Optimization processes".

Merit Order/Generation Dispatch Information Requirements

13.101. To address some of the identified issues and to facilitate periodic assessment and ongoing monitoring of the merit order/generation dispatch system, the company shall submit:

- A monthly detailed Dispatch Report that addresses all generation dispatch operations during the month, including the cost impact of out-of-merit dispatch, and dispatch deviations, which shall be submitted to the OUR within ten (10) days after the end of the applicable month. For transparency, pursuant to section 45(8) of the EA, the System Operator shall also issue the monthly Dispatch Report, and all relevant dispatch related information to all generation Licensees with utility-scale generation facilities interconnected to the system.

VOM Costs in the Merit Order/Generation Dispatch System

13.102. It was observed in JPS' 2019-2024 generation dispatch simulation data that the VOM cost component was not included in the total variable cost of JPS' generating units used in the merit order/dispatch calculations, but those for the IPP plants were included. The exclusion of this cost component for JPS' generating units is not a fair dispatch practice and suggests a preference for JPS' plants, which may not be economical. This issue was previously raised during the 2014-2019 Tariff Review process after similar observations were made by the OUR and should be addressed.

13.103. In principle, this practice clearly deviates from the legal and regulatory requirements. For reference, the provisions of the Electricity Sector Codes (Section DSC5) pertaining to VOM cost, state as follows:

> *"The System 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) x Full Load Heat Rate (MBTU/MWh) + VOM ($/MWh…"*

13.104. In essence, the VOM cost is a function of the operation of each generating unit, and therefore should be properly accounted for in JPS' cost structure and dispatch process.

13.105. The relevant variable cost calculations, including the VOM cost for each dispatchable generating unit, shall be included as part of the merit order/generation dispatch reporting requirements defined in this Determination Notice.

Generation Dispatch Audit

13.106. Taking into consideration the described merit order/generation dispatch issues, as well as other related problems identified during the OUR's Heat Rate review, the OUR, pursuant to section 45(7) of the EA, will commission an independent audit of JPS' merit order/generation dispatch system during the 2020-2021 rate adjustment period.

Generation Maintenance

13.107. Generation maintenance is a critical system function necessary for maintaining operational efficiency and ensuring reliability and service continuity. The Application includes annual generation maintenance schedules for the Rate Review period and the proposed generation maintenance projects, which were reviewed by the OUR and found to be reasonable. However, a retrospective look at JPS' generation maintenance activities to date reveals a less than impressive track record. JPS has had challenges with maintenance scheduling, protracted completion time, and significant cost overruns. Therefore, in order to improve the execution of generation maintenance:

1) It is imperative that JPS pays greater attention to proper maintenance planning and execution, detailed outage planning, project risk assessment and mitigation strategies, execution monitoring and timely reporting;

2) Without prejudice to the proposed maintenance projects, as part of the reporting requirements, the company shall continue to submit the updated annual generation maintenance schedule to the Office in accordance with the provisions of the Electricity Sector Codes.

Heat Rate Test Data

13.108. The Heat Rate Test data is a key input to the dispatch optimization process. Therefore:

1) To maintain the effectiveness of the generation dispatch operations, the System Operator shall ensure that the requisite Heat Rate Tests are conducted in accordance with the relevant provisions of the Electricity Sector Codes;

2) For regulatory compliance, the System Operator shall submit the following to the OUR:

   a) The Heat Rate Test schedule for all dispatchable generating units within fourteen (14) days after the specified timeline for development, as per the Electricity Sector Codes.

   b) A report on the Heat Rate tests conducted on all dispatchable generating units (JPS and IPPs), in accordance with the requirements of the Electricity Sector Codes. This report shall be submitted as part of the monthly Technical Reports, as per the test schedule.

IPP Related Issues

13.109. Based on recent developments in the generation segment, IPPs have emerged as the dominant power producers. With this outcome, there will be greater need to maintain fairness and transparency in relation to the operation of the relevant generation facilities. IPPs' commercial arrangements are mainly governed by their respective PPAs. Even so, the OUR, in accordance with the legal and regulatory framework, will ensure that specific details involving their generation operations, fuel costs, fuel payments, and other relevant aspects are submitted by JPS, for its periodical review and assessment.

13.110. On the issue of IPPs' forced outages raised by JPS, the OUR is mindful that there will be IPP related events from time to time. However, the company's claim that the OUR has not factored these conditions in setting the Heat Rate targets, is without merit. To be clear, the OUR in setting the relevant Heat Rate targets over the years has consistently assessed the probabilities of exceptional forced outages occurring on all dispatchable generating units, with their potential risks analysed within the framework of the OUR's Heat Rate evaluation model. This approach has proven effective, as manifested by the company's Heat Rate performance over the past fifteen (15) years. The performance largely reflects that JPS has consistently achieved the determined targets, regardless of occurrences of exceptional IPP forced outage events.

13.111. Further, the OUR takes the position that this issue involves a high degree of reciprocity. While there are implicit Heat Rate benefits to JPS from favourable IPP operations, on the opposite side, there could be some negative impact due to extra-ordinary forced outages, which would likely create a counter balance, thereby minimizing the scope of any exposure.

13.112. JPS claims that compensation for IPP forced outages via Liquidated Damages (LDs) does not offset the consequential adverse impact on its Heat Rate performance, and resultantly, does not satisfy the condition that JPS should be held harmless against actions it cannot control, as set out in Schedule 3, Exhibit 2, footnote 3 of the Licence. Notwithstanding JPS' claims, the Office maintains that Heat Rate targets that have been previously set for JPS and now determined for this 2019-2024 Rate Review, have satisfied the following key conditions:

a) Alignment with the existing/projected generation system configuration/capability;
b) Incorporates the impact of IPPs, forced outage rates; and
c) Accords with the legal & regulatory framework, the established Heat Rate target principles, and good regulatory practice.

Fuel Reporting Requirements

13.113. Subject to the provisions of the Licence, fuel-related expenses prudently incurred should be recovered through the approved FCAM. To ensure that the total fuel cost (JPS and IPPs) incurred in each billing month is reasonable and prudent, the OUR will systematically assess the actual fuel cost, the relevant power purchase costs, and the supporting determinants/parameters reported by JPS, for the subject month. To facilitate this review process, JPS shall submit a complete Fuel Rate Calculation Report to the Office each month, which shall include, among other things, the following components:

1) The relevant schedules and calculations used to derive the average monthly Fuel & IPP Charge, and the allocations to each rate class;
2) Detailed description of the methodology and calculations used to derive the volumetric sales adjustment;
3) The applicable fuel prices based on the respective fuel supply agreements (FSAs);
4) Invoices of fuel purchases applicable to a billing period;
5) A detailed break-down of the NG cost and prices as per the respective GSAs;
6) A separate schedule containing the calculations of the applicable Net Billing Rate;
7) Net generation for each generating unit/facility for the applicable months;
8) The average Heat Rate data for each dispatchable generating unit for the applicable month;

9) The relevant power purchase costs; and

10) The calculation of the IPPs payments as per Schedule 6 of the respective PPAs in Microsoft Excel, showing all relevant calculations/formulas files.

13.114. This Fuel Rate Calculation Report shall be structured and presented as follows:

a) It shall show all the relevant fuel rate calculations/formulas and shall be submitted in an appropriate electronic format on the same day the calculation is completed by JPS (that is, prior to billing). Additionally, a hard copy of the complete report, including the IPPs transactions shall be submitted to the Office within ten (10) days after the month for which the Fuel Rates were calculated.

b) The following types of costs shall not be included in the monthly Fuel Rate calculation:

i. O&M expenses related to generating plants or storage facilities;

ii. Foreign exchange (FX) adjustment for JPS' fuel transactions; and

iii. Cost related to fuel procurement administrative functions.

13.115. Any, and all unusual or extraordinary cost items that JPS intends to recover through an adjustment in the monthly Fuel Rates, shall first be submitted to the Office for review and approval. Such submission shall be presented in sufficient detail including any relevant calculations to facilitate the evaluation of the appropriateness of such cost item.

Fuel Management Report

13.116. To ensure proper monitoring of JPS' fuel usage, the company shall submit a Fuel Management Report (FMR) to the Office each quarter. This FMR shall address the company's fuel purchases, inventory and usage in each month of the quarter, and shall include among other things, the following:

1) Budgeted and actual fuel consumption and cost for each month;

2) Quantity of fuel purchased;

3) Quality of fuel purchased, including heating value (HHV and LHV), sulphur content, etc.;

4) Fuel invoices showing quantity purchased, unit cost, and total costs for quantity purchased; and

5) The fuel inventory methodology/system employed by JPS shall be based on international standards, and the tracking of fuel consumption should be evident.

13.117. The FMR shall be submitted to the Office within thirty (30) days after the end of the applicable quarter.

Fuel Audits

13.118. An integral part of the fuel monitoring process involves periodic audits of JPS' fuel management and usage, and Fuel Rate calculation methodology. These audits are necessary to assist the OUR with the validation of fuel data reported by JPS. In that regard, the OUR intends to strategically perform these fuel audits, during the Rate Review period.

Technical Reports

13.119. The monthly Technical Reports provide generation data, which are used for corroboration purposes and continuous regulatory monitoring of key operational parameters. To support this process, for the Rate Review period, JPS shall continue to submit these reports to the OUR in electronic format, within ten (10) days after the end of the applicable month. The reports shall also capture the progress of system development projects in a format to be defined by the OUR.

Regulatory Review of Heat Rate Targets

13.120. On the matter of target adjustment, the concerns expressed by JPS in the Application appear to convey a sense of anxiety in pre-empting the OUR's approach to address factors that could impact Heat Rate performance, deemed to be outside the company's control. In principle, while the OUR accepts the relevant prescriptions of the Licence pertaining to Heat Rate targets, the company would be aware that there has been established regulatory precedence for over 15 years, in which annual Heat Rate targets have been reviewed and adjusted as applicable. In this regard, the Office having cognizance of the established regulatory principles and precedence, will continue to review the Heat Rate targets at each Annual Review, and reset if deemed necessary.

Office Determination: FCAM and H-Factor

13.121. Based on the OUR's review, the Office's decisions on JPS' H-Factor proposals and the FCAM are set out below in Determination 20.

DETERMINATION 20

1) JPS' proposed Heat Rate targets for 2020-2024 were deemed to be high and not consistent with the economic generation dispatch during the subject period. Accordingly, the Office has approved the following annual Heat Rate targets for the 2020-2024 regulatory period:

   a) 2020–2021 Annual Review: 9,675 kJ/kWh
   b) 2021–2022 Annual Review: 9,667 kJ/kWh
   c) 2022–2023 Annual Review: 9,495 kJ/kWh
   d) 2023–2024 Annual Review: 9,470 kJ/kWh

2) Having regard to the relevant provisions of the Licence and established regulatory precedence, the determined Heat Rate targets shall be reviewed by the Office at each Annual Review to account for efficiency improvements and factors outside the company's control, during each discrete rate adjustment period within the Rate Review period.

3) After the effective date of each Annual Review Determination Notice, the H-Factor adjustment shall commence with JPS' fuel cost for the preceding calendar month.

4) In accordance with legal and regulatory requirements, the VOM cost component shall be included in the total variable cost for all dispatchable generating units in the system to allow proper calculation of the merit order/generation dispatch costs.

5) Pursuant to section 45 (7) of the Electricity Act, 2015, the OUR shall commission an independent audit of JPS' merit order/generation dispatch activities during the Rate Review period.

6) In addition to the details in the hard copies, the relevant calculations for the applicable capacity and energy payments for all the IPPs in the system, as per Schedule 6 of the respective PPAs, shall be submitted in Microsoft Excel format, in the monthly Fuel Rate Calculation Report, to commence with the first billing after the effective date of this Determination Notice.

7) JPS shall comply with all the Fuel & H-Factor related requirements, including the submission of Technical Report to the OUR in electronic format, within ten (10) days after the end of the applicable month.

14. System Losses – Initiatives and Targets (Y-Factor)

14.1. Introduction

14.1.1. System Losses

14.1. Electricity losses in an electric utility power system is a key measure of the operating efficiency and financial sustainability of the electricity sector as a whole. For regulated utilities, these losses are generally defined as the difference between the quantities of electricity (kWh) injected into the grid and the actual amounts billed to customers and system-users. Mathematically, this can be expressed on a percentage basis as represented in the formula below:

System Losses (%) = [(Electricity to System (MWh) – Total Electricity Billed (MWh))/Electricity to System (MWh)] X 100%

14.2. Generally, there are two broad categories of electric System Losses: Technical Losses (TL) and Non-Technical Losses (NTL).

Technical Losses

14.3. TL is internal to the power system and represent fixed and variable losses due to energization of network equipment, current flowing through electrical devices, and consumption by equipment. These losses are also influenced by system design/configuration. The cost of these losses at a certain level is normally considered in the utility's overall cost of service.

Non-Technical Losses

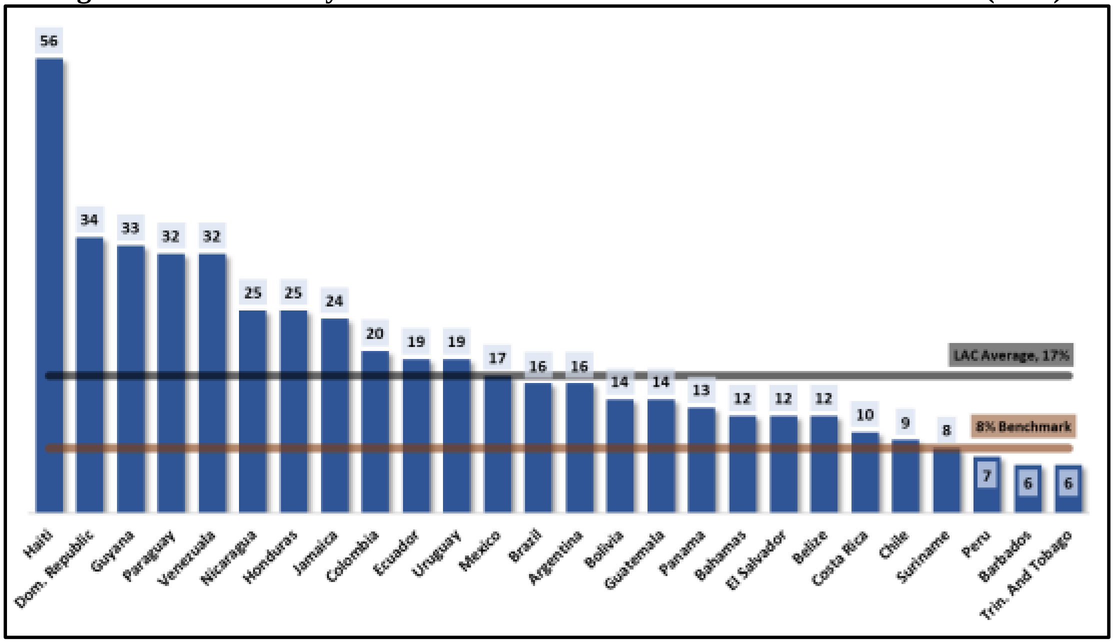
14.4. NTL are due to actions external to the power system and are typically attributed to administrative errors in the metering and billing systems, meter inaccuracies, meter tampering, throw-ups, and other forms of irregularities. Essentially, it is the amount of energy not billed, but consumed, and represents a financial loss to the system.

14.1.2. System Losses – Status

14.5. Currently, the reported energy losses in the grid are dominant in the distribution network. These losses constitute a major problem for the economic viability of JPS and by extension service delivery to its customers.

14.6. Regional losses studies for Latin America and the Caribbean (LAC) electric utility systems show that total energy losses (based on a 5-year average) for JPS' system is significantly higher than a number of utilities in the region, as demonstrated in Figure 14.1 below.

Figure 14.1: Electricity Losses in Latin America and Caribbean Countries (2014)



Source: IDB Study (2014), Power Lost – Sizing Electricity Losses in T&D Systems LAC

14.7. This level of electricity losses adversely impacts the system infrastructure and the overall cost of electricity. It is therefore important that measures be put in place through the adoption of appropriate policies, use of prudent utility planning, and the deployment of sound technological solutions to keep losses at a minimum.

14.2. Licence Requirements for System Losses

14.2.1. Relevant Provisions

14.8. The regulatory requirements applicable to the System Losses in Jamaica, defined as the Y-Factor are set out under Schedule 3, paragraphs 37, 38, and 46 c. and Exhibit 1 of the Licence; and the Legal and Regulatory framework set out in this Determination Notice.

Licence Modification in 2016

14.9. The Licence redefined the basis for System Losses (Y-Factor) adjustments in JPS' cost recovery mechanism, effective 2016 July 1. This entailed a fundamental transition from System Losses adjustment to the monthly total fuel cost, to a true-up mechanism used for adjustment to the non-fuel ART.

14.2.2. System Losses Targets

14.10. Pursuant to Schedule 3, paragraph 38 of the Licence, the targets set by the Office for System Losses shall normally be done at the Rate Review and be for a "rolling" ten (10) year period broken out year by year for the following three (3) categories:

a) Technical losses (Ya), designated TL;

b) Non-technical losses totally under JPS' control (Yb), designated JNTL; and

c) Non-technical losses not totally under JPS' control (Yc), designated GNTL.

14.11. Regarding the rolling 10-year targets, the Licence notes as follows:

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

14.2.3. System Losses True-up Mechanism

14.12. In accordance with Schedule 3, Exhibit 1 of the Licence, the Losses component of the Revenue Surcharge (RS) included in the ART adjustment mechanism, is computed based on the formulae below:

TULosy-1	**=**	**Yy-1 * ART y-1**
Yy-1	**=**	**[Yay-1 + Yby-1 + Ycy-1]**
Yay-1	=	Target System Loss "a" Rate%y-1 – Actual System Loss "a" Rate%y-1
Yby-1	=	Target System Loss "b" Rate%y-1 – Actual System Loss "b" Rate%y-1
Ycy-1	=	(Target System Loss "c" Rate%y-1 – Actual System Loss "c" Rate%y-1)*RF

Where: Ya = TL; Yb = NTL totally within JPS' control (JNTL); Yc = NTL not totally within JPS' control (GNTL); and RF is a percentage from 0% to 100%, which is determined by the Office.

14.13. Implicit in the Y-Factor design is a symmetrical incentive scheme. That is, any over-achievement or under-achievement of determined targets, results in a financial benefit or penalty, which will be reflected in the PBRM.

14.2.4. Final Criteria: Y-Factor

14.14. Regarding JPS' System Losses requirements for this 2019-2024 Rate Review, Criterion 12 of the Final Criteria provides as follows:

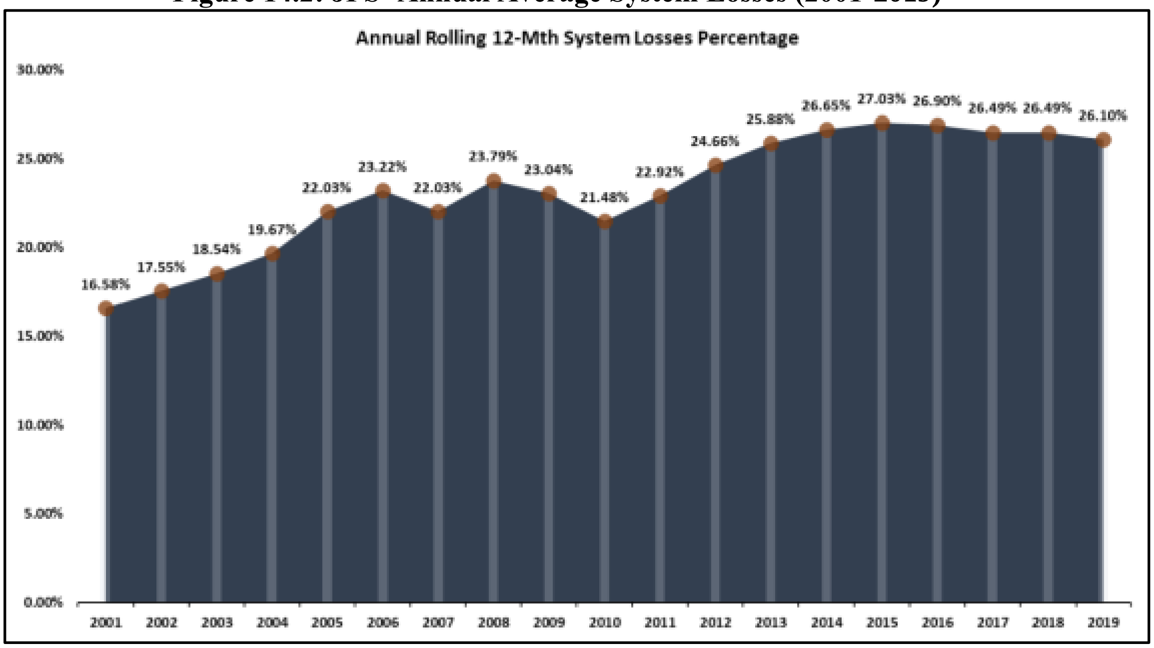
> **Criterion 12**
>
> c) In the Application, JPS shall submit its system losses covering each 12-month adjustment interval constituting the Rate Review period and which shall include:
>   i. Projected losses performance;
>   ii. Proposed targets and responsibility factors; and
>   iii. Proposed methodology to manage the financial impact of the Y-Factor.
>
> d) JPS shall provide the relevant support schedules, which document
>   i. The detailed calculations;
>   ii. Energy Loss Spectrum (ELS); and
>   iii. All other relevant data to substantiate its system losses projections and proposed targets.

14.15. Additionally, the specific information requirements pertaining to the Y-Factor for this 2019-2024 Rate Review are specified in Annex 3 of the said Final Criteria.

14.3. Evolution of JPS' System Losses and Strategy

14.16. At the start of privatization in 2001, JPS' average System Losses were reported as 16.58% of annual net generation, disaggregated into TL and NTL of 10% and 6.58% respectively. This level of NTL at the time was considered by some multinational agencies to be comparable to that of some countries within the development strata in which Jamaica is ranked. However, by the end of 2006, the aggregate losses had already climbed to 23.2% of annual net generation. This increasing trend continued, peaking at 27% in 2015, but declined marginally to approximately 26% at the end of 2019. The trajectory of the annual average losses is shown in Figure 14.2 below.

Figure 14.2: JPS' Annual Average System Losses (2001-2019)



14.3.1. Contributory Factors

14.17. The factors contributing to the observed growth in losses are many and complex. Over the past two decades, the network has experienced a significant increase in unauthorized electricity access. Some of the contributory factors include:

1) Economic and social conditions;
2) Business deficiencies; and
3) Ease of network access.

14.18. Over the years, account audit reports from JPS have consistently shown that the NTL component is largely due to factors that are considered within the utility's control. These factors generally include:

a) Direct connections/throw-ups;
b) Defective metering equipment;
c) Meter tampering/bypass;
d) Incorrect installation of metering system/account set-up;
e) Single phase conditions;
f) Open circuit; and
g) Others.

14.3.1.1. JPS' Strategy

14.19. With the rapid escalation in losses, the company initially pursued a "carrot and stick" approach as part of its mitigation efforts. The strategy was focused on three main aspects:

1) Removal of illegal connections (throw ups);
2) Reinforcement of internal controls (including audits of large accounts); and
3) Conversion of illegal users to legitimate consumers.

Illegal Throw-ups

14.20. Based on the reported losses data over the 2001-2019 period, throw-ups have been the most visible, and public manifestation of NTL. In addition, there are also more sophisticated versions of illicit electricity abstraction, such as meter bypasses by some commercial enterprises and large residential customers. According to JPS, thousands of illegal connections are removed from the system annually, however, no tangible impact from these efforts has been observed to date.

Strike Force Operations

14.21. These operations involve the removal of illegal connections from the electricity network in communities with immensely high losses, sometimes resulting in the arrest of guilty parties. Over the years, the narrative from JPS indicates that the strike force operations within the parishes have helped to deter energy theft, and resulted in the removal of significant numbers of throw-ups and idle services, with hundreds of arrests and some regularization of electricity service. However, the overall benefit of these operations continues to be debatable.

Community Outreach and Social Intervention

14.22. Another aspect of the company's strategy was a campaign to transform illegal consumers into legitimate customers. This strategy is deployed through a Community Renewal Programme (CRP), working in conjunction with relevant authorities and stakeholders. The focal point of this initiative was the inner-city communities (Red Zones), which were offered assistance for regularizing their electricity supply. In an effort to reduce the losses, recover some amount of revenue, and transition consumers to the normal applicable residential rates, a flat rate is offered. While this measure succeeded in legitimising several hundred consumers, it was not particularly successful as only a small number of these consumers consistently honoured their commitments, thus eroding the "stick" element of the loss reduction strategy.

Weakness in Internal Controls

14.23. Another prominent source of energy losses is weaknesses in the company's internal controls. Notably, the largest revenue impact of these energy leakages tends to be associated with large customers' accounts. Therefore, frequent audits of these accounts are considered an effective strategy for loss reduction.

Perception and Penalties

14.24. Up to 2019, JPS reported that approximately 180,000 illegal connections (throw-ups) to the system existed across the country. It has been posited that due to the perception of a lack of consequences for this illegal practice, the phenomenon eventually infiltrated many formal middle-income communities, inflating the NTL. To convey a strong sense of action, the company initially gave a much higher profile to the removal of the throw-ups, with several of its strike force operations receiving broad media coverage. Arrest of persons responsible and penalties were also pursued to eliminate the perception of the lack of accountability. However, these efforts turned out to be largely unproductive, as some areas were likely to escape being checked more than once a year. With that knowledge, the bad actors then restored throw-ups shortly after a raid, with little concern about being disturbed for another year. The arrests and fines were also intended to urge individuals involved in more sophisticated means of pilfering of electrical energy to desist, but it is not clear whether that discouraged the illegal behaviour.

Introduction of Advanced Metering Technology

14.25. In the last quarter of 2007, the company commenced the deployment of Advanced Metering Infrastructure (AMI) devices for priority commercial customers, which provided the increased capability to the company to monitor these accounts and to detect NTL. However, this initiative did not prevent losses from increasing to nearly 24% by the end of 2008.

EEIF to Support Loss Reduction

14.26. In light of upward spiralling system losses, the OUR at the 2009-2014 Tariff Review, approved the EEIF to allow JPS to accelerate the AMI programme. This involved approved funding of approximately US$13 million per year. Despite this intervention, among other regulatory support, by the 2014-2019 Tariff Review, the losses were on course to reach 27% by early 2015. Consequently, the apparent lack of results led to the reduction in the EEIF in 2016 and its eventually termination in 2017.

Subsequent Developments

14.27. In 2016, the level of losses was deemed by stakeholders in the sector to be untenable, and this led to licence amendments encompassing the system losses regulatory mechanism and renewed support for the deployment of new AMI devices. However, while these measures were expected to deliver tangible benefits, the outcomes continue to be undesirable and by the end of 2019, system losses remained at approximately 26% of annual net generation.

14.4. System Losses Performance (2014-2019)

14.4.1. Categorization of JPS' System Losses

14.28. System losses are often reported as a composite figure, but they are comprised of various components, which are usually represented in the form of an ELS. This ELS construct entails the methodology used for the categorization and quantification of the losses over a specified period. Essentially, the ELS calculates total energy losses (12-month rolling average basis) and decompose them into the various categories.

Application of the ELS

14.29. According to Annex 3 of the Final Criteria, the ELS should inform the strategy to measure, manage, mitigate and monitor system losses. In terms of application, it was established that the ELS at December of each year prior to a Rate Review or Annual Review will be the foundational basis for assessment of JPS' system losses performance and setting of the relevant targets, going forward.

2014-2019 ELS

14.30. The system losses reported by JPS for the 2014-2019 regulatory period is represented by the ELS provided in Table 14.1 below.

Table 14.1: JPS' 2014-2019 ELS

2014 - 2019 ENERGY LOSS SPECTRUM								
Loss Category	**Components**	**2014 December**	**2015 December**	**2016 December**	**2017 December**	**2018 December**	**2018 December (JPS Revised)**	**2019 December**
TECHNICAL LOSSES (TL)	Transmission Network	2.60%	2.60%	2.60%	2.60%	2.24%	2.24%	2.22%
	Primary Distribution Lines	1.80%	1.80%	1.80%	1.80%	1.80%	1.50%	1.80%
	Distribution Transformers	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.00%
	Secondary Distribution Lines	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%
	Total Technical Losses	**8.60%**	**8.60%**	**8.60%**	**8.60%**	**8.24%**	**7.94%**	**7.92%**
NON-TECHNICAL LOSSES (NTL)	Streetlight/Stoplight (RT60)	0.20%	0.09%	0.09%	0.09%	0.01%	0.01%	0.00%
	Large C&I (RT70)					-	-	-
	Large C&I (RT40&50)	0.75%	0.45%	0.45%	0.74%	0.43%	0.43%	0.43%
	Large C&I (RT50)	-	-	-	-	0.07%	0.07%	0.07%
	Large C&I (RT40)	-	-	-	-	0.36%	0.36%	0.36%
	Medium C&I (RT20)	0.29%	0.31%	0.38%	0.27%	0.39%	0.39%	0.40%
	Small C&I (RT20)	0.33%	0.32%	0.27%	0.34%	0.23%	0.23%	0.23%
	Residential (RT10)	6.10%	7.08%	7.48%	5.99%	6.12%	6.12%	6.16%
	Sub-Total (Billed Customers)	**7.67%**	**8.25%**	**8.67%**	**7.43%**	**7.19%**	**7.19%**	**7.21%**
	JPS Internal Losses	0.27%	0.53%	0.14%	1.08%	0.82%	0.82%	0.71%
	Illegal Users (non-customers)	10.11%	9.60%	9.30%	9.34%	10.02%	10.32%	10.22%
	Total Non-Technical Losses	**18.05%**	**18.38%**	**18.11%**	**17.85%**	**18.03%**	**18.33%**	**18.13%**
TOTAL LOSSES		**26.65%**	**26.98%**	**26.71%**	**26.45%**	**26.27%**	**26.27%**	**26.05%**
TOTAL TL (MWh)		353,692	362,002	373,568	375,225	358,764	345,698	350,688
TOTAL NTL (MWh)		742,342	773,673	786,524	776,611	785,229	798,296	803,251

TOTAL LOSSES (MWh)	1,096,034	1,135,675	1,160,232	1,154,034	1,143,993	1,143,993	1,153,940
BILLED ENERGY (MWh)	3,016,664	3,073,647	3,183,731	3,208,949	3,211,542	3,211,542	3,275,932
NET GEN (MWh)	**4,112,698**	**4,209,322**	**4,343,812**	**4,363,079**	**4,355,535**	**4,355,535**	**4,429,871**

14.31. The data in Table 14.1 above shows the following:

1) Both TL and NTL are mainly concentrated in the distribution network and account for over 80% of the total system losses. It also suggests that NTL continues to be driven by illegal actions and inefficiencies within the utility operations;
2) While the total losses on a percentage basis decreased from 26.65% of annual net generation in 2014 December to 26.05% at the end of 2019, actual losses in MWh terms have not decreased over the period;
3) The reported reduction in percentage system losses over the period was largely influenced by increases in annual net generation, rather than the impact of JPS' loss reduction initiatives;
4) Total TL was constant at 8.6% of net generation up to 2017 December, but subsequently decreased to 7.92% by 2019 December. This was reportedly due to measurement recalibration and improved modelling of the T&D system. In this regard, it was not due to any tangible impact of the company's TL reduction efforts, during the review period;
5) Total NTL have remained stubbornly high at over 18% of annual net generation for almost the entire period;
6) NTL due to large Commercial and Industrial (C&I) customers continue to be relatively high based on industry standards;
7) NTL attributable to residential customers (Rate 10) increased from 5.99% in 2017 to 6.16% by 2019 December despite JPS' mass deployment of advanced revenue meters, among other NTL reduction initiatives. Also, the spike to 7.48% in 2016 December followed by the sharp decline to 5.99% in 2017 December while not explained by JPS, appears to reflect some undue alteration to the ELS following the 2018 Annual & Extraordinary Rate Review Determination Notice; and
8) NTL caused by illegal users (non-customers) increased from 10.11% of annual net generation in 2014 December to 10.22% in 2019 December but exhibited some degree of fluctuation in between. However, the number of illegal users estimated by JPS has remained constant at 180,000 with unauthorized annual energy consumption moving from 415,794 MWh in 2014 to 403,920 MWh in 2015, and then increasing steadily to 452,607 in 2019.

14.32. Notably, the 2018 December ELS submitted as part of the Application, is a modification to the 2018 December ELS initially submitted to the OUR in 2019 April.

14.4.2. Analysis of JPS's 2018-2019 Monthly System Losses

14.33. Table 14.2 below shows the monthly breakdown of the system losses for 2018-2019. Based on the data, the following are noted:

- The reported reduction in TL over the period did not result in the commensurate elimination of that quantum of losses as a result of mitigation efforts. Instead, it was due to recalibration and correction of previous estimations, with the differentials actually shifted to the NTL category;
- NTL due to the Rate 10 customer class appears to be increasing;
- Total NTL has remained static at approximately 18% of annual net generation over the period;
- The illegal users in the NTL category appear to be a 'sink' for the spill-over losses from the correction of TL and other NTL components.

14.34. From these indications, it is apparent that the model being used by JPS to derive these loss levels, is questionable, and therefore should be subject to an independent review.

Table 14.2: JPS' 2018-2019 Monthly System Losses Breakdown

JPS' 2018 ENERGY LOSS SPECTRUM: MONTHLY BREAKDOWN														
LOSS CATE-GORY	COMPONENTS	2018 JAN	2018 FEB	2018 MAR	2018 APR	2018 MAY	2018 JUN	2018 JUL	2018 AUG	2018 SEP	2018 OCT	2018 NOV	2018 DEC	2018 DEC (Revised)
TL	Transmission	2.60%	2.60%	2.60%	2.60%	2.60%	2.60%	2.10%	2.10%	2.15%	2.21%	2.23%	2.24%	2.24%
	Primary Distribution	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.50%
	Distribution Transformers	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%	1.30%
	Secondary Distribution	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%
	Total TL	8.60%	8.60%	8.60%	8.60%	8.60%	8.60%	8.10%	8.10%	8.15%	8.21%	8.23%	8.24%	7.94%
NTL	RT 60	0.09%	0.08%	0.09%	0.07%	0.06%	0.05%	0.04%	0.04%	0.03%	0.02%	0.01%	0.01%	0.01%
	Rate 70	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Rate 40&50	0.74%	0.74%	0.74%	0.74%	0.74%	0.75%	0.75%	0.75%	0.75%	0.72%	-	-	-
	Rate 50	-	-	-	-	-	-	-	-	-	-	0.07%	0.07%	0.07%
	Rate 40	-	-	-	-	-	-	-	-	-	-	0.66%	0.36%	0.36%
	RT20 (Med)	0.39%	0.39%	0.40%	0.40%	0.40%	0.40%	0.39%	0.39%	0.39%	0.39%	0.39%	0.39%	0.39%
	RT20 (Small)	0.22%	0.22%	0.22%	0.22%	0.21%	0.22%	0.23%	0.23%	0.23%	0.23%	0.23%	0.23%	0.23%
	RT10	5.99%	6.01%	6.01%	6.02%	6.03%	6.04%	6.05%	6.06%	6.09%	6.11%	6.11%	6.12%	6.12%
	Sub-Total	**7.43%**	**7.44%**	**7.45%**	**7.44%**	**7.45%**	**7.45%**	**7.46%**	**7.47%**	**7.49%**	**7.46%**	**7.47%**	**7.19%**	**7.19%**
	JPS Internal	1.30%	1.14	1.11%	1.23%	1.18%	1.18%	1.12%	0.95%	0.94%	1.13%	1.02%	0.82%	0.82%
	Illegal Users	9.34%	9.35%	9.34%	9.33%	9.33%	9.33%	9.83%	9.85%	9.80%	9.76%	9.73%	10.02%	10.32%
	Total NTL	18.07%	17.93%	17.90%	18.01%	17.96%	17.97%	18.40%	18.27%	18.23%	18.36%	18.22%	18.03%	18.33%
2018 TOTAL		**26.67%**	**26.53%**	**26.50%**	**26.61%**	**26.56%**	**26.57%**	**26.51%**	**26.36%**	**26.38%**	**26.56%**	**26.45%**	**26.27%**	**26.27%**

JPS' 2019 ENERGY LOSS SPECTRUM: MONTHLY BREAKDOWN														
LOSS CATE-GORY	COMPONENTS	2019 JAN	2019 FEB	2019 MAR	2019 APR	2019 MAY	2019 JUN	2019 JUL	2019 AUG	2019 SEP	2019 OCT	2019 NOV	2019 DEC	
TL	Transmission	2.31%	2.37%	2.34%	2.35%	2.33%	2.34%	2.33%	2.31%	2.27%	2.26%	2.24%	2.22%	
	Primary Distribution	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	
	Distribution Transformers	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	
	Secondary Distribution	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	
	Total TL	8.01%	8.07%	8.04%	8.05%	8.03%	8.04%	8.03%	8.01%	7.97%	7.96%	7.94%	7.92%	
NTL	RT 60	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Rate 70	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
	Rate 40&50	-	-											
	Rate 50	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	
	Rate 40	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	
	RT20 (Med)	0.40%	0.39%	0.39%	0.39%	0.39%	0.39%	0.40%	0.40%	0.40%	0.40%	0.40%	0.40%	
	RT20 (Small)	0.23%	0.23%	0.23%	0.23%	0.23%	0.23%	0.22%	0.22%	0.22%	0.22%	0.22%	0.23%	
	RT10	6.14%	6.14%	6.15%	6.16%	6.16%	6.15%	6.16%	6.16%	6.16%	6.15%	6.16%	6.16%	
	Sub-Total	**7.20%**	**7.20%**	**7.20%**	**7.22%**	**7.22%**	**7.21%**	**7.21%**	**7.21%**	**7.21%**	**7.21%**	**7.21%**	**7.21%**	
	JPS Internal	0.54%	0.65%	0.60%	0.68%	0.61%	0.80%	0.69%	0.85%	0.82%	0.70%	0.71%	0.71%	
	Illegal Users	10.26%	10.18%	10.20%	10.19%	10.19%	10.16%	10.15%	10.16%	10.18%	10.20%	10.22%	10.22%	
	Total NTL	18.00%	18.03%	18.00%	18.10%	18.02%	18.16%	18.05%	18.23%	18.21%	18.11%	18.14%	18.13%	
2019 TOTAL		**26.01%**	**26.10%**	**26.04%**	**26.15%**	**26.06%**	**26.20%**	**26.09%**	**26.24%**	**26.18%**	**26.07%**	**26.08%**	**26.05%**	

14.4.3. System Losses Target

14.35. The system losses target and responsibility factor (RF) set by the OUR based on the modified Y-Factor provisions of the Licence, are shown in Table 14.3 below. These targets were used to calculate the Y-Factor necessary to derive the true-up losses that were applied to the revenue surcharge for the applicable rate adjustments periods.

Table 14.3: OUR's Determined System Losses Targets (2016-2018)

ANNUAL REVIEW	SYSTEM LOSSES TARGETS & RESPONSIBILITY FACTOR				APPLICABLE RATE ADJUSTMENT PERIOD
	Technical Losses (TL)	Non-Technical Losses Within JPS' Control (JNTL)	Non-Technical Losses Not Totally Within JPS' Control (GNTL)	Responsibility Factor (RF)	
2016	8.20%	3.50%	9.80%	20%	2017 – 2018
2017	8.00%	3.30%	9.70%	20%	2018 – 2019
2018	8.00%	3.60%	9.70%	20%	2019 – 2020

14.5. JPS' Technical Losses Proposals

14.5.1. Optimal Level of Technical Losses

14.36. Technical losses depend on many interrelated factors within the electricity network. Therefore, continual optimization of system operations together with an effective loss reduction programme, can achieve optimal TL levels over a given time period.

14.5.2. Categorization of Technical Losses

14.37. The categorization and boundaries of TL across the T&D network are represented in Figure 14.3 below. Based on the 2019 ELS, the current TL breakdown and estimation method are summarized in Table 14.4 below.

Figure 14.3: TL across the T&D System

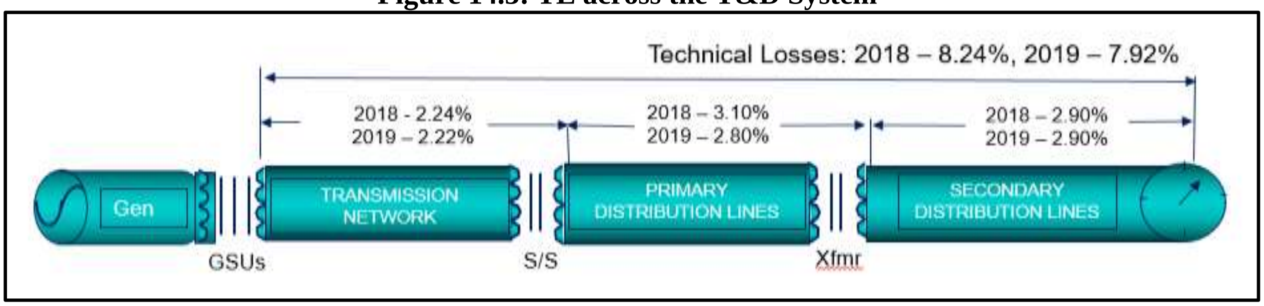
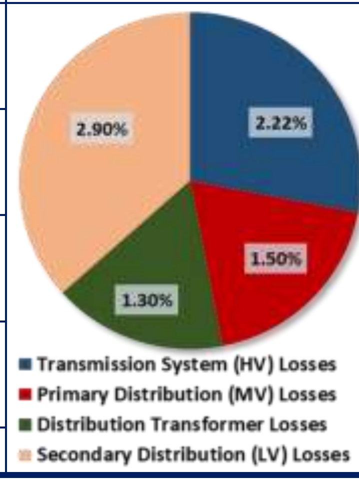


Table 14.4: JPS' TL Breakdown

JPS TL COMPONENTS						
No.	**Categories**	**2018 Dec (Initial)**	**2018 (Revised 2019 Dec)**	**2019 Dec**	**Description**	**Illustration**
1	Transmission System (HV) Losses	2.24%	2.24%	2.22%	Measured losses – metered energy inputs to transmission system minus metered energy outputs at distribution substations and HV customer locations.	
2	Primary Distribution (MV) Losses	1.5%	1.5%	1.5%	Calculated losses - computed at peak load (kW) condition then converted to kWh energy losses by applying a system loss factor. Based on DIGSILENT Simulation	
3	Distribution Transformer Losses	1.3%	1.3%	1.3%	Calculated losses - determined based on the manufacturer's power loss specification for each transformer size along with JPS' operating parameters. Based on DIGSILENT Simulation.	
4	Secondary Distribution (LV) Losses	2.9%	2.9%	2.9%	Estimated losses - estimated in three portions: secondary line losses, service drop losses, and meter coil losses. Based on JPS' Analytical model.	
	TOTAL TL	**8.24%**	**7.94%**	**7.92%**		



14.38. While these losses are unavoidable, targeted reductions are vital to ensure the sustainable operation of the system, with intrinsic benefits to the consumers, utility and country as a whole. However, in order to effectively implement such TL reduction measures, the utility must be able to, among other things:

1) Properly identify the loss drivers; and
2) Accurately segregate the losses into their constituent elements, through systematic measurement and calculation methodologies and appropriate engineering modelling techniques.

14.5.3. JPS' Proposed Technical Losses Initiatives (2019-2024)

14.39. To address TL during the Rate Review period, JPS proposed the loss reduction initiatives discussed below. These initiatives were also covered in its Business Plan.

Voltage Standardization Programme (VSP)

14.40. According to JPS, the VSP is aimed at standardizing the medium voltage (MV) network across the island at 24kV, to reduce TL and to improve flexibility for feeder load transfer. The company posited that the upgrading of the MV network to 24kV is expected to yield a considerable reduction in load current (Amperes) relative to the current requirements at the 12kV and 13.8kV voltage levels. For the Rate Review period, JPS plans to upgrade twelve (12) of the existing 12kV and 13.8kV substations to 24kV, which is expected to reduce TL by approximately 5.09 GWh (0.14% of net generation).

Distributed Generation

14.41. The strategic deployment of distributed generation (DG) resources can contribute to the reduction in TL, mainly due to proximity to local loads. In the Application, JPS asserted that as a part of the company's strategic objective to provide more reliable and efficient generating facilities on the distribution system, it plans to install a 10MVA (5 x 2MVA) NG fired plant at Hill Run, St. Catherine with co-generation facilities to supply a neighbouring customer. According to JPS, the proposed generation project is part of a 14MW Right of First Refusal (ROFR) initiative to replace a portion of its existing generation fleet with DG. The DG facility will be primarily interconnected to the New Twickenham 410 feeder, which operates at 24 kV.

Transmission Line Upgrade

14.42. Due to chronic low voltage conditions (below the specified operating range) affecting transmission lines and substations in the parishes of St. Ann and Trelawny, the company has proposed the construction of a new 69kV transmission line connecting the Bellevue and Roaring River substations, which is expected to improve bus-bar voltages, under normal and contingency conditions. JPS also claimed that in addition to improvements to grid reliability, and voltage profile, this initiative also has a technical loss benefit.

OUR's Comments

14.43. As the utility is mandated to operate more efficiently, it becomes increasingly necessary to reduce the level of technical losses. The aim is to effectively reduce losses in a way that aligns with the interest of the customers. In that context, the initiatives targeting reduction in TL must be evaluated on a case-by-case basis. According to JPS' project cost/benefit models, the proposed TL initiatives, particularly the VSP, is not cost-effective based on TL reduction alone, but may be justified due to its multidimensional goals.

14.5.4. Impact of the Proposed Technical Losses Initiatives

14.44. As presented in the Application, the proposed TL reduction initiatives for the Rate Review period are shown in Table 14.5 below.

Table 14.5: JPS' TL Reduction Initiatives - Cost & Impact Projections (2019-2023)

JPS' TL REDUCTION INITIATIVES - COST AND IMPACT PROJECTIONS (2019-2023)				
TL Initiatives	**Description**	**Implementation Period**	**Total CAPEX/OPEX (US$ M)**	**Expected TL Reduction**
VSP	Upgrading of 12 Feeders to 24kV	2019-2023	17.593	0.14%
Transmission Line Upgrade	New 69kV Transmission Line: Bellevue – Roaring River	2019-2023	6.759	0.02%
DG	DG plant to be installed in Hill Run, St Catherine.	2019-2023	9.000	0.04%
Power Factor (PF) Correction	Maintain PF of ≥ 0.95 for all Feeders	2019-2023	-	-
Phase Balancing	Upgrading of software of all Feeder revenue meters to measure phase imbalances. Phase balancing to be executed for imbalances > 10%.	2019-2023	-	-
TOTAL		2019-2023	33.352	0.20%

14.45. As indicated, the projected TL reduction is 0.20% of annual net generation, at a total cost of US$33.35M. According to JPS, this estimated impact was used to derive its proposed TL targets for the Rate Review period.

14.55 JPS' Proposed Technical Loss Targets

14.46. Based on the Application, the proposed TL targets covering each 12-month adjustment interval of the Rate Review period is presented in Table 14.6 below.

Table 14.6: JPS' Proposed Technical Losses Targets (2019-2028)

Proposed TL Targets (2019-2024)	**2019**	**2020**	**2021**	**2022**	**2023**
	7.94%	7.92%	7.89%	7.85%	7.74%
Proposed TL Targets (2024-2029)	**2024**	**2025**	**2026**	**2027**	**2028**
	7.73%	7.73%	7.72%	7.71%	7.71%

14.47. As indicated, TL targets were also proposed for 2024-2029 period. This is in accordance with the Licence requirements for a rolling 10-year target. However, this requirement was rationalized at the Loss Interface Committee (LIC) meetings, and it was established that JPS would propose firm targets for the Rate Review period only, consistent with its Business Plan, and forecast a trajectory for the latter five (5) years. In that regard, JPS presented indicative targets for the 2024-2029 period.

14.48. Based on JPS' proposals, the cumulative reduction in TL expected over the Rate Review period is 0.20% of annual net generation. With that projection, the company posited that its proposed TL targets are fair and achievable over the short and long-term.

14.6. OUR's Review of JPS' Technical Losses Proposals (Without COVID-19)

14.49. The aim of this review is to evaluate JPS' TL situation and establish determinations to encourage the company to employ the kinds of measures necessary to cost effectively reduce TL to a level that is fair and reasonable to its customers.

14.6.1. OUR's Review Approach - Technical Losses

14.50. Bearing in mind the applicable regulatory principles, the approach employed by the OUR in determining the TL targets for the Rate Review period entailed two (2) main aspects:

1) Technical evaluation to estimate the TL components using network models and calculations; and
2) Analysis to evaluate potential system conditions that could impact TL performance during the subject period.

14.51. This approach was adopted to enable the OUR to set TL targets that are reasonable and representative of the system configuration and capability.

Technical Evaluation of JPS' Technical Losses

14.52. To facilitate the review of JPS' proposed TL targets, the OUR carried out a comprehensive TL evaluation in order to inform its decisions on the TL performance over the Rate Review period. In evaluating the TL proposals, the OUR assessed the operation of the entire T&D system over the subject period.

Inputs/Assumptions for TL Evaluation

14.53. Consistent with the TL requirements outlined in the Final Criteria (Annex 3), the OUR's evaluation took into consideration, among other things, the following assumptions and parameters:

a) The existing and projected system configuration;
b) The forecasted system net generation and peak demand;
c) The proposed TL reduction initiatives; and
d) The available supporting TL data, including those received after the OUR's additional information and clarification requests.

14.6.2. Estimation of Transmission System Losses

14.54. In its ELS methodology document, JPS indicated that the existing transmission losses are measured within the defined boundary of the Transmission System. This includes the transmission lines, interbus substation transformers and distribution substation transformers. As such, the actual transmission losses are calculated as the difference between metered net generation input and the sum of the metered energy to the distribution substation feeders and HV customers, in a given billing period. This approach is deemed acceptable, provided that the respective revenue meters are operating within their specified accuracy tolerances.

14.55. In evaluating JPS' transmission losses over the Rate Review period, the OUR used a calibrated power flow software model of JPS' system to perform analysis on transmission network utilization and efficiency, taking into account the factors listed above. The results of this analysis indicate a reduction of transmission losses from **2.20% - 2.05%** of annual net generation, over the subject period. In setting the relevant TL targets, the OUR took into consideration these simulation results, the 2018-2019 ELS, historical transmission losses and the expected impact of JPS' transmission developments during the subject period.

14.6.3. Estimation of Distribution System Losses

14.56. The main areas of focus regarding the Distribution System's TL are the MV network, distribution transformers, and the low voltage network. Various models and techniques may be utilised to estimate these losses, with a reasonable level of accuracy.

Primary Distribution Line Losses:

14.57. The primary distribution line losses are associated with the MV (6.9kV, 12kV, 13.8kV, and 24kV) single-phase and three-phase lines exiting the distribution substation transformers to the MV side of the distribution pole/pad-mounted transformers for all feeders across the system. Based on the ELS methodology, JPS used an average feeder load approach to calculate the primary distribution line annual TL. JPS' approach of using a sampled distribution network at average load is outlined as follows:

1) Sample size - 34 feeders (30% of total number of feeders), with at least one (1) feeder per parish;
2) Feeder data from JPS' GIS database imported to DIgSILENT Power Factory software, which was used to calculate the MV network TL;
3) Line loss (kW) per km for each sample feeder was calculated then averages across the 34 feeders, to determine an average line loss value per km;
4) The calculated line loss (kW) per km value was extrapolated for the total distribution network length (km) to determine the total average line loss; and
5) The primary distribution lines annual average energy losses were derived by multiplying the average line loss value by 8,760 hours, then expressed as a percentage of net generation (4,355,535 MWh for 2018);
6) For each distribution transformer connected to a sample feeder, a power loss (kW) per transformer was calculated then averaged across all the distribution transformers for the 34 feeders, to determine an average power loss value per transformer;
7) Average power loss (kW) per transformer was extrapolated for the total number of transformers connected to all the feeders in the system, to determine the total average distribution transformer power loss; and
8) The distribution transformers annual average energy losses were derived by multiplying the average power loss value by 8,760 hours, then expressed as a percentage of the net generation.

14.58. The TL calculations for the primary distribution network carried out by JPS, are presented in Table 14.7 below.

Table 14.7: JPS' Primary Distribution Network TL Calculations

No.	Parish	Feeder	Feeder Length (km)	Line Loss (kW)	Line Loss (kW/km)	Number of Transformers	Transformer Losses (kW)	Loss per Transformer (kW/unit)
1	Portland	Port Antonio 310	132.13	16.95	0.13	956	27.6	0.03
2	St. Thomas	Lyssons 410	176.01	41.45	0.24	475	48.29	0.10
3	KSAN	Hope 410	55.51	52.75	0.95	508	89.53	0.18
4	KSAN	West Kings House Rd	7.41	15.05	2.03	201	58.39	0.29
5	KSAN	Washington Blvd 610	36.37	22.81	0.63	361	56.12	0.16
6	KSAN	Constant Spring 410	221.74	95.93	0.43	669	74.21	0.11
7	KSAS	Hunts Bay 110	3.75	9.7	2.59	69	29.76	0.43
8	KSAS	Cane River 410	22.41	13.96	0.62	216	39.92	0.18
9	KSAS	Duhaney 210	67.11	87.79	1.31	646	81.74	0.13
10	St. Catherine	Naggo Head 510	87.89	17.14	0.20	833	104.54	0.13
11	St. Catherine	Naggo Head 610	94.45	31.07	0.33	594	68.87	0.12
12	St. Catherine	Michelton Halt 110	209.02	213.45	1.02	678	71.92	0.11
13	St. Catherine	Michelton Halt 210	176.49	108.92	0.62	439	54.41	0.12
14	St. Catherine	Rhodens Pen 210	116.06	68.59	0.59	695	57.56	0.08
15	St. Catherine	Rhodens Pen 310	88.41	75.63	0.86	428	42.14	0.10
16	St. Catherine	Rhodens Pen 410	166.47	89.7	0.54	420	47.25	0.11
17	St. Catherine	Tredegar 410	151.48	81.31	0.54	974	91.15	0.09
18	Clarendon	May Pen 110	410.29	160.32	0.39	825	74	0.09
19	Manchester	Spur Tree 210	332.48	261.86	0.79	876	122.26	0.14
20	St. Elizabeth	Maggotty 210	487.18	284.83	0.58	1412	123.66	0.09
21	Westmorelan	Paradise 110	155.42	120.71	0.78	477	63.87	0.13
22	Hanover	Orange Bay 310	294.77	215.58	0.73	735	63.78	0.09
23	St. James	Bogue 310	235.43	95.9	0.41	993	102.89	0.10
24	Trelawny	Martha Brae 110	60.66	2.52	0.04	193	35.76	0.19
25	St. Ann	Ocho Rios 310	50.73	11.27	0.22	261	35.76	0.14
26	St. Ann	Ocho Rios 410	6.9	11.14	1.61	148	38.14	0.26
27	St. Ann	Ocho Rios 510	24.5	6.55	0.27	203	35.31	0.17
28	St. Ann	Upper White River	133.05	16.97	0.13	307	23.04	0.08
29	St. Ann	Upper White River	37	4.39	0.12	128	12.77	0.10
30	St. Mary	Oracabessa 110	59.48	5.08	0.09	230	16.15	0.07
31	St. Mary	Oracabessa 210	106.28	100.68	0.95	456	49.02	0.11
32	St. Mary	Highgate 110	123.98	8.38	0.07	289	18.86	0.07
33	St. Mary	Highgate 210	172.4	81.06	0.47	428	32.05	0.07
34	St. Mary	Blackstonedge 110	83.49	6.7	0.08	172	14.99	0.09

	PRIMARY DISTRIBUTION LINES			DISTRIBUTION TRANSFORMERS		
	Total Feeder Length (km)	**Total Power Loss (kW)**	**Average Line loss (kW/km)**	**Total No. of Transformers**	**Total Power Loss (kW)**	**Average Power Loss/Tfmer**
Sample - 34 Feeders	4,586.75	2,436.14	0.63	17,295	1,905.71	0.13
Total Number of Feeders (114)	11,469.39	7,226		48,665	6,326	
Extrapolated Annual Energy Loss	**63,300 MWh (1.5% of Net Gen)**			**55,416 MWh (1.3% of Net Gen)**		

OUR's Evaluation – Primary Distribution (MV) TL

14.59. Generally, while a sampled network approach is acceptable, the methodology described by JPS appears to have a number of shortcomings, including the following:

1) The sampled distribution network approach deviates from Annex 3 (A3.4) of the Final Criteria, which requires the breakdown of TL for each distribution feeder, transformer and other relevant equipment, in the primary distribution network;
2) The fact that there are about 112 feeders in the system, the logic behind the use of the sampled approach and the selection of 34 feeders for the loss calculations as opposed to all the feeders is not clear;
3) Further, the GIS database should contain the relevant data for all the feeders required for the TL calculations;
4) On page 153 (Table 7-2) of the Application, JPS indicated that the accuracy and completeness of the transformer mapping and transformer-to-feeder mapping were both at 98% and 99%, respectively. This suggests that sufficient distribution network data should be available in the GIS database to facilitate TL evaluation of the total number of feeders in the DIgSILENT Power Factory Model;
5) There is a discrepancy in the number of feeders stated in the ELS Methodology (114) and the Business Plan (112);
6) The calculation of the average line loss (kW) per km (0.63kW/km) and average transformer loss (kW) per unit (0.13kW/transformer), appears to be incorrect due to improper averaging; and
7) Since the actual average power loss (kW) and length (km) of each feeder is known; and the total average power loss for the total number of related transformers is also known, then the average losses per unit for the 34 feeders and associated transformers is a straight mathematical division of respective determinants.

Alternative Approaches

14.60. Given the identified limitations, the OUR performed alternative calculations, to estimate the annual average losses attributable to the primary distribution lines and distribution transformers.

Feeder Peak Load Approach:

14.61. While the energy losses for the primary lines can be calculated from power-flow analysis using hourly load data, these losses can also be estimated using the feeder peak load, load factor (LF) loss factor (LSF), and utilization time of loss (UTL). Based on the available TL and system demand data, the OUR used two different methods to estimate the primary distribution line losses. While TL is highest during peak conditions, a significant portion of the energy losses occurs off peak. Therefore, the LF and LSF, which represent the relationship between average peak and peak conditions, are useful for determining these losses. The OUR's losses calculations are shown in Table 14.8 below.

Table 14.8: OUR's Estimated TL for the Primary Distribution Network

OUR'S ESTIMATED TL FOR THE PRIMARY DISTRIBUTION NETWORK												
Year	**Net Gen (GWh)**	**Load Factor (LF)**	**Line Losses**		**Transformer Losses**		**Dist. System Total (MWh)**	**Dist. System Total (%)**	**Proposed Reduction [VSP] (MWh)**	**Projected Losses**	% of Net Gen	**Remarks**
			Annual Energy Loss (MWh)	% of Net Gen	Annual Energy Loss (MWh)	% of Net Gen						
			63,300	1.50%	55,416	1.30%						2018 - JPS calculated
2018	4,355.5	0.78	55,532	1.27%	52,406	1.20%	107,938	2.47%	-			
2019	4,429.9	0.78	55,632	1.26%	52,482	1.18%	108,114	2.44%	-	108,114	2.44%	
2020	4,359.4								674.51	107,439	2.46%	
2021	4,383.6								132.62	107,307	2.45%	
2022	4,404.1								635.65	106,671	2.42%	
2023	4,419.5								2,113.60	104,558	2.37%	
2024	4,424.6								0	104,558	2.36%	

Distribution Transformer Losses

14.62. Energy losses of a transformer largely depend on its loading levels over a period. As such, these losses were estimated in a similar way to the feeder line losses, with assumptions for the transformer's peak load loss, LSF and no-load loss. The OUR's losses calculations are presented in Table 14.8 above.

Secondary Distribution Network Losses

14.63. In its ELS methodology document, JPS noted that the calculation of the secondary distribution network TL, is a challenging and complex undertaking because this section of the network is not mapped or modelled to facilitate any form of computer load simulation. Therefore, the company adopted an estimation methodology based on rule of thumb that involves parameters including length per circuit, average loading per circuit, the number of secondary distribution circuits, and standards governing conductor type. Based on this approach, the secondary distribution network TL for 2018 were estimated at 2.90% of the net generation, as shown Table 14.9 below.

Table 14.9: JPS' TL Calculations - Secondary Distribution Network

Description	**Average Peak Loss (kW)**	**Total Average Peak Loss (kW)**	**Annual Energy Loss (kWh)**	**% of Net Gen**
Secondary CCT	0.525	15,739	6,251,884	1.36%
Service Drop (RT10)	0.007	3,749	13,399,783	0.32%
Service Drop (Small C&I)	0.013	685	2,448,208	0.06%
Service Drop (Medium C&I)	1.081	3,908	13,969,274	0.34%
Service Drop (Large C&I)	6.643	7,881	28,169,050	0.68%
Revenue Meters	-	1,681	6,008,916	0.15%
TOTAL			**120,247,115**	**2.90%**

OUR's Evaluation – Secondary Distribution Network TL

14.64. Given the constraints on modelling of this network segment and calculation of the related TL, the OUR accepts that presently, some degree of estimation may be unavoidable. However, in keeping with the relevant regulatory requirements and prudent utility practice, the estimation approach employed by the company must be clearly structured, incorporate the most updated network data, and be grounded on reasonable assumptions.

14.65. In the OUR's view the methodology presented by JPS appears to have a number of shortcomings, including the following:

1) The same level of TL (2.9%) has been reported by the company for over ten (10) years, which presumes no change in system configuration, loading and loss profile, over time;

2) The calculations do not appear to capture the impact of the deployment of the advanced revenue meters, smart streetlights and Net Billing/Self-generation supply arrangement;

3) The impact of secondary circuits avoided due to RAMI installations do not appear to be reflected; and

4) The company reported that it has commenced the mapping/modelling process based on other objectives, including reliability measurements and NTL reduction goals, but it does not appear that any calibration was done following these developments.

5. Based on these apparent limitations, the OUR is of the view that TL reported for the secondary distribution network should be lower.

6. With respect to JPS' TL reduction in general, information suggests that the benefits are not commensurate with the reported costs and efforts, which implies the initiatives may be suboptimal.

14.7. COVID-19 Impact on Technical Losses

14.66. In response to the Office's TL targets set out in its draft Determination Notice to the Application, the company proposed a revised TL forecast shown in Table 14.10 below. In its comments on the referenced draft Determination Notice, the company argued that a revision to the initial TL forecast was necessary to account for the impact of COVID-19 on its operations, which was not foreseen prior to the submission of its Application.

Table 14.10: JPS' Revised Technical Losses Forecast (COVID-19 Related)

Description	2019	2020	2021	2022	2023	Remarks
JPS TL Projections (Original)	7.94%	7.92%	7.89%	7.85%	7.74%	JPS Rate Application
OUR TL Targets (Without COVID-19 Impact)	7.75%	7.71%	7.63%	7.55%	7.54%	OUR DRAFT DETERMINATION NOTICE
JPS Revised TL Forecast (COVID-19 Related)	**7.92%**	**7.85%**	**7.90%**	**7.93%**	**7.94%**	Submitted: 2020 OCTOBER 2

14.67. The revised TL proposals were reviewed by the OUR taking into account the effect of the prevailing COVID-19 situation on system demand, load profile, power flows and the potential impact of increased NTL. The indication from this evaluation scenario infers that the potential impact of the COVID-19 situation on TL in the electricity system over the 2020-2023 timeframe will be marginal.

14.68. In the 2019 December ELS, JPS reported TL of 7.92% of net generation. However, based on the 2020 January-August ELS, which recorded System Losses during the period of escalation in COVID-19 and implementation of curtailment measures, TL decreased to 7.84% in 2020 January, then further dropped to 7.80% at the end of 2020 March, remained fairly constant until June when it went to 7.81% and therafter increasing by 0.01% monthly to 7.83% at the end of 2020 August, as shown in Table 14.11 below.

Table 14.11: JPS' Technical Losses (2020 January-August ELS) – Performance since COVID19

Network	Prior to COVID19		Performance since Entry of COVID19					
TL COMPONENTS:	**2020 JAN**	**2020 FEB**	**2020 MAR**	**2020 APRIL**	**2020 MAY**	**2020 JUN**	**2020 JUL**	**2020 AUG**
Transmission	2.14%	2.11%	2.10%	2.10%	2.10%	2.11%	2.12%	2.13%
Primary Distribution	2.80%	2.80%	2.80%	2.80%	2.80%	2.80%	2.80%	2.80%
Secondary Distribution	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%
	7.84%	**7.81%**	**7.80%**	**7.80%**	**7.80%**	**7.81%**	**7.82%**	**7.83%**

14.69. As shown, during the intensification period of the COVID-19 pandemic in 2020, TL measured by JPS was noticeably lower than that recorded at the end of 2019, with no major loss reduction initiative reported by the company.

14.70. Based on the OUR's TL forecast (without COVID-19), the Office's initial TL targets for 2019-2020 are largely consistent with JPS' 2020 January-August ELS (average of 7.81% of net generation). However, for the 2021-2023 period, JPS' revised TL projections (7.90%, 7.93% and 7.94%, respectively), show clear deviation from the OUR's TL targets for the same period, shown in Table 14.10 above.

14.71. Contrary to JPS' original 2019-2023 TL forecast, which represents a reduction in losses of 0.2%, over the 2019-2024 revenue cap period, (7.94% to 7.74%), the company's revised TL forecast is clearly reflecting a reverse trajectory. That is, a projected increase from 7.85% for 2020 to 7.94% at the end of 2023. With the presumption that the effect of COVID-19 on TL is negligible, this revised projection suggests that despite the proposed loss reduction programme for the new regulatory period, the company seems to be signalling that at the end of 2024, TL will reside at the levels reported at the end of 2018. Based on the OUR's overall TL assessment, JPS' revised 2021-2023 TL projections are not considered reasonable and therefore are not accepted as TL targets for the applicable Annual Review periods.

14.7.1. OUR's Position – COVID-19 Impact on Technical Losses

14.72. As established herein, the OUR's System Losses assessment predicts that the potential impact of COVID-19 on TL is expected to be marginal, and should not disrupt JPS' strategy to achieve reduction in TL over the new regulatory period. However, the OUR's analysis contemplates some operating scenarios, particularly involving collapse in system demand, coupled with the escalation in NTL due to COVID-19 effects that could potentially impose constraints on optimal operation of the T&D system. Taking into consideration the possibility of such effects, the OUR adjusted the TL targets for the 2019-2024 revenue cap period, as represented in Table 14.12 below.

14.8. OUR's Determination on Technical Losses Targets

14.8.1. Technical Losses Targets (2020-2024 & 2025 - 2029)

14.73. Arising from the OUR's system losses evaluation, informed by the relevant requirements of the Licence and Final Criteria, the Office determines that JPS' TL targets for the Rate Review period, shall be as set out in Table 14.12 below.

Table 14.12: OUR's Determined Technical Losses Targets for JPS (2020-2029)

OUR DETERMINED TECHNICAL LOSSES TARGETS FOR JPS (2020-2029)						
Losses Data (Year)	**Rate Adjustment Annual Review Period**	**JPS Proposed TL Targets (Original)**	**JPS Revised TL Targets Proposal (COVID-19 Related)**	**OUR Determined TL Targets (Initial)**	**OUR Determined TL Targets (COVID-19 Impact)**	**Remarks**
2019-2024 REVENUE CAP PERIOD						
2019	2020-2021	7.94%	7.92%	7.75%	**7.80%**	
2020	2021-2022	7.92%	7.85%	7.71%	**7.78%**	
2021	2022-2023	7.89%	7.90%	7.63%	**7.72%**	
2022	2023-2024	7.85%	7.93%	7.55%	**7.67%**	
2023	2024 Rate Review	7.74%	7.94%	7.54%	**7.61%**	
2024-2029 REVENUE CAP PERIOD						
2024	2025-2026	7.73%	-	7.54%	**7.60%**	Indicative TL Target: Rolling 10-Year Criteria.
2025	2026-2027	7.73%	-	7.52%	**7.59%**	
2026	2027-2028	7.72%	-	7.52%	**7.57%**	
2027	2028-2029	7.71%	-	7.52%	**7.55%**	
2028	2029 Rate Review	7.71%	-	7.51%	**7.54%**	

14.74. In addition, subject to the requirements of the Licence, the OUR determined TL targets for 2025-2029 to satisfy the rolling 10-year target criteria. These are also presented in Table 14.12 above.

14.9. JPS' Non-Technical Losses

14.9.1. Categorization of JPS's Non-Technical Losses

14.75. JPS' system losses data indicates that total NTL are attributable to three categories:

- Billed customers (RT10, RT20, RT40, RT50, RT60, and RT70);
- JPS' Internal operations; and
- Illegal Users.

14.76. However, in accordance with Schedule 3, paragraph 38 of the Licence, these categories of NTL should be classified into two (2) main categories:

- The aspect of NTL that are within the control of JPS - designated by JPS as "JNTL";
- The aspect of NTL that are not totally within JPS' control – designated by JPS as "GNTL".

14.9.2. Measurement of Non-Technical Losses

14.77. Effective management of NTL requires accurate measurements. Accordingly, the company reported that it has implemented systems to map customers to feeders and has used energy balance models to determine the level of losses on each feeder. According to JPS, the energy balance model utilizes the customer-feeder data for the calculation of the losses in different segments of the network. JPS also indicated that, as at the end of 2018, the company was able to determine energy losses by feeders, parishes and at various transformer locations.

Sources of Non-Technical Losses

14.78. The main sources and distribution of NTL as reported by JPS during the 2014-2019 regulatory period is summarized in Figure 14.4 below.

Figure 14.4: NTL by Customer Category and Cause (2015-2017)

DISTRIBUTION OF ENERGY LOSSES PER MODE PER CUSTOMER CATEGORY

MODE OF LOSSES	RATE 10				MEDIUM (C&I) RATE 20				SMALL RATE 20				RATE 40			RATE 50		
	2015	2016	2017	AVG	2015	2016	2017	AVG	2015	2016	2017	AVG	2016	2017	AVG	2016	2017	AVG
BURNT METER	14.0%	7.4%	2.3%	**7.9%**	-	5.1%	8.6%	**4.6%**	14.0%	2.3%	5.5%	**7.3%**	0.9%	16.8%	**8.8%**			
DEFECTIVE METERING	-	10.7%	13.7%	**8.1%**	25.0%	34.5%	58.2%	**39.3%**	-	13.2%	23.1%	**12.1%**	23.3%	37.2%	**30.3%**	49.0%	1.4%	**25.2%**
INCORRECT METER CONFIGURATION	-	0.3%	-	**0.1%**	3.0%	0.2%	-	**1.1%**	2.0%	0.5%	-	**0.8%**	49.2%	-	**24.6%**	5.1%	5.3%	**5.2%**
OPEN CIRCUIT	26.0%	-	9.2%	**11.7%**					14.0%	-	5.3%	**6.4%**	-	41.9%	**21.0%**	-	93.3%	**46.7%**
SINGLE PHASING	21.0%	4.6%	-	**8.5%**					9.0%	4.0%	-	**4.3%**	26.5%	-	**13.2%**	45.9%	-	**23.0%**
OPEN CIRCUIT/SINGLE PHASING					-	18.3%	29.2%	**15.8%**										
BYPASS WITHIN METER	5.0%	61.3%	21.9%	**29.4%**	-	29.3%	0.4%	**9.9%**	7.0%	70.5%	17.6%	**31.7%**	-	1.8%	**0.9%**			
INVERTED METER									2.0%	-	-	**0.7%**						
IDLE SERVICE	2.0%	0.2%	0.5%	**0.9%**	-	0.2%	-	**0.1%**	16.0%	0.3%	3.9%	**6.7%**	0.1%	1.4%	**0.8%**			
BYPASS AT/BEFORE POTHEAD	10.0%	9.0%	31.9%	**17.0%**	4.0%	12.5%	3.5%	**6.7%**	9.0%	9.2%	39.8%	**19.3%**	-	1.0%	**0.5%**			
TAMPERING	-	6.5%	20.6%	**9.0%**	27.0%	-	-	**9.0%**	-	-	4.9%	**1.6%**						
ELECTRONIC TAMPERING					4.0%	-	-	**1.3%**										
LINE TAP	21.0%	-	-	**7.0%**	37.0%	-	0.1%	**12.4%**	26.0%	-	-	**8.7%**						
OTHER	1.0%	-	-	**0.3%**					1.0%	-	-	**0.3%**						

PERCENTAGE LOSSES PER CUSTOMER CATEGORY (BASED ON ANNUAL JPS DECEMBER SPECTRUM)

	RATE 10			MEDIUM (C&I) RATE 20			SMALL RATE 20			RATE 40, 50 & 70 (2017 ONLY)		
	2015	2016	2017	2015	2016	2017	2015	2016	2017	2015	2016	2017
% LOSSES PER CATEGORY	7.08%	7.48%	5.99%	0.31%	0.38%	0.27%	0.32%	0.27%	0.34%	0.45%	0.45%	0.74%

14.10. JPS' NTL Proposals

14.79. As part of the Application, JPS submitted its NTL proposals, subject to Criterion 12 of the Final Criteria. The considerations and parameters constituting the proposals are outlined below.

14.10.1. JPS' Proposed Non-Technical Losses Initiatives (2019-2024)

14.80. The NTL initiatives proposed by JPS for the Rate Review period are outlined as follows:

Smart Meter Programme

14.81. As described by JPS, the installation of smart meters will improve the company's ability to effectively identify energy losses at a circuit level, by providing measurement visibility down to the distribution transformers, as well as greater efficiency and flexibility in its billing processes and provide benefits to customers across a range of applications.

- *Smart Check Meter Programme:* JPS indicated that this programme involves the implementation of secondary meters for each of the large (C&I) customers (where technically and economically feasible) to facilitate continuous measurement and verification of energy delivered to the respective customers in real time. Essentially, this metering arrangement is expected to immediately detect any deviation in energy supplied and energy recorded.
- *Smart Anti-Theft Residential Meters:* According to JPS, the deployment of these meters will be an expansion of its existing smart meter rollout and will be installed

in areas where electricity theft is excessive, which will also include the use of prepaid metering solutions with anti-theft enclosures.

Audits and Investigation

14.82. JPS indicated that all large accounts (Rates 40, 50, 70 and medium 20) will continue to be audited at least once annually. Also, all Rates 50, 70, and some Rate 40 customers will have check meters installed and benefit from rapid response investigations in case of deviation in measurements.

14.83. The company projects that with data analytics through the Smart Meter programme, the audit and investigations will become more effective over the next five years. The planned account audits for the new review period is shown in Table 14.13 below, which appears to be fairly practicable given the size of the customer base.

Table 14.13: JPS' Schedule of Account Audits for 2019-2024

Description	2019	2020	2021	2022	2023
R10 Audits	74,298	74,298	78,013	81,914	86,009
Small R20 Audit	11,005	11,005	11,555	12,133	12,740
Medium R20 Audits	8,632	8,632	8,632	8632	8632
Rate 40 Audits	1,722	1,722	1,722	1,722	1,722
Rate 50 Audits	126	126	126	126	126
Rate 70 Audits	23	23	23	23	23
Total	95,806	95,806	100,071	104,550	109,252

Community Renewal Programme

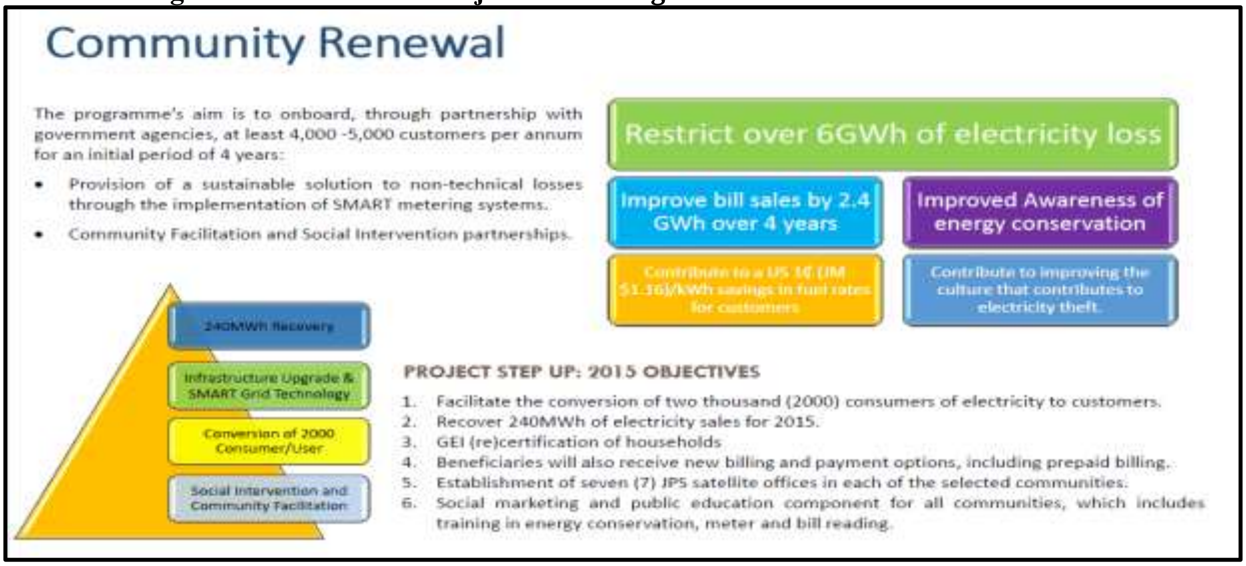
14.84. It is significant to note that JPS' 2014-2019 Community Renewal Programme (CRP) strategy has not in any noticeable way achieved the programme's objective over the period. The scope and targets of the CRP presented to the OUR at the last Tariff Review are captured in Figure 14.5 below.

14.85. In the Application, JPS stated its intention to use a different approach for its CRP, which is aimed at delivering sustainable energy services to volatile and vulnerable communities. The company is of the view that given the sensitivities involved with these areas, increased presence, coordination and harmonisation are important in creating the mind-set needed to boost cultural change towards illegal users accepting the need to become regularized.

14.86. In the Application, JPS articulated that it will embark on a different approach with the Community Renewal Programme (CRP) to deliver sustainable energy services to volatile and vulnerable communities. The company is of the view that due to the sensitivities involved with these areas, increased presence, coordination and harmonisation are important in creating the mind-set needed to boost cultural change towards illegal users accepting the need to become regularized. Given these considerations, the company submitted that it intends to employ new CRP strategies and initiatives for the 2019-2024 period.

14.87. While the company's objectives are understandable, the problem is that over the years, the CRP strategy has constantly shifted and has not been successful in transitioning unauthorized consumers to legitimate customers. Further, there is no indication that any detailed review of the programme has been undertaken by the company to examine its effectiveness, and to provide a basis for modifying the approach. This is an important concern, because, during the 2014-2019 review, the company vigorously promoted the CRP strategy, with the scope and targets outlined in Figure 14.5 below. Despite the intentions, to date, there has been no noticeable materialization of the objectives.

Figure 14.5: JPS' CRP Objectives During the 2014-2019 Review Period



Strike Force Operations

14.88. JPS indicated that during the Rate Review period, it intends to continue with the use of Strike Force operations in the communities with excessive NTL.

14.10.2. Impact of the Proposed Non-Technical Losses Initiatives

14.89. As presented in the Application, the proposed NTL reduction initiatives for the Rate Review period are shown in Table 14.14 below.

Table 14.14: JPS' NTL Initiatives - Cost and Impact Projections (2019-2024)

TL Initiatives	Implementation Period	Total CAPEX/OPEX (US$ M)	Expected NTL Reduction
Smart ANSI Meter Programme	2019-2023	82,777	1.70%
Audits and Investigation	2019-2023	26,160	
Analytical Software Procurement & Development	2019-2023	307	
Metering Infrastructure Replacements	2019-2023	815	
Smart Check Meter Programme	2019-2023	1,200	
Smart Meter Anti-theft (RAMI)/ CRP	2019-2023	17,259	0.40%
Strike Force Operations	2019-2023	5,000	
RAMI Rehabilitation		2,500	
TOTAL NTL	**2019-2023**	**136,018**	**2.10%**

14.90. As indicated, the projected NTL reduction is 2.10 percentage points over the Rate Review period at a total cost of US$136.02 million. According to JPS, this estimated impact was used to derive its proposed NTL targets for the Rate Review period.

14.91. Based on the Business Plan, the projected reduction in NTL over the period was broken down as shown in Table 14.15 below. JPS' proposed NTL targets covering each 12-month adjustment interval of the Rate Review period is presented in Table 14.16 below.

Table 14.15: JPS' Projected Reduction in NTL (2019-2024)

Project	2019	2020	2021	2022	2023	Total
Smart Meter	0.14%	0.23%	0.32%	0.38%	0.43%	**1.50%**
Smart Meter (Anti-theft)	0.10%	0.10%	0.10%	0.10%	0.07%	**0.47%**
Check Meter	0.10%	0.05%	-	-	-	**0.15%**
Total Reduction	**0.34%**	**0.38%**	**0.42%**	**0.46%**	**0.50%**	**2.10%**

Table 14.16: JPS' Proposed Non-Technical Losses Targets (2019-2028)

JPS's PROPOSED 2019-2024 TECHNICAL LOSSES TARGET						
Proposed NTL Targets (2019-2024)	**NTL Component**	**2019**	**2020**	**2021**	**2022**	**2023**
	JNTL	4.14%	4.93%	5.67%	6.36%	6.98%
	GNTL	13.85%	12.68%	11.52%	10.37%	9.25%
	TOTAL NTL	**17.99%**	**17.61%**	**17.19%**	**16.73%**	**16.23%**
Proposed NTL Targets (2024-2029)		**2024**	**2025**	**2026**	**2027**	**2028**
	NTL	15.20%	14.49%	13.83%	13.19%	12.58%

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

14.92. According to Annex 3 (A3.8) of the Final Criteria, the following categories of NTL ought not to be factored in the targets for JNTL and GNTL:

- Rate 60 - Streetlight/Stoplight/Interchange;
- Rates 40, 50 & 70 - Large C&I customer class;
- Rate 20 - Medium C&I customer class;
- JPS' Internal/Unquantified NTL.

14.93. Nonetheless, these NTL components were also assessed as part of the OUR's System Losses evaluation.

14.11.1. Rate 60 NTL

14.94. In the 2019 December ELS document, NTL related to Rate 60 accounts (479) were reported at 0% down from 0.01% in 2018 December. With respect to streetlights (the dominant energy consumer in the rate class), for 2020 January, JPS reported that a total of 106,545 lamps were billed. However, it is not clear as to the number of streetlights billed for 2018 and 2019. Since streetlight losses commonly result from under billing as well as lamps operating on 24-hour duty (due to dysfunctional photo-sensors), there will be a need for greater clarity in the computation of this category of NTL.

14.95. Additionally, with LED streetlights presently accounting for over 60% of total installed streetlights, and projected to reach 100% by 2021, it is expected that these NTL will be maintained at the current level.

Regulatory Treatment of Rate 60 NTL

14.96. Taking into consideration the factors described in the Final Criteria, JPS' previous concession (2018-2019 Annual Review Filing), and regulatory principles and precedence (OUR's previous Determination Notices), the OUR maintains that Rate 60 NTL are totally within JPS' control, and can be eliminated through appropriate action and mitigation. In that regard, the OUR's allocation of these NTL with respect to the relevant targets for the Rate Review period, is as follows:

- Rate 60 NTL allocation: JNTL = 100% and GNTL = 0%;
- Rate 60 NTL will NOT be included in the relevant NTL targets.

14.11.2. NTL due to Large C & I Customers

14.97. Based on the existing rate schedule, Large C&I accounts include Rate 40, 50 and 70, however, these rate classes were evaluated separately in terms of their respective contribution to NTL.

Rate 70 NTL

14.98. In the 2018-2019 ELS, NTL related to Rate 70 accounts (23) was reported at 0% for each year, suggesting that there has been no energy loss activity associated with this rate class during the period.

Rate 50 NTL

14.99. Based on the 2018 December ELS, NTL due to Rate 50 accounts (133) were reported as 0.07% of annual net generation (3,178 MWh), with the same value recorded for each month in the year. For 2019, they remained constant at the 2018 level (0.07%), but the actual energy losses were reduced to 3,081 MWh, while the number of accounts increased to 145. This raises questions regarding the company's efforts to address this category of NTL. Also, the specific causes contributing to these NTL in 2018 and 2019, necessary for analysis of the loss drivers, were not provided by JPS.

Rate 40 NTL

14.100. Based on the 2018 December ELS, NTL due to Rate 40 accounts (1,839) were reported as 0.36% of annual net generation (15,812 MWh), with the same value recorded for each month in the year. For 2019, they remained at the 2018 level (0.36%), with the actual energy losses also remaining constant at 15,812 MWh, while the number of accounts increased to 1,857. This indication also raises questions about the company's efforts to address these losses. Additionally, the specific causes contributing to these NTL in 2018 and 2019, necessary for analysis of the loss drivers, were not provided by JPS.

Rate 40 & 50 NTL Considerations

14.101. Despite JPS' position on these categories of NTL, the OUR maintains that their current levels are unacceptable and should be reduced to zero (0) based on the following factors:

1) JPS' historical system losses data shows that these losses largely result from normal service connection faults and meter infrastructure defects, which can be easily corrected and mitigated, and are totally within JPS' control;
2) The number of customers/meters in these rate classes are relatively small (Rate 40 – 1,857 and Rate 50 – 145 in 2019 December), compared to the total customer base (665,534), which should not pose a serious challenge to the company in monitoring and auditing these accounts on an ongoing basis;
3) Presently, all Rate 40 and 50 accounts have the full AMI capability and are also monitored by check meters, effectively providing the company the visibility and intelligence to monitor these accounts and immediately detect energy losses;
4) Based on the loss causation factors, a significant portion of the reported energy losses due to these rate classes is considered recoverable. Therefore, JPS should seek to account for these leakages as "recoverable energy" and recover the associated revenues from the involved customers, as applicable. Moreover, these energy leakages should not be classified as NTL in the ELS, on the basis that they can be detected and billed to the relevant customers;
5) JPS also has the option to recover revenues associated with these NTL by means of adjustments in accordance with the relevant "Back Billing Policy" or other means available to JPS for redress; and
6) JPS has indicated that 100% of its largest C&I accounts, are now audited/investigated annually, exceeding the Licence requirement by 100%, which should provide more information to the company, to enhance detection, analytics and mitigation.

14.102. In light of these considerations, the OUR therefore urges JPS to take the necessary actions to address these losses to the benefit of the electricity system, the sector and by extension, the country.

Regulatory Treatment to Large C&I Customers

14.103. Taking into consideration the OUR's system losses analysis, the Final Criteria, JPS' previous concessions on these losses (2018-2019 Annual Review Filing), and regulatory principles and precedents (OUR's previous Determination Notices), the OUR maintains that largest C&I accounts NTL are totally within JPS' control, and can be eliminated through appropriate action and mitigation. In that regard, the OUR's allocation of these NTL with respect to the relevant targets for the Rate Review period, is as follows:

- Rate 40, 50 & 70 NTL allocation will be: JNTL = 100% and GNTL = 0%;
- Rate 40, 50 & 70 NTL will NOT be included in the relevant NTL targets.

14.11.3. Rate 20 (Medium) NTL

14.104. Based on the 2014-2019 ELS, NTL linked to Rate 20 (medium C&I) accounts fluctuated between 0.27% and 0.40% of annual net generation over the period, at an average of 0.34% per annum. For 2019, the reported customer count was 6,716 contributing to NTL of 0.39% of annual net generation (17,681MWh). Similarly, for 2018, the losses were reported at 0.39% (17,110 MWh), but attributable to 6,536 customers. These indicators suggest that very little has happened with respect to addressing NTL in this category. Additionally, the specific causes contributing to these NTL in 2018 and 2019, necessary for evaluation of the loss drivers, were not provided by JPS. Notwithstanding, similar to NTL due to Large C&I customers, the OUR is also of the view that the current level of these NTLs assigned to this category is unacceptable and should be reduced to zero.

Regulatory Treatment of Rate 20 (Medium) NTL

14.105. Taking into consideration the OUR's system losses analysis, the Final Criteria, JPS' previous concessions (2018-2019 Annual Review Filing), and regulatory principles & precedents (OUR's previous Determination Notices), the OUR maintains that Rate 20 (medium) NTL are totally within JPS' control, and can be eliminated through appropriate action and mitigation. In that regard, the OUR's allocation of these NTLs with respect to the relevant targets for the Rate Review period, is as follows:

- Rate 20 (medium C&I) NTL allocation will be: JNTL = 100% and GNTL = 0%;
- Rate 20 (medium C&I) NTL will not be included in the relevant NTL targets.

14.11.4. Rate 20 (Small C&I Customers) NTL

14.106. This NTL category involves Rate 20 customers who consume less than 3 MWh monthly, referred to as small C&I customers. Based on the 2014-2019 ELS, NTL associated with Rate 20 (small) accounts fluctuated between 0.23% and 0.34% of annual net generation over the period, at an average of 0.29% per annum, as represented in Table 14.17 below.

Table 14.17: Rate 20 (Small) NTL Data (2014-2019)

Components	2014 Dec.	2015 Dec.	2016 Dec.	2017 Dec.	2018 Dec.	2019 Dec.	Remarks
Rate 20 (SMALL) NTL (%)	0.33%	0.32%	0.27%	0.34%	0.23%	0.23%	2019: ~ 0.88% of Total Annual Losses
Rate 20 (SMALL) NTL (MWh)	13,571	13,331	11,751	14,622	9,812	10,023	
Customer Count	56,474	56,530	59,196	59,670	60,497	61,742	
Net Gen (MWh)	4,112,698	4,209,322	4,343,812	4,363,079	4,355,535	4,429,871	

14.107. As shown, for 2019, the reported number of customers was 61,742, contributing to NTL of 0.23% of annual net generation (10,023 MWh). The same level (2.23%) was reported for 2018, except that actual losses (MWh) and the number of customers were lower. For 2017 in particular, the data shows that 59,670 customers accounted for NTL equivalent to 0.34% of net generation (11.62 GWh). This suggests that there may be a lack of consistency in the company's treatment of this category of NTL.

14.108. In the 2018-2019 Annual Review Filing, JPS indicated that the company had expended significant resources in containing the losses in this category and over 17,839 accounts were audited in 2017. Based on the data, these efforts may have belatedly realized some improvements in 2018, contributing to the NTL level of 0.23% at the end of the year. Notwithstanding, the data also infers that no impactful loss reduction initiatives targeting these NTL were pursued during 2018 and 2019. This issue is compounded by the fact that the Application does not provide any specific details on the company's loss reduction efforts to address this NTL category during the 2018-2019 timeframe. Additionally, the specific sources and causes contributing to these NTL in 2018 and 2019, necessary for analysis of the loss drivers, were not provided by JPS. These observations raise concerns regarding the execution of the proposed NTL reduction strategy for the Rate Review period.

Sources of Rate 20 (Small) NTL

14.109. Based on system losses data reported by JPS, the identified sources of Rate 20 (small) NTL, generally involve the modalities presented in Figure 14.4 above. Observations and considerations with respect to Rate 20 (small) NTL include the following:

1) As shown in Figure 14.4, there are variations in the reported sources and distribution of these losses from year to year. Based on the nature and orientation of the indicated NTL drivers, it is recognized that some of these irregularities are highly complex and sophisticated and, in the absence of full visibility and advanced theft detection capabilities, present a challenge to the company. However, most of the reported causal conditions are manifested mainly as normal electricity supply connection faults and metering infrastructure defects, which are largely within the company's control;

2) Some of these faults/defects tend to emerge over time due to continuous exposure to varying electrical conditions intrinsic to the delivery of electricity service to customers, while others may have been exacerbated by the ineffectiveness of

certain aspects of the NTL reduction strategy. Based on the OUR's assessment of the characteristics and causes of these NTL, it was determined that at least 80% of the reported levels should be allocated to JPS;

3) Based on the data, "meter bypass" and "bypass at/before pothead" appear to be the main drivers of this category of NTL. However, with the mass deployment of advanced revenue meters in the network, it is expected that this unauthorized activity will be curtailed;

4) NTL due to some of the identified causes can be addressed through the relevant "JPS Back Billing Policy", which sets out the appropriate regulatory procedure for redress and revenue recovery; and

5) NTL emanating from defects associated with a customer's owned electrical infrastructure, should be referred directly to that specific customer and not to the entire customer base, as implied by JPS in its NTL allocation approach.

JPS' Proposed Rate 20 (Small) NTL Allocation

14.110. In the Application, JPS proposed a broad allocation of NTL into JNTL and GNTL for the Rate Review period as follows:

- JNTL: 2019 (23%) – 2023 (43%);
- GNTL: 2019 (78%) – 2023 (57%).

Regulatory Treatment of Rate 20 (Small) NTL

14.111. Taking into consideration the system losses analysis, the Final Criteria, JPS' previous concessions (2018-2019 Annual Review Filing), and regulatory principles & precedents (OUR's previous Determination Notices), the OUR maintains that Rate 20 (small) NTL are within JPS' control. However, based on existing constraints, the OUR's allocation of these NTL is as follows:

- JNTL = 2019 (75%) – 2023 (95%);
- GNTL = 2019 (250%) – 2023 (5%);
- These allocations will be reflected in the relevant NTL targets prescribed by the Licence.

14.11.5. Rate 10 NTL

14.112. As reported in the 2014-2019 ELS, NTL attributable to Rate 10 customers are presented in Table 14.18 below.

Table 14.18: Rate 10 NTL Data (2014-2019)

Components	2014 Dec.	2015 Dec.	2016 Dec.	2017 Dec.	2018 Dec.	2019 Dec.	Remarks
Rate 10 NTL (%)	6.10%	7.08%	7.48%	5.99%	6.12%	6.16%	2019: ~ 23% of Total Annual Losses
Rate 10 NTL (MWh)	250,875	298,147	325,075	261,224	266,745	272,728	
Customer Count	531,363	533,705	556,883	569,488	571,524	594,567	
Net Gen (MWh)	4,112,698	4,209,322	4,343,812	4,363,079	4,355,535	4,429,871	

14.113. As shown, the losses escalated from 6.10% in 2014, peaking at 7.48% at the end of 2016 but sharply declined to approximately 6.0 % by the end of 2017, which has remained fairly constant up to the end of 2019. Concomitantly, the number of customers increased by 12%, while annual net generation increased by 8%.

14.114. In the OUR's analysis of the Rate 10 NTL data the following was observed:

1) The sudden change in loss of value from 2016 to 2017 is uncharacteristic, as such level of loss reduction (1.49 percentage points), would likely be impractical within the 12-month period. Further, there were no loss reduction initiatives reported during that period to have such an impact, at that scale;
2) This sizeable shift in the losses appears to coincide with the implementation of the 2016 licence amendments related to system losses, even though there were indications of alterations to the monthly ELS;
3) The losses for 2018 and 2019 in absolute and percentage terms, are increasing even with JPS' massive deployment of advanced revenue meters, since 2018;
4) The Application does not provide any specific details on JPS' loss reduction activities for this NTL category during the Rate Review period;
5) The specific sources and causes contributing to Rate 10 NTL in 2018 and 2019, necessary for analysis of the loss drivers, were not provided by JPS.

14.115. These issues raise major concerns regarding the execution of the proposed NTL reduction strategy for the Rate Review period.

Sources of Rate 10 NTL

14.116. Based on system losses data reported by JPS, the identified sources of Rate 10 NTL generally involve the modalities presented in Table 14.19 below. In assessing RT 10 NTL, the following considerations were taken into account:

1) As shown in Table 14.19 below, there were variations in the reported sources and distribution of these losses from year to year. Based on the nature and orientation of these NTL drivers, the resulting losses are considered to be within the utility's control. Moreover, the reported causal conditions directly or indirectly relate to JPS' service connection facilities and revenue meters, which form part of the Distribution System, which is under the direct control of the company;

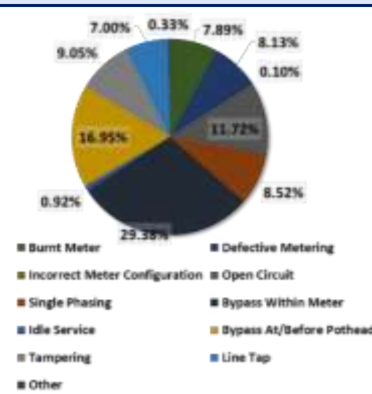
2) It is recognized that some of these irregularities are highly complex and sophisticated, and in the absence of full visibility and advanced theft detection capabilities, may create a challenge for the company. However, with the mass deployment of advanced revenue meters in the network, it is expected that this unauthorized activity will be curtailed;

3) NTL due to some of the identified causes can be addressed through the relevant "JPS Back Billing Policy", which sets out the appropriate regulatory procedure for redress and revenue recovery;

4) NTL emanating from defects associated with a customer-owned electrical infrastructure, should be referred directly to those specific customers and not to the entire customer base, as implied by JPS in its NTL allocation approach.

Table 14.19: Rate 10 - Energy Losses Distribution

RATE 10: ENERGY LOSSES DISTRIBUTION				
Mode of Losses	**2015**	**2016**	**2017**	**Average**
Burnt Meter	14.00%	7.43%	2.25%	7.89%
Defective Metering Infrastructure	-	10.72%	13.68%	8.13%
Incorrect Meter Configuration	-	0.29%	-	0.10%
Single Phasing	21.00%	4.57%	-	8.52%
Bypass Within Meter	5.00%	61.28%	21.87%	29.38%
Idle Service	2.00%	0.22%	0.54%	0.92%
Bypass At/Before Pothead	10.00%	8.97%	31.89%	16.95%
Line Tap	21.00%	-	-	7.00%
Open Circuit	26.00%	-	9.15%	11.72%
Tampering	-	6.52%	20.62%	9.05%
Other	1.00%	-	-	0.33%
TOTAL	**100.00%**	**100.00%**	**100.00%**	**100.00%**



14.117. For the Rate Review period, JPS expects that its Smart Meter programme will considerably improve its intelligence capability, and will have outcomes, including reduced cycle times for detection, correction and recovery of NTL and the improved management of audit resources.

14.118. JPS' broad Rate 10 NTL allocation proposed for the Rate Review period are:

- JNTL: 2019 (23%) – 2023 (43%);

14.119. GNTL: 2019 (77%) – 2023 (57%).

Regulatory Treatment of Rate 10 NTL

14.120. Taking into consideration the system losses analysis, the Final Criteria, JPS' previous concessions (2018-2019 Annual Review Filing), and regulatory principles & precedents (OUR's previous Determination Notices), the OUR maintain that NTL due to Rate 10 customers are largely within JPS' control, and can be reduced significantly through appropriate action and mitigation. However, based on existing constraints, the OUR has allocated these NTL as follows:

- JNTL = 2019 (70%) – 2023 (90%);
- GNTL = 2019 (30%) – 2023 (10%);
- These allocations will be reflected in the relevant NTL targets prescribed by the Licence.

Accordingly, the OUR has not accepted JPS' proposed Rate 10 NTL allocation into JNTL and GNTL.

14.11.6. JPS' Internal NTL

14.121. Based on the 2014-2019 ELS, NTL classified as "Internal Losses" ranges from 0.14% to 1.08% of annual generation, as shown in Table 14.20 below. From an efficiency perspective and based on industry standards, these NTL are excessive.

Table 14.20: JPS' Internal NTL Data (2014-2019)

Components	2014 Dec.	2015 Dec.	2016 Dec.	2017 Dec.	2018 Dec.	2019 Dec.	Remarks
Internal Losses (%)	0.27%	0.53%	0.14%	1.08%	0.82%	0.71%	2019: ~ 3% of Total Annual Losses
Internal Losses (MWh)	11,104	22,387	5,900	47,110	31,319	31,319	
Net Gen (MWh)	4,112,698	4,209,322	4,343,812	4,363,079	4,355,535	4,429,871	

14.122. As defined in the ELS methodology document included in the Application, Internal Losses are due to actions or inactions on the part of the company, and also accounts for estimation errors for all other NTL categories. According to JPS, these losses result from errors in billing, account setup, meter reading and inadequate maintenance.

14.123. Retrospectively, during the 2014-2019 Tariff Review process, the company submitted that the identified inefficiencies and process weaknesses were largely due to its outdated CIS and billing system. At the time, JPS affirmed that the described process deficiencies driving the Internal Losses would be resolved with the implementation of its new CIS by the end of 2014. However, as indicated, these losses have remained high since 2017, suggesting that the company's internal inefficiencies have remained undiminished.

14.124. In the 2018-2019 Annual Review Filing, the company confirmed that it accepts full responsibility for these NTL. However, despite the company's affirmation, their persistence at the reported levels is unacceptable. In that regard, the OUR urges the company to take swift actions to eliminate or minimize them.

Treatment of JPS' Internal NTL

14.125. Taking into consideration the system losses analysis, the Final Criteria, JPS' previous concessions (2018-2019 Annual Review Filing), and regulatory principles & precedents (OUR's previous Determination Notices), the OUR maintains that JPS' Internal NTL are totally within the company's control, and can be eliminated through appropriate action and mitigation. In that regard, the OUR's allocation of these NTL with respect to the relevant targets for the Rate Review period, is as follows:

- JNTL = 100% and GNTL = 0%;
- JPS's Internal NTL will NOT be included in the relevant NTL targets.

14.11.7. NTL due to Illegal Users

14.126. According to JPS, this category of NTL is due to unauthorized connections to its network by "Illegal users" involved in the illicit abstraction of electrical energy. As reported in the 2014-2019 ELS, on average, these losses represent almost 10% of annual net generation, caused by approximately 180,000 illegal electricity consumers, as represented in Table 14.21 below.

Table 14.21: NTL due to Illegal Users (2014-2019)

NTL DUE TO ILLEGAL USERS (2014-2019)							
Components	2014 December	2015 December	2016 December	2017 December	2018 December	2019 December	Remarks
Illegal Users NTL (%)	10.11%	9.60%	9.30%	9.34%	10.32%	10.22%	2019: ~ 39% of Total Annual Losses
Illegal Users NTL (MWh)	415,794	403,920	403,920	407,722	449,400	452,607	
Customer Count	180,000	180,000	180,000	180,000	180,000	180,000	
Net Gen (MWh)	4,112,698	4,209,322	4,343,812	4,363,079	4,355,535	4,429,871	

14.127. Notably, at the end of 2019, these NTL accounted for approximately 39% of the annual total system losses, which creates a burden on the sector and the country.

14.128. With respect to the perpetuation of these losses, JPS contends that they are caused by illegitimate actions, influenced by socio-economic conditions, which are largely outside of the company's control. The OUR differs on this point based on the premise that despite the complexities, the orientation of these losses present opportunities for curtailment, and in many cases, there are "low hanging fruits".

JPS' Methodology for Estimating NTL due to Illegal Users

14.129. According to the ELS methodology document, JPS' estimation of NTL due to Illegal Users are based on the following assumptions:

1) A study conducted in Seaview Gardens in 2010, where RAMI systems were installed as a loss-preventative measure. The electricity consumption data for the regularized consumers over a three-month period was used to estimate the average NTL per illegal consumer;

2) The estimated number of illegal consumers was derived from the STATIN census done in 2011. The number of households with signs of electrification was compared with the number of households billed by JPS, and the number of households with illegal connections was conservatively estimated at 180,000;

3) The resulting annual NTL was derived from the product of the estimated number of Illegal Consumers and their assumed average consumption (kWh).

14.130. Based on OUR's review of the reported customer count and consumption data and other relevant information, the reported level of these NTL are questionable given the broad assumptions on which the estimates are based. Therefore, given the magnitude of these NTL relative to total system losses and in light of the embedded estimation deficiencies, the OUR is of the view that a more sophisticated study, independently conducted, of this category of NTL will be necessary.

OUR's Treatment of NTL due to Illegal Users

14.131. With respect to NTL in general, the OUR is of the view that all aspects of the system losses are largely within JPS' control, although some elements may be more difficult to control. However, subject to the provisions of the Licence, the OUR is required to give consideration to NTL that are totally within JPS' control and those considered to be not totally within its control. The OUR believes that due to the nature and orientation of these NTL, with the adoption of a comprehensive loss reduction strategy, encompassing a systematic approach for proper loss quantification, infrastructure regularization and application of innovative technologies, complemented by a robust monitoring strategy, the company can cost effectively eliminate a significant portion of these losses.

14.132. Therefore, taking into consideration the system losses analysis, the Final Criteria, and regulatory principles & precedents (OUR's previous Determination Notices), the OUR's allocation of these NTL with respect to the relevant targets for the Rate Review period, is as follows:

- Illegal Users NTL allocation will be: JNTL = 0% and GNTL = 100%;
- This NTL allocation will be factored in the relevant NTL targets.

14.12. OUR's NTL Targets Analysis (Without COVID-19 Impact)

14.12.1. JPS' NTL Target Approach

14.133. With respect to the proposed NTL, targets set out under section 8.5.4 (page 198) of the Application are shown in Figure 14.6 below.

14.134. The following observations by the OUR regarding JPS' proposed NTL targets are worth noting:

1) The projected reduction in total NTL for 2019 was 0.34%. However, the 2019 December ELS shows that NTL decreased by 0.20% of annual net generation, but the actual losses increased from 798.3 GWh to 803.3 GWh;

2) The projections indicate that GNTL would decrease by 4.86% of annual net generation over the period, but JPS has declared that this NTL component is not within its control;

3) The proposed targets appear to be inverted in the sense that the supporting NTL initiatives predominately target losses due to "billed customers" but as shown in

Figure 14.6 below, the projected NTL reduction will only be achieved through GNTL, which is a clear misalignment;

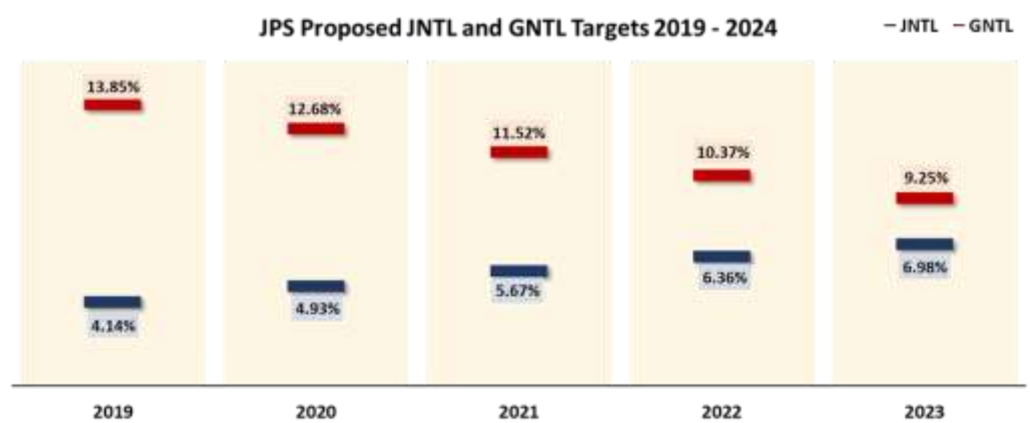
4) With respect to JNTL which are defined to be within JPS' control, the proposed targets infer that over the Rate Review period, the company will become increasingly less responsible for these NTL, pushing more of the burden on customers. It may be argued that this is unreasonable and in conflict with the company's proposed allocation of JNTL and GNTL; and

5) The way in which the proposal is presented, it is not clear whether the data represent forecasted performance or targets.

14.135. In light of the above observations, the proposed targets for JNTL and GNTL do NOT appear to be plausible.

Figure 14.6: JPS' Proposed NTL Targets for (2019-2023)

JPS' PROPOSED 2019-2024 NON-TECHNICAL LOSSES TARGET							
NTL Component	2018	2019	2020	2021	2022	2023	TOTAL IMPACT
JNTL	4.22%	4.14%	4.93%	5.67%	6.36%	6.98%	2.76%
GNTL	14.11%	13.85%	12.68%	11.52%	10.37%	9.25%	-4.86%
TOTAL NTL	18.33%	17.99%	17.61%	17.19%	16.73%	16.23%	2.10%
JNTL Change	-	-0.08%	0.79%	0.74%	0.69%	0.62%	2.76%
GNTL Change	-	-0.26%	-1.17%	-1.16%	-1.15%	-1.12%	-4.86%
TOTAL CHANGE	-	-0.34%	-0.38%	-0.42%	-0.46%	-0.50%	-2.10%



14.12.2. OUR's Methodology – NTL Targets

14.136. In view of the identified defects in JPS' NTL target methodology, it was not considered to be reasonable for adoption in the OUR's NTL target analysis. Alternatively, the OUR used available historical system losses data, including the modes and distribution of NTL, JPS' forecasted NTL reductions, to perform statistical and probabilistic analyses to forecast the annual JNTL and GNTL levels over the Rate Review period. The results from these analyses are presented in Table 14.22 below.

Table 14.22: OUR's Estimated JNTL and GNTL for 2019-2024 (Without COVID-19 Impact)

OUR'S ESTIMATED JNTL AND GNTL (2019-2024)						
NTL Projections	**2019**	**2020**	**2021**	**2022**	**2023**	**Remarks**
JNTL	6.02%	5.86%	5.61%	5.40%	5.22%	
GNTL	12.11%	11.75%	11.58%	11.32%	11.01%	
TOTAL NTL	18.13%	17.61%	17.19%	16.73%	16.23%	2019 NTL – actual value from ELS

14.137. These projections for JNTL and GNTL were used as the basis for setting the relevant targets.

JNTL Targets

14.138. As defined by the Licence, JNTL represent NTL that are totally within JPS' control. Regarding this definition, the regulatory interpretation is that these losses should be fully absorbed by the company. Based on the analysis, the annual JNTL targets for the Rate Review period should be zero (0.0%). However, taking into consideration certain challenges faced by JPS in addressing some aspects of these losses, the OUR, consistent with established regulatory precedents and good regulatory practice, has allowed a portion of the projected annual JNTL in the respective targets. This means shifting some of the burden to the customers, based on the rationale that the resulting financial relief would be used by the company to drive reductions in these losses. Further, the OUR is of the view that this approach could provide incentives to JPS for a more aggressive approach towards addressing these losses.

GNTL Targets

14.139. For the 2018-2019 and 2019-2020 Annual Review adjustment periods, the target for GNTL was set at 9.7% of annual net generation. However, for the Rate Review period, the GNTL targets were determined based on the NTL analyses and the impact of the proposed loss reduction initiatives.

14.13. COVID-19 Impact on Non-Technical Losses

14.140. JPS in its response to the Office's NTL targets in the draft Determination Notice submitted 2020 August 19, proposed a revised NTL forecast shown in Table 14.23 below, for review by the OUR. In its comments on the referenced draft Determination Notice, the company argued that a revision to the initial NTL forecast was necessary to account for the impact of COVID-19 on these energy losses, which was unforeseen prior to the submission of the Application.

Table 14.23: JPS' Revised Non-Technical Losses Forecast (COVID-19 Related)

Description	Category	2019	2020	2021	2022	2023	Remarks
JPS NTL Forecast (Original)	JNTL	4.14%	4.93%	5.67%	6.36%	6.98%	JPS Rate Review Application
	GNTL	13.85%	12.68%	11.52%	10.37%	9.25%	
	TOTAL NTL	**17.99%**	**17.61%**	**17.19%**	**16.73%**	**16.23%**	
OUR NTL Targets (Without COVID-19 Impact)	JNTL	4.07%	3.95%	3.79%	3.65%	3.52%	OUR DRAFT DETERMINATION NOTICE
	GNTL	10.50%	10.22%	10.07%	9.85%	9.58%	
JPS Revised NTL Forecast (COVID-19 Related)	JNTL	5.80%	7.54%	6.63%	6.50%	6.30%	Submitted: 2020 OCT 2
	GNTL	12.33%	13.94%	12.94%	12.00%	11.59%	
	TOTAL NTL	**18.13%**	**21.48%**	**19.57%**	**18.50%**	**17.89%**	

14.141. A breakdown of the revised NTL forecast in the various sub-categories are represented in Table 14.24 below.

Table 14.24: Breakdown of JPS' Revised System Losses Forecast (2019-2023)

	2019	2020	2021	2022	2023	REMARKS
TL	7.92%	7.85%	7.90%	7.93%	7.94%	
NTL						
Rate 70	0.00%	0.00%	0.00%	0.00%	0.00%	
Rate 60	0.00%	0.00%	0.00%	0.00%	0.00%	
Rate 50	0.07%	0.08%	0.08%	0.07%	0.07%	
Rate 40	0.36%	0.42%	0.39%	0.36%	0.35%	
Rate 20 (Med)	0.40%	0.47%	0.43%	0.41%	0.39%	
Rate 20 (Small)	0.23%	0.27%	0.24%	0.23%	0.22%	
Rate 10	6.16%	7.29%	6.64%	6.28%	6.07%	Projected Escalation:
Illegal Users	10.22%	12.10%	11.03%	10.42%	10.08%	Projected Escalation:
Internal Losses	0.71%	0.84%	0.76%	0.72%	0.70%	
SUB-TOTAL NTL	**18.13%**	**21.48%**	**19.57%**	**18.50%**	**17.89%**	
TOTAL LOSSES	**26.05%**	**29.33%**	**27.47%**	**26.43%**	**25.83%**	

14.142. The revised NTL proposals were reviewed by the OUR taking into account the effect of the prevailing COVID-19 situation on system net generation, electricity sales and average system losses. The indication from this evaluation scenario infers that there is the potential for some degree of adverse consequences in terms of increased NTL levels, due to the impact of the pandemic in conjunction with the GOJ's curtailment measures. Based on the data, the resulting impact is expected to escalate within the 2020-2021 timeframe.

14.143. With respect to the revised System Losses forecast for 2020, the company indicates that NTL is expected to increase from its original projection of 17.61% to 21.48% of net generation by the end of the year. However, based on the 2020 January-August ELS (actual measurements), which captured System Losses performance during the period of COVID-19 intensification and response measures, total NTL was reported at 18.20% in 2020 January then increased to 19.26% at the end of 2020 August, as shown in Table 14.25 below.

Table 14.25: JPS' NTL (2020 January-August ELS) – Actual Performance since COVID19

Description	Prior to COVID19		Performance since Entry of COVID19					
NTL COMPONENTS:	**2020 JAN**	**2020 FEB**	**2020**	**2020 APR**	**2020**	**2020 JUN**	**2020 JUL**	**2020**
Rate 70	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 60	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rate 50	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.06%	0.06%
Rate 40	0.36%	0.35%	0.36%	0.36%	0.36%	0.36%	0.36%	0.37%
Rate 20 (Med)	0.40%	0.40%	0.40%	0.40%	0.39%	0.39%	0.39%	0.39%
Rate 20 (Small)	0.23%	0.23%	0.23%	0.23%	0.23%	0.22%	0.22%	0.22%
Rate 10	6.15%	6.14%	6.16%	6.70%	6.76%	6.82%	6.86%	6.90%
NTL - Billed	**7.21%**	**7.19%**	**7.22%**	**7.76%**	**7.81%**	**7.86%**	**7.89%**	**7.94%**
Illegal Users & Internal Losses	10.99%	11.13%	11.18%	10.62%	10.93%	11.00%	11.20%	11.32%
Total: NTL	**18.20%**	**18.32%**	**18.40%**	**18.38%**	**18.74%**	**18.86%**	**19.09%**	**19.26%**

14.13.1. OUR's Position – COVID-19 Impact on Non-Technical Losses

14.144. While JPS' revised System Losses forecast for 2019-2023 projects total NTL of 21.48% for 2020, the OUR's System Losses evaluation scenario factoring COVID-19 impacts, estimates the total NTL for 2020 to be approximately 19.78%. Taking into consideration the revised electricity sales and net generation parameters due to assumed impact of the pandemic, the OUR believes that this NTL projection (19.78%) is reasonable and appears to be in alignment with the monthly NTL trajectory reflected in JPS' 2020 January-August ELS. Based on this extrapolated 2020 NTL performance level, among other things, the revised 2020 NTL (21.48%) proposed by JPS appears to be highly inflated and is deemed not reasonable and representative of the system's energy balance for 2020 under the imposing COVID-19 conditions.

14.145. Regarding the 2021-2023 NTL performance predictions, the OUR's System Losses evaluation (COVID19 Scenario) generated NTL projections, which were found to be fairly consistent with JPS' revised NTL forecast.

14.146. Using the OUR's COVID-19 related NTL forecast (2019-2023) and the established allocation factors for JNTL and GNTL, the NTL targets for the 2019-2024 revenue cap period was adjusted, as represented in Table 14.26 below.

14.14. OUR's Determined NTL Targets for JPS

14.14.1. Non-Technical Losses Targets (2019-2024)

14.147. Based on the OUR's NTL Losses evaluation, including the impact of COVID-19, the requirements of the Licence and the Final Criteria, the Office determines that JPS' NTL targets for the Rate Review period shall be as set out in Table 14.26 below.

Table 14.26: OUR's Determined NTL Targets for JPS (2020-2029)

Loss Data (Year)	Rate Adjustment Period	JPS Proposed NTL Targets (Original)		JPS Revised NTL Target Proposal (COVID-19 Related)		OUR Determined NTL Targets (Initial)		OUR Determined NTL Targets (COVID-19 Impact)		Remarks
		JNTL	GNTL	JNTL	GNTL	JNTL	GNTL	JNTL	GNTL	
2019-2024 REVENUE CAP PERIOD										
2019	2020-2021 Annual Review	4.14%	13.85%	5.80%	12.33%	4.07%	10.50%	**4.07%**	**10.50%**	
2020	2021-2022 Annual Review	4.93%	12.68%	7.54%	13.94%	3.95%	10.22%	**4.71%**	**11.58%**	
2021	2022-2023 Annual Review	5.67%	11.52%	6.63%	12.94%	3.79%	10.07%	**4.58%**	**11.50%**	
2022	2023-2024 Annual Review	6.36%	10.37%	6.50%	12.00%	3.65%	9.85%	**4.24%**	**10.75%**	
2023	2024 Rate Review	6.98%	9.25%	6.30%	11.59%	3.52%	9.58%	**3.99%**	**10.39%**	
2024 -2029 REVENUE CAP PERIOD										
2024	2025-2026 Annual Review	15.20%		-	-	3.50%	9.50%	**3.70%**	**10.01%**	Indicative Targets: Rolling 10-year Criteria.
2025	2026-2027 Annual Review	14.49%		-	-	3.15%	10.22%	**3.40%**	**9.60%**	
2026	2027-2028 Annual Review	13.83%		-	-	2.70%	10.07%	**3.15%**	**9.23%**	
2027	2028-2029 Annual Review	13.19%		-	-	2.20%	9.85%	**2.70%**	**9.00%**	
2028	2029 Rate Review	12.58%		-	-	2.15%	9.58%	**2.20%**	**8.85%**	

14.148. Under the circumstances, the OUR takes the view that NTL targets are fair and reasonable and have the potential of providing an incentive to JPS to reduce its overall electricity losses.

14.14.2. Non-Technical Losses Targets (2024-2029)

14.149. Subject to the requirements of the Licence, the OUR also determined NTL targets to satisfy the rolling 10-year target criteria, which are also presented in Table 14.26 above.

14.15. Consideration for NTL Reduction

14.150. In electric utility operations, NTL are synonymous with illegitimate electricity usage, which often leads to over-consumption, thus imposing significant strain on supply capacity and T&D network facilities. Given this predicament, tangible reduction of these losses will be necessary to ensure the financial sustainability of the utility.

14.15.1. NTL Reduction Philosophy

14.151. In previous regulatory reviews, the OUR examined the issue of NTL and discussed strategies to detect and reduce them. While some of these losses come with varying degrees of complexity, the general view is that the utility should employ the measures necessary to reduce them to a level that do not overburden society, or diminish the capacity of the utility to sustain operations and maintain service quality.

14.15.2. NTL Abatement Framework – Metered Customers

14.152. The OUR takes the view that it is imperative that JPS do more with regard to the abatement of NTL in the following areas:

- *The identification of NTL:* The existing approach used to analyse customers' data, to identify patterns that would signal possible fraud/theft, is still largely mechanical and manual. This approach is ineffective in addressing sophisticated irregularities. In this respect, the identification of NTL will be significantly improved with the use of specialised software and data analytics tools and process automation;
- *Use of Advanced Technology:* Process automation by software will facilitate analyses of more inputs and parameters, such as GIS data, seasonal and weather-related data, and socio-economic information, to provide better signals for NTL detection. Consequently, selecting the right software tool is necessary to loss detection, monitoring and controlling the complete process in an efficient manner.

14.15.3. Use of Advanced Technology

Automated Metering Infrastructure

14.153. AMI metering is a modern, effective metering system that provides near-real time measurements of consumption and other useful electrical data, as well as alarms to alert the utility when irregular conditions are detected. AMI metering provides an enormous quantity of data and can include some limited level of data analytics. Back in 2009, the World Bank had identified the deployment of AMI as a feasible strategy to address NTL in the power sector. Although not fool-proof as observed from the Jamaican experience, with appropriate security protocols, AMI can be very effective in avoiding meter tampering and other modes of electricity theft. In the Application, JPS indicated that 144,721 advanced meters have been installed in the network up to 2019 February. Also, between 2018 March and 2020 April, the OUR approved 238,618 of these meters for installation. Therefore, with the company's proposal for almost full AMI coverage by 2024, it should have full visibility and increased intelligence to deal with NTL.

Analytics Integrated with AMI

14.154. To support its 2019-2024 NTL targets, JPS proposed the expansion of its Smart Meter programme to be integrated with planned deployment of analytics software tools. According to JPS, these initiatives are to be coupled with the Advanced Automated Theft Detection Analytical Tool (AATDAT), to employ greater use of analytics in the fight against NTL. The OUR takes the view that the effective use of AMI in concert with the appropriate analytical tools is a step in the right direction.

<u>Value of Analytics with AMI</u>

14.155. Currently, in the domain of NTL, analytics integrated with AMI is one of the most effective technological solutions. The predictive analytics technology when applied to the AMI data can generate the type of information to more easily identify customers that perpetrate fraud and use sophisticated methods to illicitly abstract electricity, which otherwise may not be easy to detect. Project references on analytics/AMI utilization by utilities in other jurisdictions have demonstrated the efficacy of this novel technological approach. Reports of deployments of nearly 100% of this composite in some utility systems have realized over 75% reduction in NTL. However, since there is always the potential for re-incidence, this strategy must be supported with sustained public education, stakeholder action and community engagement.

14.16. Responsibility for Non-Technical Losses

14.16.1. Responsibility Factor

14.156. To compute the annual Y-Factor, according to Schedule 3, Exhibit 1 of the Licence, the difference between the annual GNTL (Yc) target and the actual GNTL (Yc) shall be multiplied by a responsibility factor (RF). As defined by the Licence, RF is the responsibility factor determined by the Office, which is a percentage between 0% and 100%. The RF shall be determined by the Office, in consultation with JPS, having regard to (i) nature and root cause of losses; (ii) roles of JPS and the Government to reduce losses; (iii) actions that were supposed to be undertaken and resources to be allocated in the Business Plan; (iv) actual actions undertaken by the resources spent by JPS; (v) actual cooperation by the Government; and (vi) change in the external environment that affected losses.

14.16.2. JPS' RF Proposal

14.157. In the Application, JPS proposed that RF should be set at 10% initially and adjusted annually. Currently, the value of the RF is 20%. JPS' justification for this change is presented below.

14.158. With respect to JNTL, the company identified the following factors that it claimed must be achieved to ensure success in the reduction of NTL:

- Prevention - The ability of the utility to prevent a loss from occurring;
- Detection - The ability of the utility to detect when and how a loss occurs;
- Recovery - The ability of the utility to "back-bill" or otherwise fully recover from the affected accounts;
- Sustainability - The ability of the utility to prevent further loss from occurring.

14.159. In reference to these defined factors, the company argues that:

- While some modes of NTL like defective infrastructure, are within its control (subject to resource constraints), to prevent, detect and sustain the proper quality of infrastructure, many other modes can only be under the utility's total control, if the social conditions of the neighbourhoods are at an adequate level across the country;
- It does not have the resources to control all 600,000 plus customers on a continuous basis, while being responsible for reliable and safe electricity supply. The company further argued that while it can be successful in detection of many of the modes of JNTL, it has no capacity to prevent NTL from occurring, fully recover lost sales

when detected, and more importantly, to sustain any achieved level of success in fighting system losses across the country.

14.160. In that regard, the company emphasized that Government support should not be limited only to GNTL, but to overall system losses reduction, and this support has to be continuous. Further, JNTL targets as well as actual performance results must be tied to the GOJ's legal and financial long-term support to the company's loss reduction initiative.

OUR's Comments

- While the difficulties of combating system losses are recognised, JPS' proposal for the reduction in RF is not compelling given the fact that 80% of the GNTL category of losses is already borne by customers.
- Further, the proposed construct that seeks to pass on an even greater portion of the losses to paying customers as against focused, consistent, persistent and sustained efforts to effect meaningful reductions is not economically sustainable.

14.16.3. OUR's Determination on Responsibility Factor

14.161. In determining the annual RFs for the Rate Review period, the OUR carried out an assessment, taking into account, the following:

- Historical NTL data, including their orientation, causes, and distribution;
- Actual NTL reduction activities undertaken by JPS during the 2016-2019 rate adjustment period;
- JPS' proposed NTL reduction programmes and initiatives including funding for the 2018-2019 adjustment period;
- The proposed NTL initiatives for the Rate Review period;
- The initiatives contemplated by the GOJ to address NTL going forward; and
- The findings of its NTL evaluation and analyses for 2019-2024.

14.162. The OUR's assessment found that while a collaborative approach to address GNTL is being articulated, there is no indication of any anticipation of a tangible impact in terms of a shift in responsibility for GNTL to date, and also no clear projection for any material change until about the year 2022.

14.163. Based on the OUR's RF assessment, the Office determines that:

1) The RF shall remain at **20%** for the 2020-2021 and 2021-2022 Annual Review adjustments; and
2) At the 2022-2023 Annual Review adjustment, the RF will be reviewed and adjusted as necessary, based on the progress of the programmes targeting GNTL.

14.17. OUR's Comments and Position

14.164. In addressing system losses, this review has revealed a number of issues that requires JPS' attention, if significant and enduring reduction in system losses are to be achieved. These issues are delineated below.

14.17.1. System Losses Review – Issues and Decisions

ELS Issues

Modification to the ELS

14.165. As stipulated in Annex 3 (A3.3) of the Final Criteria, no modification to the ELS shall be undertaken by JPS without prior consultation with the OUR. However, the 2018 December ELS included in the Application, indicates material modifications to the one initially submitted to the OUR in 2019 April, without the required prior consultation. As such, the adjusted TL and NTL were not considered in this Rate Review process.

Disaggregation of NTL

14.166. In the Application, JPS admitted that there are shortcomings with the disaggregation of NTL and asserted the NTL breakdown in the ELS should not be used as a basis for target setting. Instead, the target setting should be based on the provisions of the Licence, which is the base year, historical performance, and agreed resources in the five-year plan and GOJ's involvement. However, the OUR is of the view that this proposition is unacceptable based on the following:

1) The ELS is based on historical performance data;
2) The losses are calculated on a 12-month rolling average basis to level out some degree of error in the calculations;
3) JPS would be aware that aspects of TL and NTL reported in ELS are based on estimation assumptions;
4) The Final Criteria stipulates that the ELS will form the basis of the TL and NTL targets, and will be set in accordance with the requirements of the Licence; and
5) The targets have been consistently determined and will continue to be set in accordance with the requirements of the Licence.

TL Measurement Issues

14.167. In the 2018-2019 Annual Review Filing, JPS asserted that it recognized the need to more accurately account for TL, and as such, has made investments towards improving its measurement and modelling capabilities. Accordingly, JPS reported that it acquired the DIgSILENT PowerFactory, updated the existing SCADA/EMS and implemented an ADMS. Following these developments, in the Application, JPS indicated that to date the modelling of transmission network is completed while the primary distribution network is approximately 75% complete.

14.168. The company noted that based on the degree of progress, the measurement of TL continues to be a mixture of direct measurement and estimations from modelling. However, given the system losses data supporting the Y-Factor proposals, the monthly/annual ELS, and other regulatory reports, it is still not clear that the defined TL components are being measured, calculated and evaluated on a systematic basis.

14.169. This issue is particularly important as it directly involves the methods and practices for categorizing TL and calculating the losses for each component. While the reported T&D network modelling currently being done by the company is a notable development, for regulatory evaluation, going forward, the company shall be required to clearly outline in each month the basis of any changes to TL.

Metering Data

14.170. Currently, transmission losses are calculated using energy metering at the generation interconnection points and at the secondary side of the distribution substations. However, there could be a margin of error if all the meters are not revenue-grade. Typically, the meters at the generation interconnection points are revenue-grade and generally provide accurate metering data, but at the distribution substations, all the feeder meters may not be revenue-grade, which can impact the accuracy of the computed losses. In that regard, the company shall provide a listing of all the installed feeder meters to the OUR, including the meter type, serial number, specifications, accuracy, class and other technical characteristics, within three (3) months of the effective date of this Determination Notice.

TL Assessment - Distribution System

MV Network

14.171. With respect to the MV distribution network, TL assessments usually include the losses of each network component, from the customer meter up to the substation transformer, for both peak and energy losses. Peak demand losses are commonly calculated at the coincident peak for each level. Energy losses can be calculated by two main methods:

1) The use of hourly data to calculate losses for each hour of the study period, which requires extensive data collection and detailed modelling;
2) The peak load loss and loss factor approach, which is commonly used due to the constraints with the hourly data method. This method entails the calculation of energy losses based on the peak loss of equipment or at the feeder level, multiplied by the loss factor for the equipment or feeder.

14.172. Based on the submitted losses information, the approach being used by JPS to estimate TL in the primary distribution network appears to deviate from both of the described methodologies. Hence, the losses calculation may not be reliable.

14.173. In light of this, the company shall complete a full assessment of the primary distribution network TL, including the total number of feeders and total number of distribution transformers, based on the methodologies identified above, within six (6) months of the effective date of this Determination Notice. After completion, a copy of the assessment report shall be submitted to the Office.

Secondary Distribution Network

14.174. The TL reported for the secondary distribution network has remained static at 2.90% for more than ten (10) years. However, the OUR's TL review found that the estimation model is deficient and does not reflect current system configuration. As such, JPS is required to update this model to enable more accurate estimation of these losses.

TL Initiatives and Reduction

14.175. In the Application and Business Plan, JPS proposed three main initiatives for the TL reduction and mitigation in the T&D system, as described herein. However, the strategy appears to be limited in scope and has innate weaknesses. These issues are delineated below:

1) In terms of TL reduction, the proposed 69kV Bellevue – Roaring River transmission line was evaluated and determined not to be cost-effective, and also not justified as a solution to address the purported reliability and voltage-related issues;

2) Regarding the mitigation of transmission losses, the OUR takes the view that in addition to the existing hardware options, the company should also consider the following measures:

   a) Optimization of existing controls for transformer LTCs, generator voltages, switched shunt capacitor banks, and other transmission equipment, to reduce current flow and minimize losses;

   b) Assessment of existing shunt capacitor banks (fixed and switched) in the system, with the addition of new units where necessary, to reduce current flow and minimize losses;

   c) The use of advanced technologies to improve the efficiency of the existing transmission network and mitigate TL;

   d) Explore the use of Optimal Power Flow (OPF) software technology to dispatch the system more efficiently during non-peak hours. Although TL is highest during peak conditions, a significant portion of the total annual energy losses occurs off-peak, and during this period, the System Operator will have more flexibility to make adjustments due to lower demand levels. Studies have shown that the use of OPF techniques during off-peak hours could be cost-effective in reducing TL.

<u>TL Projects - Distribution System</u>

14.176. In the Business Plan, JPS posited that its TL reduction strategy entails a number of initiatives, including, PF management, VSP, phase balancing and voltage regulation. However, based on the OUR's system losses review; it seems that the strategy is anchored on the VSP, which on its own, may not be effective in addressing these losses. It is also important to note that JPS has been implementing this programme for over ten (10) years, but the resulting impact on TL has not been quantified. Also, based on the reported system losses data, there is no clear indication of any reduction in TL attributable to this initiative. Therefore, with the continuation of this programme, the company is required to submit a status report to the OUR detailing the activities performed and the impact on TL. This report shall be submitted within one (1) year of the effective date of this Determination Notice.

Distributed Generation

14.177. During system operations, DG has been proven to reduce TL in the distribution network, due its proximity to the load. However, given the number of existing DG facilities connected to the system, as well as the committed facilities, it appears that the projected TL reduction from the operation of these facilities is hugely underestimated. This means that there will be a need for further examination of this issue.

TL Reduction through O&M Programme

14.178. As described in the Business Plan, some of the proposed TL reduction efforts such as PF correction and phase balancing, is to be executed as part of the company's O&M programme.

Power Factor Correction

14.179. According to the Business Plan, JPS intends to continue to install/repair capacitor banks along with feeders to maintain a PF of at least 0.95 on all feeders, and capacitors will be placed where they are most needed following an assessment done monthly. However, it is unconvincing due to the lack of an updated distribution plan. Further, no loss reduction was quantified for this activity over the entire Rate Review period, which raises questions about the commitment to these efforts.

Phase Balancing

14.180. As described by JPS, the objective of this initiative is to balance the phases of each feeder so that the maximum deviation of the average phase current is less than 10%. JPS also indicated that phase balancing is an ongoing O&M activity and it is in the process of updating the feeder metering software to measure the level of imbalance on each feeder.

14.181. While these proposed activities are considered to be practical and reasonable, the OUR notes that in 2016, the company had indicated that the focus for 2017-2021 was identifying feeders with phase imbalances above 20% and improving them within acceptable phase balanced levels (< 10%). However, to date no specific details on the progress or the impact of this initiative has been provided by JPS.

Efficiency Improvement

14.182. As it relates to efficiency improvement, the OUR notes:

1) The system losses review demonstrates that the technical efficiency of the electricity system can be improved through proactive utility action and appropriate TL initiatives. Notwithstanding, if the key criterion for the economic justification of these initiatives is the marginal cost of energy, then they may not be cost-justified without consideration of ancillary benefits. Therefore, if the core of the projects is not loss reduction, then the question arises, as to whether the targeted TL reductions can be realized;

2) Given the adverse impact of high TL, system efficiency considerations should be entrenched in every facet of the company's commercial operation and should also attract greater focus in future business plans;

3) It is expected that the determined TL targets will provide incentives to unlock the potential for TL mitigation and system efficiency improvement.

Non-Technical Losses Estimation Issues

<u>NTL due to Streetlights</u>

14.183. For 2020 January, JPS reported that 106,545 lamps were billed. However, NTL due to unreported streetlights may result from under billing, as well as lamps operating on 24-hour duty (due to dysfunctional photo-sensors). Consequently, there is a need that greater attention be paid to the computation of this category of NTL.

<u>Impact of Advanced Meters on Rate 10 NTL</u>

14.184. The 2017-2019 ELS indicate that Rate 10 NTL in absolute and percentage terms have increased, even with the company's massive deployment of advanced revenue meters, during the period. No details regarding this situation were provided in the Application. However, given the level of capital expenditure for the programme at this stage and the proposed investments for the Rate Review period, the company is required to submit a detailed report on the advanced meter programme up to 2020 June, to the OUR. The report is to address the scope, cost, benefits and impact on NTL, within six (6) months of the effective date of this Determination Notice.

<u>Estimation of NTL due to Illegal Users</u>

14.185. The OUR's review of JPS' ELS methodology revealed that the estimation of NTL due to Illegal Users is not grounded on any robust scientific model for the following reasons:

1) The referenced Seaview Gardens' study used to substantiate the company's assumptions is dated (2010) and very limited in scope, thus would not adequately represent the dispersion and consumption characteristics of Illegal Users in the various service areas across the country;
2) The number of illegal consumers was reportedly estimated based on STATIN's 2011 population & housing census. However, the model used to establish the relationship between the number of households and illegal connections is not clear; and
3) There is no reference to the impact of the CRP and Red Zone initiatives.

14.186. Based on the OUR's analysis of these losses, taking into account the existing customer count and consumption data, and other relevant information, the reported level of these NTL are questionable. Therefore, given the magnitude of these NTL relative to total system losses and in light of these apparent estimation deficiencies, the OUR has determined that JPS shall conduct an independent study/survey of this category of NTL, to establish a credible baseline. The baseline is to facilitate calibration of the reported NTL and regulatory decisions, going forward. This study shall be completed within one (1) year of the effective date of this Determination Notice, and a copy of the report of the study shall be submitted to the OUR.

NTL Allocation Mechanism

14.187. In the Application, JPS acknowledged that while the Licence introduced the concept of control over NTL by establishing two categories of NTL (JNTL and GNTL), it however, does not explicitly outline a method to determine which aspects of NTL are within the company's control. Based on that position, JPS proposed a framework to be used as the basis for the determination of JNTL and GNTL. However, the OUR's review of the methodology found that it is characteristic of a hypothetical concept and does not meet the standard for practical application.

14.188. Further, the OUR is surprised that after a series of LIC consultations on this matter, which established that the NTL sources and distribution will be the basis for JNTL and GNTL allocations, that the proposed option has surfaced. Additionally, since 2016, there has been established regulatory precedence to allocate the NTL based on modes of losses and distribution. Therefore, consistent with the Final Criteria, the OUR will continue to allocate the NTL using this approach, throughout the Rate Review period.

Modes of NTL

14.189. Based on the NTL data submitted to support the proposed targets, the specific causes, modes and distribution of losses for the various NTL categories were not provided, which is a deviation from the requirements of the Final Criteria. In fact, this omission constrained the OUR's NTL evaluation. Given this situation, going forward, at each Annual Review or Rate Review, the company will be required to submit with reasonable accuracy the specific sources and distribution of the energy losses for all the NTL categories, supported by the associated reports and details of the field investigations and analyses.

Reporting of System Losses

14.190. For the Rate Review period, JPS shall continue to report all TL and NTL in the monthly ELS.

Technical Losses Data

14.191. All TL shall be disaggregated into the four (4) defined categories, and shall include the following:

1) For the Transmission System, the TL losses for each transmission line, substation transformer and other relevant equipment; and
2) For the Primary Distribution Network, the TL for each feeder and distribution transformer.

Non-Technical Losses Data

14.192. All NTL shall continue to be disaggregated into the components as represented in the 2019 ELS.

System Losses Audit

14.193. Taking into consideration the extent of the issues and deficiencies identified from the OUR's system losses review, the Office will commission an independent audit of JPS' system losses, prior to the 2021-2022 Annual Review.

Need for Customer Education

14.194. As the power sector evolves, it is inevitable that the utility will be confronted with complex challenges that will require the attention of all the relevant stakeholders, including consumers. Against that background, the drive to accomplish the stated efficiency goals will undoubtedly require a customer base that is more informed about energy use and system issues. In that context, there will be a need for the utility to amplify its efforts to improve consumer education, awareness and understanding, to assist in reducing NTL caused by electricity theft and fraud.

14.18. Office Determination: System Losses

14.195. Based on the OUR's review, the Office determinations on JPS' System Losses proposals are as follows:

DETERMINATION #21

1) The proposed system losses targets for Rate Review period are not approved as they are deemed not reasonable and prudent, due to measurement inaccuracies and unrepresentative projections.

2) The approved System Losses targets for Rate Review period are as follows:

<u>Technical Losses</u>

a) 2020–2021 Annual Review: 7.80%
b) 2021–2022 Annual Review: 7.78%
c) 2022–2023 Annual Review: 7.72%
d) 2023–2024 Annual Review: 7.67%
e) 2024 Rate Review: 7.61%

<u>Non-Technical Losses</u>

a) 2020–2021 Annual Review: JNTL – 4.07%, GNTL – 10.50%
b) 2021–2022 Annual Review: JNTL – 4.71%, GNTL – 11.58%
c) 2022–2023 Annual Review: JNTL – 4.58%, GNTL – 11.50%
d) 2023–2024 Annual Review: JNTL – 4.24%, GNTL – 10.75%
e) 2024 Rate Review: JNTL – 3.99%, GNTL – 10.39%

3) The Responsibility Factor for the Rate Review period shall be as follows:

a) The RF shall remain at 20% for the 2020-2021 and 2021-2022 Annual Review;
b) At the 2022-2023 Annual Review, the RF will be reviewed and adjusted as necessary based on the progress of the initiatives to address GNTL.

4) The company shall complete a full assessment of the primary distribution network TL, including the total number of feeders and total number of distribution transformers, within one (1) year of the effective date of this Determination Notice, and a copy of the assessment report shall be submitted to the OUR.

5) The company shall submit a detailed report on the advanced meter programme up to 2020 June to the Office, addressing the scope, cost, benefits and impact on NTL, within six (6) months of the effective date of this Determination Notice.

6) The company shall conduct an independent study of NTL due to Illegal Users, to establish a credible baseline, to facilitate calibration of the reported NTL and regulatory decisions going forward. This study shall be completed within one (1) year of the effective date of this Determination Notice, and a copy of the report of the study shall be submitted to the Office.

7) At each Annual Review during the Rate Review period, the company shall submit with reasonable accuracy, the specific sources and distribution of the energy losses for all the NTL categories, supported by the associated reports and details of the field investigations and analyses.

8) The OUR shall commission an independent audit of JPS' system losses to be completed prior to the 2021-2022 Annual Review.

9) JPS shall comply with all the system losses related requirements, including the reporting requirements specified in this Determination Notice.

15. Quality of Service (Q-Factor) and Grid Security

15.1. Introduction

15.1 Reliability of supply refers to the availability and continuity of electricity service to all customers and users of the electricity system. It involves the evaluation of supply interruption events (sustained and momentary) experienced by customers, during which the voltage at the supply terminal to the customer or network user drops to zero, in a given period.

15.2 From the perspective of the customer, supply interruptions are the most noticeable indications of a change in the quality of service from the utility, which convey signals of reliability expectations. In essence, this dynamic indicates that reliability is a key dimension of quality of service, which will be central to the implementation of the Q-Factor system.

14.19. Quality of Service Metrics

15.3 To effectively manage system reliability, it must be accurately measured and monitored. Performance metrics become useful in achieving this objective as they provide a framework for quantitative reliability measurements and quality of service assessments.

15.4 Generally, there are two broad categories of electric System Losses: Technical Losses (TL) and Non-Technical Losses (NTL).

15.5 These metrics are also necessary to support regulatory functions, such as, performance monitoring, determination of performance targets

Measuring Quality of Service

SAIFI: the System Average Interruption Frequency Index is a quality of service metric used in the electric utility business to measure reliability of electricity service. It assessing reliability of service the index focuses on the average number of interruption (above a predetermined threshold) the customer experiences over a year.

$$SAIFI = \frac{total\ No.of\ customer\ interruption}{total\ No.of\ customer\ served}$$

[Number of interruptions (duration> 5mins)/year]

SAIDI: the System Average Interruption Duration Index is used to measure the average duration of interruptions (above a predetermined threshold) in the power supply experienced by customers on an electric power grid. SAIDI is a measure of reliability in electricity service.

$$SAIDI = \frac{customer\ interruption\ durations}{total\ No.of\ customer\ served}$$

[Minutes/year (duration> 5mins)]

CAIDI: the Customer Average Interruption Duration Index is also quality of service metric. It also measures reliability of service in the electric utility business. CAIDI captures the average duration of an interruption (above a predetermined threshold) in power supply.

$$CAIDI = \frac{customer\ interruption\ durations}{total\ No.of\ interruptions}$$

[Minutes/interruption (duration> 5mins)]

MAIFI: the Momentary Average Interruption Frequency Index is a quality of service metric similar to SAIFI. However, in measuring service reliability it captures the average number of interruption (below a predetermined threshold) the customer experiences over a year. Hence, it reflects the extent of interruptions of relatively short durations on the system.

$$MAIFI = \frac{total\ No.of\ customer\ interruption}{total\ No.of\ customer\ served}$$

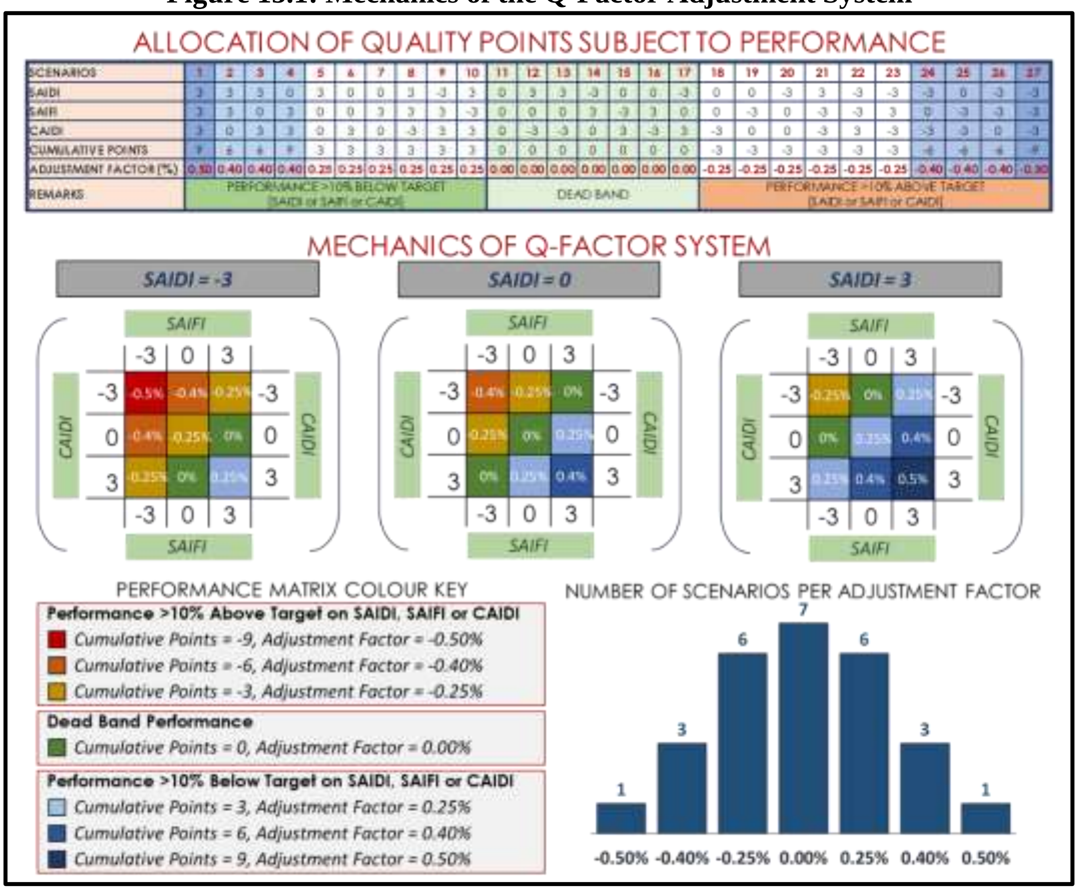
[Number of interruptions (duration< 5mins)/year] and development of incentive mechanisms aimed at improving the quality of electricity service to all customers and system users. Reliability indices commonly used in quality of service assessments include:

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

14.20. Q-Factor Adjustment System Design

15.6 As prescribed by the Licence, the performance of each reliability measure (SAIDI, SAIFI, or CAIDI), can either be below target, above target or on target (dead band), with the allocation of quality points of **3, -3, or 0**. Effectively, this would translate to a Q-Factor points system with twenty-seven (27) possible scoring scenarios, resulting in adjustment factors ranging between a minimum of -0.5% and a maximum of +0.5%, as presented in Figure 15.1 below. Consistent with the requirements of the Licence, the scheme is symmetrically oriented, which, provides for the equitable application of rewards and penalties.

Figure 15.1: Mechanics of the Q-Factor Adjustment System



14.21. Final Criteria - Q-Factor Requirements

15.7 Regarding the Q-Factor requirements, Criterion 11 of the Final Criteria states as follows:

> *"a) In the 2019 – 2024 Rate Review application, JPS shall include its proposed Q-Factor Baseline, projected annual quality of service performance, and proposed annual Q-Factor targets for each of the 12-month adjustment periods, during the Rate Review period.*
>
> *b) JPS shall provide the supporting schedules, documentation, calculations and relevant data to substantiate its Q-Factor proposals."*

15.8 The Final Criteria also required JPS to include quality of service information on the MAIFI in the rate application. Additionally, the information requirements pertaining to the Q-Factor for this 2019-2024 Rate Review, are specified in Annex 2 of the Final Criteria.

14.22. JPS's Q-Factor Proposal

15.9 To fully apply the Q-Factor to the PBRM, JPS has proposed a baseline and annual targets for the operation of the scheme over the Rate Review period. To establish the proposed baseline, JPS indicated that the company utilized the most recent three-year average of the actual outage dataset adjusted to exclude non-reportable and IPP caused outages.

JPS' Proposed Q-Factor Baseline

15.10 For the Q-Factor implementation, JPS recommends that the baseline for the three prescribed quality indices (SAIDI, SAIFI and CAIDI), be established based on the 2016-2018 annual outage datasets submitted to the OUR, including outages attributed to major event days (MEDs).

15.11 JPS indicated that in developing the proposed baseline, it recognized the OUR's position set out in previous Determination Notices, that the Licence provision does not permit the exclusion of major event days (MEDs) and Force Majeure events not addressed in accordance with Condition 11 2. of the Licence.

15.12 JPS also indicated that work is ongoing to resolve lingering data issues, which should result in the further improvement in outage data accuracy. Despite these conditions, the company is of the view that the use of the referenced annual outage datasets for establishing the baseline provides a sound basis for the establishment of reasonable and achievable Q-Factor targets against which JPS' quality of service performance can be measured.

15.13 Table 15.1 below shows the proposed baseline values for SAIDI, SAIFI and CAIDI of 1,973.37 (Minutes), 15.498 (Interruptions/customer) and 127.331 (Minutes) respectively, calculated by JPS for the implementation of the Q-Factor.

Table 15.1: JPS' Q-Factor Baseline Calculation

JPS Q-FACTOR BASELINE - 2016-2018 OUTAGE DATA									
YEAR	Reportable SAIDI (Minutes)	Reportable SAIFI (Interrup-tions/ Customer)	IPP SAIDI (Minutes) (Excluded)	IPP SAIFI (Interrup-tions/ Customer)	SAIDI (Did not meet data dictionary criteria - included)	SAIFI (Did not meet data dictionary criteria - included)	SAIDI (Minutes)	SAIFI (Interrup-tions/ Customer)	CAIDI (Minutes)
2018	1,719.654	14.141	27.716	1.127	-	-	1,691.938	13.014	130.009
2017	2,059.545	17.471	19.719	1.609	146.189	0.672	2,186.015	16.534	132.213
2016	1,993.191	17.548	13.979	0.813	62.944	0.211	2,042.156	16.946	120.510
AVG							**1,973.37**	**15.498**	**127.331**

15.14 As shown in Table 15.1 above, the proposed Q-Factor baseline was derived using the three-year arithmetic average of the 2016 -2018 outage datasets, subject to the following conditions:

- 2016-2018 forced outages due to IPPs excluded;
- Non-reportable outages excluded; and
- MEDs included in outage data.

Proposed Investment Programme for Reliability Improvement

15.15 In the Application, JPS indicated that the results of its cost of unserved energy (COUE) study, (commissioned in 2017, completed in 2018 December and updated in 2019 September), were used to inform the company's proposed capital investments to improve quality of service and to optimize the operation of the T&D system. JPS reported that the study estimated the average value of COUE for the system to be 4.77 US$ per kWh.

15.16 The company commented that it does not view the updated COUE value as a basis for increases in electricity rates, but instead as a key metric to signaling the need for improvement in quality of service provided to customers. It also provides justification for upgrading and modernizing parts of the grid plagued with intolerably high levels of outages.

15.17 The proposed capital investment programme to achieve reliability improvements over the Rate Review period is presented in Table 15.2 below.

Table 15.2: JPS' Proposed Annual Capital Investments for Reliability Improvement

JPS RELIABILITY IMPROVEMENT CAPITAL INVESTMENT PLAN							
#	PROJECTS	CAPEX (US$ Million)					
		2019	2020	2021	2022	2023	TOTAL
1	Voltage Standardization Programme	1.975	3.496	3.254	4.239	4.628	**17.592**
2	Grid Modernization Programme	1.784	2.092	2.827	2.968	2.864	**12.535**
3	Distribution Structural Integrity	3.771	4.489	4.564	4.763	4.822	**22.409**
4	Distribution Line Reconductoring and Rehabilitation	2.000	1.345	2.173	2.084	2.405	**10.007**
6	Transmission Structural Integrity	1.800	1,.70	1.870	1.858	1.839	**9.137**
7	Substation Structural Integrity	1.553	1.700	1.753	1.830	1.870	**8.706**
8	Energy Storage	9.110	-	-	-	-	**9,.10**
9	Michelton Halt (LILO)	1.817	-	-	-	-	**1.817**
11	Distribution Transformer Replacement/Upgrade Programme	3.008	2.848	2.243	1.635	0.361	**10.095**
12	Bellevue/Roaring River 69 kV	-	0.500	3.170	3.089	-	**6.759**
	TOTAL	**26.818**	**18.240**	**21.854**	**22.466**	**18.789**	**108.167**

15.18 The company noted that some projects in the Capital Investment Plan are justified, not necessarily based on reliability impact, but rather based on condition and the level of risk to grid security. For example, the replacement and upgrading of substation transformers may not necessarily result in a direct improvement in reliability, but if the asset has exceeded its useful life and is in poor condition, then the probability of failure is high and the risk to the grid may be severe, hence the asset must be replaced. Further, JPS believes that some of the projects will also enable the company to improve compliance with the requirements of the Electricity Sector Codes.

15.19 In terms of impact, JPS proffered that based on the proposed Capital Investment Plan and designated O&M activities, the quality of service improvement expected to be gained from the implementation of the reliability projects, as per schedule, are shown in Table 15.3 below.

Table 15.3: JPS' Projected Quality of Service Impact from Proposed Reliability Projects

JPS' EXPECTED QUALITY OF SERVICE IMPROVEMENTS (2019-2023)		
YEAR	Expected Annual SAIDI Improvement (Minutes/Customer)	Expected Annual SAIFI Improvement (Interruptions/Customer)
2019	100.961	0.793
2020	127.147	0.999
2021	85.423	0.671
2022	64.927	0.510
2023	78.778	0.619
CUMULATIVE	**457.246**	**3.592**

15.20 The projected impact in quality of service measured by improvements in SAIDI and SAIFI for the Rate Review Period is 26% for each indicator. This outcome is premised on JPS' approach of keeping CAIDI fixed and deriving SAIFI from the calculated SAIDI and fixed CAIDI. While CAIDI can be mathematically defined as a quotient (SAIDI/SAIFI), the described approach for deriving SAIFI raises questions of model credibility and acceptability of calculations.

15.21 In principle, based on the established quality of service framework, the outage frequency measure (SAIFI) is independent of the duration component (SAIDI). Therefore, the forecasting of improvements in SAIDI and SAIFI should be based on separate assumptions relating to the drivers of these metrics. Following JPS' computational approach, it would appear that SAIDI is at the core of its quality of service strategy, with the index determined from forecasted outage duration data, while SAIFI is derived from a mathematical transposition using a fixed CAIDI (from the baseline) throughout the five-year period.

Consequently, SAIDI and SAIFI would improve or worsen at the same rate, which is not likely. The problem with the approach is that the two indices (CAIDI and SAIFI) are determined for application over a five-year period on some notional grounds devoid of any sound technical basis.

<u>JPS' Forecasting of Reliability Indices for 2019-2024</u>

15.22 According to JPS, the forecasting of reliability indices was done by estimating the most likely impact that a proposed reliability project will have on the baseline and accumulating the individual effects to derive a combined impact on the baseline. Regarding the planning process, JPS contends that the absence of the IRP prior to the submission of the Application had constrained its forecasting of system reliably performance for the Rate Review period, with potential risks to the company in selecting investment projects which may not be in alignment with the results of the IRP when issued. With respect to maintenance projects, JPS asserted that they are not assumed to have a permanent impact on the reliability indices and would not generate step reductions in the reliability target. This raises concerns regarding the direction of the proposed reliability strategy on the premise that network maintenance is crucial for mitigating outage frequency, which is reflected in SAIFI. This also brings into question the issue of outage drivers, and the extent to which they were considered in the development of the reliability improvement plan.

<u>JPS' Proposed Q-Factor Targets for the Rate Review Period</u>

15.23 JPS argued that the underlying principles of the establishment of the Q-factor adjustment mechanism underscores the need for the target to be set at a level where it remains within the reach of the utility, but provides a stretch factor that requires improvement on current performance.

15.24 In developing the proposed Q-Factor targets, JPS indicated that it used the anticipated outcomes from the implementation of the projects captured in the Capital Investment Plan to develop an adjusted view of the potential for improvement in service reliability.

15.25 As detailed in the Application, the following approach was employed by JPS to develop the proposed Q-Factor targets:

1) Establishment of the Q-Factor baseline using the 2016-2018 outage data;
2) Estimation of the reliability impact of proposed projects involving transformer upgrades and new transmission lines, using the DIgSILENT Power Factory

software tool, and mathematical models to estimate the impact of all other reliability projects;

3) Consideration of the expected benefits, from the retirement of aged generation units in the derivation of the reliability improvements over the Rate Review period.

15.26 Accordingly, JPS developed the proposed Q-Factor targets for the Rate Review period, which are presented in Table 15.4 below.

Table 15.4: JPS' Proposed Q-Factor Targets

JPS' PROPOSED Q-FACTOR TARGETS (2019-2023)					
YEAR	SAIDI (Minutes)	SAIFI (Interruptions/ Customer)	CAIDI (Minutes)	Improvement in SAIDI over previous years	Improvement in SAIDI over previous years
Baseline (3-year Average)	1,973.37	15.50	127.33	-	-
2019	1,872.41	14.70	127.33	5%	5%
2020	1,745.26	13.71	127.33	7%	7%
2021	1,659.84	13.04	127.33	5%	5%
2022	1,594.91	12.53	127.33	4%	4%
2023	1,516.13	11.91	127.33	5%	5%
CUMULATIVE				26%	26%

15.27 As indicated, the proposed targets are expected to result in overall reliability improvement of 26%, with reference to SAIDI and SAIFI.

15.28 With respect to CAIDI, JPS asserted that if the rate at which SAIFI improves is greater than that of SAIDI then the value of CAIDI will actually increase, indicating that its performance has worsened. To overcome this situation, JPS posited that it equated the annual targets for CAIDI to the calculated baseline value of 127.33 minutes, which remained fixed over the Rate Review period and then deriving the SAIFI targets from the SAIDI projections predicated on the Business Plan. According to JPS, this methodology allows for the development of targets for the three quality indices that are fair and reasonable in keeping with the provisions of the Licence. However, the OUR is of the view that the described methodology is not reflective of a reasonable and prudent approach for quality of service performance assessment.

14.23. Evaluation of JPS' 2014-2019 Reliability Performance

Outage Data for Q-Factor Baseline

15.29 To establish the baseline to facilitate the implementation of the Q-Factor adjustment mechanism for 2019-2024 Rate Review, JPS proposed the use of the 2016-2018 annual outage datasets. The annual outage datasets report events occurring in the period from January 1 to December 31 of each year, as captured by JPS' Outage Management System (OMS).

15.30 Based on OUR records, the 2016 and 2017 outage datasets were previously submitted as part of the 2017 and 2018 Annual Review filings respectively. The 2018 outage data was included in the Application, but the OUR subsequently requested the 2019 data which would have been available based on the timing of the application. With the submission of the 2019 outage data, the OUR decided that it would be more insightful to execute an analysis of the Q-Factor using the 2016 – 2019 annual outage datasets, since the data accuracy appear to have improved over time. The annual outage datasets were represented in Microsoft Excel format, with the contents listed in Table 15.5 below.

Table 15.5: Structure and Contents of JPS' 2016 - 2019 Outage Data

STRUCTURE OF JPS OMS DATA (2016-2019)				
	2016	**2017**	**2018**	**2019**
1	Annex A - Raw Data	Annex A - Raw Data	Annex A - Raw Data	Annex A - Raw Data
2	Annex B - Calibrated Dataset	Annex B - Calibrated Dataset	Annex B - Calibrated Dataset	Annex B - Calibrated Dataset
3	Annex C - Summary Table	Annex C - Summary Table	Annex C - Summary Table	Annex C - Summary Table
4	Annex D – MED Calculation	Annex D – MED Calculation	Annex D - 2016-2018 Trend	Annex D - 2016-2019 Trend
5	Annex E – 2014-2016 Trend	Annex E – 2014-2016 Trend		Annex E - Outage Drivers 2019
6	Annex F – MED/Force Majeure	Annex F – MED/Force Majeure		

15.31 As represented, each of the annual datasets contained similar categories of information across the spectrum, including the base data required for calculating the reliability indices. As shown, some of the data elements change from year to year, which results from recommendations by the OUR to improve the reporting process. As an example, outage drivers were requested for 2018, but were submitted separately in a similar format to those included for 2019.

15.32 For validation of the data and calculations, the OUR performed a thorough examination of the contents to identify the presence of any significant discrepancies, omissions, errors or misrepresentations, as well as any adjustments to the raw outage data by JPS, for calibration or normalization. This review also included checks for outages with negative duration, checks for duplicate outage event records, events incorrectly classified as momentary or sustained outage events (subject to the relevant requirements of the Licence), among other things.

The review revealed no instances of these conditions in the 2018 and 2019 outage data. These checks were considered necessary considering that similar problems have been previously identified. Based on the definitions of the prescribed quality indices, material deficiencies or errors in the outage dataset can adversely impact the accuracy of the calculated values, which are key constituents of the Q-Factor baseline.

<u>The 2016-2019 Outage Data</u>

15.33 JPS outage records and parameters captured by the Outage Management System (OMS) were presented in the Raw Outage Data and the Calibrated Dataset of Annexes A & B of the Application.

15.34 Table 15.6 below provides a summary of some of the main aspects of the outage datasets (Annex A and Annex B), including details of service interruptions occurring on each day, covering the period January 1 to December 31 of each year.

Table 15.6: Summary of 2016-2019 Outage Data

Annex	Minimum	Maximum	Annex	Minimum	Maximum	Annex	Minimum	Maximum
2016			**2016**			**2016**		
A	0	67,774	**A**	0	55,866	**A**	0	55,841,259
B	0	37,879	**B**	0	55,866	**B**	0	12,130,524
F	1	24,159	**F**	0.017	7,324	**F**	0.1	6,419,653
2017			**2017**			**2017**		
A	0	37,499	**A**	0.0	146,254.8	**A**	0.0	225,278,085.5
B	0	37,499	**B**	0.0	146,254.8	**B**	0.0	225,278,085.5
F	0	20,153	**F**	5.0	37,347.0	**F**	0.0	11,064,110.2
2018			**2018**			**2018**		
A	0	74,254	**A**	0.02	83,318.73	**A**	0.00	78,045,550.40
B	0	21,891	**B**	0.02	80,127.90	**B**	0.00	78,045,550.40
2019			**2019**			**2019**		
A	1	31,700	**A**	0.02	155,361.52	**A**	0.02	229,058,455.40
B	1	31,700	**B**	0.02	155,361.52	**B**	0.02	229,058,455.40

SUMMARY OF DAILY CUSTOMER COUNT DATA					
Year	**Avg.**	**Min**	**Max**	**Max Daily Δ**	**@ End of Period**
2016	581,960	574,614	620,936	25,582	613,959
2017	611,219	590,949	619,811	6,408	590,949
2018	644,004	633,359	658,497	795	658,497
2019	671,169	664,517	679,857	895	679,857

Observations from Outage Data Review

15.35 From the review, observations relating to the data records are outlined below:

Daily System Customer Count Records

15.36 System daily customer count is a very pivotal input for the calculation of the prescribed quality indices. This means that the accuracy of SAIDI, SAIFI and CAIDI is highly dependent on the correctness of this parameter. In keeping with the OUR's Q-Factor recommendations, commencing with the 2016 outage data, JPS adopted the use of the daily customer count instead of the annual count previously used, for the calculation of the reliability indices.

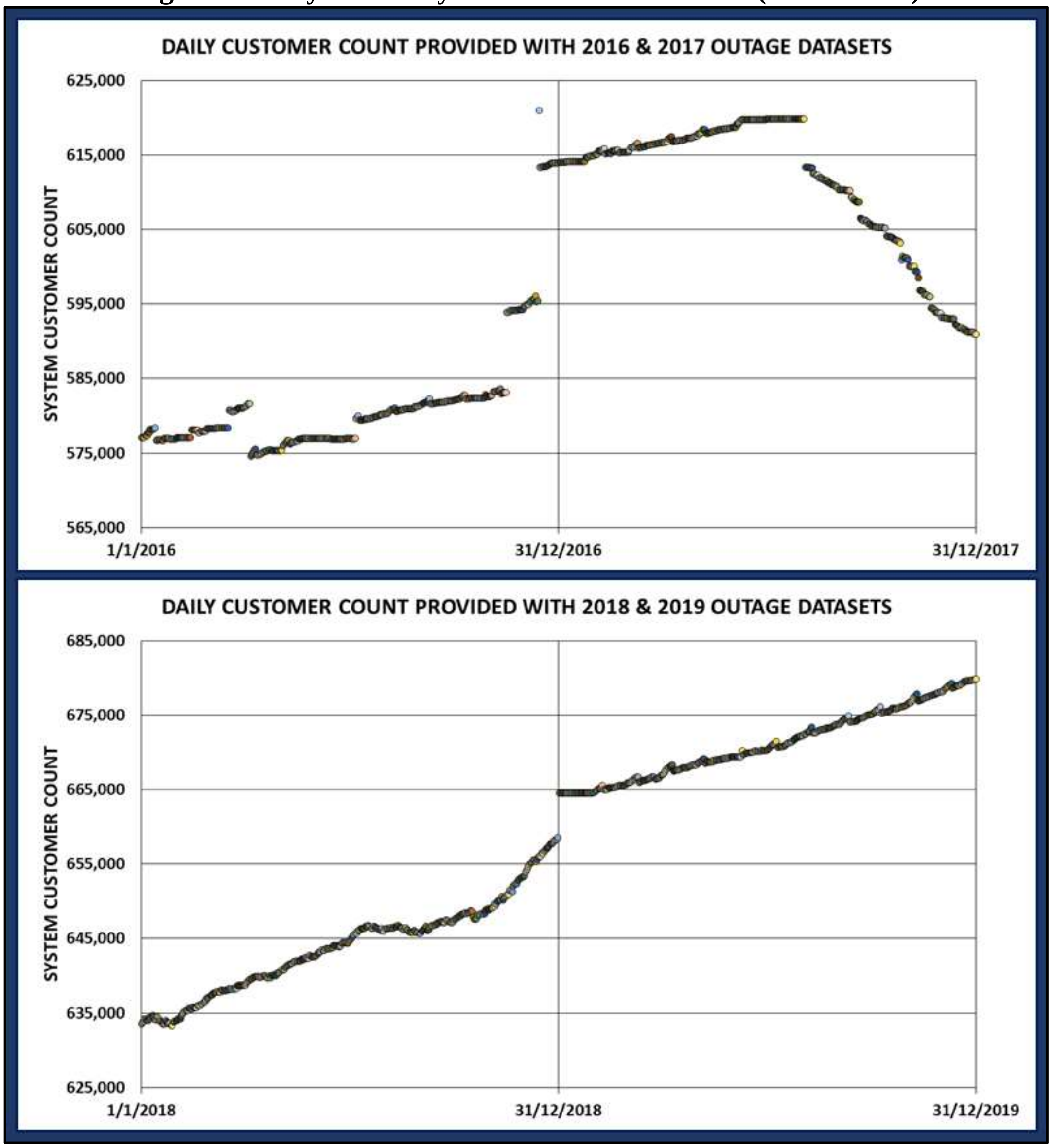
15.37 This approach generated more representative results, as the daily customer count fluctuates throughout the year based on the company's commercial operations, which are reflected in the reliability calculations. However, the review revealed that the reported OMS customer count data continue to show inconsistencies with those provided in other JPS reports, which creates uncertainty regarding the accuracy of the calculated quality indices. A summary of the 2016 – 2019 OMS customer count records is shown in Table 15.7 below.

Table 15.7: Summary JPS' OMS 2016-2019 Daily Customer Count Data

Year	Avg.	Min.	Max.	Avg. Daily Δ	Max. Daily Δ	Count – Jan 1	Count – Dec 31
2016	581,960	574,614	620,936	225	25,582	577,065	613,959
2017	611,219	590,949	619,811	114	6,408	614,020	590,949
2018	644,004	633,359	658,497	134	795	633,506	658,497
2019	671,169	664,517	679,857	92	895	664,561	679,857

15.38 As indicated, there were excessive maximum single-day variations in the daily customer count reported by JPS for 2016 and 2017, which has remained unexplained. However, after the issue was raised by the OUR, it appears that the company made corrections to its methodology, which generated more plausible daily customer count data for 2018 and 2019.

Figure 15.2: System Daily Customer Count Trend (2016 – 2019)



15.39 A plot of the OMS 2016-2019 system daily customer count data is shown in Figure 15.2 above. As illustrated, although there were fluctuations in customer count in some years, in general, it followed an upward trend, increasing from 577,065 customers at 2016 January 1 to 679,857 at 2019 December 31, with varying rates of increase for each year in the period, except for 2017 which had a net reduction in customer count.

15.40 Despite this trajectory, there were cases of uncharacteristically large variations in daily customer count in the four-year dataset, which were not explained. For instance, the data show an increase of over 6,000 customers between 2018 December 31 and 2019 January 1, which is far greater than the maximum daily customer count changes during 2018 and 2019.

15.41 There is also is a clear difference in the general shape of the plot for the 2019 customer count data compared to that for 2018. It is not clear as to the basis of these observed differences, therefore explanation from JPS may be required.

Adjustment/Calibration of Raw Outage for Calculation of Reliability Indices

15.42 As observed during the review, the 2016-2019 quality indices reported by JPS were not calculated from the raw outage data collected by the OMS, but from data defined as a "calibrated dataset". In previous Annual Review filings, JPS indicated that data calibration is done when outage conditions are recognized as abnormal or there are clear errors in the outage data, which could distort the outage reporting process. JPS' approach to addressing such defects is the application of its "Rules-Based Data Dictionary", to guide the necessary data calibration and adjustments. This dictionary is presented in Table 15.8 below.

15.43 The OUR's review of the data calibration/adjustments effected by JPS can be generally categorized as follows:

a) Inclusion of additional information for each outage record contained in the Calibrated Data (Annex B), compared to the information contained in Raw Data (Annex A); and
b) Amendments to outage information, which appear to be a result of data calibration.

15.44 A breakdown of the identified amendments made by JPS to the outage data is provided in Table 15.9 below.

15.45 Table 15.9 indicates the total number of changes made to data points between the raw and calibrated outage data sets in the respective years. The number of amendments made in most instances, includes changes made to multiple data points describing the same outage event. The breakdown of the number of outage events 2016-2019 Calibrated Datasets, which had amended data points is as shown below:

- 2016: 6,721 outages;
- 2017: 9,502 outages;
- 2018: 3,868 outages;
- 2019: 4,213 outages.

Table 15.8: JPS' "Rules-Based Data Dictionary"

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

Table 15.9: Breakdown of Amendments to 2016-2019 Outage Data

CATEGORY	NUMBER OF DATA CHANGES				SCOPE OF ADJUSTMENT
	2016	2017	2018	2019	
"Sustained"	47	60	4	2	Reclassification of outage event from Sustained to Momentary or vice versa - outage duration changed due to a change in outage start or restoration time.
"EventDay"	5	7	2	0	Changing outage start time such that the date to which an outage is attributed to would change.
"TimeStarted"	82	80	38	15	Changes in outage start time - actions taken subject to Rule 1 (Condition 3) of the "Rules Base Data Dictionary".
"TimeRestored"	2,766	3,211	2,315	2,749	Changes in outage restoration time - actions taken subject to Rule 1 (Condition 4) .
"DurationMins"	2,848	3,291	2,353	2,764	Changes to outage duration - changes made to the outage start or restoration time or both.
"CustomersAffected"	1,910	2,691	120	219	Changes to number of customers affected by an outage event - actions taken subject to Rule 1 (Condition 1 or 2) of the "Rules Base Data Dictionary".
"CML"	4,668	5,845	2,470	2,969	Changes to CML - changes to the duration of an outage event or changes to the number of customers affected by an outage event.
"TimeStartedBy"	3,072	3,184	1,461	1,284	Amendments to the data source for the outage start time.
"TimeRestoredBy"	5,897	6,524	3,830	4,081	Amendments to the data source for the outage restoration time.
TOTAL	**21,295**	**24,893**	**12,593**	**14,083**	

Classification of Forced Outages – Reportable & Non-Reportable

15.46 For the 2016-2019 outage data, 239,938 (92.7%) of the total number of forced outages (258,699) recorded, were classified by JPS as being "Reportable" while 18,761 (7.3%), were defined as "Non-Reportable", as shown in Table 15.10 below.

Table 15.10: Classification of Forced Outages (2016-2019)

YEAR	REPORTABLE	% of TOTAL	NON-REPORTABLE	% of TOTAL	TOTAL
2016	64,603	92.2%	5,431	7.8%	70,034
2017	76,042	93.3%	5,436	6.7%	81,478
2018	54,904	94.8%	3,040	5.2%	57,944
2019	44,389	91.1%	4,854	9.9%	49,243
TOTAL	**239,938**	**92.7%**	**18,761**	**7.3%**	**258,699**
AVERAGE	***59,985***	***92.7%***	***4,690***	***7.3%***	***64,675***

15.47 According to JPS, certain forced outage conditions (which should be infrequent), cannot be currently treated within the automated OMS platform in its current form. As a result, the respective outages may be classified as "Non-Reportable" and eliminated from the outage data used to calculate the quality indices.

15.48 However, as indicated in Table 15.10 the percentage of Non-Reportable outages relative to total forced outages is very high, averaging over 7% each year, which advanced to almost 10% for the 2019 Outage data. The OUR has raised concerns about the relative level of Non-Reportable outages in previous Annual Review Determination Notices during the 2014-2019 regulatory period, and urged JPS to address the situation. However, no action has been taken. From the perspective of data integrity this is problematic, therefore JPS is required to implement appropriate measures to address this issue.

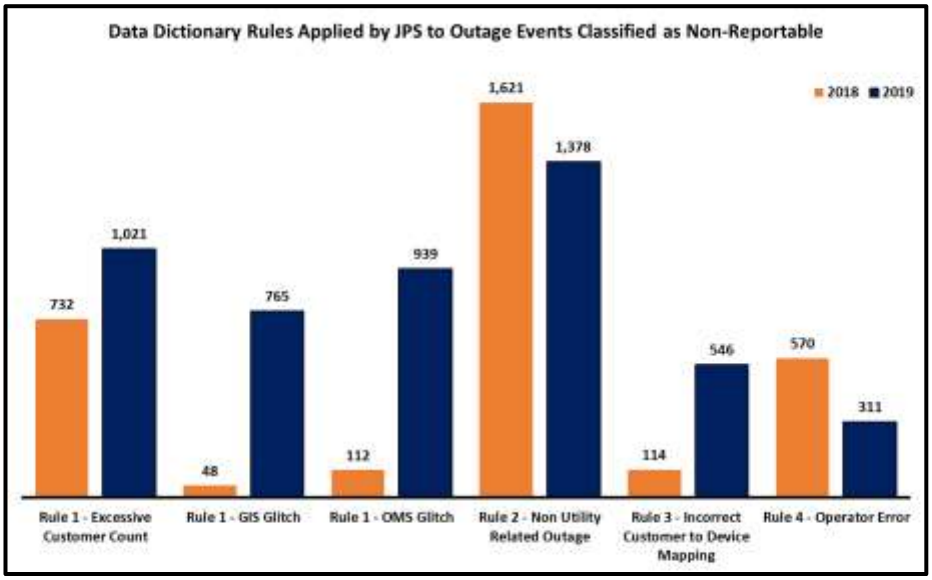
15.49 In particular, the 2018 and 2019 annual outage datasets indicate that the conditions that JPS identified which triggered the need for defining forced outages as Non-Reportable, are:

1) Rule 1 - Excessive Customer Count, GIS Glitch and OMS Glitch;
2) Rule 2 - Non Utility Related Outage;
3) Rule 3 - Incorrect Customer to Device Mapping;
4) Rule 4 - Operator Error.

15.50 The breakdown of JPS' Non-Reportable outages for 2018 & 2019, based on the above modality is represented in Figure 15.3 below.

15.51 In light of this, the Office takes the view that JPS' Non-Reportable forced outages level is too high and does not accord with a credible Q-Factor mechanism. Consequently, JPS shall implement measures to ensure that Non-Reportable forced outage does not exceed 5% of total forced outages reported for each year.

Figure 15.3: Breakdown of JPS' Non-Reportable Outages by Modality (2018-2019)



14.24. Evaluation of Outages for Calculation of Quality Indices

15.52 The OUR's calculation of the prescribed quality indices (SAIDI, SAIFI and CAIDI), considers only the Reportable forced outages, resulting in sustained interruptions. However, the OUR's assessment will also encompass momentary interruptions and MAIFI calculations for performance analysis and regulatory monitoring. Prior to performing these calculations, the OUR made some adjustments to normalize the 2016-2019 outage data, to ensure accurate representation and results.

15.53 In order to validate the 2016-2019 quality indices computed by JPS, the OUR performed similar calculations based on the respective Calibrated Datasets for 2016-2019. The outage data used in determining the quality indices is summarized in Table 15.11 below.

Table 15.11: OUR's Classification of Outage Data for Calculation of Quality Indices

CUSTOMER COUNT					
Year	**Avg.**	**Min**	**Max**	**Max Daily Δ**	**@ End of Period**
2016	581,960	574,614	620,936	25,582	613,959
2017	611,219	590,949	619,811	6,408	590,949
2018	644,004	633,359	658,497	795	658,497
2019	671,169	664,517	679,857	895	679,857

REPORTABLE vs. NON-REPORTABLE OUTAGE EVENTS		
Year	**Reportable**	**Non-Reportable**
2016	65,746	5,591
2017	78,794	5,655
2018	57,532	3,197
2019	46,282	4,960
TOTAL	**248,354**	**19,403**

FORCED vs. PLANNED REPORTABLE OUTAGE EVENTS		
Year	**Forced**	**Planned**
2016	64,603	1,143
2017	76,042	2,752
2018	54,904	2,628
2019	44,389	1,893
TOTAL	**239,938**	**8,416**

MOMENTARY vs. SUSTAINED REPORTABLE FORCED OUTAGE EVENTS		
Year	**Momentary**	**Sustained**
2016	3,829	60,774
2017	6,816	69,226
2018	4,971	49,933
2019	3,068	41,321
TOTAL	**18,684**	**221,254**

15.54 Based on JPS' forced outage classifications, a total of 239,938 forced outage events was considered relevant to the calculation of quality indices for the 2016 – 2019 period.

15.55 Prior to 2018, JPS' annual outage data did not specifically identify outages, which were attributable to IPPs' generation facilities. As stipulated in the Final Criteria, IPP generation outages should not be included in the calculation of the quality indices, unless they resulted from actions of JPS. Based on this apparent disparity in outage reporting over the 2016-2019 period, adjustments were made to account for IPP-related outages in the calculation of the Q-Factor baseline indices. However, to ensure consistent treatment across the four years, IPP- related outages were not excluded from 2018 & 2019 data, prior to finalizing the baseline indices.

Outage Analysis

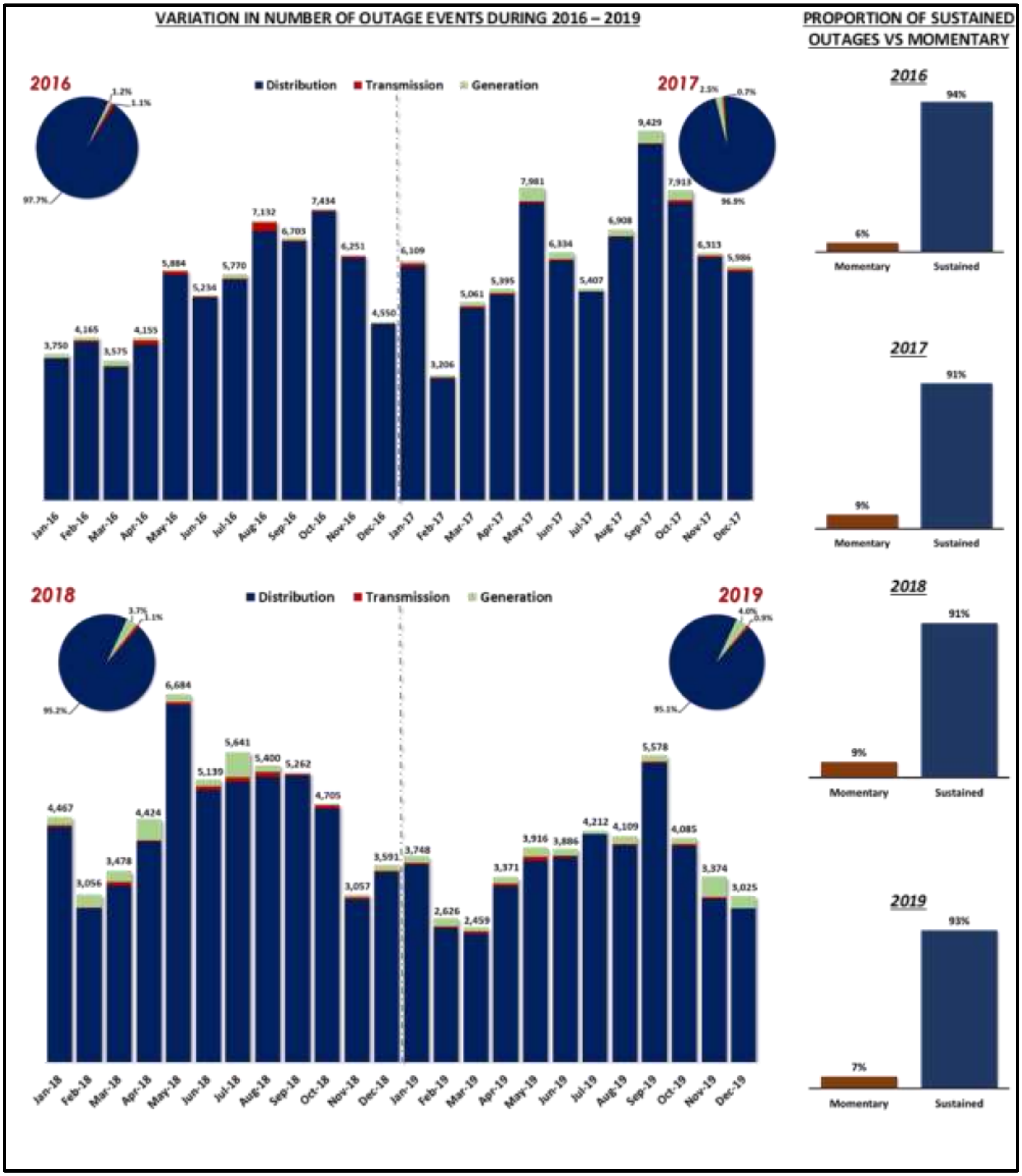
15.56 With the classification of the outage data, the reported forced outages were categorized as shown in Table 15.12 below.

Table 15.12: A Reportable Forced Outages by Category

ANNUAL REPORTABLE FORCED OUTAGES SHOWN BY CATEGORY										
Year	Generation			Transmission			Distribution			TOTAL
	Momentary	Sustained	Total	Momentary	Sustained	Total	Momentary	Sustained	Total	
2016	337	470	**807**	163	519	**682**	3,329	59,785	**63,114**	**64,603**
2017	984	888	**1,872**	159	353	**512**	5,673	67,985	**73,658**	**76,042**
2018	1,205	834	**2,039**	98	502	**600**	3,668	48,597	**52,265**	**54,904**
2019	597	1,191	**1,788**	57	340	**397**	2,414	39,790	**42,204**	**44,389**

15.57 The variations in the categories of Reportable outages during the 2016-2019 period is illustrated in Figure 15.4 below.

Figure 15.4: Variation of Reportable Forced Outages Events (2016-2019)



14.25. OUR's Calculation of the Quality Indices

15.58 Based on the outage data classification, input parameters and specified calculation criteria, the OUR computed the relevant quality indices for 2016-2019, which are presented in Table 15.13 below.

Table 15.13: OUR's Computed Quality Indices (2016-2019)

OUR CALCULATED QUALITY INDICES																
Year	Generation				Transmission				Distribution				Aggregate			
	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI
2016	102.771	5.324	19.302	6.421	211.942	2.534	83.641	0.833	1,720.397	9.772	176.051	17.690	2,035.110	17.630	115.431	24.944
2017	110.135	6.198	17.770	9.986	120.640	1.200	100.541	1.023	1,828.772	10.073	181.543	23.064	2,059.546	17.471	117.881	34.074
2018	94.235	4.493	20.972	9.854	87.130	1.367	63.745	0.309	1,538.289	8.281	185.759	11.504	1,719.654	14.141	121.605	21.667
2019	218.844	6.231	35.119	3.178	98.220	0.867	113.352	0.140	1,131.497	6.411	176.494	5.917	1,448.560	13.509	107.230	9.235

For comparison, the 2016-2019 quality indices computed by the OUR and those by JPS are presented in Table 15.14 below.

Table 15.14: Comparison of OUR's and JPS' Computed 2016-2019 Quality Indices

COMPARISON OF 2016 – 2019 QUALITY INDICES CALCULATED BY OUR AND JPS (IPP OUTAGES NOT EXCLUDED)												
	SAIDI minutes/customer			SAIFI interruptions/customer			CAIDI minutes/customer			MAIFI interruptions/customer		
Year	JPS	OUR	Δ	JPS	OUR	Δ	JPS	OUR	Δ	JPS	OUR	Δ
2016*	1,774.288	2,035.110	14.70%	15.654	17.630	12.62%	113.344	115.431	1.84%	24.936	24.944	0.03%
2017*	1,755.514	2,059.546	17.32%	16.447	17.471	6.23%	106.740	117.881	10.44%	32.894	34.074	3.59%
2018	1,719.654	1,719.654	0%	14.141	14.141	0%	121.605	121.605	0%	21.667	21.667	0%
2019	1,448.560	1,448.560	0%	13.509	13.509	0%	107.230	107.230	0%	9.235	9.235	0%

* - *Indices calculated by JPS for 2016 and 2017 exclude outages occurring on days identified as Major Event Days*

15.59 As shown, the indices calculated by JPS deviated from those determined by the OUR for the years 2016 and 2017. This occurrence was largely due to the fact that JPS excluded outages occurring on the days identified as MEDs during these years. In contrast, the indices calculated by JPS for 2018 and 2019, were fairly consistent with those computed by the OUR.

<u>Treatment of IPP Outages in the reliability Calculations</u>

15.60 To ensure consistency and efficacy in the reliability assessment process, the outages identified by JPS as "IPP Outages" were all evaluated and their respective reliability measurements accounted for in the determination of Q-Factor baseline. The reliability measurements resulting from IPP Outages are shown in Table 15.15 below.

Table 15.15: Impact of IPP Outages on Quality Indices

CLASSIFICATION OF "IPP OUTAGE" EVENTS											
REPORTABLE/NON-REPORTABLE			CATEGORIZATION OF REPORTABLE "IPP OUTAGE" EVENTS								
Year	Reportable	Non-Reportable	Generation		Transmission		Distribution		Aggregate		
			Sustained	Momentary	Sustained	Momentary	Sustained	Momentary	Sustained	Momentary	Total
2018	220	0	203	0	6	0	11	0	220	0	220
2019	636	1	345	258	0	0	3	30	348	288	636

CONTRIBUTIONS OF "IPP OUTAGES" TO RELIABILITY INDICES												
Year	Generation			Transmission			Distribution			Aggregate		
	SAIDI	SAIFI	MAIFI	SAIDI	SAIFI	MAIFI	SAIDI	SAIFI	MAIFI	SAIDI	SAIFI	MAIFI
2018	26.684	0.988	0.000	0.362	0.056	0.000	0.670	0.083	0.000	27.716	1.127	0.000
2019	71.717	1.749	1.482	0.000	0.000	0.000	1.651	0.019	0.145	73.368	1.768	1.627

15.61 As indicated, JPS reported a total of 857 IPP Outages for the 2018-2019 period, which were largely associated with generation problems, but some were identified with connections to the T&D system. No basis has been provided by JPS for these classifications. Notwithstanding these discrepancies, the IPP Outages were treated in accordance with the established Q-Factor principles and Final Criteria, in the determination of the Q-Factor baseline.

14.26. Reliability Indicators across Service Areas

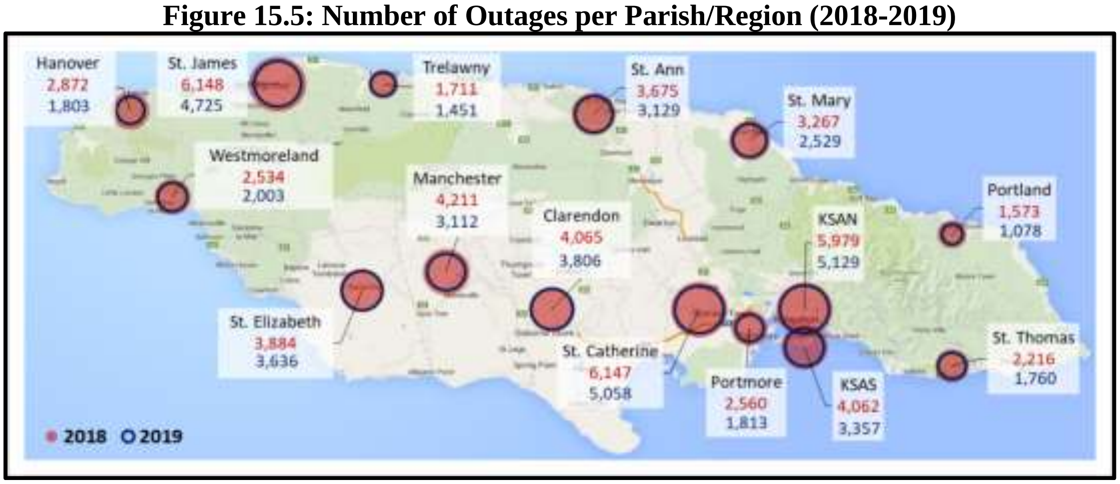
15.62 A unique feature of the Q-Factor mechanism is that the relevant quality indices represent system-wide average reliability performance across the entire country, suggesting that all customers on the system are expected to experience similar service levels. However, in actual operations, this expectation may not materialize due to disparities in power delivery across service areas, driven by geography and the topographical orientation of the power system. Given this characteristic, some regions may experience superior service reliability relative to the average performance metrics, while simultaneously, other areas may suffer disproportionately from poor service reliability.

15.63 To explore this issue, the OUR performed further analysis of the 2016-2019 outage data, which includes locational records for each outage event, mainly parishes and associated feeders. This analysis entailed a comprehensive assessment of reliability performance across the different parishes and major service areas of the country, as well as the reliability across feeders, using indicators derived from the respective outage datasets. Table 15.16 below shows the number of outages per parish/region as well as the estimated quality indices for the respective service areas. Additionally, the number of outages based on geographical regions for 2018 and 2019 is shown in Figure 15.5 below.

Table 15.16: Reliability Performance by Service Area (2016-2019)

NUMBER OF OUTAGES & RELIABILITY INDICES FOR EACH PARISH/REGION														
Parish / Region	Number of Outages						Estimated Reliability Indices							
	Momentary		Sustained		Total Outages		SAIDI		SAIFI		CAIDI		MAIFI	
							(min/customer)		(intrp/customer)		(min/customer)		(intrp/customer)	
	2016	2017	2016	2017	2016	2017	2016	2017	2016	2017	2016	2017	2016	2017
Clarendon	312	418	3,826	5,161	4,138	5,579	1,328.50	2,217.79	8.41	11.79	157.97	188.14	31.61	25.27
Hanover	253	681	2,928	3,360	3,181	4,041	3,953.75	4,856.69	58.15	68.63	68.00	70.77	152.23	104.97
KSAN	237	666	8,752	9,297	8,989	9,963	1,909.76	1,548.62	10.20	10.71	187.24	144.66	8.09	6.43
KSAS	309	480	4,281	4,102	4,590	4,582	968.35	747.94	13.47	13.32	71.86	56.17	14.45	18.63
Manchester	442	946	3,882	4,622	4,324	5,568	1,239.43	1,266.51	15.15	17.17	81.79	73.75	68.99	47.56
Portland	72	94	1,731	1,959	1,803	2,053	1,194.24	1,365.99	10.00	11.74	119.46	116.32	4.15	10.18
Portmore	75	162	2,773	3,086	2,848	3,248	1,234.25	1,280.63	10.87	12.53	113.54	102.20	18.37	11.03
St. Ann	416	645	4,434	4,730	4,850	5,375	1,727.42	2,294.85	12.98	13.55	133.05	169.38	55.15	28.31
St. Catherine	329	601	6,470	7,720	6,799	8,321	1,318.57	1,701.24	9.10	10.87	144.88	156.57	26.35	14.43
St. Elizabeth	305	469	3,083	3,363	3,388	3,832	2,005.89	2,611.03	41.84	55.99	47.94	46.64	108.38	79.06
St. James	341	531	6,893	8,519	7,234	9,050	2,854.39	2,547.43	25.16	19.85	113.45	128.34	16.42	15.11
St. Mary	404	595	4,012	4,393	4,416	4,988	2,963.39	3,574.53	12.63	15.63	234.67	228.66	25.47	32.57
St. Thomas	43	118	2,706	3,135	2,749	3,253	3,913.69	5,817.35	19.54	21.06	200.25	276.20	18.53	6.66
Trelawny	149	194	2,055	2,409	2,204	2,603	2,512.62	4,373.05	16.29	29.45	154.29	148.51	32.26	25.40
Westmoreland	142	216	2,948	3,370	3,090	3,586	2,103.65	2,283.04	18.72	18.23	112.40	125.26	22.06	21.16
	2018	2019	2018	2019	2018	2019	2018	2019	2018	2019	2018	2019	2018	2019
Clarendon	145	167	3,920	3,639	4,065	3,806	2,168.64	2,649.91	11.38	14.83	190.51	178.66	1.79	2.52
Hanover	424	162	2,448	1,641	2,872	1,803	3,073.13	2,262.87	32.45	18.33	94.71	123.48	80.57	13.09
KSAN	338	381	5,641	4,748	5,979	5,129	866.57	1,230.11	7.21	9.43	120.26	130.47	3.13	5.00
KSAS	430	228	3,632	3,129	4,062	3,357	1,136.07	865.77	10.22	7.18	111.15	120.54	7.02	4.42
Manchester	764	138	3,447	2,974	4,211	3,112	906.83	1,024.35	10.21	6.97	88.81	146.94	50.30	7.52
Portland	257	91	1,316	987	1,573	1,078	889.62	526.83	7.05	6.38	126.26	82.59	31.82	8.18
Portmore	147	72	2,413	1,741	2,560	1,813	1,591.75	710.86	13.95	7.42	114.11	95.86	5.30	0.31
St. Ann	205	96	3,470	3,033	3,675	3,129	1,519.28	1,999.50	8.59	10.90	176.82	183.49	10.22	0.55
St. Catherine	427	206	5,720	4,852	6,147	5,058	1,288.97	1,568.68	9.24	11.89	139.50	131.91	11.59	6.14
St. Elizabeth	624	574	3,260	3,062	3,884	3,636	3,165.63	1,463.35	66.05	36.93	47.93	39.62	153.18	50.28
St. James	436	378	5,712	4,347	6,148	4,725	2,042.22	1,932.64	20.78	29.04	98.27	66.55	13.79	20.66
St. Mary	372	204	2,895	2,325	3,267	2,529	2,443.58	1,421.69	10.31	5.95	237.04	238.93	13.29	4.20
St. Thomas	122	136	2,094	1,624	2,216	1,760	2,958.29	2,180.90	14.91	14.86	198.46	146.78	9.83	3.79
Trelawny	102	68	1,609	1,383	1,711	1,451	2,437.02	1,415.96	17.90	11.43	136.17	123.86	9.73	3.98
Westmoreland	178	167	2,356	1,836	2,534	2,003	4,597.32	1,447.09	16.43	14.76	279.80	98.02	11.54	9.45

Figure 15.5: Number of Outages per Parish/Region (2018-2019)



15.64 The disaggregation of SAIDI, SAIFI and MAIFI across the various service areas, is represented in Figures 15.6 to 15.8 below.

Figure 15.6: Estimated SAIDI per Parish/Region (2018-2019)

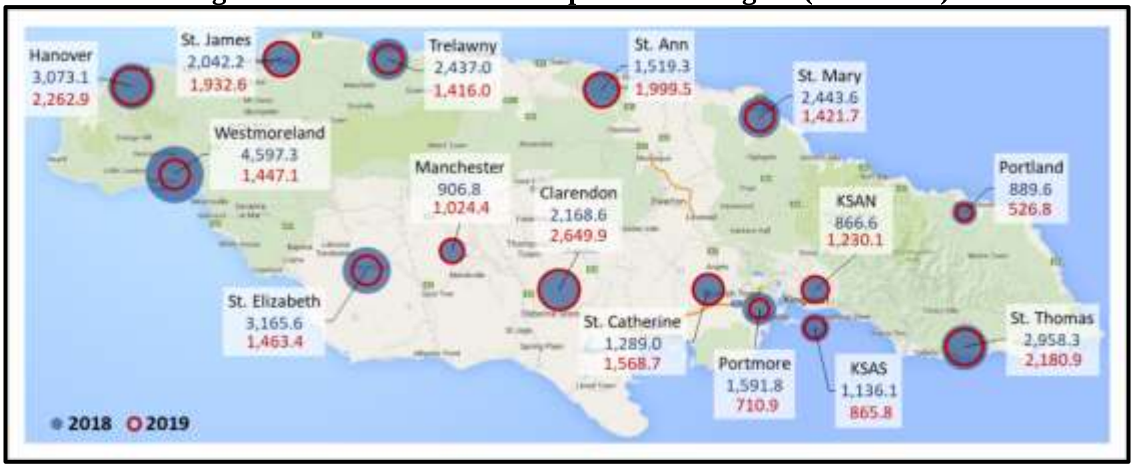


Figure 15.7: Estimated SAIFI per Parish/Region for 2018

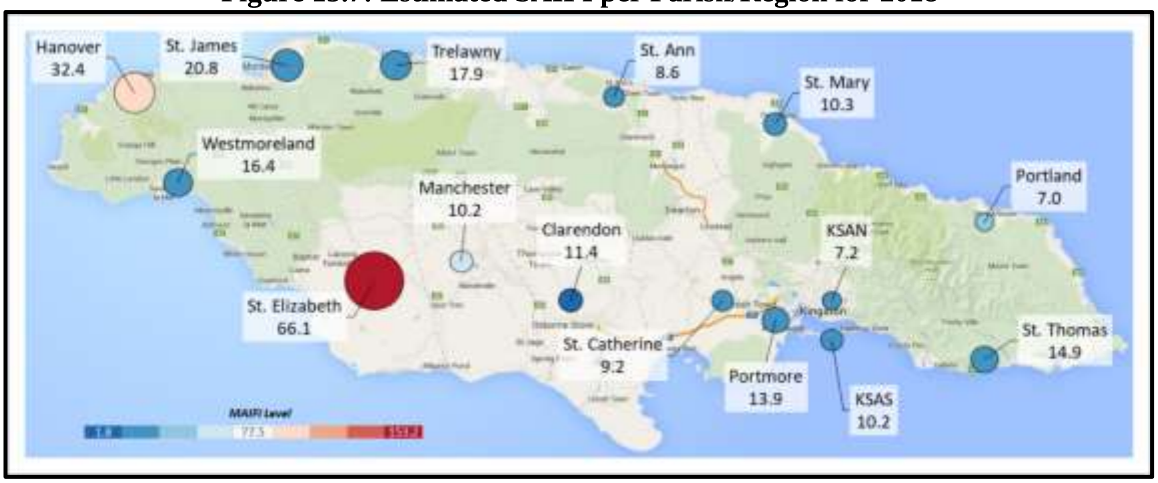
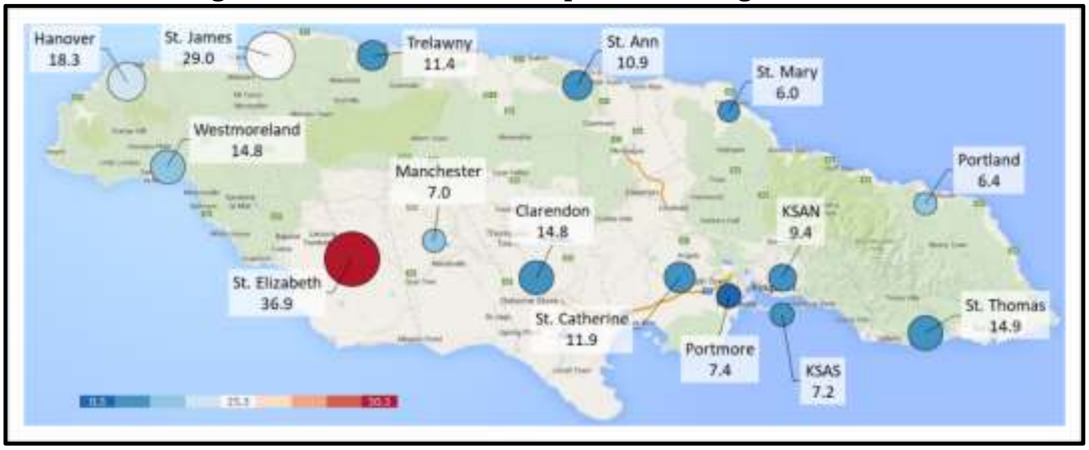


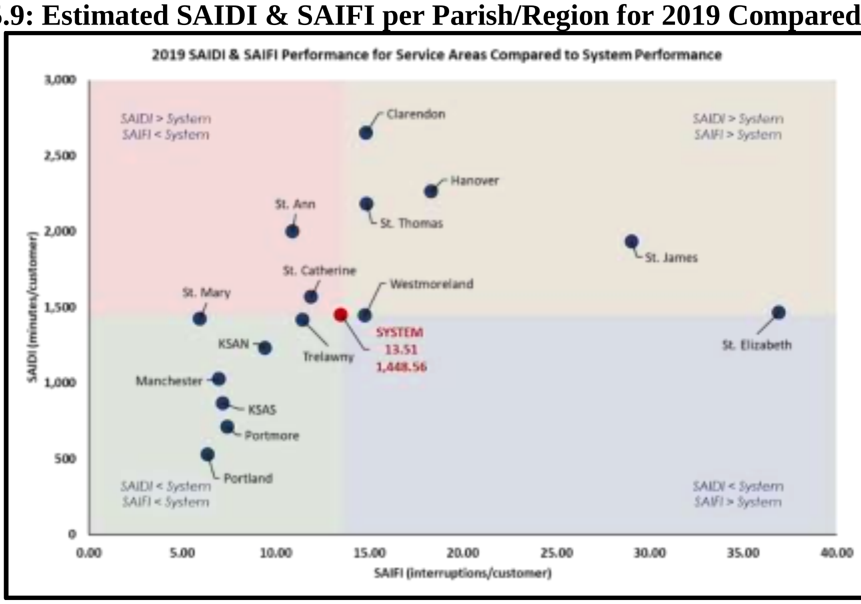
Figure 15.8: Estimated SAIFI per Parish/Region for 2019



15.65 Figures 15.6 to15.8 demonstrate the variation in service reliability experienced by JPS customers across the various service areas during 2018 and 2019. Based on the data, the average customers in the parishes of Hanover, Westmoreland and St. Elizabeth, for example, experienced well over three (3) times the outage duration, as those in the KSAN region.

15.66 However, this situation appears to have improved considerably during 2019. Additionally, customers in St. Elizabeth, in particular, experienced very high outage frequency, both sustained and momentary, when compared, again, to the KSAN region during 2018. This situation persisted during 2019; however the differences were not as great. The performance of the different regions, when compared to system performance, during 2019, is further demonstrated in Figure 15.9 below.

Figure 15.9: Estimated SAIDI & SAIFI per Parish/Region for 2019 Compared to System



15.67 The variation in service reliability levels across the country was also assessed based on distribution feeders. The outage data indicate that a total of 111 feeders was associated with forced outage events during the 2016-2019 period. From this list, the ten (10) feeders with the highest and lowest number of outages in each year during the period are listed in Tables 15.17 and 15.18 below, with feeders that featured in all four years, in the respective categories, highlighted in red.

Table 15.17: Ten Worst Performing Feeders (2016-2019)

TEN FEEDERS ASSOCIATED WITH THE HIGHEST NUMBER OF FORCED OUTAGE EVENTS 2016 – 2019								
	2016				2017			
	Feeder	Momentary Outages	Sustained Outages	Total Outages	Feeder	Momentary Outages	Sustained Outages	Total Outages
1	Constant Spring 410	54	2,941	2,995	Bogue 210	203	3,827	4,030
2	Bogue 210	96	2,858	2,954	Orange Bay 310	582	2,986	3,568
3	Orange Bay 310	215	2,631	2,846	Constant Spring 410	181	2,774	2,955
4	Bogue 310	88	2,323	2,411	Spur Tree 310	686	2,209	2,895
5	Spur Tree 310	238	1,762	2,000	Bogue 310	125	2,542	2,667
6	Cardiff Hall 310	173	1,775	1,948	Cardiff Hall 310	257	1,944	2,201
7	May Pen 110	94	1,594	1,688	May Pen 110	179	1,848	2,027
8	Maggotty 210	81	1,532	1,613	Constant Spring 210	105	1,841	1,946
9	Rhodens Pen 410	54	1,534	1,588	Michelton Halt 110	110	1,756	1,866
10	Hope 310	42	1,528	1,570	Kendal 210	163	1,647	1,810
	TOTAL	**1,135**	**20,478**	**21,613**	**TOTAL**	**2,591**	**23,374**	**25,965**
	2018				2019			
	Feeder	Momentary Outages	Sustained Outages	Total Outages	Feeder	Momentary Outages	Sustained Outages	Total Outages
1	Bogue 210	108	2,469	2,577	Spur Tree 210	524	1,490	2,014
2	Orange Bay 310	359	2,208	2,567	Bogue 210	82	1,797	1,879
3	Spur Tree 310	563	1,604	2,167	Orange Bay 310	57	1,486	1,543
4	Spur Tree 210	540	1,368	1,908	May Pen 110	51	1,438	1,489
5	Constant Spring 410	85	1,563	1,648	Bogue 310	55	1,384	1,439
6	Bogue 310	67	1,555	1,622	Constant Spring 410	78	1,348	1,426
7	Cardiff Hall 310	71	1,431	1,502	Spur Tree 310	69	1,303	1,372
8	Maggotty 210	49	1,441	1,490	Maggotty 210	52	1,318	1,370
9	May Pen 110	36	1,445	1,481	Cardiff Hall 310	34	1,222	1,256
10	Tredegar 410	207	1,221	1,428	Tredegar 410	153	1,087	1,240
	TOTAL	**2,085**	**16,305**	**18,390**	**TOTAL**	**1,155**	**13,873**	**15,028**

Table 15.18: Ten Best Performing Feeders (2016-2019)

TEN FEEDERS ASSOCIATED WITH THE LOWEST NUMBER OF FORCED OUTAGE EVENTS DURING 2016 – 2019

	2016				2017			
	Feeder	Momentary Outages	Sustained Outages	Total Outages	Feeder	Momentary Outages	Sustained Outages	Total Outages
1	RockFort 310	5	5	10	RockFort 310	4	2	6
2	Hunts Bay 110	5	14	19	Hunts Bay 110	3	9	12
3	Roaring River 310	10	19	29	Three Miles 410	8	28	36
4	West Kings House Road 210	13	37	50	Roaring River 310	10	30	40
5	Hope 510	13	47	60	Rose Hall 110	7	43	50
6	Up ParkCamp 310	11	49	60	West Kings House Road 210	24	40	64
7	Hunts Bay 710	9	68	77	Hunts Bay 710	14	56	70
8	Three Miles 510	4	80	84	Three Miles 510	8	75	83
9	Hunts Bay 210	18	70	88	Up ParkCamp 310	37	47	84
10	Duhaney 410	8	84	92	Washington Boulevard 410	5	88	93
	TOTAL	96	473	569	TOTAL	120	418	538

	2018				2019			
	Feeder	Momentary Outages	Sustained Outages	Total Outages	Feeder	Momentary Outages	Sustained Outages	Total Outages
1	Hunts Bay 610	1	1	2	RockFort 310	1	-	1
2	Monymusk 310	4	1	5	Hunts Bay 110	-	13	13
3	Hunts Bay 110	3	3	6	Three Miles 310	1	12	13
4	RockFort 310	4	5	9	Monymusk 310	10	13	23
5	Three Miles 310	-	19	19	Hunts Bay 710	2	24	26
6	West Kings House Road 210	13	7	20	Roaring River 310	2	24	26
7	Martha Brae 210	1	26	27	Hunts Bay 510	3	27	30
8	Roaring River 310	10	29	39	West Kings House Road 210	2	36	38
9	Up ParkCamp 310	20	26	46	Martha Brae 210	3	43	46
10	Rose Hall 110	10	39	49	Twickenham 410	-	48	48
	TOTAL	66	156	222	TOTAL	24	240	264

15.68 As indicated in Table 15.17 and 15.18, between 15,028 and 25,965 forced outages (up to 31.9% of the total) each year during the 2016-2019 period was associated with the ten (10) worst performing feeders in the system. Conversely, for the same period, the situation at the other end of the spectrum, is superior, with only between 222 and 569 forced outages (no more than 0.81% of total) per year, on average linked to the ten best performing feeders, with as low as 222 outages in 2018.

15.69 As demonstrated by the data, the wide variations in reliability indicators across regions and feeders, serve to highlight the disparities in the quality of service being provided by JPS to its customers across various locations. This situation also points to the inherent limitations in the Q-Factor mechanism in its current form, where customers who experience poor quality of service are required to pay the same rates as those who consistently enjoy relatively high quality service. Given this disproportionality, greater effort will be required by JPS to minimize the level of disparities in the delivery of electricity service to its customers.

14.27. Outage Causation

15.70 In 2019, prior to the submission of the 2018 outage dataset, the OUR requested that JPS starts, including the specific cause of each outage recorded on its OMS. Given the quality of service objectives, this information is considered critical to facilitate robust assessment of the reliability drivers and JPS' reliability improvement plans. The 2018 and 2019 annual outage datasets supporting JPS' Q-Factor proposals for the Rate Review period, include summary information on the causes of the outages that occurred in the respective years. The reported causation includes:

1) Contamination;
2) Equipment Failure;
3) Lightning;
4) Power Supply;
5) Vegetation;
6) Wild Life;
7) Public Error;
8) Other;
9) Unknown.

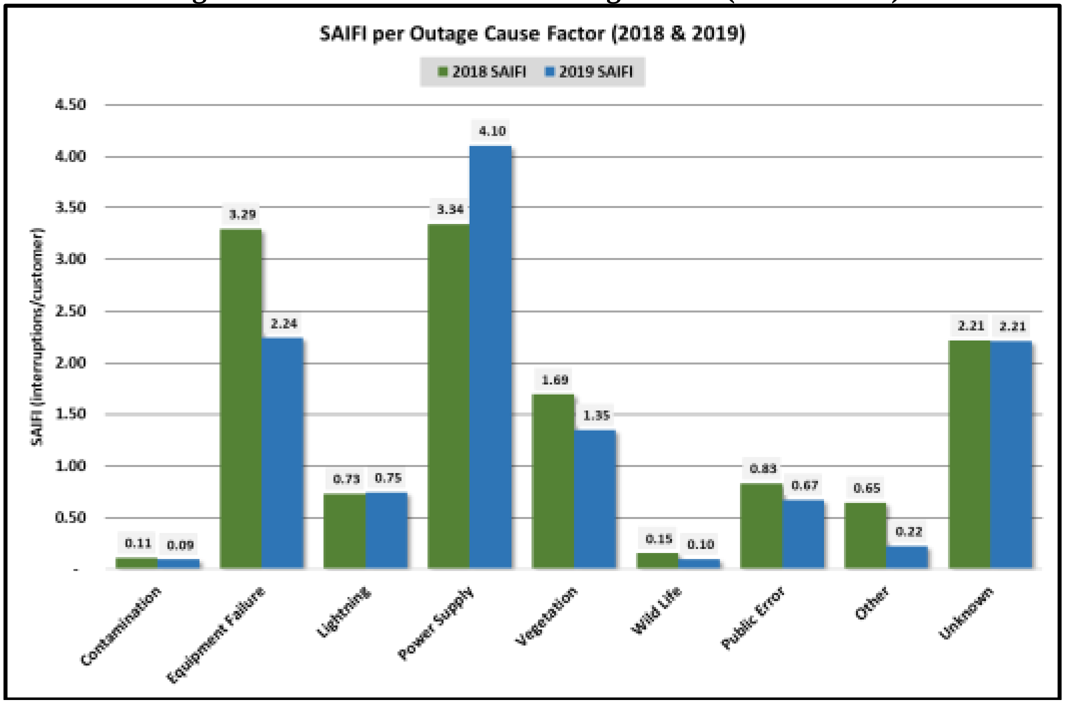
15.71 For 2018 and 2019, these outage causes were presented with corresponding SAIDI and SAIFI values. However, the specific cause of each recorded outage event was not provided, thus, preventing the allocation of the outages to the associated cause category. While the indicated outage causations are typical across the industry, the absence of data on the number of related outages, at least for 2019, created a major constraint to the OUR's analysis. Considering the importance of this data, going forward, JPS will be required to fully incorporate the specific causation of each recorded event in its reporting of system outages.

15.72 Based on the data based on the data received, the respective SAIDI and SAIFI values linked to each outage driver, along with their annual percentage contributions are provided in Table 15.19 below. The effect of outage causes on reliability is further illustrated in Figure 15.10 below.

Table 15.19: SAIDI and SAIFI based on Outage Cause

SAIDI & SAIFI PER OUTAGE CAUSE FACTOR (MINUTES/CUSTOMER) WITH ANNUAL % CONTRIBUTION [IPP OUTAGES NOT INCLUDED]																			
Year	**Contamination**		**Equipment Failure**		**Lightning**		**Power Supply**		**Vegetation**		**Wild Life**		**Public Error**		**Other**		**Unknown**		**Total**
SAIDI																			
2018	33.97	*2%*	433.73	*26%*	147.63	*9%*	62.67	*4%*	392.31	*23%*	21.66	*1%*	153.13	*9%*	57.72	*3%*	389.12	*23%*	1,691.94
2019	16.37	*1%*	345.98	*25%*	167.90	*12%*	136.02	*10%*	325.28	*24%*	17.00	*1%*	115.78	*8%*	30.85	*2%*	220.01	*16%*	1,375.19
Δ	-17.60		-87.74		+20.27		+73.35		-67.03		-4.66		-37.34		-26.87		-169.11		-316.75
SAIFI																			
2018	0.11	*1%*	3.29	*25%*	0.73	*6%*	3.34	*26%*	1.69	*13%*	0.15	*1%*	0.83	*6%*	0.65	*5%*	2.21	*17%*	13.01
2019	0.09	*1%*	2.24	*19%*	0.75	*6%*	4.10	*35%*	1.35	*11%*	0.10	*1%*	0.67	*6%*	0.22	*2%*	2.21	*19%*	11.74
Δ	-0.02		-1.05		+0.02		+0.76		-0.35		-0.06		-0.16		-0.42		0.00		-1.27

Figure 15.10: SAIFI based on Outage Cause (2018 & 2019)



15.73 As represented, the outage cause analysis shows that outages resulting from "Power Supply" issues had the highest frequency during the 2018-2019 period, followed by "Equipment Failure", which appear to be reflective of the reported system operating conditions and constraints during 2018 and 2019.

15.74 While these indications illuminate the reliability/outage cause dynamic, with the availability of the relevant outage cause data, a deeper assessment will be necessary to evaluate the effect of outage drivers on system reliability and investment strategy. According to the data, outage causes classified as "Unknown" accounted for a significant number of outages during the period. However, it is not clear from the Application how JPS proposes to deal with this challenge, but the OUR takes the view that it is significant enough and should be addressed.

14.28. OUR Determination of Q-Factor Baseline

15.75 To determine the baseline values for the quality indices (SAIDI, SAIFI and CAIDI) required to launch the Q-Factor adjustment mechanism, the 2016 – 2018 outage data was utilized as proposed by JPS. The data was comprehensively vetted by the OUR and was considered fairly suitable for the reliability calculations, within tolerable limits of error.

Data Inputs for Q-Factor Baseline

15.76 Based on the outage data normalization process, the data inputs and parameters used for the Q-Factor baseline computations are presented in Table 15.20 below.

Table 15.20: Summary of Data Inputs for Q-Factor Baseline

	CUSTOMER COUNT					FORCED OUTAGE EVENTS (IPP Outages Included)	SUSTAINED FORCED OUTAGE EVENTS (REPORTABLE)
Year	**Avg.**	**Min**	**Max**	**Max Daily Δ**	**End of Year**		
2016	581,960	574,614	620,936	25,582	613,959	64,603	60,774
2017	611,219	590,949	619,811	6,408	590,949	76,042	69,226
2018	644,004	633,359	658,497	795	658,497	54,904	49,933

Q-Factor Baseline Methodology

15.77 The methodology used to determine the Q-Factor baseline involves two main steps:

1) Construction of a reliability assessment model integrated with statistical distribution functions to derive indicative baseline values for SAIDI, SAIFI and CAIDI; and

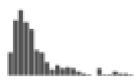
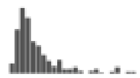
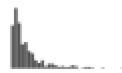
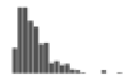
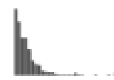
2) Analysis of the indicative results and making adjustments as necessary to reflect current system capabilities, to determine the required Q-Factor baseline.

Baseline Computations

15.78 Using the baseline data inputs and parameters, average daily values for SAIDI and SAIFI were computed for each of the selected annual outage datasets (2016-2018). This was done to show the daily reliability performance of the system as measured by the quality indices as well as the daily variations in the indicators based on the nature and characteristic of the system outages experienced daily by customers.

15.79 The discrete annual distributions of daily SAIDI and SAIFI values, for the selected years, were subjected to statistical analysis. The resulting summary statistics are presented in Table 15.21 below. It should be noted that the computed values of these quality indices include IPP forced outages.

Table 15.21: Summary Statistics for Daily SAIDI and SAIFI (2016 – 2018)

STATISTIC	2016		2017		2018	
	DAILY SAIDI	DAILY SAIFI	DAILY SAIDI	DAILY SAIFI	DAILY SAIDI	DAILY SAIFI
Count	366	366	365	365	365	365
Minimum	0.210	0.001	0.365	0.002	0.261	0.001
Maximum	130.136	1.028	97.526	0.605	127.176	0.341
Range	129.926	1.027	97.161	0.603	126.915	0.340
Sum	2,035.110	17.630	2,059.546	17.471	1,719.654	14.141
Mean	5.560	0.048	5.643	0.048	4.711	0.039
Median	3.806	0.030	3.580	0.028	3.495	0.026
STD DEV	8.250	0.075	7.198	0.057	7.596	0.047
Kurtosis	143.646	90.321	77.123	26.722	190.885	14.814
Skewness	10.073	7.998	7.083	3.844	12.431	3.347
Histogram						

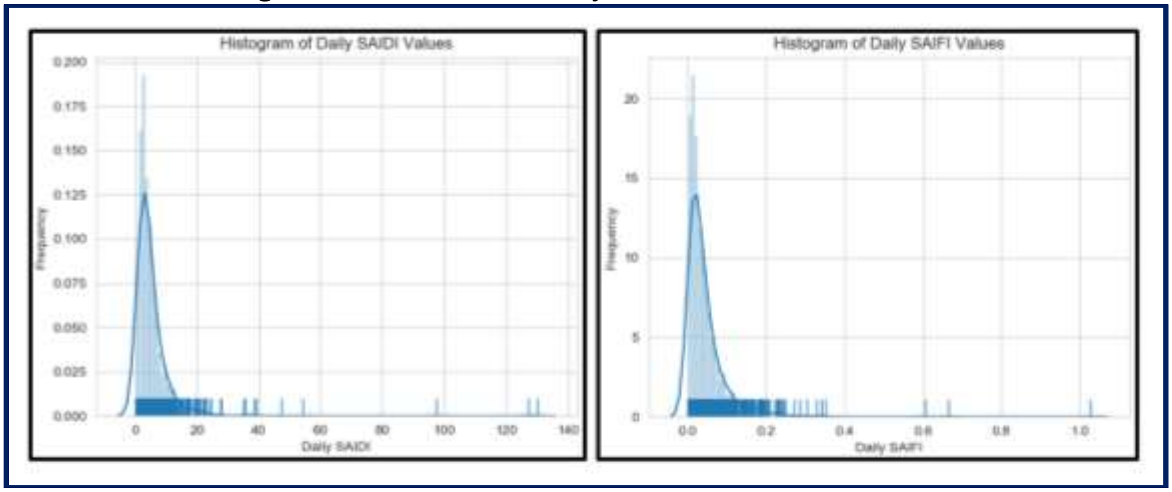
15.80 As shown in Table 15.21 above, the mean and median as well as the minimum and maximum values, indicate significant skewness in the annual SAIDI/SAIFI distributions. This is likely due to the effect of abnormal outage frequency and duration in the outage datasets. Nevertheless, the statistics shown in Table 15.21, were fully integrated into separate three-year (2016-2018) distributions for daily SAIDI and SAIFI, to derive the Q-Factor baseline indices. The aggregated statistics for the integrated 2016-2018 daily SAIDI/SAIFI distributions are presented in Table 15.22 below.

Table 15.22: Aggregated Statistics for 2016-2018 Daily SAIDI/SAIFI Distribution

AGGREGATED STATISITICS: 2016-2018 DAILY SAIDI AND SAIFI (IPP OUTAGES INCLUDED)										
STATISTIC	Count	Minimum	Maximum	Range	Sum	Mean	Median	Standard Deviation	Kurtosis	Skewness
DAILY SAIDI	1,096	0.210	130.136	129.926	5,814.310	5.305	3.657	7.700	141.008	9.991
DAILY SAIFI	1,096	0.001	1.028	1.027	49.243	0.045	0.028	0.002	79.849	6.637

15.81 The statistical distribution of the integrated 2016-2019 daily SAIDI and SAIFI values are represented graphically, in the form of the histogram overlaid with a Kernel Density Estimator (KDE) plot and a Rug plot, as shown in Figure 15.11 below.

Figure 15.11: 2016-2018 Daily SAIDI/SAIFI Distribution



14.29. Modelling of the Computed Daily SAIDI and SAIFI

15.82 Since the Q-Factor system is predicated on a system average principle with a symmetrical incentive structure, to ensure uniformity, the characteristics of the computed daily outage frequency and duration metrics were further evaluated. As evidenced by the statistical data and charts above, the 2016-2018 daily SAIDI and SAIFI values are highly right-skewed, with skewness factors of 9.991 and 6.637 respectively.

15.83 Typically, a dataset is considered to be highly skewed if the skewness factor is less than -1 or greater than +1. The degree of skewness in the data suggests that it is due to a significant number of large outliers in the daily SAIDI and SAIFI distributions. A major concern with this level of skewness is that it tends to shift the mean statistic from the centre of the distribution because the mean is not robust to extreme outliers. Having cognizance to this issue, without some form of normalization, the use of the computed average values of daily SAIDI and SAIFI to set the Q-Factor baseline, may cause distortions, as the data is evidently not normally distributed.

15.84 It is important to note that in the operation of the system, the performance of T&D circuits varies widely for many reasons, including differences in circuit lengths, load density, age of equipment, and the physical environment. Consequently, reliability measurements are not usually normally distributed and tend to exhibit a skewed distribution. The skewed distribution may be explained by several factors, including:

- Average performance measures are usually higher than the median value. The median value of the reliability indices provides a better reference from the perspective of the typical customer;
- Poor performing circuits and the resulting poor quality of service to customers can dominate the indices;
- Storms and other outliers can easily skew the indices.

15.85 To address the skewness in the data, two statistical methods were considered:

1) Use of data transformation techniques – Lognormal Transformation; and
2) Data modelling with statistical distribution applicable for skewed data – Gamma Distribution.

Normalization of Daily SAIDI/SAIFI using Lognormal Transformation

15.86 A lognormal transformation is commonly used in reliability applications to address skewed data distributions by creating a closer alignment to a normal distribution. To overcome the skew effect in the 2016-2018 computed daily SAIDI and SAIFI values, the lognormal transformation method was applied by converting the respective values to their natural log [y=log(x)], and plotting them against their frequency. This method transformed the data to a normal distribution referred to as lognormal normal distribution as shown in Figure 15.12 and Figure 15.13 below, for SAIDI and SAIFI, respectively.

Figure 15.12: 2016-2018 Daily SAIDI Values Represented by Lognormal Distribution

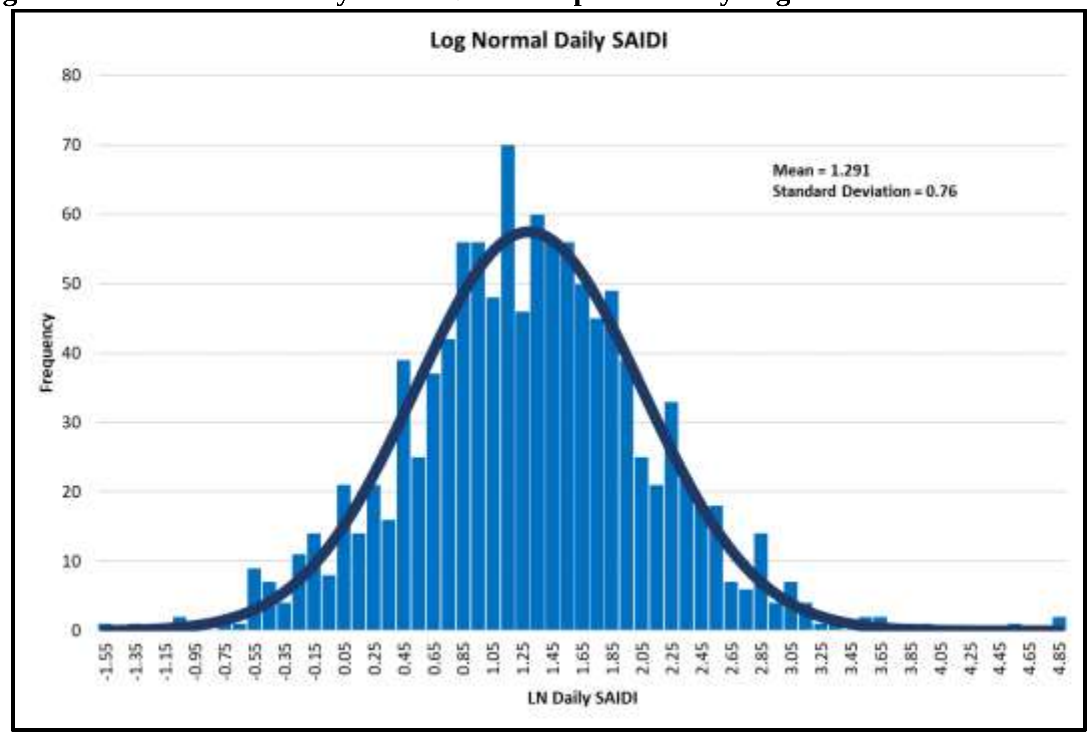
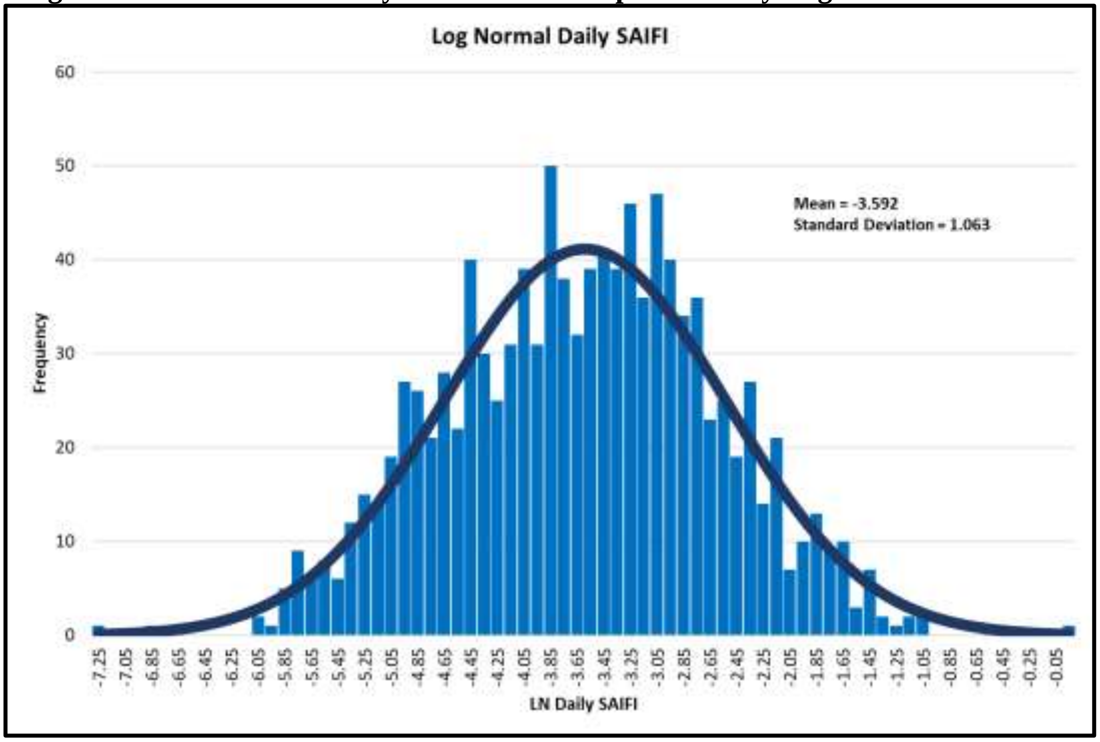


Figure 15.13: 2016-2018 Daily SAIFI Values Represented by Lognormal Distribution



15.87 As illustrated in the SAIDI and SAIFI plots, the lognormal distribution has effectively condenses the large values on the right side of the skewed distribution and moved them closer to the centre. The two plots also show optimized normal distribution curves fitted to the respective lognormal frequency distributions, with the corresponding mean and standard deviation.

<u>Estimation of SAIDI/SAIFI from Lognormal Distribution</u>

15.88 Taking the inverse log of the estimated daily mean value of SAIDI and SAIFI given in the respective lognormal distribution plots above, generates normalized daily average values for the respective indices. These average daily values were then scaled to obtain the annual average SAIDI and SAIFI values given below:

- SAIDI (annual average): **1,327.33** Minutes/customer
- SAIFI (annual average): **10.05** Interruptions/customer
- CAIDI (annual average): **132.07** Minutes/customer – derived from SAIDI and SAIFI

Modelling of Daily SAIDI/SAIFI Using Gamma Distribution

15.89 For validation, an alternative approach was employed to test the soundness of the initial data normalization model and related results. This was accomplished by using the two-parameter gamma distribution to model and analyse the skewed daily SAIDI and SAIFI distributions. The probability density function (PDF) of the gamma distribution, applied in the analysis is:

$$f(x) = \frac{1}{\beta^{\alpha}\Gamma(\alpha)} x^{\alpha-1} e^{-x/\beta} \; ; x \geq 0$$

Where:

Γ – represents the gamma function;
β – represents the scale parameter; and
α – represents the shape parameter.

15.90 The modelling of the daily SAIDI and SAIFI data with the two-parameter gamma distribution produced the plots shown in Figures 15.14 and Figure 15.15 below, for SAIDI and SAIFI, respectively.

Figure 15.14: 2016 – 2018 Daily SAIDI Values Fit to Gamma Distribution

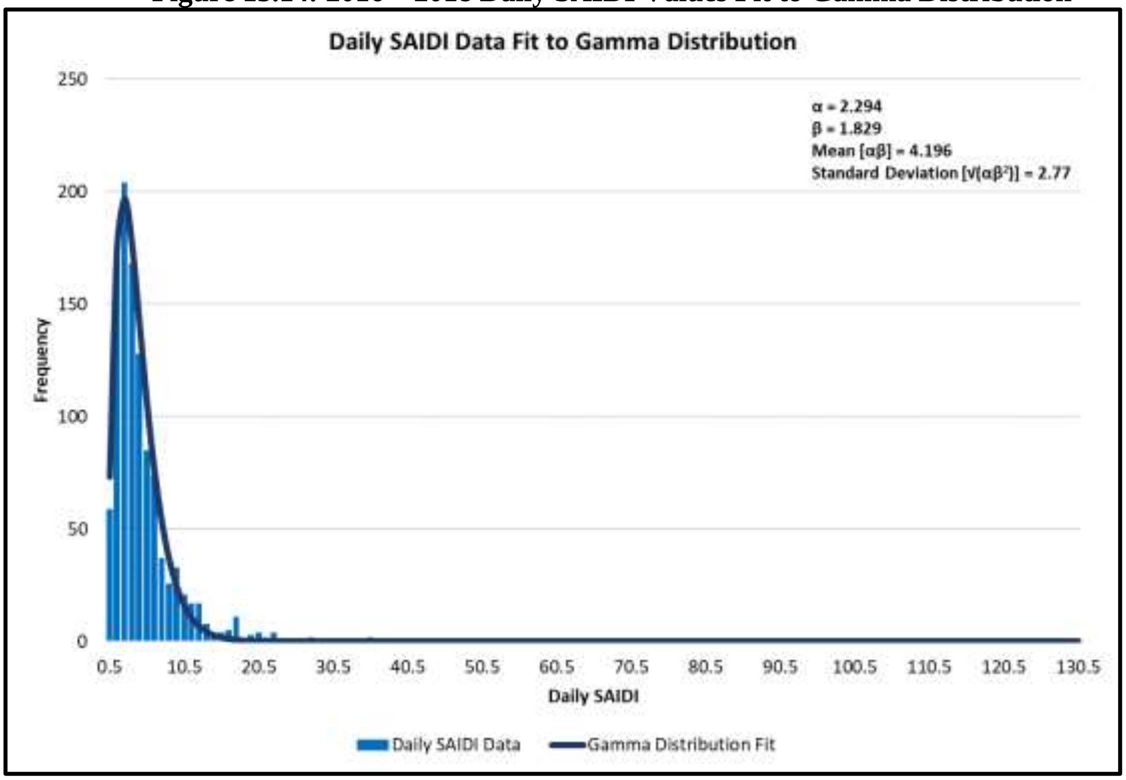
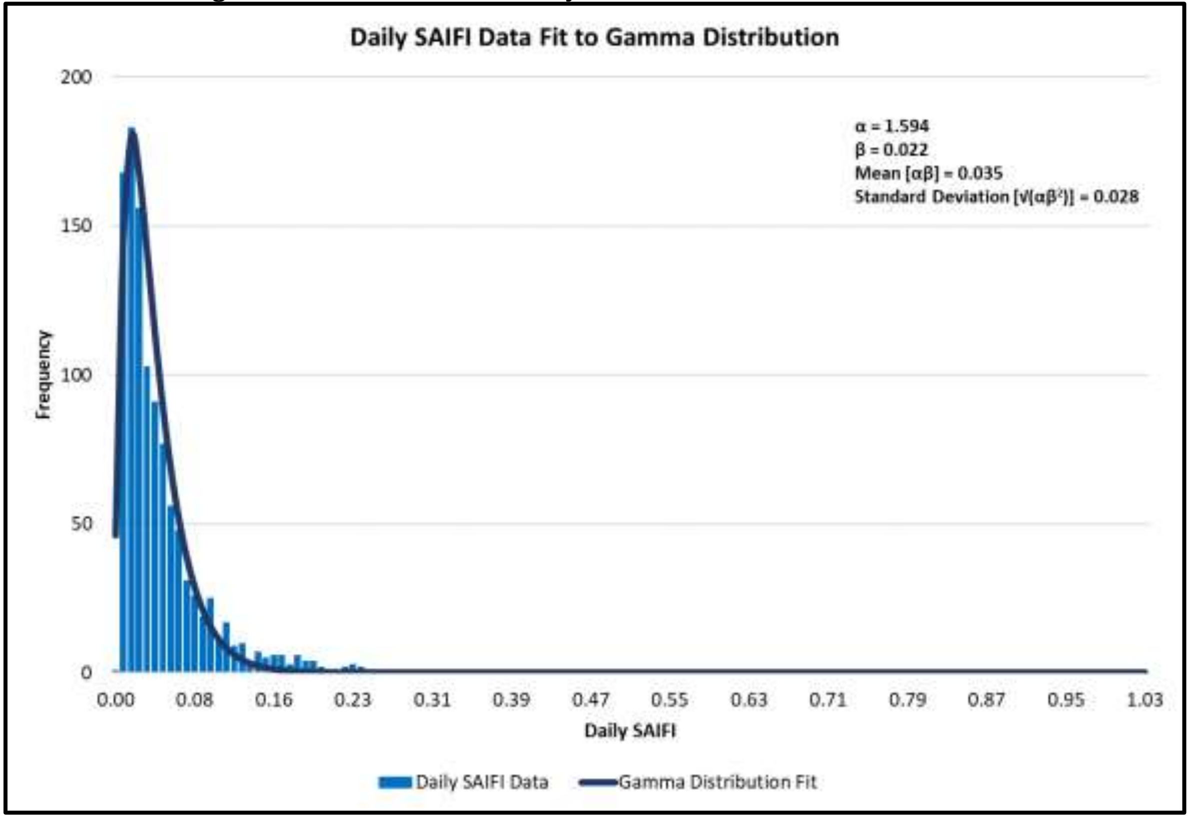


Figure 15.15: 2016 – 2018 Daily SAIFI Values Fit to Gamma Distribution



Estimation of SAIDI/SAIFI from Gamma Distribution

15.91 The estimated daily mean value of SAIDI and SAIFI given in the respective gamma distribution plots above, were scaled to obtain the corresponding annual values given below:

- SAIDI (annual average): **1,531.44** Minutes/customer
- SAIFI (annual average): **12.70** Interruptions/customer
- CAIDI (annual average): **120.59** Minutes/customer – derived from SAIDI and SAIFI

Summary of Daily SAIDI/SAIFI Normalization

15.92 The results obtained from the two approaches used to model and normalize the skewed 2016-2018 daily SAIDI and SAIFI distributions are summarized in Table 15.23 below. While the two statistical models generated reasonable representations of the data, it can be inferred that the Gamma distribution yielded a more robust approximation. Accordingly, the results from this normalization approach were used in deriving the values of the Q-Factor baseline indices.

Table 15.23: Summary Results – Quality Indices derived from Lognormal & Gamma Distribution

Methodology	Quality Indices (IPP Outages Included)			% Impact of IPP Outages		Quality Indices (IPP Outages Excluded)		
	SAIDI	SAIFI	CAIDI	SAIDI	SAIFI	SAIDI	SAIFI	CAIDI
Lognormal Distribution	1,327.33	10.05	132.07	1.61%	7.97%	**1,305.96**	**9.25**	**141.18**
Gamma Distribution	1,531.44	12.70	120.59	1.61%	7.97%	**1,506.78**	**11.69**	**128.89**

14.30. OUR Determined Q-Factor Baseline

15.93 With regard to the statistical modelling and analysis, it can be deduced that the values derived for the relevant quality indices provide an indicative baseline for the Q-Factor. However, the OUR is cognizant of the relationship between historical reliability performance and system configuration/operational capabilities, which are consequential to the baseline.

15.94 Given this consideration, the OUR conducted scenario analysis using historical data to set a reasonable Q-Factor baseline. This analysis reveals that system reliability performance has progressively improved during the 2014-2019 review period, with SAIDI reduced from 2035 minutes/customer in 2016 to 1448 minutes/customer (IPP outages included) at the end of 2019.

However, but there were indications of the effects of seasonal variability, extreme weather conditions and other factors, that could potentially impact the future quality of service performance, which were taken into consideration in the deriving the Q-Factor Baseline values. As a result, the OUR determined that the baseline values for SAIDI, SAIFI and CAIDI to be in the Q-Factor adjustment mechanism are as follows:

- SAIDI (annual average): **1,582.0 Minutes/customer**
- SAIFI: (annual average)**: 12.9 Interruptions/customer**
- CAIDI (annual average): **122.7 Mins/customer –** derived from SAIDI and SAIFI

15.95 A comparison of the Q-Factor baseline proposed by JPS and that determined by the OUR, is provided.

Table 15.24: Comparison of JPS' and OUR's Q-Factor Baseline

BASELINE PERIOD		*SAIDI BASELINE*		*SAIFI BASELINE*		*CAIDI BASELINE*	
JPS	OUR	JPS	OUR	JPS	OUR	JPS	OUR
2016-2018	2016-2018	1,973.37	1,582	15.5	12.9	127.33	122.7

15.96 As shown in Table 15.24 above, there are differences in the calculated Q-Factor baseline values, which is primarily due to the methodology used to carry out the evaluation. Based on the 2019 outage data, which became available in 2020, the values of SAIDI, SAIFI and CAIDI (IPP outages excluded) were calculated to be 1,375.20, 11.29 and 121.80

respectively. These values indicate that SAIDI and SAIFI had improved considerably, relative to JPS' proposed baseline by approximately 43% and 37%, respectively in excess of the proposed targets (5% for each index). Intuitively, considering these indications, the Q-Factor baseline proposed by JPS, was deemed untenable, effectively causing the proposed 2019-2024 targets to collapse.

15.97 Based on the OUR's analysis, from all indications the calculated Q-Factor baseline is reasonable and is consistent with the historical performance and technical characteristics of the system.

14.31. Q-Factor Targets Set by the OUR

OUR's Evaluation of JPS's Q-Factor Targets

15.98 In the Application, JPS proposed the Q-Factor targets shown in Table 15.25 below, for the Rate Review period, which were evaluated by the OUR.

Table 15.25: JPS' Proposed Q-Factor Targets for the Rate Review Period

JPS' PROPOSED Q-FACTOR TARGETS (2019 – 2024)			
Year	**Target SAIDI**	**Target SAIFI**	**Target CAIDI**
BASELINE	$SAIDI_{Base}$ (1,973.37)	$SAIFI_{Base}$ (15.5)	$CAIDI_{Base}$ (127.33)
2019	$SAIDI_{Base}$*(1-0.05)	$SAIFI_{Base}$*(1-0.05)	$CAIDI_{Base}$*(1-0.00)
2020	$SAIDI_{Base}$*(1-0.12)	$SAIFI_{Base}$*(1-0.12)	$CAIDI_{Base}$*(1-0.00)
2021	$SAIDI_{Base}$*(1-0.16)	$SAIFI_{Base}$*(1-0.16)	$CAIDI_{Base}$*(1-0.00)
2022	$SAIDI_{Base}$*(1-0.19)	$SAIFI_{Base}$*(1-0.19)	$CAIDI_{Base}$*(1-0.00)
2023	$SAIDI_{Base}$*(1-0.23)	$SAIFI_{Base}$*(1-0.23)	$CAIDI_{Base}$*(1-0.00)

15.99 The OUR's evaluation encompassed a reliability analysis to evaluate the impact of JPS' proposed reliability projects on the quality of service over the Rate Review period. This evaluation took into account, among other things, the following:

- The existing system configuration;
- Historical reliability performance;
- Outage causation/drivers;
- The effect of the HESS commissioned in 2019;
- Reliability projects currently being implemented by JPS;
- The proposed reliability improvement projects allowed and their forecasted impact;

- JPS' proposed maintenance activities focused on bolstering service reliability; and
- JPS' calculated COUE.

15.100 From this analysis, incremental improvements in annual SAIDI and SAIFI for the Rate Review period were estimated by the OUR. These projections were taken into consideration in the setting of the annual Q-Factor targets for the stated period. The OUR's estimated reliability improvements versus those forecasted by JPS are shown in Table 15.26.

Table 15.26: OUR' Projected Incremental Improvements in Reliability (2019-2024)

PROJECTED QUALITY OF SERVICE IMPROVEMENTS (2019-2023)				
	JPS Baseline (2016-2018)		OUR Baseline (2016-2018)	
	SAIDI	SAIFI	SAIDI	SAIFI
	1,973.37	15.5	1,582	12.9
YEAR	**JPS' Projected Annual SAIDI Improvement year over year**	**JPS" Projected Annual SAIFI Improvement year Baseline**	**JPS' Projected Annual SAIDI Improvement relative to Baseline**	**JPS" Projected Annual SAIFI Improvement relative to Baseline**
2019	5.0%	5.0%	-	-
2020	7.0%	7.0%	5.0%	4.0%
2021	5.0%	5.0%	6.0%	5.0%
2022	4.0%	4.0%	4.0%	4.0%
2023	5.0%	5.0%	2.0%	2.0%
TOTAL	**26.0%**	**26.0%**	**17.0%**	**15.0%**

OUR's Determined Q-Factor Targets

15.101 Taking into consideration the requirements of the Licence, the OUR's reliability assessment and the related quality of service issues, the annual Q-Factor targets determined for the Rate Review period are as presented in Table 15.27 below.

Table 15.27: JPS' Q-Factor Targets for the Rate Review Period

OUR DETERMINED Q-FACTOR TARGETS FOR JPS (2019-2024)				
Outage Data	**Description**	**Target SAIDI**	**Target SAIFI**	**Target CAIDI**
2016-2018	**BASELINE**	**$SAIDI_{Base}$ (1,582)**	**$SAIFI_{Base}$ (12.9)**	**$CAIDI_{Base}$ (122.7)**
2019	2020-2021 Annual Review	No Pre-set Target	No Pre-set Target	No Pre-set Target
2020	2021-2022 Annual Review	$SAIDI_{Base}*(1-0.05)$	$SAIFI_{Base}*(1-0.04)$	$CAIDI_{Base}*(1-0.01)$
2021	2022-2023 Annual Review	$SAIDI_{Base}*(1-0.11)$	$SAIFI_{Base}*(1-0.09)$	$CAIDI_{Base}*(1-0.02)$
2022	2023-2024 Annual Review	$SAIDI_{Base}*(1-0.15)$	$SAIFI_{Base}*(1-0.13)$	$CAIDI_{Base}*(1-0.02)$
2023	2024 PBRM Adjustment	$SAIDI_{Base}*(1-0.17)$	$SAIFI_{Base}*(1-0.15)$	$CAIDI_{Base}*(1-0.02)$

15.102 Given that the 2019 outage data, applicable to the 2020-2021Annual Review, became available in 2020 prior to this Determination Notice, no pre-determined target would be available for quality of service measurement and PBRM Q-Factor adjustment for the referenced review period. As such, the Q-Factor to be applied in the 2020 Annual Review shall be zero.

14.32. Other Q-Factor Issues

15.103 While there have been noticeable improvements in outage data quality since 2017, there are a number of issues with implications for the operation of the Q-Factor performance that merits examination. These issues are delineated in the section below.

Major System Failures

15.104 Section 45 (16) of the EA defines a major system failure as follows:

a) "major system failure" means a system failure that –
i. has not been planned by the System Operator;
ii. affects at least one thousand customers; and
iii. *lasts at least two hours;"*

15.105 In reviewing the 2018 and 2019 annual outage datasets, the OUR identified **379** and **343** outages respectively, which satisfied the criteria, but practically, could not be rationally defined as a major system failure. In this regard, the OUR takes the view that there is the need for a consultative approach to facilitate a resolution of this matter.

System Outages Related to Force Majeure Conditions

15.106 In the OUR's review of JPS' 2016 and 2017 system outage datasets a number of outages that the company claimed were caused by Force Majeure events were identified. The reliability data for each of these years, showed that JPS excluded the described outages from the calculation of the respective quality indices. Although, Schedule 3, Exhibit 1 of the Licence, which defines the Q-Factor adjustment mechanism has no specific provision for the treatment of Force Majeure in relation to the Q-Factor, Condition 11 2. of the Licence sets out the requirements for compliance in relation to Force Majeure, which provides as follows:

"On application to the Minister, which has been granted, the Licensee shall be excused from any non-compliance with this Licence caused by Force Majeure."

15.107 As per this Licence provision, for outages related to Force Majeure conditions to be excluded from the reliability calculations, JPS would be required to provide evidence of the specific Force Majeure event and the relevant supporting documentation relieving the company from complying with the applicable quality of service requirements.

However, no such information has been presented by JPS, therefore, the OUR did not exclude these outages from the calculation of the relevant quality indices. In the Application, JPS noted that the company was in discussion with the MSET to establish a mechanism for the approval of the referenced outages, as per Licence requirements.

Momentary Interruptions and MAIFI

15.108 Although, MAIFI is not a feature of the existing PBRM, nevertheless, the reported momentary interruptions and related reliability calculations were reviewed by the OUR pursuant to the OUR's position outlined in the Final Criteria. In the Application, JPS noted that the company has certain limitations in the collection of MAIFI data, because currently, the system can only capture the data at the circuit breaker and Pole Mounted Re-closer (PMR) level, which excludes interruptions at the fuse and transformer level.

The company also has indicated that the collection of MAIFI data at a more granular level would require further investment in the data collection system, but will continue to report the data that is available.

15.109 However, momentary interruptions in service have an unfavourable effect on the quality of service and the company stands to gain from the improvement in the measurement of this reliability indicator.

15.110 In this regard, JPS shall be required to continue to record all momentary interruptions it can capture, and report them to the OUR, with the corresponding MAIFI calculations.

Major Event Days

15.111 During the 2014-2019 price control period, a number of Major Event Days (MEDs) were identified in the JPS' annual outage datasets, for a variety of reasons. However, in accordance with the existing legal and regulatory framework, there is no provision to exclude outages captured under MEDs from the calculation of the prescribed quality indices. Even though, JPS initially disagreed with this position, citing the IEEE Standard 1366 – 2012 (the Guide for Electric Power Distribution Reliability Indices) in the Application, the company has since changed its position.

15.112 JPS has now conceded that there is presently no basis to substantiate the exclusion of outages associated with MEDs from the calculation of the quality indices. The OUR welcomes JPS' modified perspective on this issue.

Reliability Reporting Requirements

15.113 To facilitate periodic assessment monitoring of JPS' outage data and system reliability performance, the company shall submit to the OUR a detailed Reliability Report on a quarterly basis. The report should include all the data requirements applicable to the Annual Outage Data Report, with the specific "cause" indicated for each outage (forced and planned), as well as the status/progress of reliability projects being implemented. This report shall be submitted within thirty (30) days after the end of the applicable quarter.

DETERMINATION #22

Based on the OUR's review, the Office determinations on the Q-Factor are as follows:

a) The approved Q-Factor baseline and targets for the Rate Review period are set out under **Tables 15.24 & 15.27** of this Determination Notice.

b) The Q-Factor to be applied to the PBRM for the 2020 Annual Review shall be zero.

c) For each Annual Review application during the Rate Review period, JPS shall include an outage cause analysis to support its JPS Q-Factor proposal.

d) JPS shall put measures in place to ensure that Non-Reportable forced outages shall not exceed 5% of total forced outages reported for each year.

e) JPS shall report to the OUR all momentary interruptions that occurred on the system, which it is able to capture, along with the related MAIFI calculations.

f) JPS shall submit to the OUR, a detailed Reliability Report on a quarterly basis, which shall include all the data requirements applicable to the Annual Outage Data Report, with the specific "cause" indicated for each outage (forced and planned), as well as the status/progress of reliability projects being implemented. This report shall be submitted within **thirty (30) days** after the end of the applicable quarter.

16. Load Research and Cost of Service Study

16.1. Introduction

16.1 Jamaica's electric power industry has experienced significant changes over the last decade due to a number of forces, including: a new orientation in international and national energy policy agendas; the drive to increase the adoption of renewable fuels, the proliferation of new distributed energy technologies; the introduction of LNG and an expansion of consumer choice and expectations.

16.2 Rooftop solar has been one of the most significant disruptive forces that have impacted the Jamaican power industry. There has been significant growth in roof top solar over the past few years. The 'net billing' arrangement, which has been in place since 2012 provides an incentive for residential and commercial customers of the electric utility to capitalise on the use of, distributed solar generation.

16.3 LNG was introduced in the Jamaican energy market in 2016 when JPS signed a gas supply agreement with NFE for the supply of natural gas to 120MW Bogue combined cycle unit. The introduction of LNG in 2016 is a significant game changer for the industry as some of the electric utility's largest customers are contemplating leaving the electric grid to pursue low cost self-generation solutions using natural gas. In response, JPS is currently exploring customer-sited distributed cogeneration in an attempt to meet the needs and expectations of its largest customers while maintaining customer loyalty.

16.4 To respond to changing customer needs, JPS has increased its service offerings to its customers. For example, the company:

- Introduced prepaid electricity in 2015;
- Explored changes in the existing residential rate class construct to address low income households with limited means to afford electricity service, while reducing the incentive for electricity theft;
- The introduction of a new rate class (Rate 70) for the company's largest customers (i.e. demand above 2MVA) to reduce and arrest the rate of migration among that category of customers.

16.5 The OUR, in recognition of the disruptive forces shaping the electricity sector, has contemplated the role of tariff design in transitioning Jamaica's electricity sector on a sustainable, secure and affordable trajectory.

16.6 With the exception of the Rate 70 class, JPS' existing tariff structure has been in place for more than two decades. Residential (Rate 10) and small to medium commercial customers (Rate 20) tariffs are predicated on a two-part structure, comprised of a volumetric energy rate with a customer charge. Large Commercial and Industrial (C&I) customers (Rates 40, 50 and 70) have a three-part tariff structure inclusive of demand charges, with a time of use option.

16.7 Historically, the rate structure has worked well. However, recent developments in the electricity sector suggest that a review of the tariff structure at this point is appropriate. These developments include:

- JPS' initiative of rolling out of smart meters across all customer categories. This makes it now possible for the introduction of TOU charges to all rate classes;
- Amendments to the OUR Act, which has impacted the setting of electricity tariffs. These amendments include the clear delineation of GOJ's economic and social policy objectives for the electricity sector;
- The introduction of the Licence, which signalled among other things, a change from a price cap tariff to a forward-looking revenue cap regime.

16.8 Notably, these developments substantially informed the Final Criteria published by the OUR to guide JPS in its tariff application process.

16.9 According to Criterion 17 of the Final Criteria "JPS shall submit as part of its 2019 – 2024 Rate Review application":

(a) an embedded cost of service study based on the revenue cap for 2019;
(b) a study done on a bottoms-up Long Run Marginal Cost basis, with reconciliation to the revenue cap for 2019;
(c) a load research study report detailing the sampling technique and methodology used in its programme as well as an analysis of the structure of demand over a typical day (weekday, Saturday and Sunday) for each rate class.

16.2. JPS Cost of Service Study

16.10 In response to the OUR's request for the submission of a Cost of Service Study (COSS), JPS submitted a Load Characterization Study, Long Run Marginal Cost (LRMC) Study and an Embedded Cost Study (ECS).

16.11 JPS stated that in developing the COSS, it sought to address concerns expressed by the OUR in its 2014 – 2019 Determination Notice, when the Office indicated that in its view, "the company's submission was not sufficient to establish a cost-causation relationship among existing rate classes and functionalized cost to satisfy the requirements of the Office."

16.3. JPS' Load Characterization Study

16.12 JPS indicated that it engaged a consulting company, Macro Consulting, to develop its Load Characterization Study to support the COSS. JPS also noted that Load Characterization has two main uses in the determination of regulated rates, namely (1) cost allocation; and (2) rate design. Additionally, JPS pointed out that the parameters estimated forms the basis for the allocation of system cost (Revenue Requirement) among the different ratepayers.

16.13 The company also indicated that in order to allocate costs based on causation, various allocation factors and methods were utilized based on:

- Type of cost (function and classification);
- System characteristics (planning principles, T&D network); and
- Load characteristics (seasonality, load profile).

16.14 JPS employed input data from the load characterization study from its billing and smart meter databases. The database analysed spanned the period 2008 January through to 2018 December.

16.15 JPS noted that the Final Criteria established that *"…the Load Research sample should be selected to ensure a minimum statistical precision of peak hour demand estimate of* ± 10% *at a 90% confidence level*." In this regard, JPS calculated that a sample of 316 from all rate classes would be required to meet the Final Criteria's minimum load research sample. However, given the wide availability of AMI interval meters, JPS opted to select a larger sample of customers, which would increase the statistical accuracy of the sample at minimal cost. Table 16.1 below shows JPS' final sample selection.

Table 16.1: JPS' Final Sample Selection

Rate Class	Population Size	Final Criteria Sample Size (90% CI and 10% margin of error)	JPS Final Sample Selection
R10	577,196	68	10,000
R20	66,446	68	1,000
R40	1,822	66	1,555
R50	157	48	113
R60	457	60	
R70	23	18	21
Total	**646,099**	**328**	**12,689**

16.4. JPS' Load Research Results

16.16 JPS reported that its analysis of consumption patterns for all customer classes showed a clearly distinctive summer peak, especially in the months of June, July, August, and September. Further, residential customer's consumption peaked in August while commercial customers tended to peak in July.

16.17 Table 16.2 below shows the summary of the coincidence and load factors calculated by JPS while Table 16.3 below shows the summary of the external and total coincidence factors. These were the factors and methods that were used in the ECS and the LRMC tariffs.

Table 16.2: Summary of JPS' Proposed Coincidence and Load Factors

Factors	Definition	MT10	MT20	MT40	MT50	70	MT60
Class 1-CP	Peak demand at the time of the annual system peak (kW)	205,373	85,799	107,165	34,049	41,158	15,747
Class 4-CP	Average of the class peaks at the times of the four highest peaks throughout the year	232,833	163,061	158,865	54,233	53,903	15,890
Class 12-CP	Average of the class monthly peaks	218,844	151,433	141,508	45,280	47,627	14,529
Class NCP	Peak of the class which is not necessarily coincident with system peak	226,816	162,311	143,871	41,016	47,750	15,747
Class NCP MD	Class non-coincident peak maximum demand - the sum of the individual maximum demand regardless of when each customer maximum demand occurs	406,408	220,508	162,622	46,784	52,220	15,747
Class LF	Class load factor	59.9%	47.1%	65.6%	69.3%	73.1%	41.7%
Class Internal Coincidence Factor	The internal coincidence factor of the class is the ratio of the maximum power of the class and the sum of all non-coincidental maximum powers of the customers in class	55.8%	73.6%	88.5%	87.7%	91.4%	100.0%
Class KonP	Percentage energy consumption of the class in the on-peak block	14%	11%	11%	12%	12%	22%
Class KpaP	Percentage energy consumption of the class in the partial peak block	36%	54%	48%	46%	44%	11%
Class KoffP	Percentage energy consumption of the class in the off-peak block	50%	36%	41%	42%	44%	67%

Table 16.3: Summary of JPS' Proposed External and Total Coincidence Factors

Rate	Coincidence factors											
MT10	External Coincidence Factor											
	On Peak				Partial Peak				Off Peak			
	GEN	TR	MV	LV	GEN	TR	MV	LV	GEN	TR	MV	LV
	0.91	0.91	0.91	0.97	0.65	0.65	0.65	0.65	0.99	0.99	0.99	0.99
	Total Coincidence Factor											

Rate	Coincidence factors											
	On Peak				Partial Peak				Off Peak			
	GEN	TR	MV	LV	GEN	TR	MV	LV	GEN	TR	MV	LV
	0.51	0.51	0.51	0.54	0.36	0.36	0.36	0.36	0.55	0.55	0.55	0.55
MT20	External Coincidence Factor											
	On Peak				Partial Peak				Off Peak			
	GEN	TR	MV	LV	GEN	TR	MV	LV	GEN	TR	MV	LV
	0.53	0.53	0.53	0.46	0.91	0.91	0.91	0.91	0.37	0.37	0.37	0.37
	Total Coincidence Factor											
	On Peak				Partial Peak				Off Peak			
	GEN	TR	MV	LV	GEN	TR	MV	LV	GEN	TR	MV	LV
	0.39	0.39	0.39	0.34	0.67	0.67	0.67	0.67	0.27	0.27	0.27	0.27
MT40	External Coincidence Factor											
	On Peak				Partial Peak				Off Peak			
	GEN	TR	MV	LV	GEN	TR	MV	LV	GEN	TR	MV	LV
	0.74	0.74	0.74	0.69	1.00	1.00	1.00	1.00	0.62	0.62	0.62	0.62
	Total Coincidence Factor											
	On Peak				Partial Peak				Off Peak			
	GEN	TR	MV	LV	GEN	TR	MV	LV	GEN	TR	MV	LV
	0.66	0.66	0.66	0.61	0.88	0.88	0.88	0.88	0.55	0.55	0.55	0.55
MT50	External Coincidence Factor											
	On Peak				Partial Peak				Off Peak			
	GEN	TR	MV	LV	GEN	TR	MV	LV	GEN	TR	MV	LV
	0.83	0.83	0.83	0.81	1.00	1.00	1.00	1.00	0.78	0.78	0.78	0.78
	Total Coincidence Factor											
	On Peak				Partial Peak				Off Peak			
	GEN	TR	MV	LV	GEN	TR	MV	LV	GEN	TR	MV	LV
	0.73	0.73	0.73	0.71	0.88	0.88	0.88	0.88	0.68	0.68	0.68	0.68
MT70	External Coincidence Factor											
	On Peak				Partial Peak				Off Peak			
	GEN	TR	MV	LV	GEN	TR	MV	LV	GEN	TR	MV	LV
	0.86	0.86	0.86	0.83	0.99	0.99	0.99	0.99	0.75	0.75	0.75	0.75
	Total Coincidence Factor											
	On Peak				Partial Peak				Off Peak			
	GEN	TR	MV	LV	GEN	TR	MV	LV	GEN	TR	MV	LV
	0.79	0.79	0.79	0.75	0.91	0.91	0.91	0.91	0.69	0.69	0.69	0.69
MT60	External Coincidence Factor											
	On Peak				Partial Peak				Off Peak			
	GEN	TR	MV	LV	GEN	TR	MV	LV	GEN	TR	MV	LV
	1.00	1.00	1.00	1.00	-	-	-	0.23	1.00	1.00	1.00	1.00
	Total Coincidence Factor											
	On Peak				Partial Peak				Off Peak			
	GEN	TR	MV	LV	GEN	TR	MV	LV	GEN	TR	MV	LV
	1.00	1.00	1.00	1.00	-	-	-	0.23	1.00	1.00	1.00	1.00

16.18 JPS also conducted an analysis of consumption patterns for pre-paid residential customers. The results indicate that pre-paid customers behave very similarly to MT10[18] post-paid customers with consumption levels of 190kWh per month or less. JPS stated that the

[18] "MT" and "RT" are used interchangeably in reference to "Rate Class". Hence "MT10" means "Rate10, etc."

analysis also showed that after migrating from post-paid to pre-paid service, average consumption goes from 2,196 kWh/year to 1,947kWh/year, a decrease of 10%.

16.5. Embedded Cost of Service Study

16.19 The starting point in assessing the reasonableness of the rates to be charged by a utility is to evaluate the cost of providing service. Cost of service studies are conducted to determine what it costs to provide service to customers, both in total and by individual rate class (e.g. residential, commercial, industrial). An embedded cost of service study does this through three (3) principal steps: functionalisation, classification and allocation.

16.20 Functionalisation involves assigning costs to the functional services provided by a utility, such as power production, purchasing electric power, the transmission of the power over high-voltage lines and the distribution of power over distribution lines.

16.21 JPS stated that it employed Title 18 Code of Federal Regulations (18 CFR), published by the Office of the Federal Register National Archives and Records Administration, in its financial and accounting systems, policies, and procedures. This methodology is commonly referred to as the FERC Uniform System of Accounts or FERC codes. Implicit in the company's utilisation of the FERC codes is the notion that JPS' accounting system already allows for the proper distinction of the assets and costs associated with the various functions of the utility.

16.22 Classification is the second step in the ECS. This involves identifying and classifying the major cost drivers for each group of functionally assigned costs. Identifying the major cost drivers allows the service characteristics that give rise to the costs to serve as a basis for allocation. The major cost drivers are:

- Energy-related costs: costs that vary with kWh energy generated and consumed;
- Demand-related costs: costs that vary with kW of instantaneous demand (and therefore peak capacity needs);
- Customer-related costs: costs that vary with the number of customers served on the system.

16.23 JPS also indicated that it utilised the National Association of Regulatory Utility Commissioners (NARUC) Cost Allocation Manual as a guide for the classification of costs under each function. Based on this approach, the company classified the functions in its operations as shown in the Table 16.4 below.

16.24 Further, JPS explained that all transmission costs and most generation costs are demand related. However, other generation cost varies with production and therefore were classified as energy-related (such as renewable power purchase cost and variable O&M). Management and Distribution assets and O&M costs were mainly recognized as being driven by demand and/or customer factors.

Table 16.4: JPS' Proposed Classification Guide

Classification of Costs				
Activity	Voltage	Demand	Energy	Customer
Generation	High/Medium/Low	X	X	
Transmission	High/Medium/Low	X		
Distribution	High/Medium/Low	X		X
	Medium/Low	X		X
	Low			X
Management	High/Medium/Low	X		X
	Medium/Low	X		
	Medium	X		
	Low	X		

16.25 Table 16.5 below shows the results of JPS' classification exercise, which indicates that generation (54.8%), and distribution (26.8%) accounted for the largest share of cost. The Table also shows that from a classification perspective, demand-related costs accounted for 43.1% of costs while energy and customer accounted for 35.5% and 21.4% respectively.

Table 16.5: JPS' Functionalization and Classification Results

Classification of 2019 Costs (JMD'M)						
Activity	Voltage	Demand	Energy	Customer	Total	**Total (%)**
Generation	High/Medium/Low	11,673	21,407	-	33,080	**54.8%**
Transmission	High/Medium/Low	3,182	-	-	3,182	**5.3%**
Distribution	High/Medium/Low	4,674	-	1,363	6,037	**26.8%**
	Medium/Low	3,885	-	1,232	5,117	
	Low	-	-	5,029	5,029	
Management	High/Medium/Low	1,026	-	5,261	6,287	**13.1%**
	Medium/Low	1,207	-	-	1,207	
	Medium	352	-	-	352	
	Low	27	-	-	27	
Total		**26,027**	**21,407**	**12,884**	**60,319**	**100.0%**
Total (%)		**43.1%**	**35.5%**	**21.4%**	**100.0%**	

16.26 The final step in the ECS, is allocation. In this step, the functionally assigned and classified costs are directly assigned (or "allocated") to the customer classes based on an allocation factor that is representative of the service characteristic that drives costs.

16.27 JPS claimed that its allocation of functionalized and classified costs among rate classes is based on the nature of cost causation, which recognizes the principle that different cost components have different drivers and therefore may require separate allocation treatment. Table 16.6 below shows the allocation methods utilized by JPS.

Table 16.6: JPS' Proposed Allocation Methods by Function, Classification and TOU Period

Function	Classification		Method (Allocation to Rate Class)	Method (Allocation to TOU Period)
Management	Demand		Not Directly Allocated	ECF
	Customer		Weighted #Cust	
Generation	Demand		Average-Excess Demand	LOLP
	Energy		Weighted Energy at Generation	SRMC
Transmission	Demand		12-CP	LOLP
Distribution	Demand	High/Med/Low	ECF On Peak MV (All)	ECF MV On Share
		Medium/Low	ECF On Peak MV (All)	ECF MV On Share
		High	-	-
		Medium	-	-
		Low	-	-
	Customer	High/Med/Low	#Cust. for High/Med/Low	
		Medium/Low	#Cust. for Medium/Low	
		Low	#Cust. for Low	

16.28 JPS then determined the demand, energy, and customer-related costs from the total costs and further allocated the costs by rate class. The results obtained are shown in Table 16.7 below.

16.29 Based on this approach, JPS explained that RT10 was allocated ~52% of all costs incurred even though this rate class was responsible for only 33% of energy consumption and 41% of Non-coincident Peak (NCP) demand, which is primarily a result of the bulk of customer costs (89%) being attributed to RT10. The next largest rate classes (in terms of allocated costs) were RT20 and RT40, which were allocated approximately 18% and 16% of overall costs respectively. All other rate classes were allocated 15% of all costs incurred.

Table 16.7: Results of JPS' Cost Allocation and Classification

Tariff Category	Demand Costs	Energy Costs	Customer Costs	Total Costs
RT 10 LV Res. Service	11,552,267,413	8,495,574,199	11,621,647,937	31,669,489,549
RT 20 LV Gen. Service	4,781,472,170	4,565,092,359	1,339,506,390	10,686,070,919
RT 60 LV Street Lighting	953,491,522	350,981,883	9,485,897	1,313,959,302
RT 40 MV Power Service All	4,941,249,796	4,546,112,964	44,047,471	9,531,410,231
RT 50 MV Power Service All	1,469,587,461	1,401,372,860	2,260,623	2,873,220,943
RT 70 MV Power Service All	1,696,789,763	1,541,945,918	366,157	3,239,101,839
RT 20 LV Gen. Service (Other)	274,070,808	265,456,930	39,546	539,567,283
RT 50 MV Power Service (Cement Company)	626,902,210	461,395,384	15,920	1,088,313,514
Total	26,295,831,143	21,627,932,497	13,017,369,941	60,941,133,581

16.30 JPS used the ECS to determine average tariffs for each rate class. From this, the overall costs for each rate class was divided by the energy consumption of each class to derive the embedded costs average tariff. Additionally, using the 2018 Rate Schedule, JPS determined what the average tariff for each rate class would be if the Revenue Requirement is scaled to the 2019 Revenue Requirement. The result of this is shown in the Table 16.8 below.

Table 16.8: JPS' Proposed Embedded Costs Average Tariffs

Tariff Category	Total Costs (JMD)	Total Energy (kWh)	Average Costs (JMD/kWh)	Adj Existing Average Tariff (JMD/kWh)
RT 10 LV Res. Service	31,669,489,549	1,066,621,238	29.69	28.35
RT 20 LV Gen. Service	10,686,070,919	600,743,680	17.79	23.64
RT 60 LV Street Lighting	1,313,959,302	62,362,528	21.07	29.08
RT 40 MV Power Service All	9,531,410,231	801,257,962	11.9	10.52
RT 50 MV Power Service All	2,873,220,943	267,274,115	10.75	9.80
RT 70 MV Power Service All	3,239,101,839	294,123,893	11.01	7.50
RT 20 LV Gen. Service (Other)	539,567,283	34,953,384	15.44	22.06
RT 50 MV Power Service (Cement Company)	1,088,313,514	88,261,194	12.33	7.39
Total	60,941,133,581	3,215,597,993	18.95	18.95

16.6. Long Run Marginal Cost Study

16.31 According to JPS, its LRMC study examined both the long run marginal and short run marginal costs (SRMC) and yielded the generation and network investment decisions that would be required given AC load flow, contingency and reliability constraints (N-1), system security along with co-optimized cost minimization economic analysis.

16.32 JPS developed a generation and transmission least cost development plan through an Excel based dispatch model (JPSED_BaseCaseStudy.xlsx). JPS explained that JPSED is a long-term generation and transmission expansion planning tool premised on the four-hourly optimal economic dispatch to meet a given four-hourly demand for an entire year based on demand projections.

16.33 Using the outputs of the model, JPS determined generation and transmission LRMC as follows:

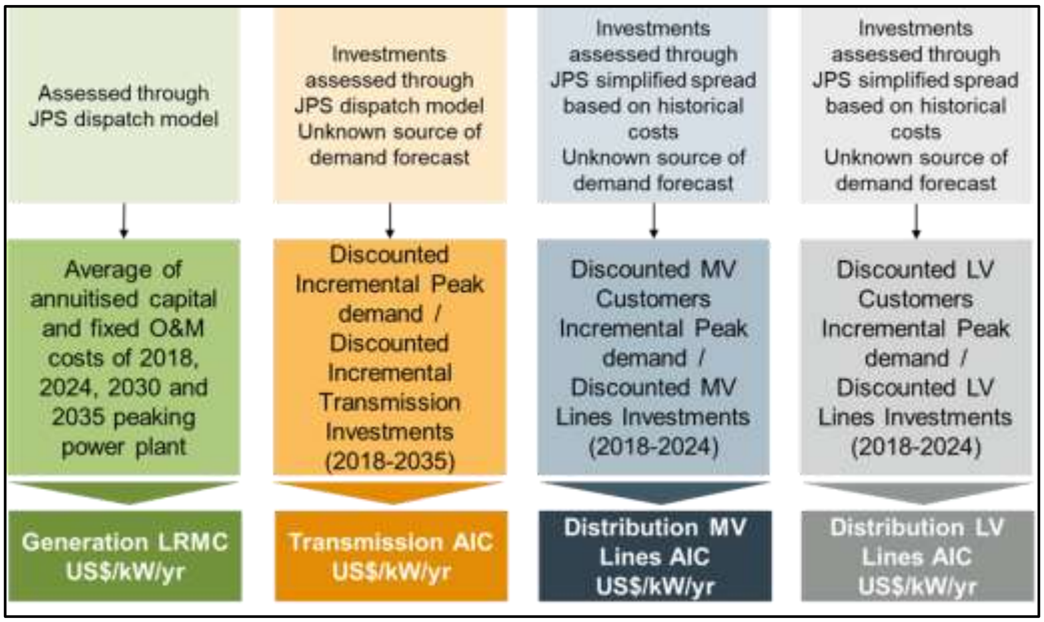
- Generation LRMC - average of annuitized capital and fixed O&M costs of 2018, 2024, 2030 and 2035 marginal power plants;
- Transmission long run average incremental cost (LRAIC) - discounted incremental transmission line investments that are determined by the model for 2018 to 2035 divided by the discounted incremental system peak demand entered in the model.

16.34 For the distribution system, JPS uses a simplified spreadsheet model to estimate investment costs from 2018 to 2024 and calculates LRAIC for the MV and the LV network:

- MV distribution LRAIC - discounted incremental MV lines investments that are determined by the model for 2018 to 2024 divided by the discounted incremental MV customers Peak demand entered in the model;
- LV distribution LRAIC - discounted incremental LV lines investments that are determined by the model for 2018 to 2024 divided by the discounted incremental LV customers Peak demand entered in the model.

16.35 The approach JPS adopted to estimate generation, transmission and distribution LRMC is summarised in the Figure 16.1 below.

Figure 16.1: JPS' System LRMC calculations



Generation LRMC

16.36 Generation LRMC of capacity are calculated as the average of the annuitized capital and fixed O&M costs of 2018, 2024, 2030 and 2035 marginal power plants. The cost assumptions used by JPS for the calculations of generation LRMC are presented in Table 16.9 below.

Table 16.9: JPS' LRMC of Generation

Year	Peaking unit in the year	Capital Costs (US$/kW)	Economic lifetime (Years)	Fixed O&M (US$/kW/y)	WACC (%)	LRMC (US$/kW)
2018	Med. speed diesel	1,450	20	30	12.12	225.4
2024	CCGT	1,454	30	15	12.12	197.1
2030	OCGT	870	25	7	12.12	118.9
2035	CCGT	1,454	30	15	12.12	197.1
Average	-	-	-	-	-	184.6

Transmission LRMC

16.37 Transmission LRAIC were calculated as the discounted incremental transmission line investments for 2018 to 2035 divided by the discounted incremental system peak demand. The results of the calculation are presented in Table 16.10 below.

Table 16.10: JPS' LRAIC of Transmission

Period	**Discounted transmission investment costs (mUS$)**	**Discounted incremental Peak demand (MW)**	**Incremental LRMC for transmission capacity (US$/KW)**
2018-2035	22.7	19.0	1,191.97
69kV	3.51	19.04	183.06
138kV	30.95	19.04	1008.91

Distribution LRMC

16.38 LRAIC of MV and LV networks were calculated as the discounted incremental distribution line investments for 2018 to 2024 divided by the discounted incremental network's Peak demand, separately for the MV and the LV networks. This translates into the following formula:

$$LRMC = \frac{PV\ \sum_i IC_i}{PV\ \sum_i ID_i}$$

Where,

IC = incremental cost (IC), and

ID = incremental demand.

16.39 The underlying assumptions for the LRAIC calculations and the LRAIC are presented in Table 16.11 and Table 16.12 below, for the MV and the LV networks respectively.

Table 16.11: JPS' LRAIC of MV Network

Year	MV lines investment plan (US$)	Annuitized MV lines investment plan (US$)	MV Peak demand forecast (MW)	Incremental MV Peak demand forecast (MW)	MV Lines LRAIC (US$/kVA)
2018	271,708	729,769	2,203	9	-
2019	271,819	1,300,649	2,214	11	-
2020	279,761	1,881,664	2,226	11	-
2021	281,558	2,472,195	2,238	12	-
2022	283,393	3,072,417	2,250	12	-
2023	285,270	3,682,515	2,263	13	-
2024	287,190	4,302,675	2,276	13	-
WACC	-	13.22%	-	13.22%	-
NPV	-	9,664,066	-	49	195.5

Source: Distribution PCM Calculation.xlsx, JPS, 2019

Table 16.12: JPS' LRAIC of LV Network

Year	LV lines investment plan (US$)	Annuitized LV line investment plan (US$)	LV Peak demand forecast	Incremental LV Peak demand forecast (MW)	LV Lines LRAIC (US$/kVA)
2018	271,708	37,607	271,708	9.3	-
2019	271,819	75,230	271,819	1.8	-
2020	279,761	113,951	279,761	-4.3	-
2021	281,558	152,922	281,558	3.3	-
2022	283,393	192,146	283,393	3.7	-
2023	285,270	231,630	285,270	4.3	-
2024	287,190	271,380	287,190	5.5	-
WACC	-	13.22%	-	13.22%	-
NPV	-	590,519	-	15.8	39.4

Source: Distribution PCM Calculation.xlsx, JPS, 2019

16.40 The results of JPS' LRAIC for distribution capacity is summarized Table 16.13 below:

Table 16.13: Summary of JPS' Results for LRMC for Distribution Capacity

LRIC LV (USD/kVA)	39
LRIC MV (USD/kVA)	195
LRIC MV/LV (USD/kVA)	121

Non-Fuel SRMC for Generation and Transmission

16.41 JPS indicated that the SRMC of the combined generation and transmission systems was calculated by an economic dispatch that considered the marginal energy cost at each bus of the transmission network for each hourly demand level.

16.42 According to JPS, this short-term optimization model was the same one used to calculate the expansion plan with the only difference being fixed investments. The resulting SRMC reflected the marginal cost of supplying one additional MWh of electricity at each transmission network bus and include the generation costs (fuel and O&M) for that MWh, the additional costs due to transmission losses, and the incremental dispatch costs caused by transmission network congestions. The weighted average price across all demand buses, i.e. the average cost of each MWh of demand, were also calculated.

16.43 Non-fuel SRMC are assumed to be 10% of total SRMC. Table 6.14 below shows total SRMC presented by JPS and the resulting non-fuel SRMC.

Table 16.14: JPS' Non-fuel SRMC

Period	**SRMC (US$/MWh)**	**Non-fuel SRMC (10% of SRMC) (US$/MWh)**
On Peak	160.07	16.01
Partial Peak	143.34	14.33
Off-Peak	139.60	13.96
Average	147.67	14.77

Source: Marginal Cost Model, JPS, 2019

16.44 JPS also calculated the average nodal price across all demand buses per time of use period. The share of SRMC in each TOU period is shown in Table 16.15 below:

Table 16.15: JPS' Generation and Transmission SRMC Results

Cost	Total (average)	On-Peak	Partial-Peak	Off-Peak
SRMC (USD/MWh)	147.67	160.07	143.34	139.60
10%				
SRMC (USD/kWh)	0.01	0.02	0.01	0.01
SRMC Shares	100.0%	36.1%	32.4%	31.5%

SRMC for Distribution

16.45 JPS calculated the SRMC of the distribution activity as the cost of technical energy losses occurring at the distribution level. According to JPS, the calculation requires the costs of supplying energy at the transmission nodes (substations) as well as the amount of losses incurred in distributing power to a particular voltage level. JPS indicated that the calculation was not used in the tariff computation. Consequently, JPS' process for calculating this cost will not be further discussed.

16.7. Loss of Load Probability (LOLP)

16.46 The loss of load probability (LOLP) determines the likelihood of a shortage in generation capacity to satisfy demand. JPS used a model called the FLOP model, which is available online (see https://www.iit.comillas.edu/aramos/flop.htm) to calculate the LOLP as well as the Expected Energy Not Supplied (EENS) for 2024.

16.47 Using this model, JPS calculated that for 2024, the LOLP was 0.000043 and the EENS was 9,475 kWh. The allocation of LOLP to TOU period was calculated by the probability score for each period, which is summarized in Table 16.16 below.

Table 16.16: JPS' Calculation of LOLP Shares to TOU Period

Periods	LOLP (% of total annual LOLP)
On Peak	44.2%
Partial Peak	41.1%
Off-Peak	14.7%

16.8. JPS Functionalisation and Classification of Marginal Costs

16.48 The results of JPS' functionalisation and classification process is shown in Table 16.17 below. The company posits that the values represent pure marginal costs before any adjustments to the 2019 Revenue Requirement.

Table 16.17: JPS' Marginal Cost Functionalisation and Classification Results

Classification of Marginal Costs			
Activity	Voltage Level	Demand (USD/kW)	Energy (USD/MWh)
Generation	High/Medium/Low	184.63	147.67
Transmission	High/Medium/Low	1,191.97	
Distribution	Medium	195	
	Low	39	

16.9. JPS Allocation of LRMC to Customer Classes

16.49 JPS indicated that the functionalised and classified LRMC were allocated to rate classes and TOU periods using (where possible) the same methods and factors employed in its ECS.

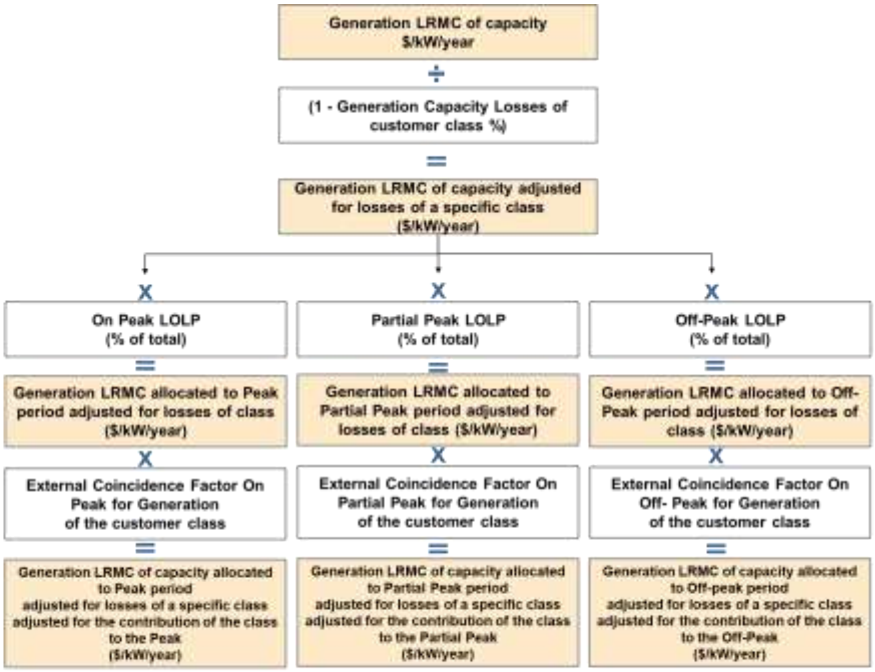
16.50 System LRMC are allocated to TOU periods and then to customer classes to estimate marginal costs of supply by customer class. The allocation of Demand-related LRMC to TOU periods was based on the LOLP of each TOU period while the allocation of Energy-related costs was derived from the apportionment of SRMC. The allocation to customer classes was done using loss factors and external coincidence factors.

16.10. Allocation of Generation LRMC

16.51 Generation LRMC are initially calculated at the generators sent-out level. To derive costs at the supply level of each customer class, JPS used loss factors by customer class to account for the cost of losses. Then, according to the contribution of each customer class to the Peak demand, JPS estimated the generation capacity costs each customer class imposes to the system in the long run. The contribution of each customer class to the Peak demand was assessed by JPS in the Load Research report looking at the External Coincidence Factors (ECF) of each class.

16.52 The overall process JPS followed for the calculation of generation capacity costs by customer class is depicted in the Figure 16.2 below.

Figure 16.2: JPS' Allocation of Generation LRMC Capacity Costs by Period and Customer Class



16.53 The assumed loss factors and ECF by customer class are shown in the Table 16.18 below.

Table 16.18: JPS' Generation capacity losses and ECF by Customer Class

Customer category	Generation Capacity Losses (% of incoming power)	External Coincidence Factors (ECF) On Peak ECF	Partial Peak ECF	Off-Peak ECF
MT 10 LV Res. Service	44.6%	91%	65%	99%
MT 20 LV Gen. Service	43.4%	53%	91%	37%
MT 60 LV Street Lighting	17.3%	100%	-	100%
MT 40 MV Power Service All	14.6%	76%	100%	66%
MT 50 MV Power Service All	4.7%	76%	100%	66%
MT 70 MV Power Service All	6.1%	86%	99%	75%
MT 20 LV Gen. Service (Other)	43.4%	53%	91%	37%
MT 50 MV Power Service (Cement Company)	16.5%	95%	99%	79%

16.54 The resulting generation capacity costs customers impose to the system in the long run are presented in Table 16.19 below.

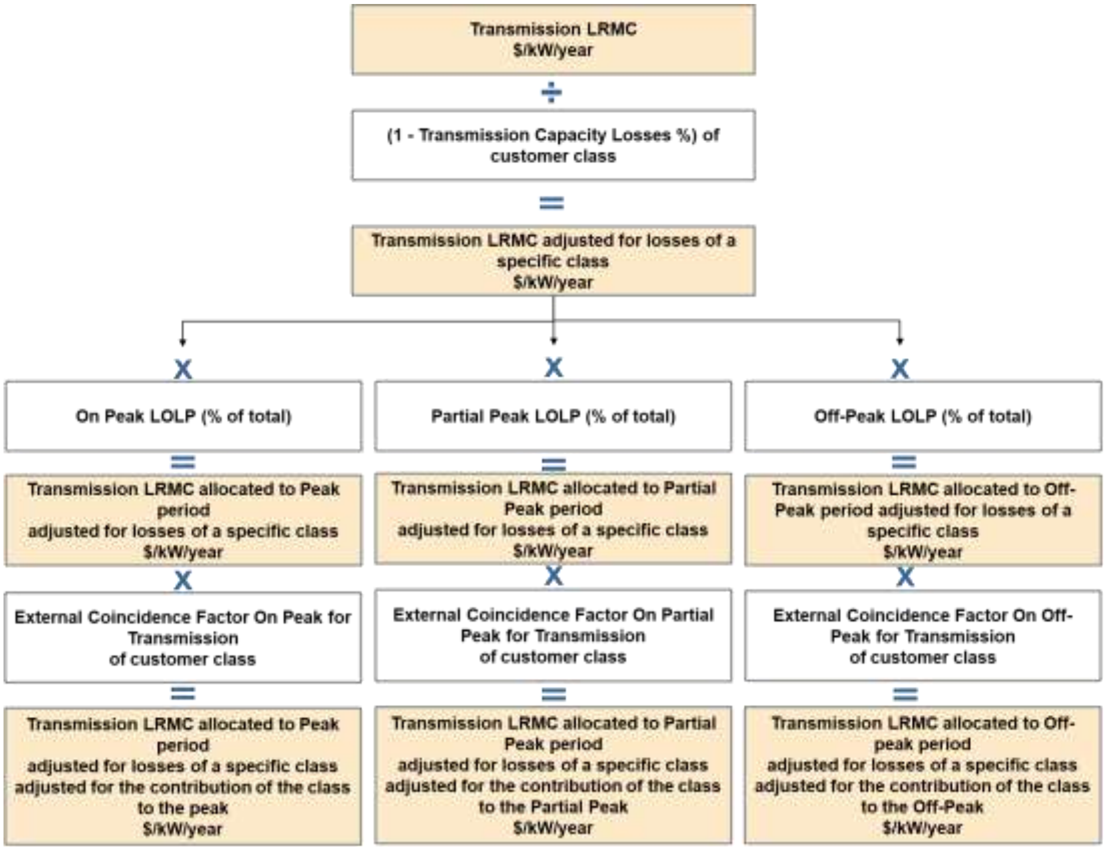
Table 16.19: JPS' Generation LRMC by Customer Class

Customer category	Generation LRMC (US$/kVA/ year)			
	On Peak	Partial Peak	Off-Peak	Sum
MT 10 LV Res. Service	156.9	104.1	56.9	317.9
MT 20 LV Gen. Service	89.6	143.7	21.0	254.3
MT 60 LV Street Lighting	116.0	-	38.7	154.7
MT 40 MV Power Service All	85.8	104.2	24.6	214.6
MT 50 MV Power Service All	76.9	93.4	22.0	192.3
MT 70 MV Power Service All	88.1	94.3	25.7	208.1
MT 20 LV Gen. Service (Other)	89.6	143.7	21.0	254.3
MT 50 MV Power Service (Cement)	109.4	105.8	30.2	245.4

Allocation of LRMC for Transmission to Customer Classes

16.55 Transmission LRMC are allocated to customer classes similarly to generation LRMC. JPS' process for the calculation of transmission LRMC by customer class is depicted in Figure 16.3 below. To derive costs at the customers' level transmission, LRMC are scaled to account for the cost of losses of each class. Then, costs are allocated to TOU periods using the LOLP of each period (see Figure 16.3). Finally, to derive the costs by customer class by period, JPS uses the ECF of each class.

Figure 16.3: JPS' Allocation of Transmission LRAIC by Period and Customer Class



16.56 The assumed loss factors and ECF by customer class are presented in Table 16.20.

Table 16.20: Transmission Capacity Losses and ECF by Customer Class

Customer category	Transmission Capacity Losses (% of incoming power)	External Coincidence Factors (ECF) On Peak ECF	Partial Peak ECF	Off-Peak ECF
MT 10 LV Res. Service	44.6%	91%	65%	99%
MT 20 LV Gen. Service	43.4%	53%	91%	37%
MT 60 LV Street Lighting	17.3%	100%	-	100%
MT 40 MV Power Service All	14.6%	76%	100%	66%
MT 50 MV Power Service All	4.7%	76%	100%	66%
MT 70 MV Power Service All	6.1%	86%	99%	75%
MT 20 LV Gen. Service (Other)	43.4%	53%	91%	37%
MT 50 MV Power Service (Cement Company)	16.5%	95%	99%	79%

16.57 Using the methodology outlined in Figure 16.3, the transmission LRMC by customer class by TOU period and annually as calculated by JPS are presented in Table 16.21 below.

Table 16.21: JPS Transmission LRMC by Customer Class

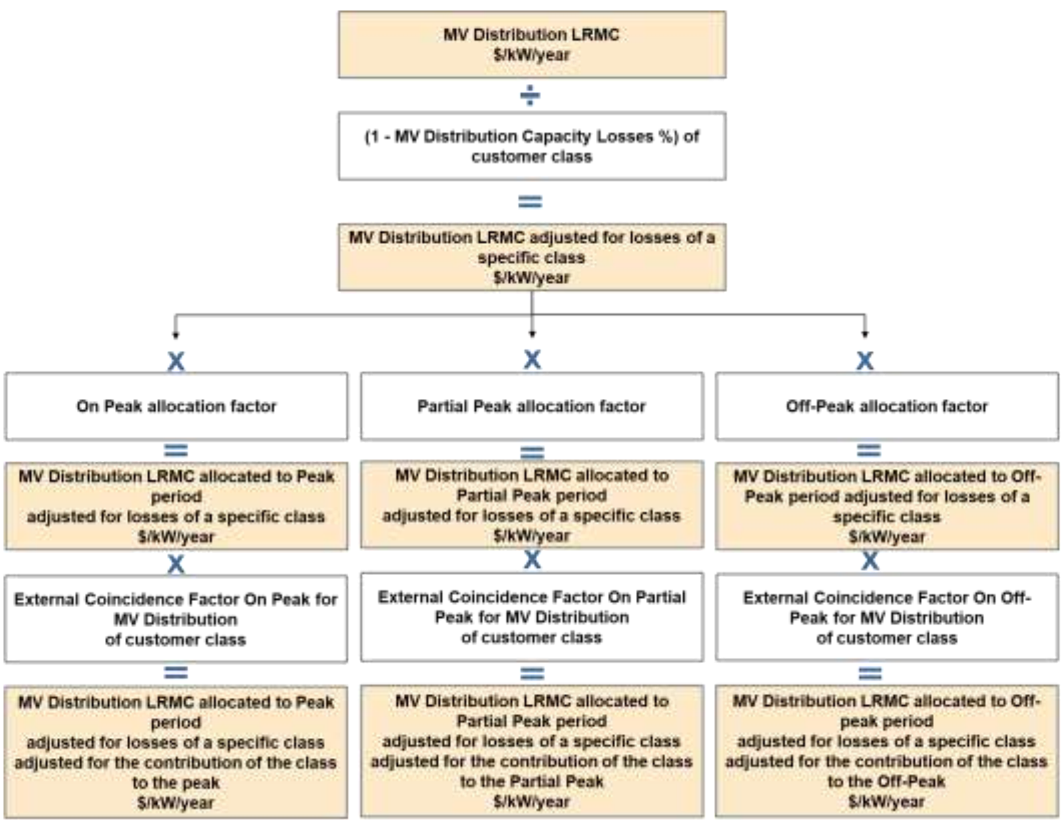
Customer category	On Peak (US$/kVA/year)	Partial Peak (US$/kVA/year)	Off-Peak (US$/kVA/year)	Sum (US$/kVA/year)
MT 10 LV Res. Service	1,012.7	672.1	367.7	2,052.5
MT 20 LV Gen. Service	578.7	927.9	135.5	1,642.1
MT 60 LV Street Lighting	749.2	-	250.0	999.2
MT 40 MV Power Service All	553.7	672.6	158.8	1,385.1
MT 50 MV Power Service All	496.2	602.8	142.4	1,241.4
MT 70 MV Power Service All	569.0	608.7	165.8	1,343.5
MT 20 LV Gen. Service (Other)	578.7	927.9	135.5	1,642.1
MT 50 MV Power Service (Cement Company)	706.6	683.3	194.7	1,584.6

Source*: Marginal Cost Model, JPS, 2019*

16.11. JPS allocation of Distribution LRMC

16.58 The process for the allocation of distribution LRMC is the same for the MV and the LV network. LRAIC of MV and LV network are allocated to the Peak, Partial Peak and Off-Peak periods. Then, LRAIC of each period are allocated to customer classes using the ECF of each class, and they are also scaled to account for the cost of losses of each class. The process followed by JPS to estimate Distribution LRMC by customer class is shown in Figure 16.4 below.

Figure 16.4: JPS' Allocation of Distribution MV LRAIC by Period and Customer Class



16.59 The factors used in the allocation of LRMC to TOU periods are presented in Table 6.22 below. The factors used by JPS distribute costs evenly to the Peak, Partial Peak and Off-Peak periods.

Table 6.22: JPS' Distribution capacity losses and ECF by Customer Class

Customer category	Distribution Capacity Losses (% of incoming)		External Coincidence Factors (ECF)					
	MV network	LV Network	MV network			LV Network		
			On Peak	Partial Peak	Off-Peak	On Peak	Partial Peak	Off-Peak
MT 10 LV Res. Service	41%	0%	91%	65%	99%	97%	65%	99%
MT 20 LV Gen. Service	39%	0%	53%	91%	37%	46%	91%	37%
MT 60 LV Street Lighting	10%	0%	100%	-	100%	100%	23%	100%
MT 40 MV Power Service All	9%	0%	76%	100%	66%	72%	100%	66%
MT 50 MV Power Service All	0%	0%	76%	100%	66%	72%	100%	66%
MT 70 MV Power Service All	0%	0%	86%	99%	75%	83%	99%	75%
MT 20 LV Gen. Service (Other)	39%	0%	53%	91%	37%	46%	91%	37%
MT 50 MV Power Service (Cement Company)	0%	0%	95%	99%	79%	98%	99%	79%

16.60 The final distribution LRMC by customer class estimated by JPS are presented in Table 6.23 below. It is worth noting that residential service distribution LRMC are approximately two times higher than all other customer costs.

Table 6.23: JPS' Distribution LRMC by Customer Class

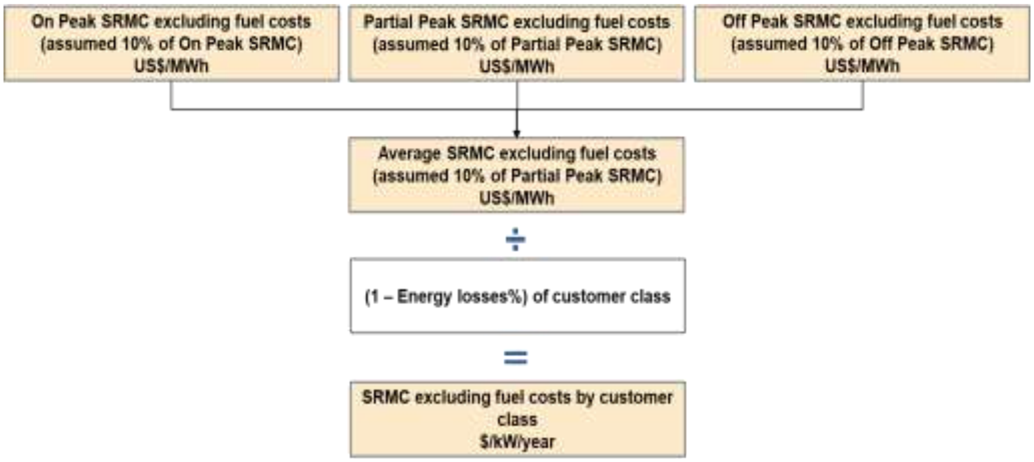
Customer category	Distribution MV LRMC by customer class (US$/kVA/year)				Distribution LV LRMC by customer class (US$/kVA/year)			
	On Peak	Partial Peak	Off-Peak	Sum	On Peak	Partial Peak	Off-Peak	Sum
MT 10 LV Res. Service	102.4	68.5	108.8	279.7	13.2	7.8	13.2	34.2
MT 20 LV Gen. Service	58.3	94.2	40.0	192.5	6.3	11.0	5.0	22.3
MT 60 LV Street Lighting	74.3	-	72.6	146.9	13.6	2.8	13.4	29.8
MT 40 MV Power Service All	56.1	68.7	47.1	171.9	9.8	12.0	8.8	30.6
MT 50 MV Power Service All	51.1	62.6	42.9	156.6	-	-	-	-
MT 70 MV Power Service All	57.7	62.2	49.2	169.1	-	-	-	-
MT 20 LV Gen. Service (Other)	58.3	94.2	40.0	192.5	6.3	11.0	5.0	22.3
MT 50 MV Power Service (Cement Company)	63.7	62.1	51.4	177.2	-	-	-	-

16.12. JPS' Calculation of Non-fuel Energy Costs by Customer Class

16.61 The non-fuel SRMC was estimated as a percentage (10%) of total SRMC for each period. The total annual non-fuel SRMC was derived as a simple average of the non-fuel SRMC of each period.

16.62 Finally, annual non-fuel SRMC are scaled to account for the cost of losses by customer class. Figure 16.5 below describes the process JPS followed to estimate non-fuel SRMC by rate class.

Figure 16.5: JPS' SRMC excluding Fuel Cost Calculations by Customer Class



16.63 The loss factors that were used to estimate the cost of losses for non-fuel SRMC are presented in the Table 6.24.

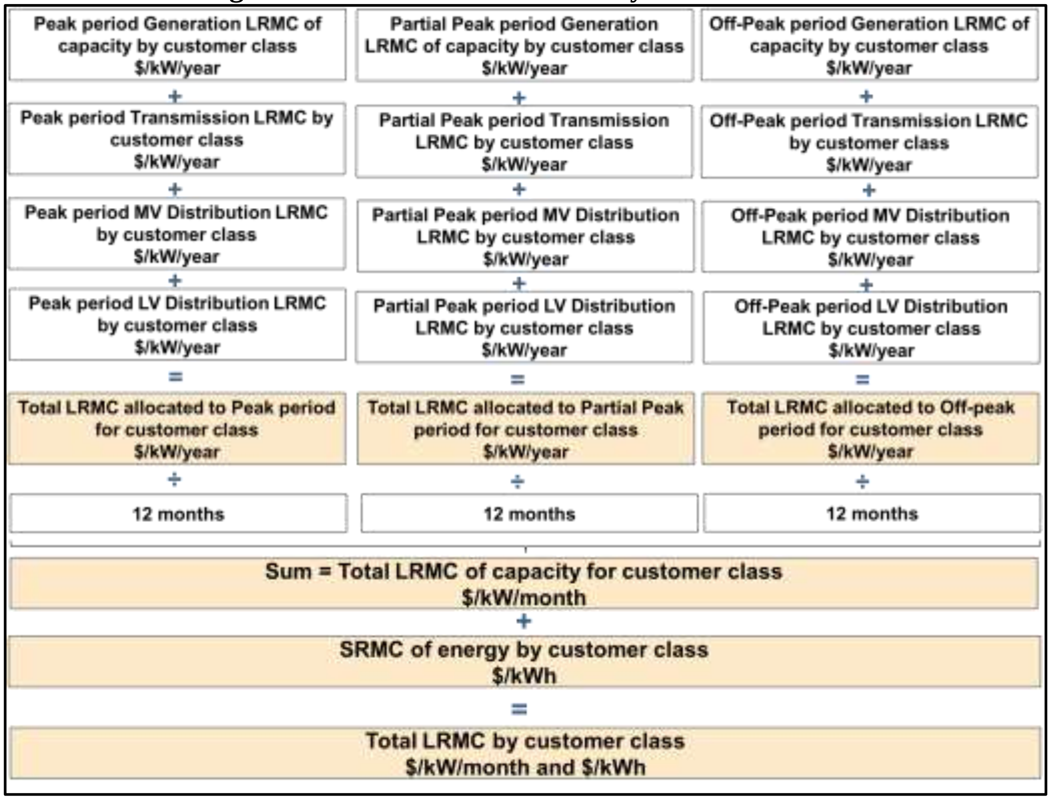
Table 6.24: JPS' Estimated Energy Loss Factors by Customer Class

Customer category	Energy loss factors (% of incoming energy)
MT 10 LV Res. Service	37.7%
MT 20 LV Gen. Service	34.7%
MT 60 LV Street Lighting	11.5%
MT 40 MV Power Service All	12.7%
MT 50 MV Power Service All	5.4%
MT 70 MV Power Service All	5.4%
MT 20 LV Gen. Service (Other)	34.7%
MT 50 MV Power Service (Cement Company)	5.4%

16.13. JPS Total LRMC by Customer Class

16.64 Total LRMC based rates by customer class was estimated by JPS by adding together generation, transmission and distribution LRMC of each customer class of each period. LRMC by period by customer class was divided by 12 months to estimate the monthly LRMC by customer class by period. Then monthly LRMC by customer class by period was added to estimate monthly LRMC for all periods by customer class as shown in Figure 16.6 below.

Figure 16.6: JPS' Total LRMC by Customer Class



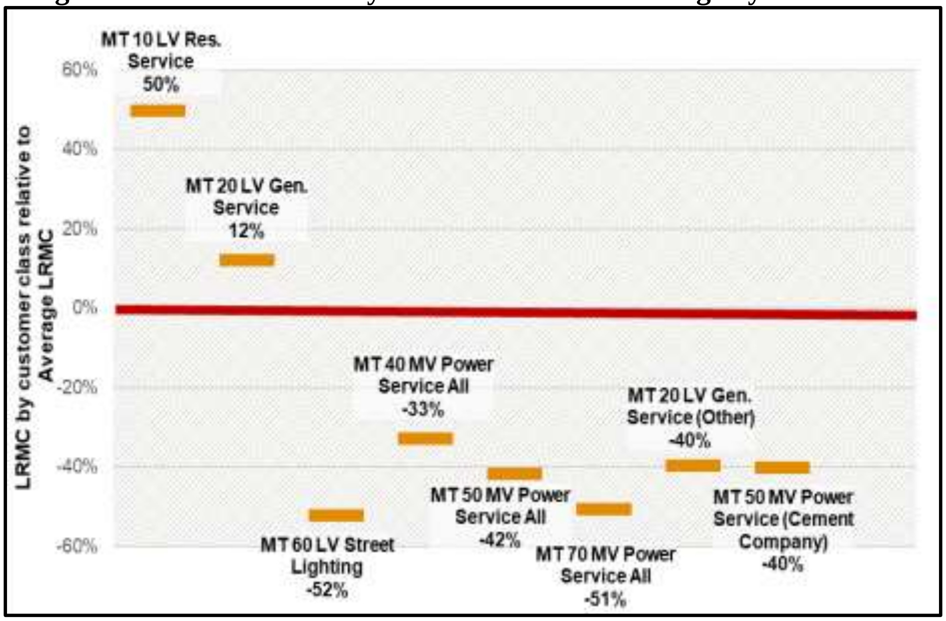
16.65 The resulting LRMC of capacity and non-fuel SRMC by customer class are depicted in Table 16.25 below. The Table presents LRMC of capacity in US$/kVA/month and non-fuel SRMC in US$/kWh. The total LRMC and non-fuel SRMC are set out in an equivalent US$/kWh rate.

Table 16.25: Total LRMC based on rates by Customer Class

Customer class	LRMC of capacity US$/kVA/month	Non-fuel SRMC US$/kWh	Total LRMC and non-fuel SRMC US$/kWh
MT 10 LV Res. Service	223.7	0.024	1.135
MT 20 LV Gen. Service	175.9	0.023	0.850
MT 60 LV Street Lighting	110.9	0.052	0.362
MT 40 MV Power Service All	150.2	0.017	0.508
MT 50 MV Power Service All	132.5	0.016	0.441
MT 70 MV Power Service All	143.4	0.016	0.375
MT 20 LV Gen. Service (Other)	175.9	0.023	0.458
MT 50 MV Power Service (Cement Company)	167.3	0.016	0.454

16.66 Figure 16.7 below presents JPS' LRMC based rates by customer class in comparison with the average system LRMC.

Figure 16.7: JPS' LRMC by Customer class vs Average System LRMC



16.14. JPS adjustment of LRMC based rates for revenue recovery

16.67 LRMC based rates are adjusted with a uniform multiplicative adjustment factor to recover the NPV of the Revenue Requirements for the Rate Review period.

16.68 The Revenue Requirements used by JPS to adjust LRMC based rates is the NPV of the Revenue Requirement over the Rate Review period. The NPV of the Revenue Requirement over the Rate Review period is US$ 2,049M.

Table 6.26: JPS' Total adjusted LRMC based rates by customer class

Customer class	Adjustment factor for revenue recovery	Adjusted Total LRMC US$/kWh
MT 10 LV Res. Service	LRMC rate x 0.20 =	0.23
MT 20 LV Gen. Service	LRMC rate x 0.20 =	0.17
MT 60 LV Street Lighting	LRMC rate x 0.20 =	0.07
MT 40 MV Power Service All	LRMC rate x 0.20 =	0.10
MT 50 MV Power Service All	LRMC rate x 0.20 =	0.09
MT 70 MV Power Service All	LRMC rate x 0.20 =	0.08
MT 20 LV Gen. Service (Other)	LRMC rate x 0.20 =	0.09
MT 50 MV Power Service (Cement Company)	LRMC rate x 0.20 =	0.09

16.15. Required Rebalances to Achieve Cost Reflectivity

16.69 As shown in Figure 16.8 below, to implement cost reflective and cost recovering rates, JPS proposed to increase MT 10 by 42%, MT 20 by 2% and MT 70 by 6%; MT 60, MT 40, MT 50 and MT20 would be decreased by -65%, -3%, -8% and -41%, respectively. This proposed rebalancing of the rates is based on JPS' LRMC estimates and the NPV of the Revenue Requirements over the Rate Review period. The methodology employed by JPS is outlined in Figure 16.9.

Figure 16.8: JPS' Required rebalances from 2018 rate levels to achieve cost reflectivity and cost recovery

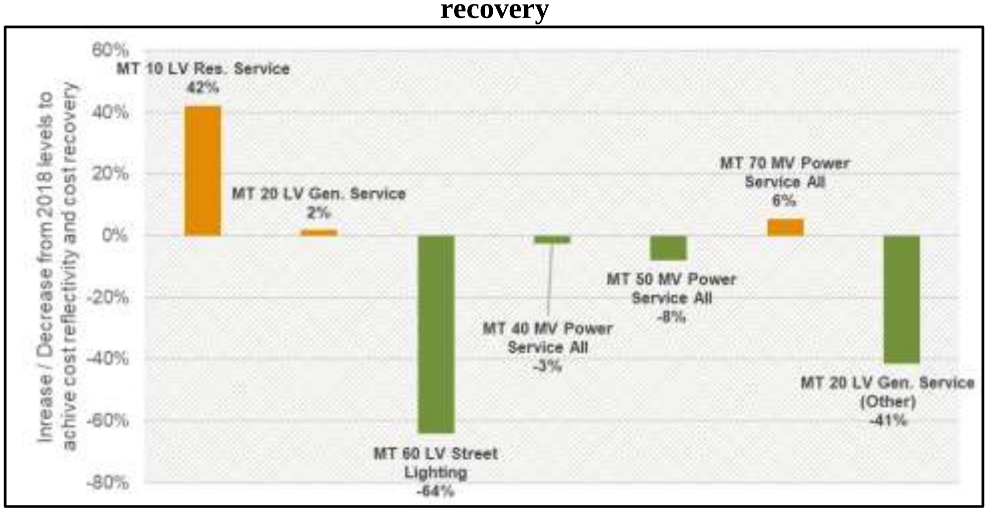
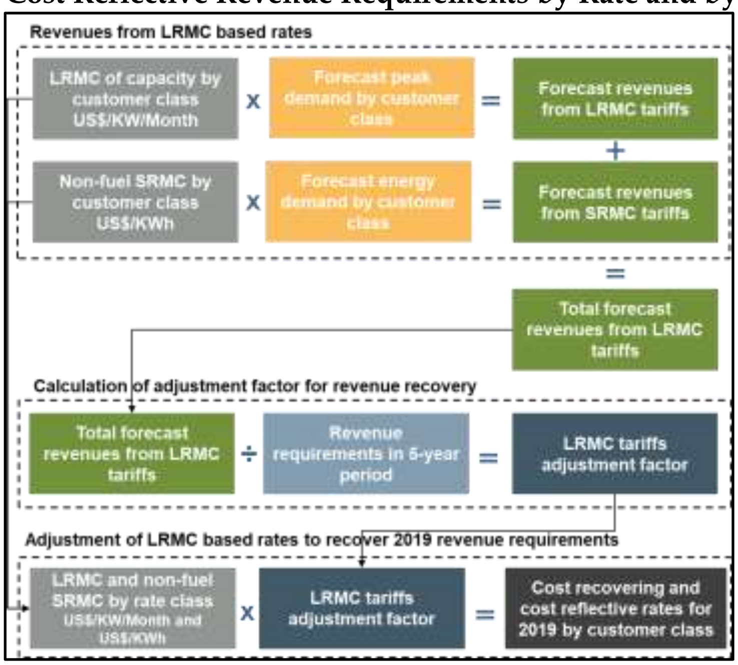


Figure 16.9: JPS' Cost Reflective Revenue Requirements by Rate and by Customer Class



16.16. JPS' Proposed Approach to Setting End User Rates

16.70 To set the relative ratio of rates by customer class, JPS initially estimated the LRMC by customer class and scaled LRMC based rates to achieve revenue recovery.

16.71 JPS initial estimates LRMC by function by Peak, Partial Peak and Off-Peak periods and allocates LRMC of each function by period to customer classes. Then it adds the costs of each function by period for each customer class to get the total LRMC for each customer class by period. Total LRMC for each customer class by period are summed to derive total annual LRMC by customer class. Total annual LRMC of each class are expressed in JMD per kWh and are adjusted with a uniform multiplicative adjustment to recover the net present value (NPV) of the 5-year Revenue Requirements (JPS cost-reflective and cost-recovering rates).

16.72 JPS' cost-reflective and cost-recovering rates are then compared with current JPS rates to estimate the level of increase/decrease that would be required to implement cost-reflective and cost-recovering rates. For customer categories that would require big increases, JPS caps the increase to a certain level and then rebalances all other rates to achieve revenue recovery. Based on the capped and rebalanced level of rates of each customer class and forecast sales/peak demand, JPS estimates the revenues that should be recovered from each customer class.

16.73 Additionally, JPS designed the type of charges that would apply to each rate class (e.g. kWh charges, demand or capacity charges (kW or kVA) and customer charges (J$ per month, increasing block rates, etc.) and sets the relative ratio of each charge for each customer class. JPS claims that relative ratios were derived from its Embedded Cost calculations for each customer class. However, from the OUR's calculations, this is not clear.

16.74 Finally, JPS scales the rate designs of each customer class using a uniform multiplicative adjustment for the specific class to achieve the revenues that should be recovered from each customer class. The above process is depicted schematically in Figure 16.10 below.

Figure 16.10: JPS' Overall Process for setting End-User Rates

Step 1: LRMC by customer class and adjustment for Revenue Recovery

Peak		Partial Peak		Off-Peak
Generation LRMC Transmission LRAIC Distribution LRAIC		Generation LRMC Transmission LRAIC Distribution LRAIC		Generation LRMC Transmission LRAIC Distribution LRAIC
x		x		x
Allocation factors and loss factors by customer class		Allocation factors and loss factors by customer class		Allocation factors and loss factors by customer class
=		=		=
Generation LRMC Transmission LRAIC Distribution LRAIC by customer class		Generation LRMC Transmission LRAIC Distribution LRAIC by customer class		Generation LRMC Transmission LRAIC Distribution LRAIC by customer class
=		=		=
Total Peak LRMC by customer class	+	Total Partial Peak LRMC by customer class	+	Total Off-Peak LRMC by customer class

=

Total Annual LRMC by customer class (JMD/kWh)

x

Adjustment factor for 5 year period Revenue Recovery

=

Total Annual LRMC by customer class adjusted for revenue recovery (JMD/kWh)

Step 2: Revenue Requirement by class

Total Annual LRMC by customer class adjusted for revenue recovery (JMD/kWh)

x

Number of customers, Sales and Peak demand forecast by customer class

=

Revenues that have to be recovered by customer class

Rebalance revenues that have to be recovered by customer class to avoid big increases (A)

Step 3: Design class rates and adjust them for Revenue Recovery (A)

Rate design by customer class (eg energy charge, increasing blocks, demand charge, TOU, etc)

x

Adjustment factor to recover Revenues that have to be recovered by customer class

=

End user rates by customer class

16.17. JPS Proposed Average End User Rates

16.75 JPS argues that based on its calculations, cost reflective rates could not be implemented in the next regulatory period due to the high increases that would be imposed on residential customers. As indicated before, JPS estimates that the required increase for the residential category would be 42% relative to the average rate in 2018, if the full cost reflectivity and cost recovery are to be achieved.

16.76 In light of this, JPS proposed capping the increase of residential rates to 30% and rebalances the average rates of other customer categories to achieve cost recovery. The justification for the level of rebalancing proposed by JPS on the other customer categories was not given in the Application.

16.77 Table 16.27 below presents the average change in rates by customer category proposed by JPS for the next regulatory period versus the required change to achieve cost recovery and cost reflectivity. The highest increases away from cost reflectivity are proposed for MT 40 (TOU), MT 50 and MT 50 (TOU) customer categories. Specifically, MT 50 and MT 50 (TOU) faces an average increase instead of a decrease that would be required to achieve cost reflectivity. Additionally, Street lighting will see a decrease of 5% instead of 65%.

Table 16.27: JPS' Proposed Rate Rebalances

Rate category	2018 Average Rate	Proposed JPS 5-year NPV end user rates	5-year NPV cost-reflective and cost recovering rate	JPS proposed Increase/ Decrease (JPS Application vs 2018 rate)	Required Increase/ Decrease to achieve cost reflectivity and cost recovery (Cost-reflective and cost recovering rates vs 2018 rate)
MT 10	20.5	26.7	29.2	30%	42%
MT 20	21.5	22.3	21.8	4%	2%
MT 40	13.7	14.7	13.1	7%	-5%
MT 50	12.3	14.3	11.3	16%	-8%
MT 60	26.0	24.7	9.3	-5%	-64%
MT 70	9.0	9.8	9.6	9%	7%
MT 20O	20.1	20.1	21.8	0%	9%
MT 40 (TOU)	11.8	14.3	13.1	22%	11%
MT 50 (TOU)	12.3	13.7	11.3	12%	-7%
MT 70 (TOU)	9.8	9.8	9.6	1%	-1%
Average rate	17.0	20.0	20.0	18%	18%

Table 16.28: JPS Proposed Rate Rebalances without the Impact of Revenue Requirements

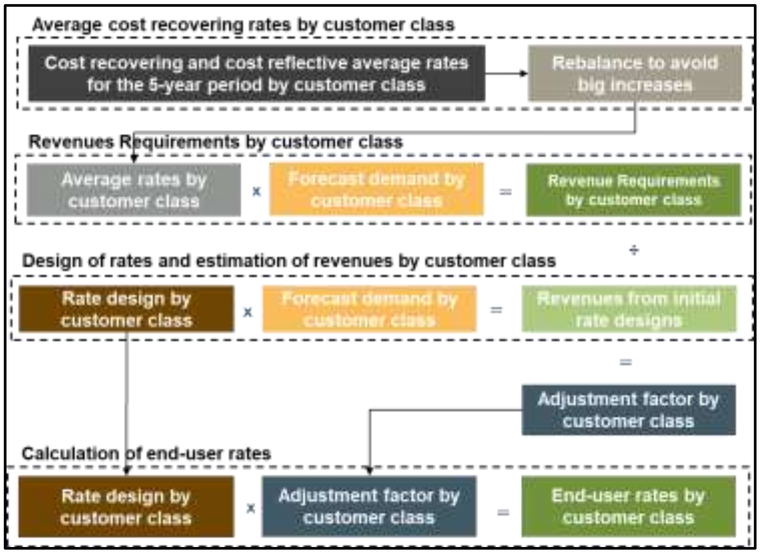
Rate category	2018 Revenue adjusted rates	Proposed JPS 5-year NPV end user rates	5-year NPV cost-reflective and cost recovering rate	JPS proposed Increase/ Decrease for cost reflectivity (JPS Application vs 2018 revenue adjusted rates)	Required Increase/ Decrease to achieve cost-reflectivity (Cost-reflective vs 2018 revenue adjusted rates)
MT 10	24.1	26.7	29.2	11%	21%
MT 20	25.2	22.3	21.8	-11%	-13%
MT 40	16.1	14.7	13.1	-9%	-19%
MT 50	14.5	14.3	11.3	-1%	-22%
MT 60	30.6	24.7	9.3	-19%	-70%
MT 70	10.6	9.8	9.6	-7%	-9%
MT 20O	23.7	20.1	21.8	-15%	-8%
MT 40 (TOU)	13.8	14.3	13.1	4%	-5%
MT 50 (TOU)	14.4	13.7	11.3	-5%	-21%
MT 70 (TOU)	11.5	9.8	9.6	-14%	-16%
Average rate	20.0	20.0	20.0	0%	0%

16.78 The proposed rebalance in Table 16.27 above includes both increases / decreases to achieve cost reflectivity and impacts from the increases / decreases in the Revenue Requirements. Table 16.28 above shows the effect of the removal of the impact of the increases / decreases in the Revenue Requirements and looks at the rebalances proposed by JPS purely to reflect the cost of supply. It also shows the rebalancing that would have to be introduced to eliminate cross subsidies.

16.79 JPS used the proposed cost recovering rates included in Table 16.28 above to estimate the Revenue Requirements by rate category. Then, designed rates for each class (such as kWh, demand or capacity charges (kW or kVA) and fixed charges (J$ per month), increasing block rates, etc.), and adjusts them with a uniform multiplicative adjustment to ensure that the rates recover the Revenue Requirements of each customer class. The rate designs for each class are reviewed in detail in the following sections.

16.80 JPS' process to set end user cost recovering rates outlined above is presented in the Figure 16.11 below.

Figure 16.11: JPS' Process for the Calculation of End-User Rates



16.81 The Revenue Requirements used by JPS to set end user rates are shown in the Table 16.29 below. These were calculated as the NPV of the revenue requirements that need to be recovered by customer class over the Rate Review period.

Table 16.29: JPS' Revenue Requirements by Rate Class

Rate category	JPS NPV of average proposed rate		NPV of forecast sales		JPS 5-year NPV revenue requirements
	JMD/kWh		kWh		JMD
MT 10- Metered Residential	26.68	X	4,687,404,358	=	125,060,818,227
MT 20- Metered Small Commercial	22.34	X	2,040,492,402	=	45,592,644,923
MT 40 - Metered Large Commercial (STD)	14.69	X	2,626,644,541	=	38,586,639,161
MT 50 - Meter Industrial (STD)	14.33	X	494,603,854	=	7,088,647,399
MT 60 - Streetlighting	24.72	X	193,645,728	=	4,787,857,999
MT 70 - MV Power Service (STD)	9.81	X	776,667,486	=	7,618,186,722
MT 20O - Others MT 20	20.13	X	141,910,074	=	2,856,742,336
Electric Vehicles	20.24	X	378,363	=	7,657,995
MT 40 - Metered Large Commercial (TOU)	14.32	X	1,167,806,027	=	16,725,515,235
MT 50 - Meter Industrial (TOU)	13.69	X	214,968,671	=	2,942,546,237
MT 70 - MV Power Service (TOU)	9.81	X	400,585,644	=	3,929,269,974
MT40X_TOU	13.16	X	216,433,101	=	2,848,403,370
MT50X_TOU	8.61	X	490,963,567	=	4,228,631,677
Total			**13,452,503,815**		**262,273,561,254**

16.18. The OUR's Assessment of JPS' Load Research and Cost of Service Study

16.82 The OUR reviewed the load research data, the ECS model and the Marginal Cost Model provided by JPS to evaluate the accuracy, as well as the technical and economic soundness of its assumptions and analyses.

16.83 The following is the results of the OUR's assessment of JPS' Load Research and Cost of Service Studies.

<u>Assessment of the Load Research Study</u>

16.84 In general, the OUR's assessment indicates that JPS' Load Research study followed international best practice. The OUR accepts JPS' sample selection, particularly in light of the fact that JPS selected a sample that provided greater accuracy than what was required by the Final Criteria.

16.85 The OUR also had no objection to the allocation and load parameters that JPS identified for use in its classification and allocation exercise. However, in some cases, the OUR disagreed with the calculation of JPS' proposed allocation and load parameters.

16.86 The OUR notes, for example, that in computing the load factors (LF) for the system and for customer classes that JPS applied the definition of LF as 'mean demand divided by peak demand'. This is a technically sound definition, however, in the electricity sector the definition which is used is energy consumed over a period divided by peak demand times the number of hours in the period. This creates different results from the values produced by JPS' Consultant. The system load factor for JPS in 2018, based on the conventional methodology used by the OUR and JPS, was 76%. In the accompanying Load Research Report and in its Marginal Cost Model, JPS identified the system LF as 59%.

16.87 Table 16.30 below shows the losses factors for all customers at the generation, transmission and distribution levels of the network. Based on the historic behaviour of this factor, MT 10 and MT 20 customers' loss factors appear to be extremely high. JPS' Demand Forecast Report by Macro Consulting showed that JPS allocated all non–technical losses arising from non-paying consumers and from JPS' internal inefficiency to the MT10 and MT 20 customers. JPS provided no rationale for the allocation of these losses to MT 10 and MT 20 customers only.

16.88 The OUR disagrees with this allocation since the MT 10 and MT 20 customers cannot control the actions of non-paying consumers and they cannot be made solely responsible for their actions. Similarly, these customers are not responsible for JPS' internal inefficiencies. Losses arising from non-paying customers are, to a large degree, a social problem, which should be borne by all of society. The OUR therefore took the decision to allocate the losses of non-paying consumers and JPS internal inefficiencies to all of the customer classes based on the classes kWh usage. Therefore, the ELS which was used for this allocation is the OUR's approved ELS for 2018.

16.89 The OUR also observed that JPS has calculated a Losses Load Factor (LLF) for each rate class in its Marginal Cost Model. While the numbers were hardcoded for most rate classes, a formula was applied by JPS to Rate 10. The formula was based on the following:

$$LLF = \alpha * \text{Annual Load Factor} + (1 - \alpha) * (\text{Annual Load Factor})^2$$

16.90 This formula is used to calculate MW losses due to electric current flowing through the network is same one used for calculating technical losses. We note that JPS is using the LLF to convert MWh losses to losses demand (MW) for both technical and non-technical losses, which is an incorrect application of the LLF.

16.91 Furthermore, the LLF varies with voltage level, not customer class. Customers at the same voltage level are expected to have the same LLF.

16.92 The OUR corrected JPS' Marginal Cost Model by separating technical losses from non-technical losses for each rate and applying the class' load factor for non-technical energy losses to derive the capacity losses for the class.

16.93 In the case of technical losses, the capacity loss is determined by applying the LLF for the system to technical energy losses. The system's LLF was determined from the following formula:

$$\mathbf{LLF = 0.35 * Annual\ Load\ Factor + 0.65 * (Annual\ Load\ Factor)^2}$$

16.94 The total capacity loss was then calculated by adding technical capacity loss to the non-technical capacity loss. The Capacity and Energy Losses factor computed by the OUR is shown in Table 16.30 below.

Table 16.30: OUR's Recomputed Capacity and Energy Losses

Tariff Category	Generation Capacity Losses	Transmission Capacity Losses	Distribution MV Capacity Losses	Distribution LV Capacity Losses	Energy Losses
RT 10 LV Res. Service	33.9%	33.9%	32.0%	29.3%	34.2%
RT 20 LV Gen. Service	21.7%	21.7%	19.5%	16.4%	22.3%
RT 60 LV Street Lighting	19.0%	19.0%	17.4%	15.1%	21.7%
RT 40 MV Power Service All	24.4%	24.4%	21.5%	17.3%	22.5%
RT 50 MV Power Service All	20.8%	20.8%	17.4%	0.0%	18.8%
RT 70 MV Power Service All	19.6%	19.6%	16.4%	0.0%	18.1%
RT 20 LV Gen. Service (Other)	40.3%	40.3%	0.0%	0.0%	39.9%
RT 50 MV Power Service (Cement Company)	15.3%	15.3%	0.0%	0.0%	15.1%

16.19. The LRMC Study

<u>Generation</u>

16.95 JPS adopted the "Peaking plant method" to estimate long run marginal capacity costs for generation. The peaking plant method assumes that the system is in equilibrium in the long run through the least cost plan. When the system is in equilibrium, the least cost option to supply one additional MW of demand is an OCGT unit. The costs of an OCGT unit is usually used for the estimation of long run marginal capacity costs under the peaking plant method. As such, the OUR used the cost of the OCGT unit as the LRMC for generation capacity. The OUR notes that JPS did not justify the source of its costs for each type of generating unit.

16.96 LRMC through Perturbation method were also assessed by JPS but were not used to estimate LRMC of supply.

16.97 The Table 16.31 below shows the LRMC of generation capacity approved by JPS versus the value approved by the OUR.

Table 16.31: Approved LRMC of Generation Capacity

JPS LRMC of Generation Capacity (US$/kW)	OUR Approved LRMC for Generation Capacity (US$/kW)
184.6	118.85

Transmission

16.98 JPS computed the transmission LRAIC using purely mathematical principles without consideration of whether the investments are designed to cover an increase in demand. The OUR's grid security assessment indicates that the 138kV transmission line is required to resolve security constraints in the Corporate Area. While load growth will exacerbate the need for the transmission line, it is required to resolve current conditions and the investment is not driven by the incremental load growth as JPS seems to suggest. The OUR also did not approve the Bellevue to Roaring River transmission line and its cost will not be factored in the Transmission LRAIC.

16.99 Given the inaccuracies in the JPS' calculation of the LRAIC, the OUR took the decision to utilise the calculations of transmission LRAIC that it had done for the MSET for inclusion in the IRP. Table 16.32 below shows JPS' proposed Transmission LRAIC and the LRAIC approved by the OUR. It would appear that JPS over estimated to a significant degree the incremental cost of transmission capacity.

Table 16.32: Approved LRAIC for Transmission Capacity

JPS LRAIC for Transmission (US$/kW)	OUR Approved LRAIC for Transmission (US$/kW)
1,191.97	100

Distribution

16.100 The approach JPS adopted for the estimation of the required investments in the MV and LV distribution network is very simplistic. In developing the investment forecast, JPS' model assumes that the investment trend observed in historical years will apply going forward. The OUR also notes that the timeframe for the calculation of LRAIC is short (5-

year sample). Usually ten (10) years or more are required to calculate networks LRAIC. If forward looking data is not available, then historical years should have been used in the LRAIC calculation.

16.101 There are a number of other issues that were identified with the calculations for LV and MV LRAIC for the distribution system. These include the following:

- Substation costs should have been allocated to the lower voltage of connection. For example, HV to MV substation costs should be allocated to MV and LV connected customers. The reason is that the HV to MV substations would not be required in the absence of MV and LV connected customers. Hence it is the MV and LV connected customers who impose the HV to MV substation costs;
- HV to MV substation costs are not accounted for in MV LRAIC calculations;
- Load factors used in the calculations are not the load factors presented in the Load Research study report;
- The demand forecast that was used to estimate the MV network LRAIC does not include LV customers demand. LV customers also utilise the MV network;
- The calculations ignore the power factor when transferring units from MW to MVA and vice versa;
- The WACC used to discount costs does not have the same value as the WACC presented in the Application;
- The demand forecast used for LRAIC calculations is not the same as the demand forecast presented in the Application.

16.102 Based on the number of issues identified, the OUR took the decision to revise the LRAIC for the distribution network. The calculations done by JPS were corrected to account for:

- a longer period, ten (10) years rather than five (5) years;
- the inclusion of the power factor for conversions between MW and MVA;
- the use of the approved demand forecast presented in this Determination Notice;
- the correct use of the demand in the LRAIC estimations;
- the allocation of MV/LV substation and transformer costs to LV connected customers and the use of the approved WACC for the discounting of costs.

16.103 The results of the OUR's analysis versus the amount calculated by JPS is shown in Table 16.33 below:

Table 16.33: OUR Approved LRAIC for the Distribution System

Voltage Level	JPS LRAIC for Distribution (US$/kW)	OUR Approved LRAIC for Distribution (US$/kW)
LV	35	83
MV	195	116

SRMC

16.104 The Non-fuel SRMC is assumed by JPS to be 10% of total SRMC. JPS did not provide any explanation for the 10% assumption. It is also unclear how the SRMC was estimated as the LRMC Generation and Transmission report presents different values for the SRMC by TOU period.

16.105 JPS also calculated SRMC for a year as a simple average of the SRMC of each period. Calculations should have been weighted by the volume of generation in each period. Additionally, the definition of TOU periods is also based on the load and not on costs. However, TOU periods should correctly be assessed by using marginal costs by period instead of loads.

Adjustments to Coincidence Factors in Marginal Cost Model

16.106 JPS' coincidence factors resulted in a simulated demand occurring during the peak, partial peak and the off-peak period all being close. Coincident and diversity factors were revised to provide a more realistic replication of the system demand pattern by period.

16.107 More specifically, JPS LRMC resulted in some customer classes in the Marginal Cost model being allocated higher costs in the partial peak period than in the peak period. It may be argued that this causes the coincidence factors and other factors used in the company's marginal cost model, to produce an overall system maximum demand (i.e. the sum of the coincident demands of each of the customer classes) in the partial peak period and in the off-peak period almost undifferentiated from the maximum demand in the peak period. Consequently, the partial peak period maximum demand is predicted by the factors in the LRMC model to be 98% of the peak period demand and the off-peak maximum demand is predicted to be 97% of the peak period demand.

16.108 Small changes were made to the coincidence factors such that the ratio of the aggregate demands in the peak, partial peak and off-peak are reasonably consistent with what would be expected given the system load pattern.

16.109 In this regard, the OUR focused on adjustments to the MT 10 and MT 40 customer classes as these make significant contributions to the system maximum demands. In particular, the coincidence factor for MT 10 and MT 40 were adjusted as shown in Table 16.34 below.

Table 16.34: OUR's Adjustments Made to Coincidence Factors

Category/period	Original coincidence factor	Adjusted coincidence factor
MT 10 – Peak	0.91	1.0
Partial peak	0.65	0.55
Off-peak	0.99	0.40
MT 40 – Peak	0.76	0.80
Partial peak	1.00	No change
Off-peak	0.66	0.60

16.110 The coincidence factor for the MT 10 customer class in the peak period was 0.91 (rather than 1) despite the residential customer class being the primary driver of the peak demand. The value of 0.91 was chosen by JPS because the residential load peaked at 21:00 whereas the system peaked at 19:00. The Load Research report also shows that the residential demand on the 4 highest peaks throughout the year is higher (7 percentage points higher) suggesting that a higher coincidence factor for MT 10 customers might be appropriate more generally. The assumption of an off-peak coincidence factor of 0.99 for MT 10 seems particularly unusual and the reasoning was not discussed in the Load Research report.

16.111 The adjustments to the coincidence factors for the MT 40 category were less significant, with a relatively small increase in the peak coincidence factor and a minute reduction in the off-peak coincidence factor.

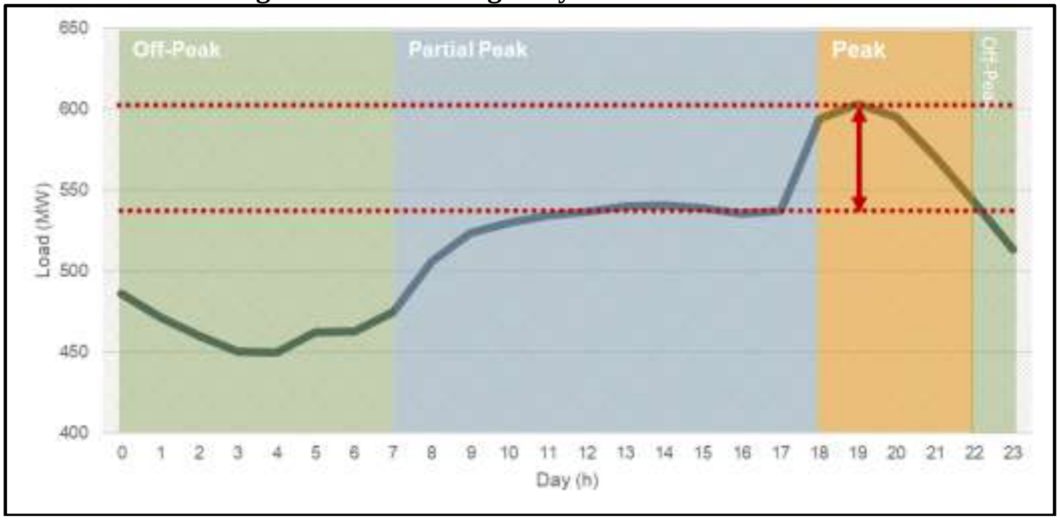
16.112 While the adjustments are somewhat intuitive, they give rise to an allocation of demands to peak, partial peak and off-peak that are more consistent with the system load pattern and helps to avoid the problem had with LRMC results, where it was seeing higher costs in the partial peak period than in the peak period.

<u>Adjustments to LOLP Results</u>

16.113 JPS' LOLP results appeared to be reasonable. The demand in the peak period is higher than the demand in the partial peak period and the available generation capacity should be the same. The peak period is only 4 hours while the partial peak is 12 hours. Hence, the higher percentage in the peak period is expected.

16.114 Figure 16.12 below presents the demand for an average day during the Peak and the Partial Peak period in 2018. The demand during the peak period is approximately 60 MW higher than the partial peak period.

Figure 16.12: Average Day Load Curve in 2018



Source: JPS Load Research Report

16.115 Even though the calculations have been deemed to be reasonable, the OUR had a less than robust assessment of the model that JPS used to estimate generation marginal cost in that the output from the model was not truly representative of the system, and this would have impacted the results.

16.116 The LOLP shares by TOU period may have contributed to the anomalous higher charges for the partial peak period in comparison to the peak period. In this regard, the LOLP estimates were revised, based on judgment and experience from other countries, to correct for this anomaly. Table 16.35 below shows the LOLP used by JPS versus that used by the OUR.

Table 16.35: LOLP Calculated by JPS versus those used in OUR's Analysis

TOU Period	JPS Computed LOLP	LOLP Used in OUR's Analysis
Peak	44.2%	60%
Partial Peak	41.1%	30%
Off Peak	14.7%	10%

Adjustments to the Calculation of Standard Demand Costs

16.117 The OUR observed that in JPS' Marginal Cost Model, it calculated the Standard demand cost (US$/kVA) as the sum of demand costs for each TOU period. This approach is inaccurate as the Standard Demand Charge should be the weighted sum of the TOU periods, where the weights are the sum of demand in each period. Accordingly, the OUR corrected for this in JPS' Marginal Cost Model.

16.118 The same thing was observed for the energy charges, but the error was less pronounced. Consequently, the standard energy charges were also corrected.

OUR Computed LRMC by Rate Class

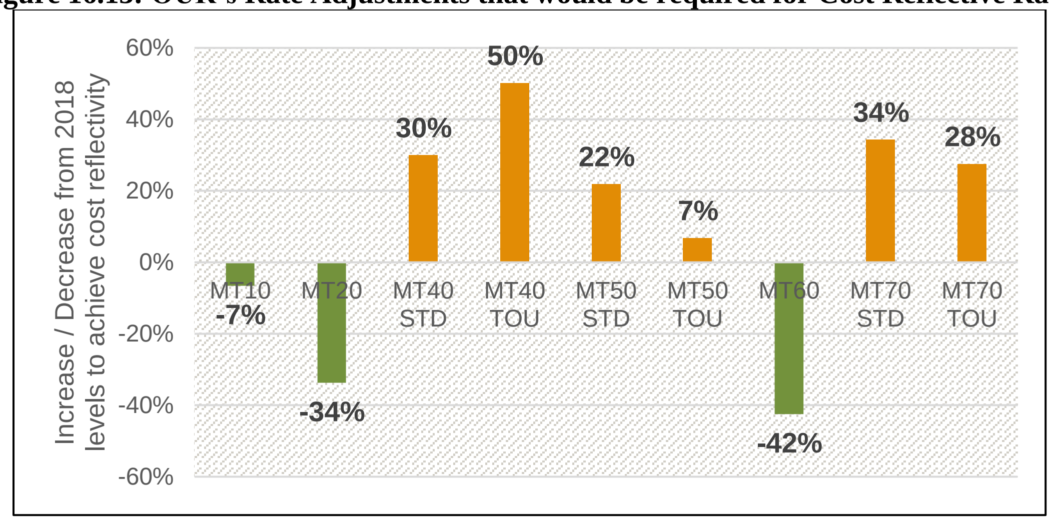
16.119 Based on corrections and adjustments made to JPS' Marginal Cost Model, the OUR recomputed the LRMC costs for each rate class. The results of this re-computation is shown in Table 16.36 below:

Table 16.36: OUR Computed LRMC for Rate Classes

Customer class		LRMC Demand (USD/kVA/Month)				Energy (USD/kWh)			
		Standard	On-Peak	Partial-Peak	Off-Peak	Standard	On-Peak	Partial-Peak	Off-Peak
MT 10	LV	41.22	30.1	9.8	3.4	0.02	0.02	0.02	0.02
MT 20	LV	32.96	20.3	13.7	2.5	0.02	0.02	0.02	0.02
MT 60	LV	31.74	24.6	0.0	7.1	0.02	0.02	0.02	0.02
MT 40	LV	38.36	20.9	15.5	4.5	0.02	0.02	0.02	0.02
MT 50	MV	30.92	16.3	12.1	4.3	0.02	0.02	0.02	0.02
MT 70	MV	33.48	18.2	11.8	4.3	0.02	0.02	0.02	0.02
MT 20 O	LV	29.67	15.1	14.9	2.6	0.03	0.03	0.03	0.02
Cement	MV	32.29	18.5	10.8	3.7	0.02	0.02	0.02	0.02

16.120 Based on the re-computation, the OUR examined the adjustment to the 2018 rate levels that will allow for cost reflectivity. This analysis is shown in Figure 16.13 below:

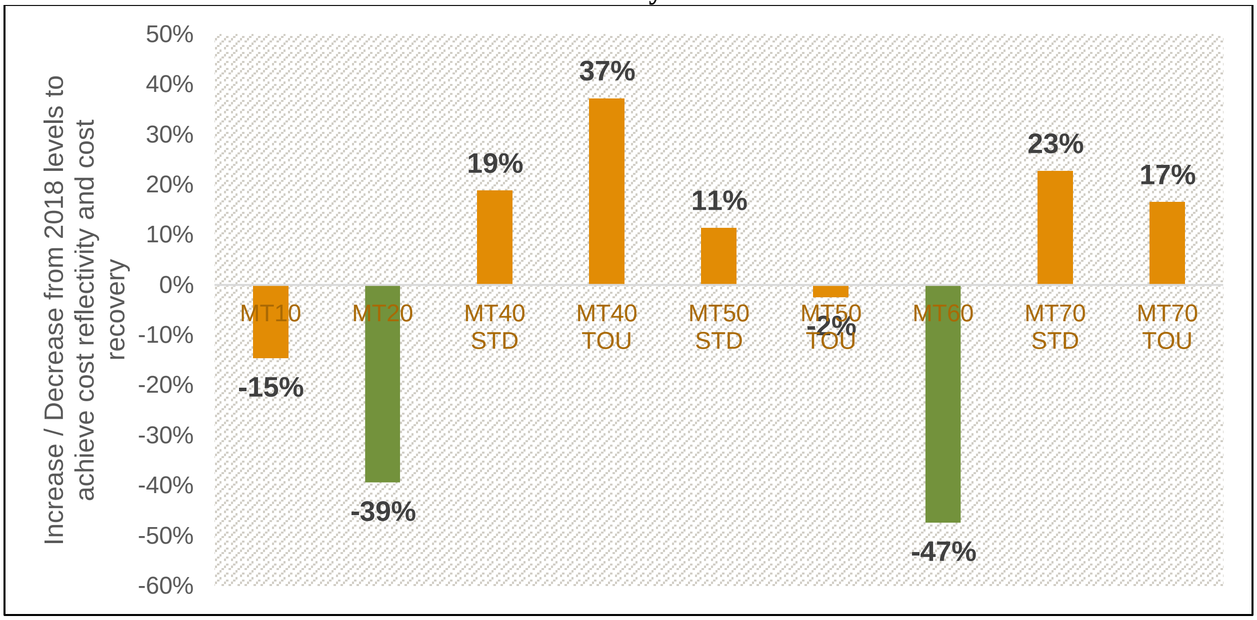
Figure 16.13: OUR's Rate Adjustments that would be required for Cost Reflective Rates



16.121 As can be observed, the results are significantly different from the results achieved by JPS. Whereas JPS predicted that MT 10 rates would have to be increased by 40% to achieve cost reflectivity, the OUR's computation is showing that MT 10 rates should be decreased by 7%.

16.122 Figure 16.14 shows the adjustment to 2018 rates that would be required for JPS to achieve cost reflectivity and revenue recovery using the OUR approved Revenue Requirement.

Figure 16.14: OUR's Rate Adjustments that would be required for Cost Reflectiveness and Cost Recovery



16.20. Summary of JPS Proposed Approach to Setting End User Rates

16.123 The OUR takes the view that JPS Load Research study was guided by international best practice, but believes that were some errors in the computation of some of the parameters, for example, the load factor for the system and for customer classes.

16.124 The OUR also disapproved of the proposed allocation of the losses of non-paying consumers exclusively to the MT 10 and MT 20 rate classes. In this regard, these losses were reallocated to all customer classes. This reallocation had a significant impact on the outcome for cost reflective rate adjustments. In addition, as discussed earlier the OUR had to make a number of adjustments and corrections to JPS' Marginal Costs model to arrive at the applicable LRMC rates.

DETERMINATION #23

Based on the OUR's assessment of the Load Characterization Study, Long Run Marginal Cost (LRMC) Study and an Embedded Cost Study (ECS) submitted by JPS in its Application, the Office approves LRMC rates for the Rate Classes as set out in Table 16.36 of this Determination Notice.

17. Demand Forecast

17.1. Introduction

17.1 Demand forecasting represents a critical exercise in the planning of the grid. Traditionally, it has played a less important role in establishing the billing determinants in rate reviews, primarily because conventional rate-making processes tended to rely heavily on historical data. In recent times, with the increasing use of forward-looking tariffs, demand forecasting has been given greater prominence in rate reviews.

17.2 A crucial component of the new decoupling tariff regime is its forward-looking orientation, which requires that the billing demand employed in setting rates be based on a five (5) year forecast. In this respect, the accuracy of the forecast has significant implications for the price of electricity. Forecasts that are significantly higher than the actual leads to excessive capital investment costs which translates to high prices. On the other hand, where forecasts are significantly below the actual it could result in underinvestment, which has negative implications for the quality of service.

17.3 In light of this, the OUR found it necessary to review its demand forecasting methodology with a view to minimizing potential inaccuracies in the billing demand projections. Additionally, for years the forecasting of electricity demand in Jamaica was derived from econometric models, which rely heavily on historical data. Rapid development in renewable technologies, changes in the regulatory framework and greater awareness among energy consumers now renders conventional linear forecasting tools less reliable.

17.4 Against this background, the OUR, in the last quarter of 2017 with the assistance of MSET, engaged the services of forecasting experts, Manitoba Hydro International Limited (MHI), to review the OUR's demand forecasting methodology. This review primarily focused on kWh sales, since kVA demand is derived from it, and customer numbers are generally (but not always) derived from simple interpolation.

17.5 A consultative approach was adopted in the demand forecasting review and both JPS and MSET participated in the exercise. This laid the foundation for the development of a more robust forecasting methodology which MHI employed to generate the energy demand forecast, which the OUR adopted for the 2019-2024 Rate Review.

17.2. The Billing Determinant Criteria

17.6 As stated in the Final Criteria, the methodology adopted by the OUR in developing the long term demand forecasts, incorporates the following three (3) steps:

1. The employment of a model that uses a combination of extrapolation, statistical and econometric approaches in forecasting the model variables for each rate class:

    a. Rates 10, 20, 40 and 60 customer categories are based on projections of the number of customers multiplied by projected unit consumption (average consumption) for the rate class.

    b. Rate 50 sales forecast is derived from a regression analysis of total sales. Table 17.1 below provides a summary of the final factors used to develop the base forecast of the number of customers and unit consumption for each rate class or, in the case of Rate 50, total consumption.

2. The computation of gross system losses by adding net system losses to station use. The model projected net system losses and station use from extrapolated trends, but also considered JPS' system loss reduction plans and JPS' stated objective of reducing station use over time[19]. Each component of gross system losses is allocated to the rate classes to derive gross electricity kWh consumption.

3. The derivation of projected system peak demand, using the following methodology:

    a. The estimation of the system load factor from recent historical trends, which is held constant across the forecast horizon.

    b. The computation of the peak demand for each year, by dividing the projected gross generation by the number of hours in the year multiplied by the system load factor.

    c. The estimation of the contribution of each rate class to the system peak, using JPS' 2009 load research information (coincident and non-coincident peak data).

    d. Adjustments to the system peak contributions through a reconciliation process which adjusts the non-coincident and coincident factors[20].

17.7 The demand forecasting methodology is summarized in Table 17.1 below. Additionally, this methodology was used to generate the demand forecast (kWh) proposed by the OUR in the Final Criteria as shown in Table 17.2 below.

[19] See the MHI's Report dated 2018 XXX (p.72-73) for the proposed plans for system losses reduction and its allocation between its various sub-components (i.e. Station Use, Technical Low Voltage Losses, Technical Medium Voltage Losses and Unbilled (Non-technical) Losses)

[20] See the MHI's Report (p.74-75) for the details

Table 17.1: OUR's Summary of Variables used in Demand Forecast Model

Rate Class	No. of customers	Unit (Average) consumption	Total Consumption	Comments
Residential (R10)	▪ Number of households	Average consumption extrapolated from average growth between 2005 and 2016	Number of customers × Average consumption	Rate Class is divided into: • Block 1 – Consumption ≤ 100kWh/month • Block 2 Consumption > 100kWh/month Analysis completed for each block and then aggregated MHI conducted a demographic analysis to forecast growth in the number of households.
Small Commercial (R20)	Population over age 15	▪ Wholesale and retail trade per capita ▪ Government services per capita	Number of customers × Average consumption	The forecasts of consumption for two (2) large interchange customers were done separately and then aggregated with the total consumption for the other Rate 20 customers
Large Commercial LV (R40)	Customer growth rate estimated from historical trend	▪ Mining and Quarrying component of GDP growth rate ▪ Hotel and restaurants component of GDP growth rate ▪ Electricity and Water Supply component of GDP growth rate	Number of customers × Average consumption	
Large Commercial LV (R50)			Producers of Government Service as a component of GDP	Total consumption was adjusted for expected changes in load due to analysis of expansion and demand reduction plans supplied by JPS' key account customers
Street Lighting (R60)	Customer growth rate extrapolated from trend from 1997 - 2016	Urban population growth rate	Number of customers × Average Consumption	Forecast of total sales was adjusted for expected reduction in sales due to the street light replacement programme which is expected to be completed by 2021

Table 17.2 – Final Criteria Demand Forecast Results by Rate Category 2016-2040

Year	Sales in GWh Rate 10	Rate 20	Rate 40	Rate 50	Rate 60	Others	Total	Total Losses	Generation Requ. (GWH)	Peak (MW) Calculated	Peak (MW) Adjusted	Load Factor
2016	1,079	599	784	626	71	25	3,184	1,178	4,362	655	656	76.0%
2017	1,097	601	787	614	71	26	3,196	1,167	4,363	656	656	76.0%
2018	1,115	604	801	596	72	27	3,215	1,100	4,315	649	649	75.9%
2019	1,134	607	828	578	74	28	3,249	1,040	4,289	645	645	75.9%
2020	1,154	612	850	561	76	28	3,281	980	4,261	641	641	75.9%
2021	1,175	616	883	555	79	29	3,337	927	4,264	641	642	75.9%
2022	1,192	625	919	555	81	30	3,403	904	4,307	647	648	76.0%
2023	1,210	634	954	557	84	31	3,471	881	4,352	653	654	76.1%
2024	1,229	644	989	564	87	32	3,545	858	4,403	660	661	76.1%
2025	1,248	653	1,024	576	90	33	3,624	836	4,460	668	669	76.2%
2026	1,267	664	1,060	594	93	34	3,712	815	4,527	678	679	76.3%
2027	1,287	674	1,096	618	96	35	3,806	796	4,602	689	689	76.3%
2028	1,308	684	1,131	647	99	36	3,904	789	4,693	702	702	76.4%
2029	1,329	696	1,165	682	101	36	4,010	781	4,791	716	717	76.4%
2030	1,351	709	1,198	722	104	37	4,121	773	4,894	730	731	76.5%
2031	1,373	722	1,232	763	107	38	4,236	765	5,001	746	747	76.5%
2032	1,391	737	1,266	803	110	39	4,347	755	5,102	760	761	76.6%
2033	1,410	753	1,300	844	113	40	4,460	744	5,204	774	775	76.7%
2034	1,429	770	1,335	886	116	41	4,576	764	5,340	794	795	76.8%
2035	1,448	786	1,371	928	119	42	4,694	783	5,477	814	814	76.8%
2036	1,468	803	1,407	970	122	43	4,811	803	5,614	833	834	76.9%
2037	1,487	819	1,443	1,013	125	43	4,931	822	5,753	853	854	77.0%
2038	1,508	836	1,480	1,056	127	44	5,051	843	5,894	873	874	77.0%
2039	1,528	853	1,517	1,100	130	45	5,174	863	6,037	894	895	77.1%
2040	1,550	870	1,554	1,144	133	46	5,297	884	6,181	915	916	77.1%
Average annual growth Rates in percentages												
2016 - 2020	1.7%	0.5%	2.0%	-2.7%	1.6%	3.3%	0.8%	-4.5%	-0.6%	-0.6%	-0.6%	0.0%
2020 - 2025	1.6%	1.3%	3.8%	0.5%	3.5%	2.9%	2.0%	-3.1%	0.9%	0.9%	0.9%	0.1%
2025 - 2030	1.6%	1.6%	3.2%	4.6%	3.0%	2.5%	2.6%	-1.6%	1.9%	1.8%	1.8%	0.1%
2030 - 2035	1.4%	2.1%	2.7%	5.1%	2.7%	2.3%	2.6%	0.3%	2.3%	2.2%	2.2%	0.1%
2035 - 2040	1.4%	2.1%	2.5%	4.3%	2.3%	2.0%	2.4%	2.4%	2.4%	2.4%	2.4%	0.1%
2016-2040	*1.5%*	*1.6%*	*2.9%*	*2.5%*	*2.6%*	*2.6%*	*2.1%*	*-1.2%*	*1.5%*	*1.4%*	*1.4%*	*0.1%*
2016-2033	*1.6%*	*1.4%*	*3.0%*	*1.8%*	*2.8%*	*2.8%*	*2.0%*	*-2.7%*	*1.0%*	*1.0%*	*1.0%*	*0.1%*
2016-2030	*1.6%*	*1.2%*	*3.1%*	*1.0%*	*2.8%*	*2.9%*	*1.9%*	*-3.0%*	*0.8%*	*0.8%*	*0.8%*	*0.0%*

17.8 Even though the OUR presented a proposed demand forecast in the Final Criteria, it did not assume an inflexible position, but was open to reasonable adjustments to the methodology and forecast. In fact, the Final Criteria[21] states that:

"In presenting its billing data projections for the 2019 – 2024 Rate Review period, JPS shall:

a) Employ the model delineated above to develop its projections, any adjustments made to the model proposed by JPS shall be supported by a clear and logical explanation."

[21] See Criterion 5 of the ***Final Criteria***.

17.9 This open approach to the billing demand determinants paved the way for the presentation of JPS' forecast in its Application.

17.3. JPS Billing Demand Methodology

17.10 JPS made modifications to OUR's proposed methodology in its Application. For the most part, the methodological variations were not seemingly consequential and may be summarized as follows:

- The use of Auto Regressive Integrated Moving Average (ARIMA) modelling instead of simple averaging to derive unit consumption rate for customer categories;
- The reliance on regression analysis rather than the simple growth rate of the adult population[22] to forecast the number of small Commercial (Rate 20) customers;
- The application of cluster analysis in determining sub-groups in the large commercial and industrial classes (i.e. Rate 40, 50 & 70);
- The substitution of a bottom up or engineering approach to the streetlight/traffic signal class (Rate 60) based on lamp numbers, type and average consumption instead of a top-down extrapolation approach used in the OUR's proposal.

17.11 In varying from the methodology outlined in the Final Criteria, JPS argues that its selective application of ARIMA modelling, cluster analysis and regression analysis made for a more statistically robust forecast. The details of the differences between the Final Criteria methodology for the various rate classes are set out in Tables 17.3 – 17.7 below.

Table 17.3 – RT10 Demand Forecast: OUR's Criteria vs. JPS' Approach

Variable	OUR's Criteria	JPS Approach	Differences
No. of customers	Number of households	Number of households	No Differences
Unit (Average) consumption	Average consumption extrapolated from average growth between 2005 and 2016	Average consumption projected with an ARIMA model using monthly data for the period 2005-2018	Using monthly data and an ARIMA model allows more statistically robust short term estimates
Total Consumption	Number of customers × Average consumption	Number of customers × Average consumption	No Differences

Source: JPS 2019-2024 Tariff Application (Dec 2019)

[22] Adult population here means persons over 15 years old.

Table 17.4 – RT20 Demand Forecast: OUR's Criteria vs. JPS' Approach

Variable	OUR's Criteria	JPS Approach	Differences
No. of customers	Population growth over age 15	Average growth rate over the last 10 years - OLS function of population over age 15	Using a regression instead of the same growth rate improves statistical robustness
Unit (Average) consumption	• Wholesale and retail trade per capita • Government services per capita	Average consumption projected with an ARIMA model using annual data for the period 2008-2040 separated in 3 consumption blocks	Using monthly data and an ARIMA model allows more statistically robust short term estimates
Total Consumption	Number of customers x Average consumption	Number of customers x Average consumption	No Differences

Source: JPS 2019-2024 Tariff Application (Dec 2019)

Table 17.5 – RT40 Demand Forecast: OUR's Criteria vs. JPS' Approach

Variable	OUR's Criteria	JPS Approach	Differences
No. of customers	Customer growth rate estimated from historical trend.	OUR's Criteria growth rate applied to 2018 figures	Difference is only on initial number of customers.
Unit (Average) consumption	• Mining and Quarrying component of GDP growth rate • Hotel and restaurants component of GDP growth rate • Electricity and Water Supply component of GDP growth rate	• Cluster analysis according to 2-digit industrial code, • 4 clusters (C1; C2; C3; Hotels) • Within cluster *total* consumption projected with ARIMA models using monthly data for the period 2008-2018	Cluster analysis allows to objectively group users with similar behaviour in terms of growth rates. ARIMA model provides statistically robust short term estimates. Avoids problems of forecasting exogenous variables.
Total Consumption	Number of customers Average consumption	Total consumption was estimated as the sum of each clusters' projected demand	Total consumption was the forecasted variable.

Source: JPS 2019-2024 Tariff Application (Dec 2019)

Table 17.6 – RT50 &70 Demand Forecast: OUR's Criteria vs. JPS' Approach

Variable	OUR's Criteria	JPS Approach	Differences
No. of customers	Customer growth rate estimated from historical trend (Rate 50).	OUR's Criteria growth rate applied to 2018 figures (and split between Rate 50 and Rate 70)	Difference is only on initial number of customers.
Unit (Average) consumption	Producers of Government Service as a component of GDP (Rate 50)	• Cluster analysis according to 2-digit industrial code, • 4 clusters (C1; C2 & C3; Caribbean Cement Co.; Hotels) • Within cluster *total* consumption projected with ARIMA models using monthly data for the period 2008-2018	Cluster analysis allows to objectively group users with similar behaviour in terms of growth rates. ARIMA model provides statistically robust short term estimates. Avoids problems of forecasting exogenous variables.
Total Consumption	Total consumption was adjusted for expected changes in load due to analysis of expansion and demand reduction plans supplied by JPS' key account customers (Rate 50).	Total consumption was estimated as the sum of each clusters' projected demand This was also done for Rate 70, were 2 clusters arose from the clustering analysis: C1 and hotels.	Total consumption was estimated under both approaches, but JPS split analysis into clusters.

Source: JPS 2019-2024 Tariff Application (Dec 2019)

Table 17.7 – RT60 Demand Forecast: OUR's Criteria vs. JPS' Approach

Variable	OUR's Criteria	JPS Approach	Differences
No. of customers	Customer growth rate extrapolated from trend from 1997 - 2016	+ Lighting policy (2019 - 2023) + Urban population growth (2024-2040) Bulbs stock composition arising from replacement plan (number of LED and HPS bulbs)	No customers were estimated instead bulbs were
Unit (Average) consumption	Urban population growth rate	Average consumption per bulb, LED and HPS (LEDs twice as efficient)	A bottom-up or engineering approach was used
Total Consumption	Number of customers × Average consumption	• Number of each type of bulb • Consumption of each type of bulb	A bottom-up or engineering approach was used

Source: JPS 2019-2024 Tariff Application (Dec 2019)

17.12 In keeping with Criterion 7 of the Final Criteria, JPS also included its proposed demand forecast for prepaid electricity service and a special electric vehicle (EV) category. The assumptions associated with these two considerations are outlined in Table 17.8 below:

Table 17.8 –Demand Forecast: Prepaid Service & Electric Vehicles

Category	Rate 10	Rate 20
Prepaid Service	• 2018: Proportion of rate 10 prepaid overall rate 10 consumption equal to past proportion (0.5%), based on billing data. • 2019-2024: Same historical proportion and all customers from wiring policy initiative are pre-paid (when assuming a wiring policy).	• 2018: Proportion of Rate 20 prepaid overall Rate 20 consumption (without considering "Others") equal to past proportion (0.07%), based on billing data. • 2019 – 2023: Increasing pre-paid proportion until reaching 2% of total Rate 20 consumption by 2023 (without considering "Others")
Electric Vehicles	• Average Efficiency: 0.178 kWh/km • Annual distance covered: 10,000 km • % Station charge: 25% • EV Annual Growth in stock (2019-2030): 55%	

Source: JPS 2019-2024 Tariff Application (Dec 2019)

17.13 Significantly, even though projected consumption for prepaid service and electric vehicle were requirements stipulated in the Final Criteria, the OUR did not provide for these two categories in its forecast.

System Losses

17.14 JPS' has indicated in its Application that its system losses forecast reflects its outlook for the gap between net generation and sales. In this regard, it projects a 2.3 percentage point reduction in system losses over the Rate Review period. The company therefore states that the "primary components of system losses, non-technical and technical losses, are expected to decrease from the recorded 18.03% and 8.24% in 2018 to 15.93 % and 8.03% respectively by 2024."

JPS' Billing Demand Methodology

17.15 Based on the modified methodology and assumptions described above, JPS arrived at the forecast for disaggregated sales (kWh) and number of customers shown in Table 17.9 and Table 17.10 below.

Table 17.9 –JPS Sales (GWh) Forecast: 2019 - 2024

Billed Sales	Units	2018	2019	2020	2021	2022	2023	2024
Rate 10	GWh	1,066	1,073	1,096	1,116	1,133	1,150	1,168
Rate 20	GWh	598	604	444	448	451	455	459
Rate 40	GWh	801	809	978	988	998	1,008	1,018
Rate 50	GWh	356	364	373	378	382	385	387
Rate 60	GWh	62	58	48	40	40	40	41
Rate 70	GWh	294	272	274	279	284	289	294
Other	GWh	35	34	34	34	33	33	32
EV	GWh		0.07	0.08	0.08	0.10	0.12	0.19
Total Sales	GWh	**3,212**	**3,215**	**3,246**	**3,284**	**3,322**	**3,361**	**3,399**
System Losses	GWh	1,144	**1,126**	**1,113**	**1,099**	**1,082**	**1,059**	**1,025**
Net-Generation	GWh	4,356	**4,341**	**4,359**	**4,384**	**4,404**	**4,420**	**4,425**

Table 17.10 –JPS Customer Forecast: 2019 - 2024

Rate class	2018	2019	2020	2021	2022	2023	2024
Rate 10	587,606	597,467	610,270	623,172	633,918	644,644	655,847
Rate 20	67,944	68,392	68,031	68,690	69,357	70,029	70,708
Rate 40	1,847	1,882	1,888	1,897	1,906	1,915	1,924
Rate 50	144	144	146	148	152	155	159
Rate 60	486	494	509	524	538	553	568
Rate 70	23	23	23	23	24	24	25
Other	2	2	2	2	2	2	2
Total Customers	**658,052**	**668,404**	**680,868**	**694,457**	**705,897**	**717,322**	**729,233**

17.16 It is worth noting that although JPS was required to provide a KVA demand forecast disaggregated by customer classes, this was omitted from its Application.

17.4. OUR's Analysis of the Demand Forecast

17.17 In reviewing JPS demand forecast, the OUR made a few adjustments to the company's sales and customer forecast based on the information derived from the Excel model submitted with the Application.

17.18 Firstly, even though it was not explicitly stated in the Application, JPS' model indicates that it intends to move 1,015 Rate 20 customers in 2020 from that customer grouping to

Rate 40. Apparently, the heterogeneous nature of customer consumption in the Rate 20 class might have made the Rate 40 class a better fit for this Rate 20 sub-group. However, while this sub-group was removed from Rate 20 they were inadvertently not added to the Rate 40 class as shown in Table 17.10 above, even though it was correctly captured in JPS' model. Consequently, the OUR corrected this error and for the purpose of this analysis, the customers targeted for transfer were retained in Rate 20.

17.19 Secondly, by dint of the fact that the sales forecast in each rate class is derived from the product of the forecasted number of customers and the average expected consumption, changes to the customer count impacts the sales forecast. Hence, the OUR's corrections for this and the sales forecast used in this analysis for Rates 20 and 40 are slightly different from those presented by JPS in Table 17.9 above.

17.20 It is instructive that even though the Final Criteria stipulated that a KVA-billing demand forecast should be submitted as a part of the demand forecast, it was omitted from the Application. As such, the OUR derived its own KVA-demand forecast based on the projection of the sales growth. JPS' sales and customer KVA-demand forecast are compared with the projections from the Final Criteria in Tables 17.11 and 17.12 below.

Figure 17.1 –Total Sales Forecast: 2019 - 2024

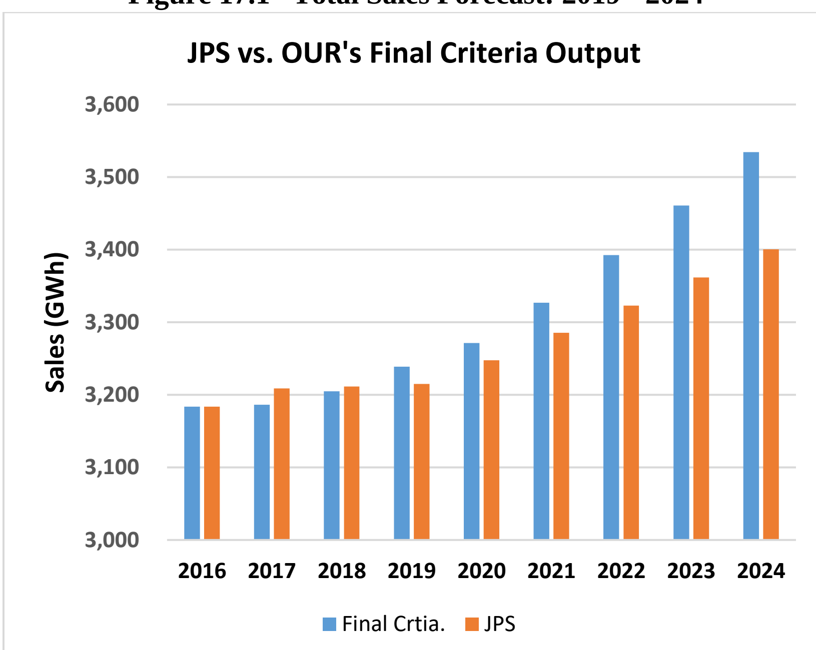


Table 17.11 –Sales Forecast 2019[23] – 2024: JPS vs. Final Criteria Result

		2016	2017	2018	2019	2020	2021	2022	2023	2024	CAGR 2018-2024
		GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	
Rate 10	Final Crtia.	1,079	1,093	1,112	1,131	1,151	1,171	1,189	1,207	1,225	1.6%
	JPS	1,079	1,069	1,066	1,073	1,096	1,116	1,133	1,150	1,168	1.5%
	% Variance	0.0%	-2.2%	-4.1%	-5.1%	-4.8%	-4.7%	-4.7%	-4.7%	-4.6%	
Rate 20*	Final Crtia.	624	625	628	633	638	644	653	663	674	1.2%
	JPS	624	639	633	639	644	648	652	656	661	0.7%
	% Variance	0.0%	2.2%	0.7%	1.0%	0.8%	0.6%	-0.2%	-1.1%	-1.9%	
Rate 40	Final Crtia.	784	785	799	826	847	880	916	951	986	3.6%
	JPS	784	786	801	809	813	823	832	840	849	1.0%
	% Variance	0.0%	0.2%	0.3%	-2.0%	-4.0%	-6.5%	-9.2%	-11.7%	-13.9%	
Rate 50	Final Crtia.	626	538	300	304	285	274	269	266	269	-1.8%
	JPS	626	572	356	364	373	378	382	385	387	1.4%
	% Variance	0.0%	6.5%	18.4%	19.6%	30.6%	38.1%	42.0%	44.5%	44.1%	
Rate 60	Final Crtia.	71	71	72	73	76	78	81	84	87	3.2%
	JPS	71	68	62	58	48	40	40	40	41	-6.9%
	% Variance	0.0%	-4.1%	-13.3%	-21.0%	-36.0%	-48.4%	-50.8%	-51.9%	-53.0%	
Rate 70	Final Crtia.	-	75	294	272	274	279	284	289	294	0.0%
	JPS	-	75	294	272	274	279	284	289	294	0.0%
	% Variance	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
EV	Final Crtia.	-	-	-	-	-	-	-	-	-	0.0%
	JPS	-	-	-	-	0.1	0.1	0.1	0.1	0.2	0.0%
	% Variance	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Sales	Final Crtia.	3,184	3,186	3,205	3,239	3,271	3,327	3,393	3,461	3,534	1.6%
	JPS	3,184	3,209	3,212	3,215	3,248	3,285	3,323	3,362	3,400	1.0%
	% Variance	0.0%	0.7%	0.2%	-0.7%	-0.7%	-1.2%	-2.1%	-2.9%	-3.8%	
Losses	Final Crtia.	1,165	1,164	1,097	1,037	977	925	902	878	856	-4.1%
	JPS	1,166	1,154	1,144	1,126	1,113	1,099	1,082	1,059	1,025	-1.8%
	% Variance	0.0%	-0.8%	4.3%	8.6%	13.9%	18.9%	20.0%	20.5%	19.8%	
Net Gen	Final Crtia.	4,349	4,350	4,302	4,276	4,248	4,251	4,294	4,339	4,390	0.3%
	JPS	4,349	4,363	4,356	4,341	4,361	4,385	4,405	4,420	4,426	0.3%
	% Variance	0.0%	0.3%	1.2%	1.5%	2.6%	3.1%	2.6%	1.9%	0.8%	

Actual   * =Includes "Others"

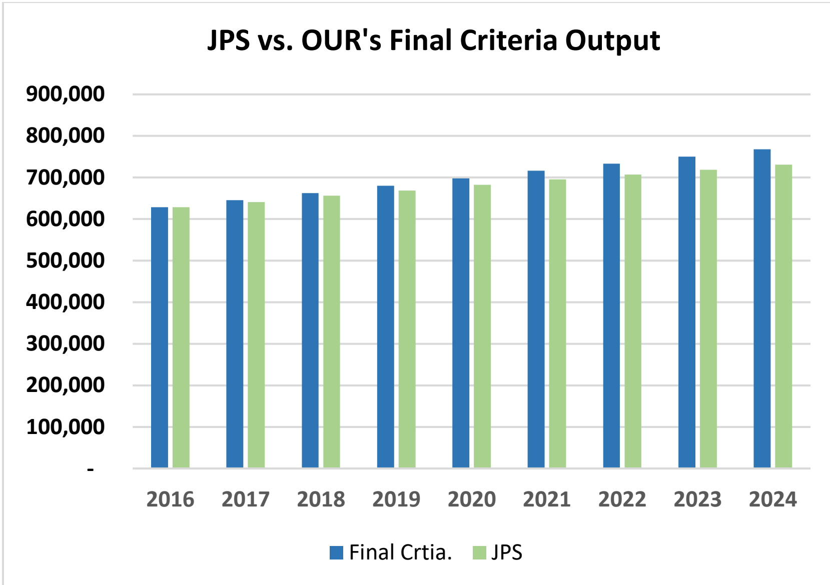
17.21 For the period 2018-2024, JPS forecasts a compound annual growth rate (CAGR) of 1.0% for total sales. This compares with a CAGR of 1.6% in the Final Criteria. As shown in Figure 17.1 above, in every year of the Rate Review period, the Final Criteria forecast far exceeds that of JPS' and diverges over time.

17.22 This pattern is replicated across all rate classes except for Rate 50 & 70 (combined) and Rate 60. In the case of Rate 50 & 70 (combined), the Final Criteria projects a CAGR of -0.9% versus +0.8% for JPS. This suggests that even with the threat of migration (triggered

[23] The Final Criteria did not include a RT70 category. However, JPS' RT70 forecast was accepted and the Final Criteria for the RT50 class was reduced by an equivalent number.

by relatively high electricity prices) from the grid by large commercial/industrial customers, JPS still anticipates an expansion of demand in this rate category.

Figure 17.2 –Total Customer Forecast: 2019 - 2024



17.23 With respect to the Rate 60 (i.e. the Streetlight category), the Final Criteria forecasts a CAGR of 3.2% versus JPS' projection of -6.9%. The OUR concedes that JPS' bottom-up approach which is predicated on streetlamp counts is a more robust approach, than the urban population growth method used in the Final Criteria. Accordingly, JPS' sales growth for this category of customers have been accepted by the OUR.

17.24 Notably, JPS completed its demand forecast in 2018, and based on the output, total sales in 2019 was put at 3,215 GWh. However, actual total sales for that year was 3,276 GWh. In fact, JPS' forecast suggests that the 3,276 GWh registered in 2019 would not be exceeded until 2023, one year before the Rate Review period ends.

17.25 Similarly, for the overall customer count, the Final Criteria growth rate was more aggressive than that of JPS' forecast (see Figure 17.2 above). Over the period 2018-2024, the CAGR for the Final Criteria and JPS' forecast were 2.5% and 1.8% respectively as shown in Table 17.2 below.

T-Test Sales & Customer Forecast (Paired Sample)

TOTAL SALES (GWh):

- Mean Difference: -141.9
- Std. Error Difference: 39.1
- 95% Confid. Interval (lower): -225.8

t	df	p-value
-3.632	14	0.003

TOTALCUSTOMER COUNT:

- Mean Difference: -20,179.66
- Std. Error Difference: 6,167.26
- 95% Confid. Interval (lower): -46,634.5

t	df	p-value
-5.417	14	0.000

17.26 In light of this, the OUR sought to establish whether there is a significant difference between JPS' overall forecast and the one provided in the Application for the overall sales and customer forecast. This analysis was done by applying a paired difference t-test (2-tail) to the forecasts over the 2016 -2030 period at the 5% significance level.

17.27 The result of t-test in the case of both the overall sales and the total customer count revealed that there is a statistically significant difference between the outputs of the two forecasts.

Table 17.12 –Customer Forecast 2019[24] – 2024: JPS vs. Final Criteria Result

		2016	2017	2018	2019	2020	2021	2022	2023	2024	CAGR 2018-2024
Rate 10	Final Crtia.	561,944	578,067	594,722	611,903	629,609	647,860	664,281	681,100	698,331	2.7%
	JPS	561,944	572,337	586,167	597,467	610,270	623,172	633,918	644,644	655,847	1.9%
	% Variance	0.0%	-1.0%	-1.4%	-2.4%	-3.1%	-3.8%	-4.6%	-5.4%	-6.1%	
Rate 20	Final Crtia.	64,638	65,045	65,310	65,551	65,831	65,982	66,246	66,554	66,794	0.4%
	JPS	64,638	65,799	67,732	68,512	69,287	70,072	70,866	71,668	72,480	1.1%
	% Variance	0.0%	1.2%	3.7%	4.5%	5.3%	6.2%	7.0%	7.7%	8.5%	
Rate 40	Final Crtia.	1,786	1,804	1,822	1,840	1,858	1,877	1,896	1,915	1,934	1.0%
	JPS	1,786	1,814	1,848	1,882	1,899	1,918	1,937	1,956	1,976	1.1%
	% Variance	0.0%	0.6%	1.4%	2.3%	2.2%	2.2%	2.2%	2.2%	2.2%	
Rate 50	Final Crtia.	157	137	140	143	146	149	152	156	159	2.1%
	JPS	157	139	145	144	146	148	152	155	159	1.5%
	% Variance	0.0%	1.5%	3.6%	0.7%	0.0%	-0.7%	0.0%	-0.6%	0.0%	
Rate 60	Final Crtia.	439	453	468	482	496	511	525	539	553	2.8%
	JPS	439	475	486	494	509	524	538	553	568	2.6%
	% Variance	0.0%	4.8%	3.9%	2.5%	2.6%	2.6%	2.5%	2.6%	2.6%	
Rate 70	Final Crtia.	-	23	23	23	23	23	24	24	25	1.4%
	JPS	-	23	23	23	23	23	24	24	25	1.4%
	% Variance	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
Other	Final Crtia.	2	2	2	2	2	2	2	2	2	0.0%
	JPS	2	2	2	2	2	2	2	2	2	0.0%
	% Variance	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
Total	Final Crtia.	628,966	645,531	662,487	679,944	697,965	716,404	733,126	750,290	767,799	2.5%
	JPS	628,966	640,589	656,403	668,523	682,136	695,859	707,436	719,002	731,056	1.8%
	% Variance	0.0%	-0.8%	-0.9%	-1.7%	-2.3%	-2.9%	-3.5%	-4.2%	-4.8%	

Actual

17.5. The OUR's Position

17.28 The methodology used by JPS to generate its demand forecast is not fundamentally different from the one in the Final Criteria. Notwithstanding, there were statistical enhancements to JPS' methodology that makes it more robust. However, paradoxically, the output from the Final Criteria, in most part, seems more intuitive. In balancing the risk of a forecast that is too high versus one that is too low, the OUR deemed it prudent to adopt the mean of both forecasts for all rate classes except Rate 60 and 70, as its normal forecast over the Rate Review period as shown in Table 17.13 below.

[24] The Final Criteria did not include a RT70 category. However, JPS' RT70 forecast was accepted and the Final Criteria for the RT50 class was reduced by an equivalent number.

17.29 The Rate 70 group represents a small group of customers with demand of 2KVA and above. This group was created after the Final Criteria forecast was prepared. Hence, Rate 70 was not captured as a distinct class in that analysis. Instead, it was treated as a part of the Rate 50 class.

17.30 Given the small size of the Rate 70 group[25] and the detailed focus it was accorded in JPS' analysis, it may be argued that this augers well for forecasting accuracy. Accordingly, the OUR has opted to accept JPS' Rate 70 forecast and reduce its original Rate 50 projection by the same magnitude.

Table 17.13 –Approved Sales Forecast 2019[26] – 2024: Normal vs. Covid-19

	Mode	Unit	2016	2017	2018	2019	2020	2021	2022	2023	2024	CAGR 2018-2024
Rate 10	Normal	GWh	1,079	1,069	1,066	1,102	1,123	1,144	1,161	1,179	1,197	1.9%
	Covid-19	GWh	1,079	1,069	1,066	1,102	1,235	1,201	1,123	1,144	1,161	1.4%
	Growth	%	-	-0.9%	-0.3%	3.4%	12.1%	-2.8%	-6.5%	1.8%	1.5%	
Rate 20*	Normal	GWh	624	639	633	636	641	646	653	660	668	0.9%
	Covid-19	GWh	624	639	633	636	577	613	641	646	653	0.5%
	Growth	%	-	2.4%	-0.9%	0.5%	-9.3%	6.4%	4.5%	0.8%	1.1%	
Rate 40	Normal	GWh	784	786	801	817	830	852	874	896	917	2.3%
	Covid-19	GWh	784	786	801	817	747	809	830	852	874	1.5%
	Growth	%	-	0.2%	1.9%	2.0%	-8.5%	8.2%	2.6%	2.5%	2.6%	
Rate 50	Normal	GWh	626	572	356	334	329	326	326	326	328	-1.3%
	Covid-19	GWh	626	572	356	334	296	310	329	326	326	-1.5%
	Growth	%	-	-8.6%	-37.9%	-6.0%	-11.4%	4.7%	6.2%	-0.8%	-0.2%	
Rate 60	Normal	GWh	71	68	62	58	48	40	40	40	41	-6.9%
	Covid-19	GWh	71	68	62	58	48	40	40	40	41	-6.9%
	Growth	%	-	-4.2%	-8.6%	-7.1%	-16.6%	-16.5%	-1.2%	1.1%	0.9%	
Rate 70	Normal	GWh	-	75	294	272	274	279	284	289	294	0.0%
	Covid-19	GWh	-	75	294	272	247	265	274	279	284	-0.6%
	Growth	%	-	-	293.7%	-7.4%	-9.4%	7.6%	3.3%	1.9%	1.8%	
EV	Normal	GWh	-	-	-	-	0.1	0.1	0.1	0.1	0.2	0.0%
	Covid-19	GWh	-	-	-	-	0.1	0.1	0.1	0.1	0.2	16.0%
	Growth	%	-	-	-	-	-	9.0%	15.8%	28.2%	50.3%	0.0%
Sales	Normal	GWh	3,184	3,209	3,212	3,219	3,246	3,287	3,337	3,389	3,444	1.2%
	Covid-19	GWh	3,184	3,209	3,212	3,219	3,151	3,239	3,237	3,287	3,338	0.6%
	Growth	%	-	0.8%	0.1%	0.2%	-2.1%	2.8%	-0.1%	1.5%	1.6%	
Losses	Normal	GWh	1,165	1,154	1,144	1,089	1,059	1,031	1,012	990	963	-2.8%
	Covid-19	GWh	1,166	1,154	1,144	1,126	1,059	1,031	1,059	1,031	1,012	-2.0%
	Growth	%	-	-1.0%	-0.9%	-1.6%	-6.0%	-2.6%	2.7%	-2.6%	-1.8%	
Net Gen	Normal	GWh	4,349	4,363	4,356	4,309	4,304	4,318	4,350	4,380	4,408	0.2%
	Covid-19	GWh	4,349	4,363	4,356	4,345	4,209	4,270	4,296	4,318	4,351	0.0%
	Growth	%	-	0.3%	-0.2%	-0.2%	-3.1%	1.4%	0.6%	0.5%	0.8%	

Actual   * =Includes "Others"

17.31 As previously mentioned, the bottom-up approach employed by JPS in its Rate 60 forecast is practical and more likely to yield a sounder forecast. This is particularly relevant in the context of the SSP in progress. This programme involves the replacement of high pressure

[25] There were 294 customers in the Rate 70 group in 2018.

[26] The Final Criteria did not include a RT70 category. However, JPS' RT70 forecast was accepted and the Final Criteria for the RT50 class was reduced by an equivalent number.

sodium lamps with LED lamps. Consequently, given that the number of street lamps in Jamaica has been already close to saturation point, the use of more efficient LED lighting is likely to result in a reduction in Rate 60 energy consumption than an increase. Hence, JPS' Rate 60 sales forecast was accepted by the OUR.

17.32 With respect to the customer forecast, the OUR adopted the mean of the two forecasts for all rate classes as the normal projection for the Rate Review period.

17.5.1. Covid-19 Forecast

Initial Covid-19 Forecast

17.33 Under normal circumstances, the determination of the OUR's demand forecast would have been reasonable. However, the advent of the Covid-19 pandemic has had a disrupting effect on economic and social life globally. This has translated into the dramatic changes in consumption patterns, which cannot be ignored.

17.34 In light of this development, the OUR communicated to JPS via letter dated 2020 April 18 requesting that the company submit a demand forecast that captures the effect of Covid-19 on its billing determinants. However, JPS did not respond to the OUR's request therefore, JPS' original forecast remained as is.

17.35 Given the circumstances, the OUR considered it prudent to generate a Covid-19 forecast based on the billing data and various global and national economic projections available at that time.

17.36 Arising from that analysis, the OUR's Covid-19 forecasted that, relative to the levels registered in the previous year:

- Residential (kWh) sales would increase by 10% in 2020 and 5% in 2021;
- Non-residential (kWh) sales, with the exception of streetlights, would decrease by 10% in 2020 and 5% in 2021.

17.37 The streetlight pre-Covid-19 forecast, however was maintained, since this service was not subject to changes in customer behaviour.

17.38 Additionally, it was assumed that in 2022 electricity consumption would recover from the effects of the pandemic, registering the residential and non-residential (excluding streetlights) levels projected for 2020 in the original sales forecast.

Table 17.14 –OUR's Original and Initial Covid-19 Sales Forecast 2019– 2024

FORECAST	Unit	2016	2017	2018	2019	2020	2021	2022	2023	2024	CAGR 2018-2024
Original Sales	GWh	3,184	3,196	3,203	3,219	3,246	3,287	3,337	3,389	3,444	1.2%
Original Growth	%		0.4%	0.2%	0.5%	0.8%	1.3%	1.5%	1.6%	1.6%	
Covid-19 Sales	GWh	3,184	3,209	3,212	3,219	3,151	3,239	3,237	3,287	3,338	0.6%
Covid-19 Growth	%	-	0.8%	0.1%	0.2%	-2.1%	2.8%	-0.1%	1.5%	1.6%	

17.39 As shown in Table 17.4, the OUR's Covid-19 revision to the original forecast results in total sales growth of -2.1% in 2020 and 2.8% in 2021. The result is a CAGR of 0.6% for the 2018-2024 period versus the 1.2% growth projection for the original forecast.

JPS Comments on the Initial Covid-19 Forecast

17.40 As is the practice, before publishing this Determination Notice, the OUR shared the draft document with JPS and invited the company's comments. In respect of the OUR's initial Covid-19 forecast, the company argued that:

> *"The OUR Sales Forecast is overly optimistic. Energy Sales declined 8.5% for the six-month period March 2020 to August 2020 and 5.4% YTD August 2020 and JPS believes that the level of recovery will be lower than projected by the OUR."*[27]

17.41 In support of a less optimistic sales outlook, JPS also stated, among other things, that:

- *"The Jamaican economy is estimated to have contracted in the range 14% to 17% for the June 2020 quarter, a faster pace of contraction compared to the 2.3% decline recorded for the March 2020 quarter";*
- *The BOJ [Bank of Jamaica]revised their earlier projections of a reduction in GDP in the range of 4% -7%. The Bank is now projecting that the economy will contract between 7% and 10% during the 2020/21 fiscal year because of the impact of COVID-19."*

17.42 Notwithstanding, JPS'critque of the OUR's initial Covid-19 sales forecast, the company still did not provide its own Covid-19 sales forecast. Hence, once again the OUR has taken on the task of reviewing its initial forecast without the benefit of a Covid-19 forecast from the utility.

Final Covid-19 Forecast

17.43 Even though the OUR's Covid-19 forecast was done in 2020 mid-June, without the insights from BOJ and the Planning Institute of Jamaica's (PIOJ) second quarter analyses[28], the OUR accepts JPS' view that the initial Covid-19 forecast may have been a bit more sanguine than what may be supported by the emerging evidence. In light of this and in the absence of a JPS Covid-19 forecast, the OUR has opted to revise its initial Covid-19 forecast.

17.44 Estimates as to the possible economic impact varies. The IMF in 2020 April predicts[29] global economic contraction of 3%, and in 2020 June the ***Global Economic Prospect*** puts the baseline reduction in global output at 5.2% in 2020[30]. However, there is the general

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[27] See "JPS_2019-2024 Draft Determination Response – Annex_Sept 8 20F" p.15

[28] The BOJ and PIOJ 2nd Quarter reviews were released 2020 August 26 and September 9 respectively.

[29] See article "Coronavirus: A visual guide to the economic impact" at https://www.bbc.com/news/business-51706225

[30] See "The Global Economic Outlook During the COVID-19 Pandemic: A Changed World" at: https://www.worldbank.org/en/news/feature/2020/06/08/the-global-economic-outlook-during-the-covid-19-pandemic-a-changed-world

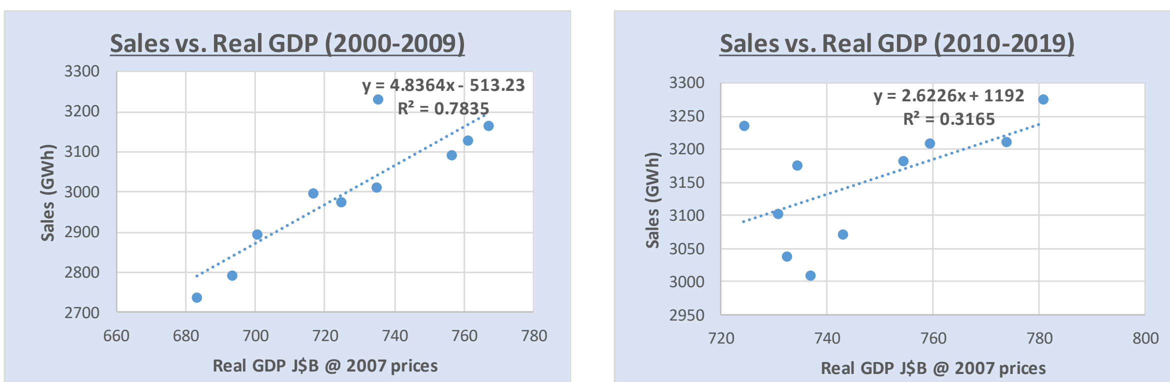
view among experts that the global economy will contract to a lesser degree in 2021 and recover in 2022.

17.45 The IMF projected in 2020 May that the Jamaican economy would contract by over 5% during the fiscal year, positing that inflows from remittance and tourism, which represents 15% and 20% of the economy will be severely affected by the pandemic. The Jamaican economy is expected to recover in tandem with the global economy[31].

17.46 The Planning Institute of Jamaica (PIOJ) estimated that real GDP in Jamaica declined by 10.2% for the first half of 2020 and projects that for the 2020/21 fiscal year there will be a contraction in economic output within the range of 8.0% – 10.0 %. Additionally, the BOJ anticipates partial economic recovery in the 2021/22 fiscal year with GDP growth within a range of 3.0% – 6.0% before registering pre-Covid-19 levels in 2022/23.

17.47 It is important to note that over the last decade, the relationship between economic output and electricity sales have weakened. For example, when real GDP is regressed against electricity sales over the period 2000-2009, the output revealed that real GDP explained 78.4% of the variation in electricity sales. However, for the period 2010-2019, real GDP only explains 31.6% of the variation in electricity sales. This is captured in the values of the Coefficient of Determination (R^2) shown in Figure 17.3 below.

Figure 17.3 –The Effect of Covid-19 on JPS Energy Consumption



17.48 It therefore follows that a simple trend analysis is likely to yield better estimates than a complex regression analysis. Hence, the OUR has adopted a simple trend analysis approach in developing the final Covid-19 forecast.

17.49 At the time of the OUR's revised analysis of the Covid-19 demand forecast in 2020 September, a pattern of how the pandemic had affected the electricity sector was evident. Even though total energy sales grew impressively in January and February, registering growth rates of 3.8% and 4.2% over the corresponding months in 2019, this pattern was

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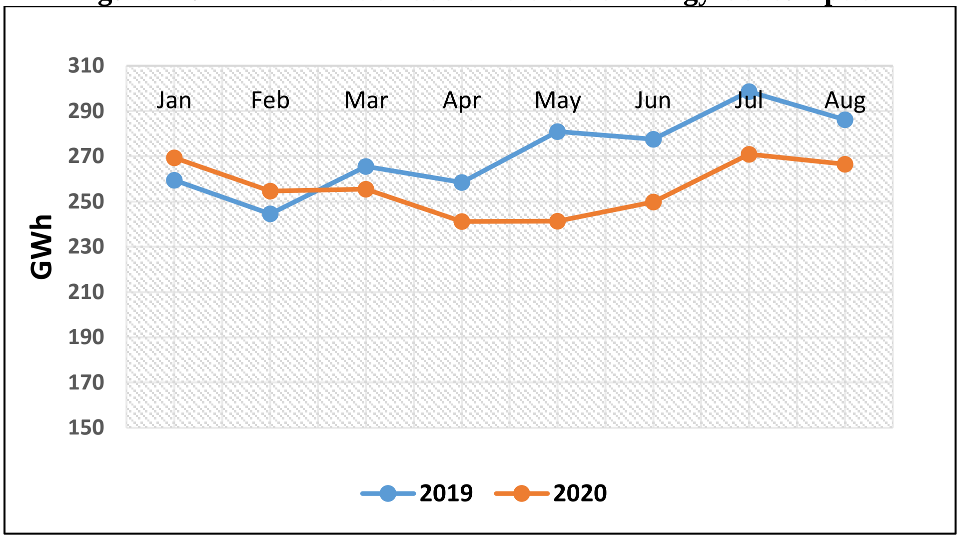
[31] See Jamaica Ramps Up Social and Economic Support in COVID-19 Response at https://www.imf.org/en/News/Articles/2020/05/27/na052720-jamaica-ramps-up-social-and-economic-support-in-covid-19-response

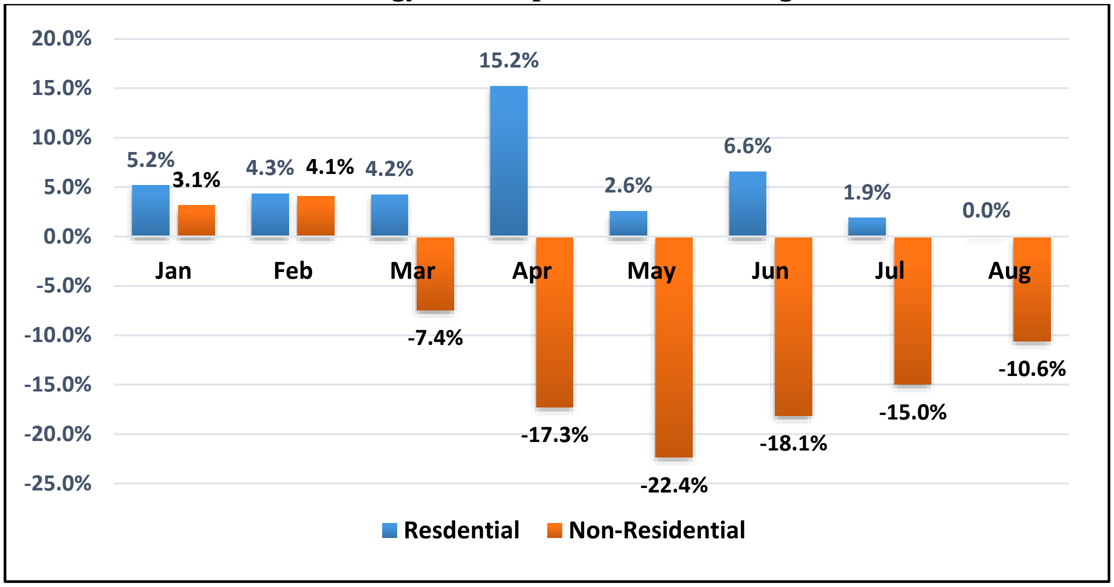
reversed in the ensuing months. In March, the month of the first occurrence of a Covid-19 case in Jamaica, total electricity sales fell by 3.8% relative to 2019 March, sinking to 14.1% in May before improving gradually to register a 6.9% reduction in August (see Figure 17.4 below). Over the eight-month period 2020 January – August, electricity sales declined by 5.6%, when compared to the same period in 2019.

Figure 17.4 –The Effect of Covid-19 on JPS Energy Consumption



17.50 With the Covid-19 containment measures, such as the lockdowns, curfews and reorientation in the approach to workplaces and schools in 2020 March onwards, more people have been forced to spend longer hours at home. This has resulted in an increase in residential energy consumption as shown in Figure 17.5 below. On the other hand, non-residential energy consumption with the exception of streetlights have contracted relative to expectation. The net effect as previously mentioned is a reduction in total energy sales since 2020 March. Figure 17.5 below shows the monthly change in residential and non-residential sales relative to the same month in 2019 over the period January – August.

Figure 17.5 – Covid-19 Effect on Residential & Non-Residential Energy Consumption 2020 Jan - Aug



<u>Energy Sales Forecast</u>

17.51 Arising from the early observation of the effects of Covid-19, the OUR modified the original or normal forecast based on the following assumptions:

- For the remaining four (4) months for which the actual is not yet know, the monthly differential between 2020 and 2019 electricity sales for all customer categories (except Streetlights) will be equivalent to the average differential registered in 2020 July and August. This was used to derive the projected annual sales differential for each of the relevant rate class;
- For 2021, the percentage change in sales is projected to be having the annual percentage differential registered in 2020 for each of the relevant rate classes;
- For all rate classes except Streetlights (RT60) and the EV category, the projected energy sales for 2022 will reflect the 2020 level in the normal forecast. Similarly, 2023 sales will reflect the 2021 levels and so on;
- The RT60 and the EV category energy consumption will see no deviation from the normal forecast.

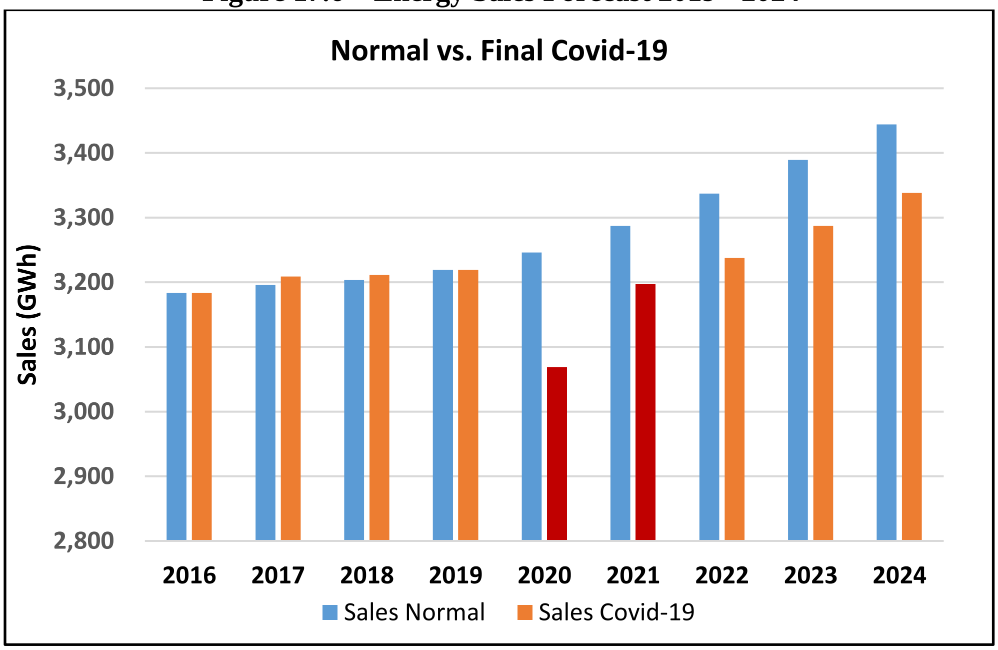
17.52 Accordingly, the differentials by which electricity in class is adjusted relative to the original sales forecast is shown in Table 17.15 below.

Table 17.15 –OUR's Sales Adjustment Factors and Final Covid-19 Forecast 2020 & 2021

Rate	Adjustment Factor (Differential)		Original Sales Forecast (GWh)		Final Covid-19 Sales (GWh)	
	2020	2021	2020	2021	2020	2021
MT10	3.50%	1.75%	1,123	1,144	1,162	1,164
MT20	-8.50%	-4.25%	641	646	586	618
MT40	-8.10%	-4.05%	830	852	763	817
MT50	-11.30%	-5.65%	329	326	292	308
MT60	0.00%	0.00%	48	40	48	40
MT70	-21.30%	-10.65%	274	279	216	249

17.53 The resultant Final Covid-19 forecast projects a CAGR of 0.6% for total energy sales versus the 1.2% CAGR over the 2018-2024 period in the Original Forecast as shown in Figure 17.6 below.

Figure 17.6 – Energy Sales Forecast 2019 - 2024



Customer Forecast

17.54 As previously mentioned, the OUR's normal customer forecast was derived from the mean of the Final Criteria and JPS' forecasts. However, unlike the energy sales forecast the Covid-19 customer forecast is the same as the normal forecast. The assumption that informs this outlook, is the notion that customers will not exit from the grid but will use more or less energy depending on the class they are in.

Demand Forecast

17.55 In light of the fact that JPS did not include a KVA demand forecast, the OUR derived a forecast by extrapolating the actual level of demand for 2017 and 2018 in the relevant customer categories. The extrapolation was based on the sales growth rate for the respective classes. Implicit in this assumption is the notion that the power factor and load factor for the system remains constant, and the share of demand between standard and TOU consumption in each rate class remains stable.

17.56 Based on this approach, the demand forecast automatically reflects the Covid-19 modifications to the normal forecast.

17.5.2. Conclusion

17.57 The OUR's original billing determinant (normal) forecasts for the Rate Review period represents a blend of the projections presented by JPS and its own forecast delineated in the Final Criteria. However, in recognition of the severe impact Covid-19 has had, and will in time have on energy consumption patterns, the OUR modified the original or normal forecast and produced an initial set of Covid-19 forecasts. This initial Covid-19 forecast was revised after receiving feedback from JPS, which the company considered to be 'overly optimistic'. Utilizing a long time series on customers' Covid-19 consumption behaviour, the OUR has fashioned its final Covid-19 forecast in relation to (a) energy sales; (b) billing demand; and (c) Customer numbers. These forecasts are set out in Tables 17.15, 17.16 and 17.1717 respectively.

17.58 Given the uncertainty that surrounds the containment of the Covid19 pandemic and absence of a clear methodology to predict its impact on the electricity sector, the OUR takes the view that this forecast should be reviewed and fine-tuned at the Annual Review due in 2021.

Table 17.1515 –Approved Covid-19 Sales Forecast 2019– 2024

	Unit	2016	2017	2018	2019	2020	2021	2022	2023	2024	CAGR 2018-2024
Rate 10	GWh	1,079	1,069	1,066	1,102	1,162	1,164	1,123	1,144	1,161	1.4%
Rate 20	GWh	624	639	633	636	586	618	641	646	653	0.5%
Rate 40	GWh	784	786	801	817	763	817	830	852	874	1.5%
Rate 50	GWh	626	572	356	334	292	308	329	326	326	-1.5%
Rate 60	GWh	71	68	62	58	48	40	40	40	41	-6.9%
Rate 70	GWh	-	75	294	272	216	249	274	279	284	-0.6%
EV	GWh	-	-	-	-	0.1	0.1	0.1	0.1	0.2	24.9%
Sales Covid-19	GWh	3,184	3,209	3,212	3,219	3,068	3,197	3,237	3,287	3,338	0.6%
Sales Growth	%		0.8%	0.1%	0.2%	-4.7%	4.2%	1.3%	1.5%	1.6%	

Table 17.16 –Approved Covid-19 Billing Demand Forecast 2019– 2024

	Mode	Unit	2017	2018	2019	2020	2021	2022	2023	2024	CAGR 2018-2024
Rate 40	STD	KVA	2,244,666	2,308,764	2,346,563	2,191,491	2,346,352	2,384,648	2,445,390	2,509,464	1.4%
	TOU-off Peak	KVA	305,174	300,993	312,382	291,738	312,354	317,452	325,538	334,068	1.8%
	TOU-part Peak	KVA	298,247	295,640	306,053	285,828	306,026	311,021	318,943	327,300	1.7%
	TOU-on Peak	KVA	235,148	240,386	245,061	228,867	245,039	249,039	255,382	262,074	1.5%
	Total	KVA	**3,083,235**	**3,145,783**	**3,210,059**	**2,997,924**	**3,209,771**	**3,262,159**	**3,345,254**	**3,432,906**	**1.5%**
	Growth Rate	**%**	**0.0%**	**1.9%**	**2.0%**	**-6.6%**	**7.1%**	**1.6%**	**2.5%**	**2.6%**	
Rqte 50	STD	KVA	701,170	661,530	624,098	545,206	575,009	614,663	609,442	608,324	-1.4%
	TOU-off Peak	KVA	198,907	193,146	179,555	156,857	165,432	176,840	175,338	175,017	-1.6%
	TOU-part Peak	KVA	185,127	177,365	166,016	145,030	152,958	163,506	162,118	161,820	-1.5%
	TOU-on Peak	KVA	136,969	129,599	122,084	106,652	112,482	120,239	119,218	118,999	-1.4%
	Total	KVA	**1,222,173**	**1,161,640**	**1,091,754**	**953,745**	**1,005,881**	**1,075,248**	**1,066,116**	**1,064,159**	**-1.5%**
	Growth Rate	**%**	**0.0%**	**-37.9%**	**-6.0%**	**-12.6%**	**5.5%**	**6.9%**	**-0.8%**	**-0.2%**	
Rate 70	STD	KVA	639,842	604,690	587,001	465,207	538,413	591,114	602,588	613,166	0.2%
	TOU-off Peak	KVA	121,649	146,040	126,259	100,062	115,808	127,144	129,612	131,887	-1.7%
	TOU-part Peak	KVA	119,705	145,522	125,098	99,142	114,743	125,975	128,420	130,674	-1.8%
	TOU-on Peak	KVA	101,808	125,316	107,126	84,899	98,259	107,877	109,971	111,901	-1.9%
	Total	KVA	**983,004**	**1,021,568**	**945,484**	**749,311**	**867,223**	**952,110**	**970,591**	**987,628**	**-0.6%**
	Growth Rate	**%**	**0.0%**	**293.7%**	**-7.4%**	**-20.7%**	**15.7%**	**9.8%**	**1.9%**	**1.8%**	
	Total	**KVA**	**5,288,412**	**5,328,991**	**5,247,298**	**4,700,980**	**5,082,875**	**5,289,518**	**5,381,961**	**5,484,693**	**0.5%**
	Growth Rate	**%**	**0.0%**	**0.8%**	**-1.5%**	**-10.4%**	**8.1%**	**4.1%**	**1.7%**	**1.9%**	

Table 17.17 –Approved Covid-19 Customer Forecast 2019– 2024

	2016	2017	2018	2019	2020	2021	2022	2023	2024	CAGR 2018-2024
Rate 10	561,944	575,202	590,444	604,685	619,940	635,516	649,100	662,872	677,089	2.3%
Rate 20	64,638	65,422	66,521	67,031	67,559	68,027	68,556	69,111	69,637	0.8%
Rate 40	1,786	1,809	1,835	1,861	1,878	1,897	1,916	1,936	1,955	1.1%
Rate 50	157	138	143	144	146	149	152	156	159	1.8%
Rate 60	439	464	477	488	503	517	531	546	561	2.7%
Rate 70	-	23	23	23	23	23	24	24	25	1.4%
Other	2	2	2	2	2	2	2	2	2	0.0%
Total	**628,966**	**643,060**	**659,445**	**674,234**	**690,051**	**706,131**	**720,281**	**734,646**	**749,427**	**2.2%**
Cust Growth		2.2%	2.5%	2.2%	2.3%	2.3%	2.0%	2.0%	2.0%	

DETERMINATION #24

a) Based on its analysis of JPS' demand forecast and after giving due recognition to the impact of the Covid-19 pandemic on the trajectory of demand, the Office has determined that JPS' energy sales, billing demand and customer forecast for the Rate Review period shall be as set out in Tables 7.14 -7.16.

b) Given the uncertainties associated with forecasting demand in light of the Covid-19 pandemic, the OUR shall revisit the demand forecast in the 2021 Annual Review with a view of fine-tuning the projections.

18 Rate Design

18.1. JPS' Current (2018-2019) Rates

18.1 JPS' current rate structure is composed of seven main rate categories. All rate categories have single rate charges, which are not sensitive to the TOU and three categories have an optional TOU rate. Prepaid and post-paid rates are available for customers with a demand lower than 25 kVA. For larger customers with a demand higher than 25 kVA only post-paid rates are available.

18.2 Table 18.1 below presents the rates applicable to all customers in the 2018-19 Rate Schedule.

Table 18.1 JPS' 2018-19 Rate Schedule

Class			Energy-J$/kWh			Demand-J$/KVA				Fuel and IPP rate - J$/kWh *
			Block Rate Option	Customer Charge J$/Mth	Energy Charge J$/kWh	Std.	Off-Peak	Part Peak	On-Peak	
Rate 10	**Residential Service**	LV	<= 100 kWh	445.39	9.66	-	-	-	-	19.56
			> 100 kWh		22.49	-	-	-	-	19.56
	Residential Service - Prepaid		<= 114 kWh		15.14	-	-	-	-	19.56
			> 114 kWh		22.49	-	-	-	-	19.56
	Community Renewal		<= 150 kWh		9.66	-	-	-	-	19.56
Rate 20	**General Service**	LV		992.24	18.55	-	-	-	-	19.56
	General Service - Prepaid		<= 10 kWh		117.77	-	-	-	-	19.56
			> 10 kWh		18.55	-	-	-	-	19.56
Rate 40	**Power Service Low Voltage**	LV - Std		6,990.81	5.77	1,790.05	-	-	-	19.56
		LV - TOU				-	75.49	787.63	1,008.48	19.56
Rate 50	**Power Service Medium Voltage**	MV - Std		6,990.81	5.57	1,603.66	-	-	-	19.56
		MV - TOU				-	71.51	697.81	895.30	19.56
Rate 70	**Power Service Medium Voltage**	MV -STD		6,990.81	3.71	1,526.30	-	-	-	19.56
		MV -TOU				-	68.33	672.78	864.33	19.56
Rate 60	**Street Lighting**	LV		2,818.88	24.19	-	-	-	-	19.56
	Standby Class – Firm & Non-Firm	No Service		6,990.81	-	82.00	-	-	-	19.56
		LV			5.77	1,790.05	-	-	-	19.56
		MV			5.57	1,603.66	-	-	-	19.56

* Fuel and IPP rate for April 2019

Source: JPS, 2019

18.3 It is important to note that the current rates are predicated on a base rate of J$128 to US$1. This means that on a monthly basis the rates billed to customers are adjusted to reflect 80% of the movement in the J$: US$ exchange rate relative to the J$128 to US$1 Base Exchange rate. Implicit in the 80% adjustment is the assumption that four-fifth of the company's Non-fuel Revenue Requirement are foreign costs requiring US$ expenditures.

18.4 JPS customers' bills may be classified in two parts:

1. The **non-fuel rate** component: according to the rate methodology, the non-fuel rate should recover JPS' net investment multiplied by WACC (capital recovery

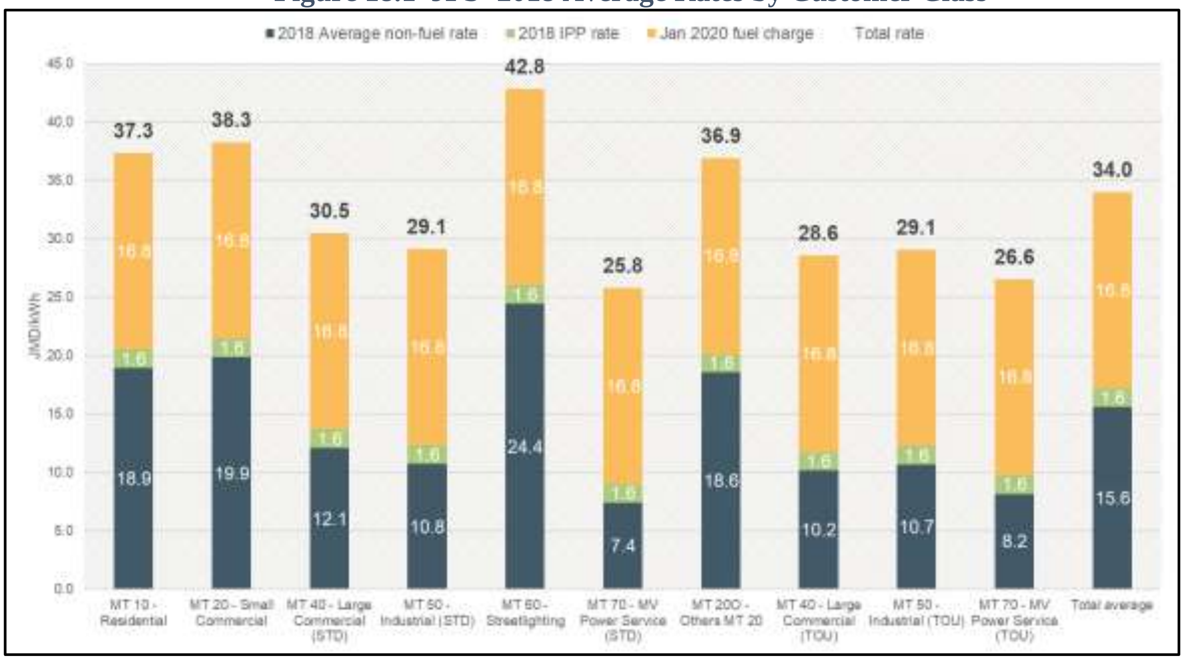
element), depreciation and all 'prudently' incurred expenses including estimated IPP cost; and

2. The **Fuel and IPP rate** component - this rate should cover the cost of fuel used for generation by JPS and IPPs, as well as the residual non-fuel IPP- cost not recovered by JPS in its non-fuel rate.

18.5 On average, the fuel rate accounts for approximately 49% of the total rate, the non-fuel rate is 46% of the total rate and the remaining 5% is the IPP rate charge.

18.6 The average rate in 2018-2019 was $34 per kWh assuming the average 2018-2019 non-fuel rate and the 2020 January fuel charge. Residential (RT10), small commercial (RT20) and street lighting customers (RT60) pay rates, which are higher than the average rate - on average 14% higher than the average rate. Large commercial (RT40), Industrial (RT50) and MV power service customers (RT70) pay rates, which are lower than the average rate – on average 17% lower than the average rate. The streetlighting customers and the lowest by MV Power Service customers pay the highest rate. The average rates by customer class in 2018-2019 are presented in the Figure 18.1 below.

Figure 18.1 JPS' 2018 Average Rates by Customer Class



Source: JPS, 2019

18.2. JPS' Current Rate Structure

18.7 All JPS customers, pay customer charges and energy charges. The energy charge of residential and pre-paid general service customers is a rising block rate, whereas all other customers pay a single rate energy charge. Power Service and Standby classes also pay a single rate demand charge. Power Services classes have the option to pay a TOU demand charge instead if they consume at least 50% of their energy during Off-Peak hours. The existing structure of JPS' rates is summarised in the Table 18.2 below.

Table 18.2 JPS' Rates Structure

Rate Class	Category	Customer charge	Energy charge		Demand charge		Fuel and IPP charge	ForEx charge
			Flat	Rising Block	Flat	TOU	Flat	Flat
10	Residential Service - post-paid	●	-	●	-	-	●	●
10	Residential Service - prepaid	●	-	●	-	-	●	●
10	Community renewal	●	-	●	-	-	●	●
20	General Service - post-paid	●	●	-	-	-	●	●
20	General Service - prepaid	●	-	●	-	-	●	●
40 - Std	Power Service Low Voltage - std	●	●	-	●	-	●	●
40 - TOU	Power Service Low Voltage - TOU	●	●	-	-	●	●	●
50 - Std	Power Service Medium Voltage	●	●	-	●	-	●	●
50 - TOU	Power Service Medium Voltage	●	●	-	-	●	●	●
70 - Std	Power Service Medium Voltage (Interim)	●	●	-	●	-	●	●
70 - TOU	Power Service Medium Voltage (Interim)	●	●	-	-	●	●	●
60	Street Lighting	●	●	-	-	-	●	●
VII	Standby Class – non-firm	●	●	-	●	-	●	●
VIII	Standby Class – firm	●	●	-	●	-	●	●

Source: JPS, ECA analysis

TOU Eligibility Criterion

18.8 Large commercial and industrial customers must consume at least 50% of their energy requirements during Off-Peak hours to qualify for the TOU option. For all rate classes with TOU rate options, the TOU windows are:

a) **On-Peak hours:** Monday – Friday 6:00pm to 10:00pm

b) **Off-Peak hours:** Monday – Friday 10:00pm to 6:00am, and weekends and Public Holidays, all hours other than 6:00pm to 10:00pm

c) **Partial Peak hours:** Monday – Friday 6:00am to 6:00pm, and weekends and Public Holidays 6:00pm to 10:00pm

18.9 For each TOU period, the billing demand is calculated as the average load in kVA (measured in 15-minute intervals) in which the average load is highest; **or** 80% of the maximum demand during the five-month period immediately preceding the billing month, whichever is higher but not less than 25 kVA.

The Fuel & IPP Rate

18.10 The Fuel and IPP rate (per kWh) is calculated each month based on two components:

- **The Fuel rate**: the total fuel consumed by JPS and IPPs in the production of electricity, adjusted for the applicable system heat rate.
- **The IPP rate**: all non-fuel IPP costs are passed through to customers on a monthly basis. Currently, 3.266 US cents per kWh is embedded in JPS' non-fuel energy rate to recover non-fuel IPP cost. In any given month, the amount recovered in the non-fuel energy rate may be higher or lower than the actual IPP non-fuel cost. The over or under-recovered balance is therefore recovered in the fuel and IPP rate. Therefore, technically, the IPP rate is really a surcharge.

18.3. Summary of JPS' Rate Design Proposal

18.11 JPS has proposed 17 rate categories in its Application, of which there were 5 new rate categories. Table 18.3 summarizes the proposed rate categories.

Table 18.3 JPS proposed rate categories

Rate symbol		Rate name
Existing rate categories		
RT10		Residential service
RT10 – Prepaid		Residential service – Prepaid
RT20		General service
RT20 – Prepaid		General service – Prepaid
RT40	STD	Power service low voltage – Standard
	TOU	Power service low voltage – TOU
RT50	STD	Power service medium voltage – Standard
	TOU	Power service medium voltage – TOU
RT60S		Public lighting
RT60T		Traffic Signals
RT70	STD	Power service medium voltage large users – Standard
	TOU	Power service medium voltage large users – TOU
New rate categories		
RT40X	TOU	MT40 with demand over 1MVA

Rate symbol		Rate name
RT50X	TOU	MT50 with demand over 1MVA
EV	TOU	Electric vehicles
DER	TOU	Distributed energy resources
RT10_TOU	TOU	Residential service – TOU

Source: JPS Rate application

18.3.1. Residential Service –RT10

Residential Rate (RT 10)

18.12 RT10 customers account for 41% of JPS' total revenue, 33% of billed kWh sales, and approximately 90% of the total customer count. The current rate structure for RT 10 rate is a two part tariff with a fixed monthly customer charge and a variable energy charge. The energy charge is based on an increasing block rate with just two blocks. The first block is the lifeline block (100kWh and less) with a low, subsidised rate, and the second block (greater than 100kWh) has a normal rate (though also subsidised).

18.13 In its Application, JPS made two (2) proposals in relation to the residential class:

1. The rationalization of the first block by reducing it from 100 kWh to 50 kWh per month;
2. The introduction of a third block for customers consuming more than 500 kWh per month. JPS proposes that the kWh charge for the third block will be lower than that of the second block.

18.14 With respect to the reduction in this lifeline tier from 100 kWh to 50 kWh, JPS argues that given that the second block subsidizes the first, the upper limit for the current first block is too high. According to JPS, this means that the average customer gets almost 2/3 of his energy at a subsidized rate. This it contends is not consistent with the economic objective of the lifeline construct, which is to improve the affordability of electricity service to low income households.

18.15 Regarding the introduction of a third RT10 block, JPS posited that the proposal was made in recognition of the impact of distributed generation and the price elasticity of this group of customers. JPS argued that the proposed change would achieve the objectives of simplicity, equity, allocative efficiency, as well as keeping the revenue of the residential class in line with the cost of service.

18.16 The average non-fuel tariff increase for RT10 customers proposed by JPS would be approximately 43.45%, with the average rate moving from J\$20.59/kWh to J\$29.54/kWh.

18.3.2. General Service (Low Voltage) – RT20

18.17 Rate 20 customers account for approximately 25% of JPS' billed revenues, 20% of kWh sales and 10% of the customer base. JPS proposes a two-tier tariff structure for General Service (RT10) Customers, where the first block is limited to 150kWh, and the second block begins at the kWh increment in excess of the first 150 kWh. Table 18.4 below shows the proposed rates.

18.18 In justifying the request for a second consumption block, JPS argued that the load profiles in the class is diverse. Approximately 50% of customers consume below 150 kWh monthly and such customers are typically micro-business operators that demonstrate consumption patterns similar to that of a RT10 customer. At the same time, the company observes approximately 3.7% of the RT20 customers with consumption over 6,000 kWh monthly.

18.19 Additionally, JPS also proposed to transition its RT20 customers that exhibited demand in excess of 25 kVA in the previous twelve (12) months to the RT40 category. These customers', the company argued, load profile were more akin to those in the RT40 category, hence this move would contribute to improved price signaling.

18.20 Table 18.4 below shows the proposed rates for the rate class. The application of the proposed rates would result in an average increase in non-fuel tariffs of approximately 5.9%.

Table 18.4 JPS Proposed MT 20 Rate

Rate category	Customer charge (JMD/month)	Block limit (kWh/month)	Energy charge (JMD/kWh)
RT 20	1,171.00	0-150	13.05
		>150	14.31

Source: JPS Rate application

18.3.3. Large Commercial & Industrial Categories (RT40, RT50, RT70)

18.21 JPS proposed to maintain the existing three part rate structure for larger customers with standard rates, which includes a monthly customer charge, a demand charge per kVA and a per kWh energy charge. For TOU customers, JPS proposed to introduce TOU energy rates instead of the existing single rate energy charge. The proposed rates are depicted in Table 18.5 below.

Table 18.5 JPS' Proposed Large Non-residential Rates (MT40, MT50 and MT70)

Rate category	Voltage Level	Customer charge (JMD/month)	TOU period	Energy charge (JMD/kWh)	Demand charge (JMD/kVA)	Avg. Rate Increase
MT40 STD	LV	12,000	All	3.64	1,296.39	-18.1%
MT40 TOU	LV	12,000	On Peak	4.95	572.90	-2.5%
			Partial Peak	4.60	532.31	
			Off-Peak	1.65	191.18	
MT 50 STD	MV	12,000	All	3.46	1,231.57	-11.5%
MT 50 TOU	MV	12,000	On Peak	4.70	544.26	-17.5%
			Partial Peak	4.37	505.69	
			Off-Peak	1.57	181.62	

Rate category	Voltage Level	Customer charge (JMD/month)	TOU period	Energy charge (JMD/kWh)	Demand charge (JMD/kVA)	Avg. Rate Increase
MT 70 STD	MV	12,000	All	2.50	1,079.59	-22.8%
MT 70 TOU	MV	12,000	On Peak	3.56	477.09	-22.8%
			Partial Peak	3.31	443.29	
			Off-Peak	1.19	159.21	

Source: JPS Rate application (December 2019),

18.3.4. Street Lighting RT 60S and RT 60T – Low Voltage

18.22 The existing tariff structure does not distinguish between the rates charged for street lighting and traffic signals. Together they are lumped into a single RT60 category. In its Application, JPS has proposed that the two be separated into RT 60S and RT 60T for street lighting and traffic signals, respectively.

18.23 JPS has pointed out that the need for separation arises from the recognition that the cost associated with the two services vary and is therefore necessary in keeping with the cost causation principle. The company further argued that the move also aims to increase the level of transparency of the RT 60 tariff design, especially within context of the SSP.

18.24 The proposed non-fuel rate for streetlights and traffic signals are shown in Table 18.6 below. JPS anticipates a general increase of 45.8% for the streetlight category.

Table 18.6 JPS' Proposed Streetlight and Traffic Light Rates (MT40, MT50 and MT70)

Rate category	Customer charge (JMD/month)	Energy charge (JMD/kWh)
RT60S	264.75	11.50
RT60T	529.50	11.50

18.3.5. Pre-Paid Tariffs- RT10 Prepaid and RT20 Prepaid

18.25 JPS proposed the retention of its pre-paid electricity tariffs for RT10 and RT20 customers. The company indicated that it has sought to improve the design of these tariffs, while giving due consideration for its tax obligations to the GOJ, customer value, and simplicity.

18.26 JPS proposed to retain the two-tier inclining block tariff structure for both RT10 and RT20 pre-paid customers. The Table 18.7 below details the proposed rate for pre-paid rate classes.

Table 18.7 JPS' Proposed RT10 & RT 20 Pre-paid Rates

Rate category	Customer charge (JMD/month)	Block limit (kWh/month)	Energy charge (JMD/kWh)
RT 10PR	Not Applicable	0-114	24.57
		>114	35.37

Rate category	Customer charge (JMD/month)	Block limit (kWh/month)	Energy charge (JMD/kWh)
RT 20PR	Not Applicable	0-10	119.68
		>10	20.18

18.3.6. New Categories: Residential Time of Use Rate (RT 10 TOU)

18.27 JPS proposed what it refers to as an optional TOU tariff for residential customers in keeping with its medium to long term strategic initiative to improve its price signaling and overall tariff design.

18.28 The RT10 TOU tariff represents a new residential rate category, which JPS indicated is consistent with the expected development in the use of electric vehicles. With the appropriate TOU tariff, residential customers, it suggests, will be incentivized to charge their vehicles during the off-peak hours (10pm – 6am) as electricity rates at that time are typically a fraction of rate during peak and partial-peak hours.

18.29 The company further argued that the new category would benefit both the customer and overall system through lowered costs. JPS also indicated an intent to consult with the OUR to improve its design during the Rate Review period. The residential TOU tariff would include a time differentiated energy charge for the kWh consumption during the respective TOU defined periods and a non-time differentiated demand charge that would be applicable to the customer's maximum demand. Table 18.8 shows the proposed Residential TOU rates.

Table 18.8: JPS' Proposed Residential TOU Interim Tariffs

Rate category	TOU period	Customer charge (JMD/month)	Energy charge (JMD/kWh)	Demand charge (JMD/kVA)
MT 10 TOU	On Peak	387.18	6.85	1,454.18
	Partial Peak		6.37	
	Off-Peak		2.29	

18.3.7. New Categories: Partial Wholesale Tariffs- RT 40X TOU LV and RT 50X TOU MV

18.30 JPS indicated in its Application that there are large commercial and industrial customers below the 2 MVA minimum load criterion for the RT 70 that are at risk of grid defection. According to JPS, they have given strong signals of their plans to self-generate and leave the grid.

18.31 In this context, JPS has proposed to establish two new rate classes - RT40X and RT50X - for customers with demand above 1 MVA but less than 2 MVA. Given that these customers would be in the traditional RT40 and RT50 classes, JPS has proposed that these rates would be optional for qualifying customers.

18.32 It is significant to note that the proposed new classes are strictly TOU rates. JPS' posits that this in keeping with its strategic objective to improve long term utilization of network assets through appropriate time varying price signals.

18.33 For the RT40X, JPS proposed that the tariff structure be aligned with its RT 40 TOU proposal with a differential in demand and energy charges, however customer charges will remain identical to the RT 40 tariff at J$12,000 per month.

18.34 Similar to the relative treatment of RT 40X and RT 40 TOU, the RT 50X tariffs proposed are adjusted relative to RT 50 TOU. Specifically, energy and demand charges are adjusted to reflect a 1.2 relative ratio between RT 50 TOU and RT 70 TOU.

18.3.8. New Categories: Public Electric Vehicle Charging – EV Tariffs

18.35 JPS indicated that it intends to invest approximately $1.5 Million USD over the Rate Review period in support of the deployment of an island-wide EV charging infrastructure. The charging stations are to be situated at various strategic, convenient and safe locations across the island that should provide adequate coverage for motor journeys across the island.

18.36 Given the non-existence of demand and load profile data associated with the use of EVs in Jamaica, JPS is proposing an interim tariff of J$26.97/kWh for the public EV charging to enable market development in alignment with broader GOJ policy initiatives. JPS further proposes, however, that access to public charging infrastructure should vary in price according to the type of chargers being used. Public EV chargers are known within the industry as Level 2 and Level 3 and are generally priced differently. Level 3 chargers are rated at a higher capacity and charges 3 to 4 times faster than Level 2 chargers. In light of this, a premium tariff is being proposed for Level 3 chargers after the roll out of the charging facilities.

18.3.9. New Categories: Distributed Energy Resources (DER) Tariff

18.37 In its Application, JPS proposed the implementation of the DER tariff for all customers with on-site generation - across all rate classes. The DER rate is proposed to replace existing Standby rates. According to JPS, Standby rates would no longer be applicable and all existing net-billing customers would also be transitioned to DER. The DER rate is intended to recover demand and capacity related cost, previously energized cost under the existing tariff structure.

18.38 The proposed DER tariff will consist of three TOU demand components as follows and is applicable regardless of the type of generation technology used by the customer: Peak demand charge, Base demand charge, and Reliability capacity charge.

18.39 The proposed DER rate structure is shown in Table 18.9 below. JPS has indicated that the rates are consistent with its LRMC Cost of Service Study, which shows an approximate 95 – 98% fixed charge ratio and speaks to the significant investments in both transmission and distribution networks.

Table 18.9: JPS' Proposed DER Rate Structure

Rate category	Energy charge (JMD/kWh)	Customer charge (JMD/month)	Peak (JMD/kVA)	Base (JMD/kVA)	Reliability Capacity (JMD/kVA)
DER 10 (LV)	0.28	853.74	1,105.04	1,035.77	894.73
DER 20 (LV)	0.42	1,331.39	1,555.80	1,458.08	1,957.76
DER 40 (LV)	0.27	12.000.00	563.95	528.73	782.10
DER 50 (LV)	0.26	12.000.00	790.37	763.66	1,179.88
DER 70 (LV)	0.20	12.000.00	424.93	462.73	1,146.66

Source: JPS Rate application (December 2019)

18.4. OUR's Position

18.4.1. Residential Service –RT10

Rate 10 –Lifeline Block

18.40 For residential customers, JPS proposed the reduction of the upper limit of the first consumption block from 100kWh to 50kWh. Additionally, it has proposed the introduction of a third block to encompass all consumption in excess of 500kWh.

18.41 The socio-economic benefits of providing affordable basic services to enhance the wellbeing of poor households are widely recognised. However, care should be taken to ensure that the provision of subsidies for these consumers will be fair, with minimal price distortions and affordable for those who provide the subsidy.

18.42 In the Caribbean, Belize, Nevis and St Vincent have set the limit to 50 kWh, Grenada to 100 kWh, Barbados to 150 kWh, Bahamas to 350 kWh and Trinidad 400 kWh. This is depicted in Table 18.10 below.

18.43 On average, the upper limit for these countries is 166 kWh, which puts the existing 150 kWh block for JPS close to the middle.

Table 18.10 Limits of Increasing Blocks in the Caribbean

Country	First block	Second block	Third block
Belize	0 – 50	51 – 200	Over 200
Nevis	0 – 50	51 – 125	Over 125
St Vincent	0 – 50	Over 50	-
Grenada	0 – 100	101 – 150	Over 150
Barbados	0 – 150	151 – 500	Over 500
St. Lucia	0 – 180	Over 180	
Bahamas	0 – 350	351 – 800	Over 800
Trinidad	1 – 400	401 – 1,000	Over 1,000

Source: ECA analysis

18.44 In its analysis of the lifeline block, JPS used, the consumption expenditure method, which looks at the affordability of customers based on annual household expenditures. The analysis focused on the affordability of vulnerable customers, i.e. the poorest members of the population.

18.45 Based on an analysis conducted by ECA, the OUR's Rate Design Consultant, the OUR concluded that JPS' proposal is within a reasonable range. JPS assumed that 5% of monthly spending could be spent for electricity bills and sets the lifeline rate, assuming 50kWh of consumption per month to 8.95 JMD per kWh.

18.46 JPS proposed to finance the subsidy through an implicit cross-subsidy within the domestic category; through the second block of the rate. The advantage of this strategy is that the rate of other customer categories is not affected by the subsidy for vulnerable domestic electricity consumers. The disadvantage is that the subsidy is provided by a smaller group of customers and it may significantly increase the rate of those customers. If the financing of the subsidy was spread to all customer categories the impact would be smaller for domestic customers.

18.47 Notwithstanding, the reasonableness of the proposed change to the lifeline block, the Office take the view that given the advent of the Covid-19 pandemic, a larger percentage of households would fall in the vulnerable income category. In this regard, the timing of the lifeline block at this time might be ill advised. Furthermore, JPS' lifeline block currently compares favourably with other Caribbean rate structures. Consequently, **the Office has decided that the current lifeline block construct shall be retained**.

RT10 – Third Block

18.48 JPS additionally proposed the introduction of a third block for customers consuming more than 500 kWh per month. JPS proposed that the kWh charge for the third block will be lower than that of the second block. This rate design:

- Is not reflective of how JPS' costs change with increased consumption (they change linearly with the kWh consumption);
- It rewards higher consumption with lower rates and is not designed to discourage higher energy consumption for environmental reasons;
- To the extent that households with higher income have higher consumption, it benefits the wealthier households at the expense of the consumption tier in the middle;

18.49 This third block therefore has very little appeal to it. Its sole benefit being that it might act as a deterrent to grid defection by discouraging high-end customers from introducing rooftop solar. However, this could be done by encouraging customers to adopt TOU rates and by making the rate design **more** cost-reflective, rather than **less** cost-reflective.

18.4.2. Small Commercial (Low Voltage) – RT20

18.50 The RT 20 category currently has only a single kWh charge, but JPS proposes to introduce a second block from 150 kWh and above. The rate for the second block is proposed to be higher than it would be for the first block (increasing block rate). This is the opposite of the residential (MT 10) rate, where the higher block has a lower rate (declining block).

18.51 This design for the RT 20 class is not reflective of the costs imposed on JPS for those with higher consumption. Further, such a design is likely to discourage business expansion beyond a certain level or to find an alternive source of power with business growth. However, there was no compelling economic justification provided for the additional tier. **The Office therefore takes the view that JPS should retain a single kWh charge for MT 20 customers**.

18.4.3. Large Commercial & Industrial Categories (RT40, RT50, RT70)

18.52 In its analysis of the proposed rate structure for Large Commercial & Industrial Categories, the OUR noted that the rate structure, which is based on customer, energy and demand charges, is aligned to proper price signalling.

18.53 Further, the OUR considers the introduction of TOU energy charges as an improvement on the existing energy charge. The variation of the energy rate across time periods provides a mechanism for more effective price signaling. The current energy charge is flat across the three TOU periods.

18.54 Additionally, the OUR would suggest that JPS considers implementing pure energy seasonal time of day (STOD) charges by incorporating the capacity costs to address seasonality. The load characteristics of these classes exhibit seasonally over the course of a twelve (12) month period.

18.4.4. Street Lighting RT 60S and RT 60T – Low Voltage

18.55 The proposal to make a distinction between the rates charged for street lighting and traffic signal is a positive development. It allows for more cost reflective rates and better price signaling.

18.56 Given the implementation of the SSP, which will see the complete replacement of conventional streetlights with smart ones, the existing billing model for streetlight will have to be replaced over time.

18.57 The existing billing model for streetlight charges customers, for the non-fuel component of the service, based on the wattage of the lamps. Implicit in this charge is the assumption that on a monthly basis each lamp is on for a fixed number of hours per day. With the introduction of smart streetlights and the relevant administrative accessories, JPS will be able to determine the precise consumption of each streetlight and bill its customers accordingly.

18.58 In light of this JPS shall be required to provide the OUR at the next Annual Review in 2021its plan to progressively roll-out its new streetlight billing model based on actual consumption of smart streetlights.

18.4.5. Pre-Paid Tariffs- RT10 Prepaid and RT20 Prepaid

18.59 The OUR endorses JPS' proposal to retain the existing pre-paid electricity tariff structure for RT10 and RT20 customers. It has also been noted that JPS has indicated that due consideration has been given to tax obligations, customer value and simplicity.

18.60 Additional information submitted by JPS in the Rate Review exercise indicates that the cost of supply to pre-paid customers is 90% of the typical RT10 customer. On the other hand, JPS has observed that consumption falls by 10% when a customer transitions from post-paid service to pre-paid service. By that logic, on average, pre-paid customers should pay the same amount for equivalent consumption as post-paid customers. Given that pre-paid customers face no customer charge, but pay a two-block $/kWh rate the billing for each kWh would not mirror perfectly the post-paid bills. However, the OUR takes the view that the total revenue recovery for a comparable number of customers and kWh sales should approximate the post-paid recovery.

Determination #25

Based on the OUR's analysis of JPS' proposed rates, which is delineated above, the Office has made the following determinations:

Conventional Designs

a) The current RT10 design based upon the 0-100 kWh lifeline block shall be retained. However, OUR is willing to revisit JPS' proposal upon the company's request once the Covid-19 pandemic has subsided.

b) JPS' proposal for a third RT10 block (i.e. >500 kWh) has been rejected as it would lead to greater distortion in the price signaling capacity of residential rates.

c) JPS' proposal for a two block per kWh charge for the RT20 class has been rejected, as this neither accords with simplicity in design nor any obvious economic justification.

d) The proposed strategy to separate the RT60 class into a streetlight category (RT60S) and a traffic light category (RT60T) is approved. This is consistent with the objective of cost reflectivity as both services would exhibit different load profiles.

e) Approval has been granted for the existing structure for Pre-Paid Tariffs- RT10 Prepaid and RT20 Prepaid to be retained.

f) In light of the implementation of the Smart Streetlight Programme, JPS shall be required to provide the OUR at the next Annual Review in 2021 its plan to progressively roll-out its new streetlight billing model based on actual consumption of each smart streetlights rather than assumed hours of usage.

18.4.6. New Category: RT10 TOU & RT20 TOU

18.61 The Office takes the view that the proposed introduction of the RT10 TOU rate is a positive step toward greater cost reflectivity. Further, the creation of a TOU category should not be restricted to residential customers, but extended to small commercial (RT20) customers as well.

18.62 TOU categories would be particularly relevant to RT10 and RT20 Net-billing customers who are subsidized by other residential and small commercial customers because the energy charge is currently not time-sensitive. Consequently, Net-billing customers' highest consumption rate takes place after sunset when the cost of electricity supply is at its peak.

18.63 However, the OUR notes that JPS has proposed that the TOU rate should comprise both a time-differentiated energy charge and a 'ratchet' demand charge.

18.64 In principle, a demand charge can be cost-reflective and modern meters should be capable of recording monthly maximum demand alongside TOU energy charges. However, it may be argued that this rate formulation, particularly the ratchet type demand charge, will be confusing for the typical residential customer. For example, few households would understand that their bill in a given month is dependent on their maximum demand from six months previously and that any attempts to reduce their demand may not register on their bills for some months.

18.65 The Office recognizes that there is a legitimate argument for charging based on maximum demand or of connection capacity, not least because it can avoid rate distortions that lead to grid defection. A better approach would be to charge per kVA of network capacity (rather than demand). In practice this would be the equivalent of a more substantial customer charge for most customers at least until a system is put in place that allows residential property to be classified according to the supply capacity. In this regard, this is something that should be explored over the longer term.

18.66 The Office is also aware of JPS' proposal to shift all Net-billing customers to a proposed DER category. However, the definition for DER in the context used by JPS requires clarification, since it is being extended to stand-by customers that do not sell energy to the grid. Further, if residential and small commercial TOU rates are cost reflective there is no reason why a DER category would be required for Net-billing customers.

18.67 In light of this, the Office has concluded that **RT10 TOU and RT20 TOU classes should be established. Further, these categories should not include a demand charge, but instead, revenue recovery shall be based on the customer and energy charges.**

18.68 **Additionally, as it relates to Net-billing customers, the RT10 TOU and the RT20 TOU should be implemented six (6) months after the effective date of this Determination Notice. During the interregnum, JPS shall engage customers in a well-structured education programme concerning their transition to TOU rates.**

18.4.7. New Categories: Partial Wholesale Tariffs- RT 40X TOU LV and RT 50X TOU MV

18.69 Currently, there are essentially three load sizes used for customer class categorization:

- RT20: for loads less than 25KVA

- RT40 & RT50: for loads 25KVA but less than 2MVA
- RT70: for loads 2MVA and above.

18.70 In its Application, JPS proposed a fourth category, an intermediate size between 25 kVA and less than 1 MVA, which it refers to RT40X and RT50X. Of course, RT40X is for low voltage (LV) customers and RT50X is for medium voltage (MV) customers.

18.71 However, from the perspective of cost drivers, the proposed category appears arbitrary. The only difference between a greater than 1 MVA customer and the less or equal to 1 MVA customer is that the latter has a lower peak demand and this characteristic is already captured through the demand charge. Moreover, an RT 40 customer (RT 40 customers are connected at LV) with a load greater than 1 MVA measured at a single meter at LV seems unlikely to exist as it would require a lot of LV wires connected to that single meter. Therefore, it may be argued that a customer supplied at LV might typically have a maximum demand of less than 250 kVA.

18.72 In this respect, the introduction of the RT40X and RT50X adds very little value except that it could be somewhat of a deterrent to grid defection. However, it could lead to an intra-class subsidy in which customers RT40 and RT50 with lower demand subsidize those with higher demand in the RT40X and RT50X classes. **The Office therefore does not approve the introduction of the proposed RT40X and RT50X classes.**

18.4.8. New Categories: Public Electric Vehicle Charging – EV Tariffs

18.73 JPS has proposed a simple J$ per kWh charge for the public EV charging points indicating that it is an interim charging structure. It further proposed that the price in the future should depend on the capacity of the charging point and the speed of the battery charging.

18.74 In making its proposal for a simple J$ per kWh charge, JPS argued that currently there are no load profiles for EV charging points and proposes to postpone a more sophisticated design until the profiles are available. However, if a TOU rate design had been proposed, the need load profiles would be less important since this construct would shape EV charging patterns from the outset.

18.75 **The Office therefore takes the view that even at this stage a more sophisticated rate design based on a TOU structure is warranted.** This would assist in getting users accustomed to time-based rate designs. In the Office's assessment, TOU rates in the context EV charging should be relatively straightforward to implement, given that there would be additional administrative cost associated with public EV charging facilities relative to residential services. **The OUR takes the view that the RT10 TOU rates plus a premium of 5% should be the rates charged for the use of public EV charging facilities.**

18.76 **Additionally, the Office concurs with JPS that introducing a charging framework that differentiates by type of charger (Level 2 or Level 3) may require more analysis and should be postponed to a later date.**

18.4.9. New Categories: Distributed Energy Resources (DER) Tariff

18.77 In its Application, JPS proposed that self-generators connected to the grid should be charged a rate to cover JPS' fixed cost of supply to such customers by way of a DER tariff. This construct would replace the current Standby rates.

18.78 Under this arrangement a customer with self-generation would:

(a) continue to need the network; the network capacity that is needed is dependent on the customer's maximum demand, which generally does not change because of self-generation; and
(b) continue to require the grid to provide back-up generation when self-generation is not available, and again the capacity of that back-up generation is largely the same whether the customer has self-generation or not.

18.79 JPS' proposed structure for DER rates is shown in Table 18.11 below. It focuses particularly on demand charges. The OUR notes that the DER rates in the Application are not the rates shown in the Marginal Cost Model workbook provided by JPS.

18.80 The Peak charge is based on metered maximum demand during the peak period (18:00 – 22:00)[32]. The base period demand charge is based on maximum demand metered during hours other than the peak period. JPS did not propose that these be charged on a ratchet basis. The reliability charge is based on metered maximum demand at any time of the day and is charged on a ratchet basis.

18.81 JPS claims that the reliability capacity charge, is to cover reserve generation capacity costs (according to the Marginal Cost Model, this is 23% of the total demand-related generation capacity costs, but the 23% is hard-coded) and all of the transmission and distribution costs. The OUR takes the view that the Peak and Base demand charges are designed to recover the remainder of what JPS classifies as its demand-related generation costs.

18.82 There is logic in charging DER rates to customers with kWh-only charges (MT 10 and MT 20). These customers avoid paying the fixed costs that are rolled into the kWh charges. However, if the conventional rate designs were cost-reflective, there should less need to charge DER rates to customers who already pay demand charges. The demand and fixed charges in the conventional rates should already reflect the costs of providing these network services and reserve generation capacity costs. **For this reason, the Office takes the position that, given that the TOU categories have been established for RT10 and RT20 customers, there is no need for residential and small commercial DER rates.**

18.83 The DER demand charges for DER customers in categories MT 40, 50 and 70 are compared with the corresponding conventional demand charges below. The combined DER demand charges are higher than the conventional demand charges for these customers[33], suggesting that some of the capacity costs have been included in the energy charges for non-DER customers in the MT 40, 50 and 70 categories. Correction of this misallocation of costs would avoid the need for DER charges for these customer categories.

[32] Monday to Friday, excluding public holidays.

[33] The DER charges replace the equivalent demand and energy charges in the MT 40, 50 and 70 categories.

18.84 There are some unusual characteristics in the DER rate designs proposed by JPS:

(a) The purpose of the reliability charge is not obvious. It is counter-intuitive that the reliability capacity charge is applied to maximum demand, occurring throughout the day and night. The cost of providing reliable services at night as backup generation should be low or zero and the network is sized to supply the overall maximum demand, which almost never occurs at night;
(b) The reliability charge uses a ratchet based maximum demand occurring at any time of the day, but the Peak and Off-Peak demand charges do not use a ratchet. There is no obvious logic to use a ratchet for one, but not for the other;
(c) The Peak demand charge for MT 70 customers is lower than the base demand charge. This cannot be correct;
(d) Normally, the costs for similar types of customers either decrease with size (because, for example, they are supplied at a higher voltage) or they remain the same. However, the demand charges for DER 50 (MV) customers for both Peak and base periods are **higher** than for the DER 40 (LV) (and also higher than for the DER 70 customers, which has economic logic), suggesting something unusual about the calculations;
(e) Similarly, the reliability charge for DER 50 is higher than for DER 40, and DER 70 is higher than DER 50. This is unusual;
(f) The demand charge during the base period for the DER 70 customer is higher than that for the DER 40 customer. Again, this is unusual;
(g) The energy charges are between J$ 0.39/kWh and J$ 0.59/kWh. These do not cover the short-run costs of producing energy.

Table 18.11 Demand Charges in the Conventional Rates versus the DER Rates

Rate category	Period	Conventional rate	DER rate	
		Demand charge (J$/kVA)	Demand charge (J$/kVA)	Reliability charge (J$/kVA)
MT 40_STD	-	2,438		
MT 40_TOU	On-Peak	1,077	880	1,420
	Partial Peak	1,001	825	
	Off-Peak	360		
MT 50_STD	-	2,316		
MT 50_TOU	On-Peak	1,023	1,243	2,104
	Partial Peak	951	1,200	
	Off-Peak	342		
MT 70_STD	-	2,141		
MT 70_TOU	On-Peak	946	774	2,362
	Partial Peak	879	843	
	Off-Peak	316		

18.85 It is clear that JPS has not constructed the proposed DER rate with the kind of rigour and thoughtfulness that is required. Accordingly, the design needs to be revisited. **In light of this, the Office has decided that JPS' proposed DER design in its present form is not approved. However, given the merits of having DER rates in a rapidly changing energy landscape and given the length of time before the next Rate Review, if JPS elects to do so, it may present its revised DER construct at the next Annual Review for regulatory consideration.**

18.86 Additionally, given that Stand-by tariffs were an integral part of JPS' DER rate proposal the Office has decided that JPS' Standy-by tariff shall be adjusted in tandem with the approved RT40 and RT50 tariff. Currently, there is a logical relationship between both. More specifically, all the charges and rates approved for the RT40 and RT50 classess are applicable relative to the MV and LV classifications. However, the existing Reserve Capacity charge shall be adjusted in line with the Growth Rate factor of 13%.

Determination 26

Based on the OUR's analysis of JPS' proposed new rate designs, the Office makes the following determinations:

New Designs

a) Approval has been granted for the establishment of a RT10 TOU class and a RT20 TOU class. However, the billing of customers in these two rate classes shall exclude the use of demand charges, and therefore the recovery of revenues shall be based entirely on the customer and energy charges.

b) Existing Net-billing customers in the RT10 and RT20 classes shall be transferred to the RT10 TOU and the RT20 TOU 6-months after the effective date of this Determination Notice. During the transition period leading up to the transfer, JPS shall engage customers in a well-structured education /promotion programme concerning the nature of TOU rates.

c) JPS' proposal for a RT40X and a RT50X specifically for customers with demand in excess of 1MVA is not approved. There is no distinguishing feature between the load shape of the proposed new classes from what obtains in the existing RT40 and RT50 categories.

d) Approval has been granted for the establishment of Public EV charging rates. These rates shall be based on the TOU rate format and shall be set at a level that is 5% more than the RT10 TOU charges.

e) The proposal for a premium to be charged for the use of Level 3 chargers relative to Level 2 chargers has been approved. However, the precise level of the premium shall be determined when JPS provides adequate data on the cost of the service.

f) JPS proposed DER rates requires additional work before it can be implemented. In light of this, the Office has decided that JPS may, if it elects to do so, present its revised DER construct at the next Annual Review for regulatory consideration.

g) All the charges and rates approved for the RT40 and RT50 classess are applicable relative to the MV and LV classifications. However, the existing Reserve Capacity charge shall be adjusted in line with the Growth Rate Factor of 13%.

18.5. Power Wheeling Rates

18.5.1. Introduction

18.87 Condition 12 of the Licence mandates JPS to implement an Electric Power Wheeling service for customers with an annual average demand in excess of one (1) MVA in accordance with such terms and conditions as are approved by the Office. According to the Licence, the Wheeling service shall be for firm capacity. The charge for wheeling services is designated as the "Use of System Charge", in the Electricity Act, and shall be determined by the Office.

18.88 In addition, given the nature of wheeling service, imbalances between supply and demand are inevitable. Therefore, JPS will be required to provide "Top-up" or "Standby" services to power wheeling customers.

18.89 In determining the Use of System Charge, the Licence and the Final Criteria stipulate that JPS is required to conduct and submit a cost of service study as part of its Rate Review application, which shall be used as the basis for establishing the proposed rate structure and the applicable non-fuel rates and tariffs, including charges for wheeling customers. Further, Criterion 6 requires that revenues that are generated from customers through the sales of electricity services by way of special contracts, "Top-up", "Standby", Electric Power wheeling or any other auxiliary services shall be treated as an offset to the total revenue requirement.

18.5.2. JPS Power Wheeling Proposal

18.90 In the Application, JPS proposed Use of System charges. In addition, the company indicated that at the request of the OUR, it submitted a proposed Power Wheeling Regulatory Framework & Code, a Draft Power Wheeling Contract, and outlined its position on a Use of System Charge in September 2018.

18.91 JPS' proposed methodology for determining the Use of System Charge for any particular system user, including Wheeling customers, is expressed as follows:

$$WC = FixedNC + VarNC + FECost + VECost\ (\delta^{T} + \delta^{NC})$$

Where:

WC	=	Monthly Wheeling Access Charge/Use of System Charge
FixedNC	=	Network Cost
VarNC	=	Variable Network Costs
FECost	=	Fixed Energy Costs
VECost	=	Variable Energy Costs
δ^{T}	=	Determined Technical Loss Factor
δ^{NC}	=	Non-Controllable Loss Factor

18.92 The proposed Wheeling charges derived by JPS from this methodology are presented in Table 18.12 below.

Table 18.12: JPS' Proposed Non-Fuel Wheeling Charges

NON-FUEL WHEELING CHARGES PER RATE CLASS				
Rate Class	Non-Fuel Wheeling Charges			Wheeling Fuel Charge (J$/kWh)
	Energy Charge (J$/kWh)	Customer Charge (J$/Month	Demand Charge (J$/kVA	
Rate 40 Wheeling	5.77	12,000.00	2,442.50	5.78
Rate 50 Wheeling	6.50	12,000.00	2,315.96	5.78
Rate 70 Wheeling	3.71	12,000.00	2,272.20	5.78

18.5.3. OUR's Position

18.93 In keeping with sound regulatory practice, the OUR in 2019 intiated a consultation on the Power Wheeling methodology to guide the design and implementation of Wheeling charges. The consultation engaged stakeholders in the energy sector and the emanating decision, Electricity Wheeling Tariff Methodology Determination Notice was published on 2020 July 31.

18.94 In keeping with the Final Criteria, the *Electricity Wheeling Tariff Methodology Determiantion Notice* emphasizes the following design principles:

- Simplicity
- Cost reflectiveness
- Economic efficiency
- Non-discriminatory cost allocation and transparency
- Compliance with all applicable rules and regulation

18.95 The OUR's assessment is that the proposed wheeling charges methodology and the resulting Wheeling charges set out in JPS's submission are not sufficiently in alignment with the principles and concepts outlined in the Electricity Wheeling Tariff MethodogyDetermination Notice. Notably, however, the Application was submitted before the publication of the Determination Notice.

18.96 Given this misalignment, the Office has not approved JPS' proposed wheeling charges. JPS, however, may elect to revise its wheeling charges and structure to make them consistent with the Electricity Wheeling Tariff Methodogies Determination Notice and submit it to the OUR at the next Annual Review for consideration. In any event, the OUR proposes to determine wheeling charges at that juncture, at which point it also expects that other elments of the Wheeling regime that are still the subject of discussion with stakehoders will be completed.

> **DETERMINATION #27**
>
> The Office has declined JPS' wheeling charges as they do not accord with the principles set out in Electricity Wheeling Tariff Methodology Determination Notice. JPS may, however, elect to revise its wheeling charges and structure in keeping with the Determination Notice and submit it to the OUR at the next Annual Review for consideration.

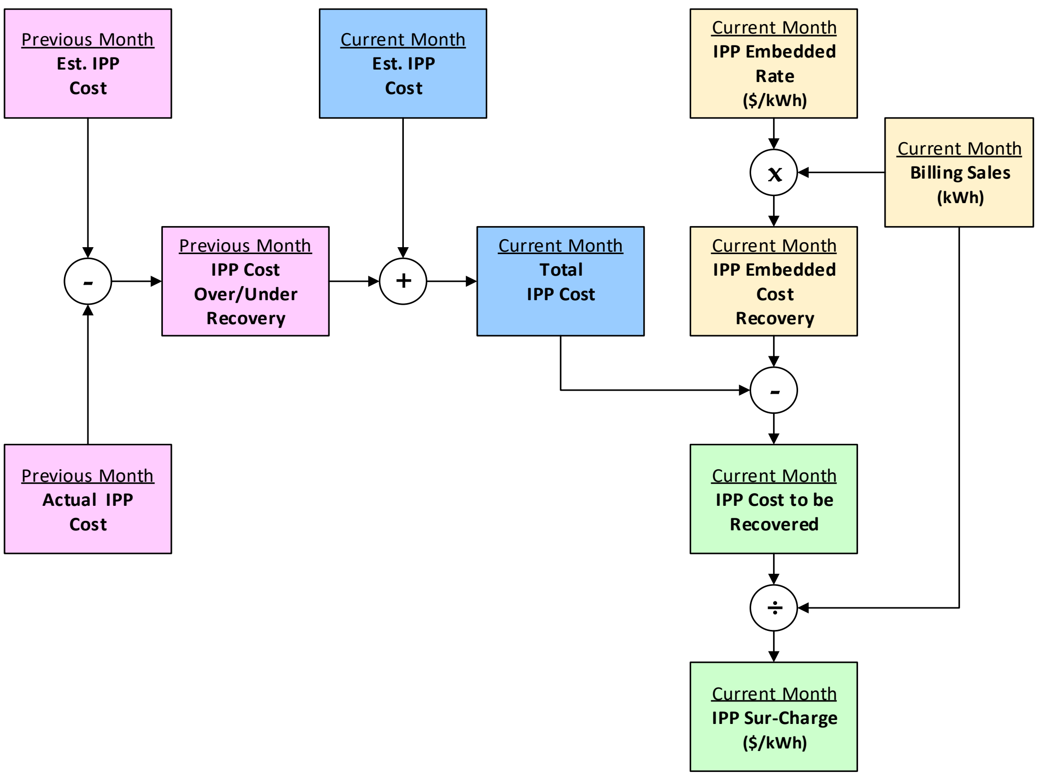
18.6. IPP Cost Recovery Mechanism

18.6.1. The Current IPP Cost Recovery Mechanism

18.97 IPPs represent competition to the Single Buyer, JPS, which also generates electricity on the grid. Consequently, the cost associated with IPP generation is passed directly on to customers with any cost additions by the Single Buyer.

18.98 Currently, the cost recovery mechanism consists of two main components; (1) an embedded cost recovery component; and (2) an IPP Surcharge component.

Figure 18.2: The Current IPP Cost Recovery Mechanism



18.99 The monthly IPP Embedded cost component is derived from a predetermined rate (or IPP Embedded Rate) in $/kWh multiplied by the Billing Sales for the current month as shown in Figure 18.2 above. The IPP Embedded Rate as the name suggests, is included in JPS' non-fuel tariff.

18.100 Arising from variations in the energy generated by the IPPs, among other things, the IPP Embedded costs are never exactly equal to the Total IPP cost in any given month. Consequently, this results in either an over-recovery or under-recovery of monthly IPP costs.

18.101 It is for this reason that an IPP Surcharge is required. The surcharge facilitates the recovery of the Total IPP cost not recovered by the IPP Embedded Cost component.

18.102 It is also worth pointing out the Total IPP Cost for the current month is derived from the current month's Estimated IPP Cost plus the previous month's IPP Cost over or under-recovery. This method of using estimates is required, because it is not feasible for JPS to get all the required IPP cost data in time to prepare its current bills in a timely manner. However, to its credit the system of estimates has worked well over time.

18.6.2. JPS' Proposed Methodology for IPP Cost Pass-Through

18.103 JPS proposed an approach with respect to the decoupling mechanism for power purchase cost and its treatment as a direct pass-through on customers' monthly bill. The following steps have been proposed by JPS for the allocation of IPP costs:

- **Step 1:** Determine and allocate the variable cost component of the IPP to tariff categories: JPS states that the variable cost component of IPP averages 35% for the Rate Review period. This portion of the IPP costs represents the energy component and can be directly allocated to all rate classes in proportion to their energy consumption;
- **Step 2:** Determine a mechanism to allocate demand (i.e. capacity) related IPP costs to tariff categories: As IPP costs relate only to generation costs, the proper allocator would be the generation LRMC and not the overall LRMC structure used in the allocation of JPS´ non IPP costs. JPS used the model developed for estimating LRMC tariffs and set all other costs (transmission and distribution costs in medium and low voltage) to 0. In this way, when the relative tariffs for each rate class are obtained, their relationship is only determined by their generation long run marginal costs.

18.6.3. JPS' Proposed Approach to IPP Charges

18.104 Decoupled IPP charges imply the separation of all power purchase costs from JPS' non-fuel costs. As such, JPS is required to represent IPP charges (power purchase costs) as a distinct line item(s) on customer's bill in keeping with the Final Criteria. This separation of IPP charges would cause a change in the presentation and calculation of electricity charges presented on customer bills.

18.105 Whilst the Final Criteria does not outline a mechanism for the recovery of decoupled power purchase cost from customers, JPS has proposed the following recovery mechanism and its treatment as a direct pass through on customers' monthly bills:

- *A Base Power Purchase cost would be reflected and recovered by way of two components:* A Base IPP Charge that will comprise of a variable charge only in the case of residential, small commercial and street lighting customers. Large commercial and industrial customers would have this Base IPP Charge separately for a variable charge and a fixed demand charge;

- *A Variable IPP Surcharge per kWh*: that is calculated on a monthly basis to ensure full power purchase cost pass through and will be subject to similar processes in the calculation and determination of JPS' monthly fuel rates and Exhibit 2 of the Licence.

18.106 The base non-fuel purchase power cost will not be subject to dPCI adjustment of the revenue cap at the Annual Adjustment periods (i.e., purchase power expense will be excluded from the ART determination). Table 18.13 below shows the details of JPS' estimated base IPP charges by rate class forecasted for 2021.

Table 18.13: JPS' Proposed Base IPP Charges by Rate Class – 2021 Forecast

			Proposed Instrument of Recovery	
	Total allocated IPP	Average IPP Rate/kWh	Energy Charge ($/kWh)	Demand Charge ($/kVa)
RT 10 LV Res. Service	10,467,331	9.38	9.38	
RT 20 LV Gen. Service	3,642,837	8.14	8.14	
RT 60 LV Street Lighting	184,594	4.57	4.57	
RT 40 MV Power Service Std	3,729,594	5.82	2.54	596.00
RT 50 MV Power Service Std	499,877	5.43	2.54	426.92
RT 70 MV Power Service Std	905,962	4.98	2.53	572.66
RT 20 LV Gen. Service (Other)	184,464	5.49	5.49	
RT 40 MV Power Service Tou	1,639,260	5.82	2.54	596.00
RT 50 MV Power Service Tou	245,886	5.43	2.54	426.92
RT 70 MV Power Service Tou	483,923	4.98	2.53	572.66
RT 40 MV Power Service X	383,363	5.82	2.54	596.00
RT 50 MV Power Service X	812,764	5.43	2.54	426.92
Total	**23,179,856**	**7.26**		

18.6.4. OUR's Comments on the Current IPP Cost Recovery Mechanism

18.107 Even though the IPP Cost Recovery Mechanism results in the fair transmission of IPP costs to customers as a whole, it may be criticized on a number of grounds.

18.108 Firstly, it is not transparent by dint of the fact that a portion of the recovery mechanism is embedded in JPS' non-fuel tariff. Customers therefore cannot know how much they are paying for IPP generation. This is further complicated by the existing practice of combining the IPP Surcharge and fuel rate into a single rate that is applied on customers' bills. Hence, customers cannot say at any time what precisely is the IPP Surcharge or what is the fuel rate.

18.109 Secondly, it lacks administrative simplicity. Given that an account has to be kept of the IPP Embedded Cost recovery separately from the Total IPP Cost derived in any particular month, it adds a layer of complexity, which only obfuscates the exercise.

18.110 Thirdly, although the current mechanism is strong on cost recovery it is not cost-reflective. The IPP costs incurred in the generation process may be classified into fixed expenditures, such as capacity payments, and variable payments. Currently, the recovery of IPP costs is done entirely on a variable ($/kWh) basis. In this regard, the correct price signals are not being sent to customers.

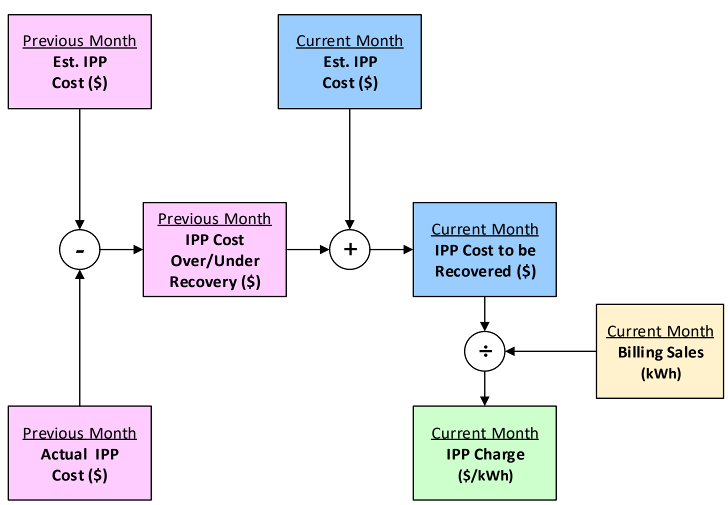
18.6.5. OUR's Revised IPP Cost Recovery Mechanism

18.111 In order to address the problem of transparency and administrative complexity the Office takes the view that the IPP Embedded Cost recovery component of the existing mechanism should be completely removed. As such, the entire derived Total IPP Cost, based on the current month's Estimated IPP Cost and the IPP Cost Over/Under-recovery from the previous month, would be shown on customers' bills. In this regard, the component of the Total IPP Cost embedded in JPS' energy rate would no longer be hidden from customers (see Figure 18.3).

18.112 The second step in the revision of the IPP Cost Recovery Mechanism is the separation of the fuel cost from the IPP cost on customers' bills. In this one step, JPS would simultaneously achieve not only IPP cost transparency, but fuel cost transparency as well.

18.113 At present, fuel costs are supposed to be indexed to the movement of international fuel prices, however, the current practice of combining the fuel cost with IPP cost creates a problem for customers interested in tracking fuel cost per kWh movement over time. The movement of fuel cost per kWh is particularly relevant to Net-billing customers whose compensation for energy sold to the grid is linked to the fuel rate[34].

Figure 18.3: The Current IPP Cost Recovery Mechanism



[34] Net-billing customer's rate of compensation is at the short run avoided cost of generation (less 5%) which is deemed to be the monthly fuel rate.

18.114 The third step involves the separation of the fixed and variable IPP costs. This will make the IPP revenue mechanism more cost reflective. The mechanism will like KVA demand to the fixed IPP cost component and kWh usage to variable IPP cost.

18.115 However, it should be pointed out that given that kVA (Demand Charge) billing is not a feature of the billing for Rate 10, 20 and 60 categories, the fixed component of the IPP cost will be rolled into the variable IPP charges for these categories.

18.116 The main disadvantage to the separation of fixed and variable IPP charges and making them transparent is that it adds another line or two to customers' bill making it little more complex.

18.6.6. OUR's Conclusion

18.117 After reviewing the current IPP Recovery Mechanism the Office has concluded that greater transparency is needed to allow customers greater accessibility to the full cost for IPP services, separate and apart from the cost of fuel.

Additionally, there is a need for cost reflectivity and JPS' proposed mechanism addresses this concern. Against this background, the Office accepts JPS' proposal, with slight modification, as it addresses directly the issues of transparency as well as cost-reflectivity. Accordingly, JPS shall introduce the following mechanism into to its tariff by establishing:

- *A Base IPP Fixed Charge*; for all rate classes except for residential, small commercial and street lighting customers. This charge shall be billed on highest kVA demand registered by the customer in a given month.
- *A Variable IPP Surcharge*; which shall capture any fixed cost not recovered in the *Base IPP Fixed charge* plus all variable charges. This charge is to be billed on a kWh basis and is applicable to all rate classes. However, given that, residential, small commercial and street lighting customers will not have a *Base IPP Fixed charge;* it shall be based on the total IPP cost assigned to these classes.

18.118 Both the *Base IPP Fixed charge* and the *Variable IPP Surcharge,* where relevant, shall be shown on the customer bill.

The Calculation of IPP Charges

18.119 The estimated total IPP cost derived from JPS' 2020 revenue requirement was J$22.3B based on a J$128.00:US$1:00 Base Exchange Rate. As taken from the OUR's approved billing demand forecast, total kVA demand and kWh energy forecast was 3.75 million KVA and 3,067 million kWh respectively. Consequently, it was these variables that were used to produce the approved *Base IPP Fixed charge* and the *Variable IPP Surcharge* for the respective rate classes.

18.120 As shown in Table 18.13, the total IPP revenues were assigned to rate classes based on a modified long run marginal cost basis. Further, in keeping with the OUR's analysis of the ratio between fixed and variable IPP costs, IPP costs for the various customer classes were assigned in the ratio of 65% to 35% respectively.

18.121 The result of this assignment of IPP cost are captured in Table 18.14, which shows that the weighted average *Base IPP Fixed charge* and the *Variable IPP Surcharge* are J$810.03/kVA and J$2.889/kWh based on the new Base Exchange Rate of J$145.00:US$1:00.

Table 18.14: Fixed and Estimated Variable IPP Charges

Rate Class	Modified LRMC IPP Revenue	IPP Cost Allocation	Allocation: Modified Revenue		Total Demand (kVA)	Total Energy (kWh)	IPP Charge @ J$128		IPP Charge @ J$145	
			Fixed 65%	Variable 35%			Fixed	Variable	Fixed	Est. Variable ($/kWh)
	(J$Million)		(J$Million)	(J$Million)	(kVA)	(kWh)	($/kVA)	($/kWh)	($/kVA)	($/kWh)
RT 10 -Residential	9,528.48	42.6%	6,193.51	3,334.97	-	1,162,452,397		8.197		9.286
RT 20 -Sm. Commercial	8,052.54	36.0%	5,234.15	2,818.39	-	586,374,085		13.733		15.557
RT 40 -Lg. Commercial (STD)	1,978.21	8.8%	1,285.84	692.37	-	656,352,299		1.055	-	1.195
RT 40 -Lg Commercial (TOU)	397.70	1.8%	258.50	139.19	2,191,491	106,848,049	586.74	1.303	664.67	1.476
RT 50 -Lg. Industrial (STD)	1,292.28	5.8%	839.98	452.30	291,738	239,354,107	886.07	1.890	1,003.76	2.141
RT 50 -Lg. Industrial (TOU)	177.19	0.8%	115.18	62.02	545,206	52,541,145	1540.67	1.180	1,745.29	1.337
RT 60 -Street lighting	651.11	2.9%	423.22	227.89	156,857	48,399,772	734.27	13.453		15.239
RT 70 -MV Power Serv.(STD)	267.97	1.2%	174.18	93.79	-	181,073,842	0.00	0.518	-	0.587
RT 70 -MV Power Serv. (TOU)	12.60	0.1%	8.19	4.41	465,207	34,490,256	374.41	0.128	424.14	0.145
TOTAL	**22,358**	**100%**	**14,533**	**7,825**	**3,650,500**	**3,067,885,952**	**715.057**	**2.551**	**810.03**	**2.889**

Determination #28

In its review of the current IPP Cost Recovery Mechanism, the Office has determined that an embedded IPP rate should no longer be embedded in JPS' non-fuel tariff. Instead, full recovery of the derived monthly total IPP cost should be achieved over the monthly billed kVA demand and kWh energy sales for each month and shown as separate line(s) on customers' bills.

a) The mechanism for IPP cost recovery shall contain the following features:

- *A Base IPP Fixed charge*; for all rate classes except for residential, small commercial and street lighting customers. This charge shall be billed on highest kVA demand registered by the customer in a given month.
- *A Variable IPP Surcharge Rate*; which shall capture any fixed cost not recovered in the *Base IPP Fixed charge* plus all variable charges. This charge is to be billed on a kWh basis and is applicable to all rate classes. However, given that residential, small commercial and street lighting customers shall not have a *Base IPP Fixed charge*. The *Variable IPP Surcharge* Rate shall be derived from the total IPP cost assigned to the respective class.

b) The *Base IPP Fixed charge* and the estimated *Variable IPP Surcharge Rate* monthly charges and cost allocation among the rate classes shall be those shown in Table 18.12. The relevant charges are at a Base Exchange Rate of J$145.00: US$1:00 and shall be adjust based on the relevant Billing Exchange Rate.

(**Note:** the *Variable IPP Surcharge Rate* shall vary from month to month depending on the difference between the actual and estimated total IPP Cost).

18.6.7. The Calculation of JPS' Non-fuel Tariff

18.122 The *Final Criteria –Jamaica Public Service Company Limited 2019-2024 Rate Review Process* specifies the methodology to be applied in deriving JPS' tariff. Given that JPS tariff is forward looking, it delineates the cost discounting technique to be used for addressing the time value of money.

18.123 In this regard the determination of the applicable tariff is based on the levelized price formulation which is captured in the mathematical identity below:

$$\boxed{P\sum_{y}\frac{S_y}{(1+d)^y}=\sum_{y}\frac{p_yS_y}{(1+d)^y}}$$

Where,

P = the levelized price for the tariff period;

S_y = the Billng Determinat in year 'y'; and

d = the discount rate

18.124 Therefore, the levelized price of electricity may be expressed as:

$$P = \frac{\sum_y \frac{p_y S_y}{(1+d)^y}}{\sum_y \frac{S_y}{(1+d)^y}}$$

18.125 Accordingly, $\boldsymbol{RC_y = T_{kWh} \cdot kWh_y + T_{kVA} \cdot kVA_y + T_C \cdot C_y}$ the average kWh tariff (T_{kWh}), kVA tariff (T_{kVA}) and average customer charges (T_C) are determined as follows:

$$T_{kWh} = \frac{\sum_y \frac{RR_y^{kWh}}{(1+wacc)^y}}{\sum_y \frac{kWh_y}{(1+wacc)^y}}$$

$$T_{KVA} = \frac{\sum_y \frac{RR_y^{KVA}}{(1+wacc)^y}}{\sum_y \frac{KVA_y}{(1+wacc)^y}}$$

$$T_C = \frac{\sum_y \frac{RR_y^{C}}{(1+wacc)^y}}{\sum_y \frac{C_y}{(1+wacc)^y}}$$

18.126 Further, as delineated in the *Final Criteria* the revenue cap (RCy) for each year "y" of the Rate Review period 2019 – 2024 shall be derived as follows:

$$\boldsymbol{RC_y = T_{kWh} \cdot kWh_y + T_{kVA} \cdot kVA_y + T_C \cdot C_y}$$

Approved Annual Revenue Requirement (2019-2023)

18.127 It is important to note that the approved pre-tax WACC of 11.87% adjusted for inflation was used as the discount rate in the equations above. This is critical given that the revenue requirements established in this tariff over the Rate Review period is based constant 2018 dollars.

18.128 The inflation rate used to derive the 'real discount' rate represents a blend of US and Jamaican inflation consistent with the 50%:50% equity to debt weight used in the WACC. US inflation rate of 2% was employed for the equity component. With respect to the debt component of the inflation calculation, the 80%:20% US-Jamaican ratio was applied. This is consistent with the concept that JPS cost represents an 80%:20% split between the US and Jamaican currencies. The Jamaican inflation rate used in the calculation was 4%, which reflects the average over the last 4 years. The result is a 10% real discount rate.

18.129 The OUR's analysis indicates that based of real 2018 prices the approved revenue requirement for the Rate Review period range from J$36,470M in 2019 to J$38,783M in 2023 (see Table 18.15 below).

Table 18.15: JPS' Approved Revenue Caps @ J$128.00: US$1.00

	Unit	2019	2020	2021	2022	2023
Revenue Cap @ Constant Prices	**J$'M**	37,439	**36,470**	**37,857**	**37,957**	**38,783**
Revenue Cap (Growth adjusted)	J$'M	37,362	**41,211**	-	-	-
Base Exchange Rate	J$/US$	128	**145**	-	-	-
US Inflation Rate	%	N/A	**15.4%**	-	-	-
Jamaica Inflation Rate	%	N/A	**5.5%**	-	-	-
Growth Rate	%		**13%**	-	-	-

18.130 As shown in Table 18.16 below, JPS proposed a non-fuel tariff (inclusive of all non-fuel IPP cost) of $20.39 per kWh. This represented a 17.53% increase in what JPS identified as its current non-fuel tariff (inclusive of all non-fuel IPP cost) at the time of the Application.

18.131 It is worth noting that JPS inclusion of all non-fuel IPP cost in its non-fuel tariff is some what different from the treatment given in previous Tariff Reviews. Traditionally, a fraction of the non-fuel IPP cost is captured in the fuel component of the tariff. However, this accords with the treatment of IPP cost in the future, as the fuel cost under this new tariff regime will contain no residual IPP cost. Acordingly, the OUR in its analysis has incuded all IPP costs in its non-fuel tariff rates.

18.132 Given the 2020 reveneue requirement cap at constant prices approved by the Office, and consistent with the rate designed principles throughout this Determination Notice, JPS' approved average non-fuel rate excluding IPP cost was determined to be $11.86 per kWh (see Table 18.17 below).

Table 18.16: JPS' Proposal Fuel & Non-Fuel Rate Proposal @ J$128: US$1 (Unadjusted for Inflation & Exch. Rate Movements)

	Current Non-Fuel Rate @J$128	JPS Proposal: Non-Fuel Rate@J$128		Fuel			Non-Fuel +Fuel		
		Rate	Increase	2019 Fuel Cost	2020 Fuel Cost	Increase	Current	Proposed	Increase
	J$/kWh	J$/kWh	%	J$/kWh	J$/kWh	%	J$/kWh	J$/kWh	%
RT 10 -Residential	20.59	29.11	41.37%	21.46	20.15	-6.10%	42.05	49.26	**17.14%**
RT 20 -Sm. Commercial	21.58	22.73	5.31%	21.46	20.15	-6.10%	43.04	42.88	**-0.38%**
RT 40 -Lg. Commercial (STD)	13.80	15.08	9.28%	19.81	18.60	-6.10%	33.61	33.68	**0.21%**
RT 40 -Lg Commercial (TOU)	11.87	14.56	22.69%	19.81	18.60	-6.10%	31.68	33.16	**4.69%**
RT 50 -Lg. Industrial (STD)	12.46	14.54	16.70%	19.81	18.60	-6.10%	32.27	33.14	**2.70%**
RT 50 -Lg. Industrial (TOU)	12.38	13.43	8.46%	19.81	18.60	-6.10%	32.19	32.03	**-0.50%**
RT 60 -Street lighting	26.17	23.92	-8.63%	19.81	18.60	-6.10%	45.98	42.52	**-7.54%**
RT 70 -MV Power Serv.(STD)	9.13	10.18	11.49%	19.81	18.60	-6.10%	28.94	28.78	**-0.55%**
RT 70 -MV Power Serv. (TOU)	9.88	9.91	0.34%	19.81	18.60	-6.10%	29.69	28.51	**-3.96%**
Average	**17.35**	**20.39**	**17.53%**	**20.64**	**19.38**	**-6.10%**	**37.99**	**39.77**	**4.69%**

Table 18.17: The OUR's Approved Average Non-Fuel Rates @ J$128: US$1 (Unadjusted for Inflation & Exch. Rate Movements)

	Current Non-Fuel Rate @J$128	Current Non-Fuel Rate With IPP Sur-charge		OUR Approved Without 'dI'				
		Base Level @J$128	After Fx Adj. @J$128	JPS	IPP	True-Up	Total	Increase
	J$/kWh	J$/kWh	J$/kWh	J$	J$	J$	J$	J$
RT 10 -Residential	18.68	22.40	22.40	13.74	8.20	-0.52	**21.42**	**-4.38%**
RT 20 -Sm. Commercial	19.96	23.67	23.67	9.26	13.73	-0.52	**22.47**	**-5.08%**
RT 40 -Lg. Commercial (STD)	12.10	15.67	15.67	13.55	3.01	-0.52	**16.04**	**2.40%**
RT 40 -Lg Commercial (TOU)	10.96	14.60	14.60	11.58	3.72	-0.52	**14.78**	**1.24%**
RT 50 -Lg. Industrial (STD)	10.86	14.43	14.43	7.60	5.40	-0.52	**12.48**	**-13.55%**
RT 50 -Lg. Industrial (TOU)	9.62	13.16	13.16	9.59	3.37	-0.52	**12.44**	**-5.48%**
RT 60 -Street lighting	24.52	29.05	29.05	11.19	13.45	-0.52	**24.12**	**-16.99%**
RT 70 -MV Power Serv.(STD)	11.25	15.78	15.78	9.42	1.48	-0.52	**10.38**	**-34.22%**
RT 70 -MV Power Serv. (TOU)	10.27	13.83	13.83	10.42	0.37	-0.52	**10.26**	**-25.76%**
Average	**15.92**	**19.58**	**19.58**	**11.89**	**7.29**	**-0.52**	**18.65**	**-4.73%**

18.133 The OUR also noted that given the fact that so much time had elapsed and there were pandemic induced changes in energy demand patterns, the average rates would have changed. In this respect, the use of the most recent billing determinant data as a reference for calculating the level of adjustments to the rates would yield a more accurate picture of the average bill impact. Consequently, the OUR's Rate Review analysis is predicated on the billing determinant data for 2020 October.

18.134 As shown in Table 18.17 above, in addition to JPS' non-fuel rate of $11.89 per kWh,t the average non-fuel IPP cost is $7.29 per kWh and the True-up adjustment from the previous Tariff Review period -$0.52 per kWh. The sum of these elements of cost results in an overall average non-fuel rate of $18.65 per kWh (at the Base Exchange rate of J$128.00: US$1.00) and an average reduction in the non-fuel tariff of 4.73% .

The Growth Rate

18.135 Schedule 3 of the Licence sets out the mechanism that should be applied annually to preserve the value of the annual revenue cap against the effects of inflation and changes in the exchange rate. This mechanism is referred to as the 'Growth Rate' (dI).

18.136 Accordingly, the 'Growth Rate' is defined as "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."

18.137 In light of this, and given that the implementation of the new tariff is set to take place in 2020 instead of 2019, the OUR has deemed it necessary to apply **dI** to the derived revenue requirement (in constant prices) to arrive at the applicable revenue cap for 2020.

18.138 As shown in Table 18.18 below, dI is 13%. This means that the revenue requirement of J$36,470M would have to be increased by 13% to arrive at the Revenue cap for 2020.

18.139 In computing dI, the OUR used a new base foreign exchange rate of J$145: US$1 relative to the current rate of J$128: US$1. The idea is to get to a Base Exchange Rate that is close to the latest billing exchange rate, which averaged J$146.47: US$1 over the 3-month period 2020 July-September. Hence, the change in the base FX rate is 13.28%. Additionally, the inflation data related to the computation were as follow:

- Jamaican inflation: 5.50%;
- US Inflation: 1.54%.

Table 18.18: The 2020 Growth Rate (dI)

Line	Description	Formula	Value
L1	Base Exchange Rate		128.00
L2	Adjusted Billing Exchange Rate		145.00
L3	**Jamaican Inflation Index**		
L4	CPI @ March 2020		103.6
L5	CPI @ March 2019		98.2
L6	**US Inflation Index**		
L7	CPI @ March 2020		258.1
L8	CPI @ March 2019		254.2
L9	Exchange Rate Factor	(L2-L1)/L1	13.28%
L10	Jamaican Inflation Factor	(L4-L5)/L5	5.50%
L11	US Inflation Factor	(L7-L8)/L8	1.54%
L12	**Growth Rate (dI)**	L9*[0.8+(0.8-0.0688)*L11] +(0.8-0.0688)*L11+(1-0.8)*L10	**13.00%**

The Average Approved Non-Fuel Rates for 2020

18.140 The application of the Growth Rate to the revenue cap results in the elevation of the Base Exchange rate to J$145: US$1 and a 2.02 percentage point increase in the overall average non-fuel rate as a result of inflation. This translates to an approved reduction in JPS' overall non-fuel rate of 2.71% (see Table 18.19 below).

Table 18.19: The OUR's Approved Average Non-Fuel Rates @ J$145: US$1 (Adjusted for Inflation & Exch. Rate Movements)

	Current Non-Fuel Rate @J$128	Current Non-Fuel Rate With IPP Sur-charge@J$145		2020 OUR Approved With 'dI'				
		Base Level @J$128	After Fx Adj. @J$145	JPS	IPP	True-Up	Total	Increase
	J$/kWh	J$/kWh	J$/kWh	J$	J$	J$	J$	J$
RT 10 -Residential	18.68	22.40	24.88	15.53	9.29	-0.52	**24.29**	**-2.35%**
RT 20 -Sm. Commercial	19.96	23.67	26.29	10.47	15.56	-0.52	**25.50**	**-3.00%**
RT 40 -Lg. Commercial (STD)	12.10	15.67	17.43	15.31	3.41	-0.52	**18.20**	**4.46%**
RT 40 -Lg Commercial (TOU)	10.96	14.60	16.25	13.09	4.22	-0.52	**16.78**	**3.28%**
RT 50 -Lg. Industrial (STD)	10.86	14.43	16.06	8.59	6.12	-0.52	**14.18**	**-11.70%**
RT 50 -Lg. Industrial (TOU)	9.62	13.16	14.66	10.84	3.82	-0.52	**14.14**	**-3.54%**
RT 60 -Street lighting	24.52	29.05	32.26	12.64	15.24	-0.52	**27.36**	**-15.20%**
RT 70 -MV Power Serv.(STD)	11.25	15.78	17.58	10.65	1.68	-0.52	**11.80**	**-32.86%**
RT 70 -MV Power Serv. (TOU)	10.27	13.83	15.39	11.78	0.41	-0.52	**11.67**	**-24.18%**
Average	**15.92**	**19.58**	**21.75**	**13.43**	**8.26**	**-0.52**	**21.17**	**-2.71%**

18.141 As shown in Table 18.19 above, the average rate varies from rate class to rate class, with the Power Service (STD) class (RT70) at one end of the spectrum registering a 32.9% rate reduction, and the Large Commercial (STD) class (RT40) experiencing an increase of 4.5%. These increases are more or less in line with the OUR's long run marginal cost analysis, which indicates that varying adjustments were required for various customer classes in order to send more accurate price signals to rate-payers.

18.142 Critical to the understanding of the outcome of the tariff is the changes occurring in the electricity sector. Firstly, since the last Tariff Review there has been a significant reduction in the share of generation commanded by JPS versus the output from IPP's. Currently, IPPs contribute 66% of the system net generation compared with 40% in 2014 (see Figure 18.4 below). Consequently, JPS' average non-fuel cost has declined while for IPPs' this cost has increased.

18.143 Secondly, the retirement or expected removal from service of a significant portion of JPS' old generation plants, namely the 190 MW OHPS and the 68MW HB plant has resulted in only a small reduction in the overall average non-fuel cost. This is explained by the fact that the old plants were virtually fully depreciated and the new IPPs represent new capital injections, which offers greater generation reliability.

Figure 18.4: JPS vs. IPPs Contribution to the System Net Generation

18.144 Thirdly, the new thermal IPPs are fuel by natural gas consequently; they are more efficient at converting fuel to energy. Consequently, there will be a 3.7% reduction in the fuel rate. Consequently, when both the non-fuel and fuel rates are taken into account, the overall reduction in the average electricity rate amounts to 3.2% (see Table 18.20 below).

Table 18.20: The 2020 OUR's Approved Average Rates by Customer Categories (Adjusted for Inflation & Exch. Rate Movements)

	Current Non-Fuel With IPP @J$145	JPS Proposed Non-Fuel @J$145		OUR Approved Non-Fuel		OUR's Fuel Rate @J$145					Overall Rate @J$145			Bill Impact @J$145	
		Rate	Increase	Avg. Rate	Increase	Current	JPS Proposal	OUR Approved	Proposed Increase	Approved Increase	Current	JPS Proposal	OUR Approved	JPS Proposal	OUR Approved
	J$	J$/kWh	%	J$	J$	J$	J$	J$	%	%	J$	J$	J$	J$	J$
RT 10 -Residential	24.88	32.20	29.4%	24.29	-2.4%	23.00	22.33	22.15	-2.9%	-3.7%	47.88	54.53	46.45	13.9%	-3.0%
RT 20 -Sm. Commercial	26.29	25.15	-4.4%	25.50	-3.0%	23.00	22.33	22.15	-2.9%	-3.7%	49.29	47.47	47.65	-3.7%	-3.3%
RT 40 -Lg. Commercial (STD)	17.43	16.68	-4.3%	18.20	4.5%	22.08	21.44	21.27	-2.9%	-3.7%	39.51	38.12	39.47	-3.5%	-0.1%
RT 40 -Lg Commercial (TOU)	16.25	16.11	-0.9%	16.78	3.3%	22.52	21.86	21.69	-2.9%	-3.7%	38.77	37.97	38.47	-2.1%	-0.8%
RT 50 -Lg. Industrial (STD)	16.06	16.08	0.1%	14.18	-11.7%	22.08	21.44	21.27	-2.9%	-3.7%	38.15	37.52	35.45	-1.6%	-7.1%
RT 50 -Lg. Industrial (TOU)	14.66	14.86	1.4%	14.14	-3.5%	21.90	21.26	21.09	-2.9%	-3.7%	36.56	36.12	35.23	-1.2%	-3.6%
RT 60 -Street lighting	32.26	26.46	-18.0%	27.36	-15.2%	22.08	21.44	22.15	-2.9%	0.3%	54.35	47.90	49.51	-11.9%	-8.9%
RT 70 -MV Power Serv.(STD)	17.58	11.26	-35.9%	11.80	-32.9%	22.08	21.44	22.15	-2.9%	0.3%	39.67	32.70	33.96	-17.6%	-14.4%
RT 70 -MV Power Serv. (TOU)	15.39	10.96	-28.8%	11.67	-24.2%	21.99	21.35	21.18	-2.9%	-3.7%	37.38	32.31	32.85	-13.6%	-12.1%
Average	**21.75**	**22.56**	**3.7%**	**21.17**	**-2.7%**	**22.60**	**21.65**	**21.76**	**-4.2%**	**-3.7%**	**44.35**	**44.21**	**42.93**	**-0.3%**	**-3.2%**

18.145 From the analyses of the revenue requirement along with the billing determinants in the demand forecast the approved customer, demand and energy charges for the rate categories derived. These charges and rates are set out in Table 8.21 below.

Table 18.21: JPS 2020 Approved Rates by Customer Categories
(Base Exchange Rate J$145:00: US$1:00)

Rate Category	Blocks	Customer Charge (J$/Month)	Energy Charge (J$/kWh)				Demand Charge (J$/kVA)				IPP Charge		True-up Adjustment (J$/kWh)
			STD	Peak	Partial Peak	Off Peak	STD	Peak	Partial Peak	Off Peak	Fixed IPP Charge (J$/kVA)	Est. Variable ($/kWh)	
Rate 10 STD	0 - 100	525.85	7.24									9.286	-0.523
	> 100	525.85	20.79										-0.523
Rate 10 Pre-Paid	0 - 117		22.47										
	> 117		29.56										
Rate 10 TOU		525.85		15.01	13.13	9.38							-0.523
Rate 20 STD		1,121.23	8.93									15.557	-0.523
Rate 20 Pre-Paid	0 - 10		136.09										
	> 10		23.97										
Rate 20 TOU		1,121.23		10.99	9.61	6.87							-0.523
Rate 40 STD		7,899.62	1.92				3935.24				664.67	1.195	-0.523
Rate 40 TOU		7,899.62		2.12	1.90	1.85		2148.00	1585.29	460.16	1003.76	1.476	-0.523
Rate 50 STD		7,899.62	2.14				2812.29				1745.29	2.141	-0.523
Rate 50 TOU		7,899.62		1.96	1.76	1.71		1622.89	1202.59	429.11	831.79	1.337	-0.523
Rate 60 Streetlight		3,185.33	12.25									15.239	-0.523
Rate 60 Traffic Signal		3,185.33	11.81										-0.523
Rate 70 STD		7,899.62	2.66				3106.16				424.14	0.587	-0.523
Rate 70 TOU		7,899.62		2.00	1.79	1.75		1861.95	1215.26	436.23	92.71	0.145	-0.523
Electric Vehicles				15.76	13.79	9.85							-0.523

Determination #29

After assessing all aspects of the Application, the Office has determined that:

- Subject to the Z-Factor conditions set out in Schedule 3 the Licence and the Final Criteria the revenue caps (RC_y) for 2019 – 2023 are as follows:
  - **2020:** J$36,470M
  - **2021:** J$37,857M
  - **2022:** J$37,957M
  - **2023:** J$38,783M

- The increase in JPS average non-fuel tariff (including IPP cost and the accumulated True-up adjustment) shall be 10.28% instead of 17.52% requested by the company in its Application.

- The rates to be applied by JPS to its customers' bills shall be those set out in Table 18.19. These rates are predicated on a Base Exchange Rate of J$145:00:US$1:00.

19 Decommissioning Cost and the Smart LED Streetlight Programme

19.1. DECOMMISSIONING COST

19.1.1. Introduction

19.1 Power plants, like all other physical utility assets, have a finite life beyond which their operation cannot be justified economically. Therefore, the decision to retire, mothball, or continue to operate a power plant is dependent on whether it will be able to deliver cost-competitive and reliable electricity in the future.

19.2 The commissioning and commercial operation of the SJPC 194MW NG-fired CCGT plant at Old Harbour Bay and the NFE 94MW CHP plant at the Jamalco Complex in Halse Hall, Clarendon, have triggered the retirement of the JPS' OHPS units at the end of 2019 and the B6 unit at the HBPS is scheduled for removal from service in 2020 December.

19.3 Since the retirement of the OHPS, JPS has reported that staff separation proceedings have been completed. Further, JPS has indicated that for the Rate Review period, other generating plants are scheduled for retirement, which may create the need for additional plant decommissioning. Against that background, JPS has given focus to its planned decommissioning in this review.

19.4 Given the risks involved, proper planning for plant decommissioning is necessary on the part of the utility. This is crucial to minimize negative impacts to local environments, economies, electricity ratepayers, and even taxpayers.

19.5 In light of the major generation capacity retirement at the end of 2019 and scheduled plant retirements during the Rate Review period, regulatory assessment of the post-retirement plans is warranted. This assessment is critical to ensuring that the proposed decommissioning plan and associated costs are justified and reasonable and do not impose an undue burden on the ratepayers.

Post Plant Retirement Activities

Following a plant closure, there are usually several considerations to take into account. These include:

- **Decommissioning:** This process begins after plant retirement and involves a series of activities, including removal of hazardous materials, structural demolition, and salvage & scrap recovery.
- **Remediation:** This relates to surface and subsurface property reclamation and restoration of the plant site to a safe environmental condition.

Redevelopment: Repurposing the site for other commercial applications.

These terminologies are often used interchangeably but technically, they have different connotations

19.1.2. Legal and Regulatory Framework

19.6 According to JPS, the decommissioning proposal involves the recovery of costs incurred in relation to the generation plants that will be retired from service during the Rate Review period. As defined by JPS, decommissioning activities are initiated after the retirement of an asset and refers to the process of 'dismantling the materials, equipment and structures comprising the asset, performing necessary environmental remediation and the restoration of the site to brownfield condition'. Further, the company argued that the proposed decommissioning costs are consistent with Schedule 3, paragraph 27 of the Licence, which provides for the recovery of all prudently incurred expenses of the Licensed Business.

19.7 The fact, though, is that neither the Licence nor the EA, or any other relevant regulatory instruments for that matter, makes specific reference to power plant decommissioning and the treatment of associated costs. Notwithstanding, it represents a real cost which correctly should be recognised in the Rate Review. It could also be argued that the activities associated with decommissioning could be mandated by the government in the public interest and in such an eventuality, it would hardly be in dispute that it would be treated as part of the cost to be recovered.

19.1.3. JPS' Decommissioning Proposal

19.8 In the Application, it is evident that JPS' proposed decommissioning strategy relied on:

- *A Decommissioning Plan*; this was derived from a Decommissioning Study prepared by CL Environmental Consultants and Plan D Global Demolition Engineering, dated 2019 May;
- *A Benchmark Decommissioning Cost Estimate;* JPS presented the benchmark decommissioning costs for plants decommissioned in the United States. This is shown in Figure 19.1 below to support its proposed cost estimates.

FIGURE 19.1: Benchmark Decommissioning Cost per MW

DECOMMISSIONING COST ESTIMATES PER MEGAWATT OF CAPACITY

		2016$ (thousands)		
Fuel type	No. of estimates	Minimum	Mean	Maximum
Offshore wind	7	$123	$212	$342
Coal	28	$21	$117	$466
Concentrated solar power (CSP)	5	$24	$94	$138
Solar photovoltaic (PV)	22	–$89*	$57	$179
Onshore wind	18	$2	$51	$222
Petroleum/petroleum + gas	19	$2	$31	$103
Gas (various types)	28	$1	$15	$50

*Negative cost estimates indicate that the salvage value of plant materials exceeds decommissioning costs.

Source: Resource for the Future - Decommissioning US Power Plants (2017 October)

19.9 Additionally, scrap metal rates at 2019 March from Metal Scrap Contractor (MIJ International DMCC), were provided, but it is not clear if these prices were used to derive the estimated salvage value.

Proposed Decommissioning Schedule

19.10 Based on the proposed strategy, the decommissioning activities are scheduled to be carried out in two phases to minimize disruption to operations and ensure reliability of supply during the transitional period. These are as follows:

- *Phase I Decommissioning:* this phase is to be implemented over 2019 and 2020 and comprises the decommissioning of 292MW of JPS' oil-fired steam generation capacity located at the OHPS and HBPS;
- *Phase II Decommissioning:* JPS has proposed the implementation of this phase in 2023 and it encompasses the decommissioning of a combined capacity of 171.5MW. Included in Phase II are:
    i. the Rockfort (RF) slow speed diesel (SSD) power plant - (40MW)
    ii. the GTs (ADO) at the HBPS (54MW); and
    iii. the Bogue Power Station (BOPS), including GT8 (77.5MW).

19.11 In its Application, JPS expressed an expectation that the Phase II decommissioning schedule will be validated by the IRP currently being finalized by MSET, and research is currently being done in relation to the technology that will be used to replace these plants.

19.12 JPS claimed that the Minister's Retirement Schedule as shown in Table 19.2 below informed its decommissioning proposals.

Table 19.2: Minister's Plant Retirement Schedule

MINISTER'S PLANT RETIREMENT SCHEDULE						
Single Buyer Generation Sets		**Installed Capacity (MW)**	**Commercial Operations Date**	**Letter of Notification**	**Minister's Retirement Deadline Year**	**Comments**
Old Harbour 1	OH1	30	1967	2008	2008	These five (5) plants add up to 292MW, which should have been replaced in, or around 2010. Through the Electricity Sector Enterprise Team, a Right of First Refusal (ROFR) in 2016 was granted for 190MW of the 292MW, via JPS' subsidiary, South Jamaica Power Company. The remaining 102MW may be available for ROFR depending on the results from subsequent Integrated Resource Plans.
Old Harbour 2	OH2	60	1968	2016	2019	
Old Harbour 3	OH3	65	1971	2016	2019	
Old Harbour 4	OH4	68.5	1972	2016	2019	
Hunts Bay 6	HB6	68.5	1976	2016	2020	
Bogue 8	GT8	14	1992	2018	2020	ROFR Letter of Notification Issued in August 2018
Hunts Bay 5	GT5	21.5	1973	2019	2023	
Hunts Bay 10	GT10	32.5	1993	2019	2023	
Rockfort 1	RF1	20	1985	2019	2023	

MINISTER'S PLANT RETIREMENT SCHEDULE						
Single Buyer Generation Sets		**Installed Capacity (MW)**	**Commercial Operations Date**	**Letter of Notification**	**Minister's Retirement Deadline Year**	**Comments**
Rockfort 1	RF2	20	1985	2019	2023	
Bogue 6	GT6	18	1990	2019	2023	
Bogue 7	GT7	18	1990	2019	2023	
Bogue 9	GT9	20	1992	2019	2023	
Bogue 3	GT3	21.5	1972	2019	2023	
Bogue 11	GT11	20	2001	2032	2036	134MW may be available for ROFR in 2032
Bogue 12	GT12	38	2003	2032	2036	
Bogue 13	GT13	38	2003	2032	2036	
Bogue 14	ST14	38	2003	2032	2036	
Remainder of the 292MW		102	n/a	2039	2043	102MW is the remainder of the 292MW (OH1, OH2, OH3, OH4 & B6) which should have been replaced approximately 8 years ago.

19.1.4. Proposed Decommissioning Costs

19.13 JPS has proposed the recovery of US$81.3 million of decommissioning costs over the Rate Review period. Of this amount, US$46.3 million has been attributed to Phase I and $35.0 million to Phase II.

Phase I Costs

19.14 JPS assigned Phase I costs as follows:

- Project management, decommissioning and remediation works: US$20.3 million;
- Incremental stranded asset depreciation: US$15.7 million;
- Staff separation cost: US$5.3 million;
- Stranded inventory: US$4.8 million;
- Decommissioning study: US$187,681;
- Estimated salvage value: -US$2.5 million.

Phase II Costs

19.15 Phase II costs were assigned as follows:

- Project management, decommissioning and remediation works: US$10.9 million;
- Incremental stranded asset depreciation: US$18.9 million;
- Staff separation cost: US$3.0 million;
- Stranded inventory: US$2.0 million;
- Decommissioning study: US$114,053;
- Estimated salvage value: -US$1.2 million.

Structural Demolition and Remediation

19.16 Given that depreciation expenses is addressed in this Determination Notice, for analytical purposes the OUR has opted to remove the incremental depreciation of stranded assets from this assessment of decommissioning costs.

19.17 The structural demolition and remediation may be summarized into three (3) main components: (i) demolition and site remediation, (ii) staff separation and (iii) recovery of stranded asset costs;

19.18 Table 19.3 below details the main components of the proposed decommissioning costs.

Table 19.3. JPS' Proposed Decommissioning Costs

Activity/Item	Phase I			Phase II				All Plants
	OH (#1, 2, 3,4)	HB (GT5&10)	Total	HB (GT5&10)	RF1&3	BOGUE	Total	Total
	US$'	US$'	US$'	US$'	US$'	US$'	US$'	US$'
Decommissioning Works	6,814,213	1,400,239	8,214,452	714,749	4,716,746	779,129	6,210,624	14,425,076
Environmental Remediation	9,869,083	1,908,937	11,778,020	1,272,625	1,385,494	1,594,013	4,252,131	16,030,151
Project Management Cost	208,888	95,067	303,955	-	109,642	293,800	403,442	707,397
Decommissioning Study	109,976	77,705	187,681		66,871	47,182	114,053	301,734
Sub Total	**17,002,160**	**3,481,948**	**20,484,108**	**1,987,374**	**6,278,752**	**2,714,124**	**10,980,250**	**31,464,358**
Stranded Inventory @ 2019 Mar	4,136,456	671,941	4,808,397	79,485	1,694,716	258,060	2,032,261	6,840,658
Depreciation - Stranded Assets	12,558,000	3,093,000	15,651,000	2,235,000	9,291,000	7,419,000	18,945,000	34,596,000
Sub Total	**16,694,456**	**3,764,941**	**20,459,397**	**2,314,485**	**10,985,716**	**7,677,060**	**20,977,261**	**41,436,658**
Staff Separation Cost	3,221,255	2,107,038	5,328,293	867,438	2,180,542	-	3,047,981	8,376,274
Total Decommissioning Cost	**36,917,871**	**9,353,927**	**46,271,798**	**5,169,297**	**19,445,011**	**10,391,184**	**35,005,492**	**81,277,290**
Estimated Salvage Value	-1,986,928	-486,546	-2,473,474	-57,440	-1,092,249	-63,600	-1,213,289	-3,686,763
Net Decommissioning Cost	**34,930,943**	**8,867,381**	**43,798,324**	**5,111,857**	**18,352,762**	**10,327,584**	**33,792,203**	**77,590,527**

Inventory Spares

19.19 JPS asserts that its inventory spares represent specialized inventory unique to the operation of generating plants at each location. With the plant retirements, the stock of inventory spares will become obsolete, as they cannot be used on other plants operating in the fleet. JPS claimed that such inventory will become stranded assets and the associated costs must be recovered through the tariff.

Staff Separation

19.20 In the Application, JPS indicated that the staff separation component of the proposed decommissioning expenditure includes staff separation costs associated with the plants that are to be taken out of service.

19.21 The OUR's preliminary review of the proposed separation costs revealed a number of discrepancies, which were pointed out to JPS. The cost schedules were eventually revised and re-submitted as part of the clarifications and additional information requests. The revised staff separation costs are provided in Table 19.4 below.

Table 19.4: JPS' Revised Proposed Staff Separation Costs

Plant(s)	2019 -2020 Rate Review		
	JPS Porposal		Decommissioning Date
	J$M	US$M	
PHASE I			
Old Harbour -OH #2, 3 & 4	784.04	3.221	*2019 Dec*
Hunts Bay - B6	265.09	2.107	*2020 Dec*
Total -Phase I	***1,049.13***	***5.328***	
PHASE II			
Hunts Bay -GT10 & 5	104.92	0.867	*2023*
Rockfort	296.70	2.181	*2023*
Bogue	-	-	*2023*
Total -Phase II	***401.62***	***3.048***	
Grand Total	**1,450.75**	**8.376**	

19.22 As shown in Table 19.4 above, JPS is proposing the recovery of J$1,450.7M of separation cost over the Rate Review period, with J$1,049.1 attributable to Phase I staff redundancy and the remaining J$401.6 to be incurred in Phase II.

19.23 Relative to its 2018 Annual Review Application, JPS noted that the increase in its separation cost is explained by:

- A delay in the commissioning of the SJPC 194MW plant, which resulted in an increase in the tenure of its staff;
- Further adjustments have been made to accommodate the conclusion of the wage negotiations between JPS and some of its labour unions for the negotiating period 2018 January 1 to 2020 December 1.

19.1.5. OUR's Findings and Position

19.24 The OUR's findings and positions emanating from the decommissioning review are delineated in the sections below.

Decommissioning Plan

19.25 In its assessment of JPS' Decommissioning Plan, the OUR takes the view that:

a) The supporting decommissioning study does not appear to sufficiently address the key requirements for prudent and cost-effective plant decommissioning;

b) Based on the proposal, it appears that the company is seeking to pursue a "utility managed" decommissioning approach, but has failed to justify the costs of the proposed decommissioning activities, as well as to demonstrate the benefits to be gained by the ratepayers;

c) The proposed decommissioning strategy appears to suffer from a number deficiencies, primarily related to its inadequacy in evaluating other options applicable in a decommissioning event, including the following:

19.26 *Sell As-Is for Decommissioning and Redevelopment:* This option involves selling the retired power plants as-is. Based on their location, these sites could have significant redevelopment potential, especially for other commercial and industrial operations. Due to this feature, buyers and project developers may be willing to assume the risk of decommissioning in exchange for a risk-adjusted lower purchase price. Remediation costs can be included and risks can be managed through the use of contract terms, environmental insurance, and other means. Sale for redevelopment is often a preferred option for plant owners because it allows them to monetize the retired asset and mitigate risks. However, even though the this option has a low probability of succeeding, it merits some consideration in the company's overall decommissioning strategy.

19.27 *Replacement with New Generation by JPS:* Given the strategic location of these plant sites, there is huge potential for them to be used for future construction of new generation facilities. In the Application, the company articulated that it plans to use the decommissioned plant sites for repowering and the objective is to restore the sites to "brownfield" conditions, suitable for industrial applications. Further, the company asserted that its strategic plan encompasses the identification of plants for decommissioning and the development of suitable replacement generation to ensure continuity of supply to the grid. The company also indicated that in relation to the OH and HB sites, procedures have already been completed. Moreover, the company has maintained that it has 102MW remaining from the 292MW ROFR allotment, which is projected to increase due to impending plant retirements. According to the company, it intends to exercise its ROFR for this capacity in the future. This planned generation capacity development is likely to be structured in the form of an IPP arrangement, as in the case of the SJPC plant. Given this dynamic, the replacement with new generation option would appear to be an effective approach to take care of a majority of the proposed decommissioning, without imposing undue cost burden on the consumers. However, the company appears to have not adequately explored this option, which is in its own favour. Notably, under such development scenarios, the generation company or utility would normally have to assume the costs of site acquisition and preparation. So, given the company's repowering objectives, the fundamental question is, why should the ratepayers be required to bear the burden of these decommissioning costs? Based on the proposal, this question has not been answered by the company.

19.28 *Replacement with New Generation by IPPs:* The site could also be attractive to private generation companies interested in power plant development. Despite this possibility, no information was presented showing that this option was evaluated as part of the decommissioning strategy.

Decommissioning Costs

19.29 The main issues identified from the review of the proposed plant decommissioning costs, include:

a) Based on the benchmark decommissioning costs for petroleum-based power plants at mean value, the proposed costs for decommissioning and site remediation of OH (#1,2,3&4), HB B6, and RF plants appear to be excessive, particularly in the context of the cost of previous decommissioning exercises done by JPS;
b) Scrap price listing of plant components was presented, but there was no detailed breakdown or projection in terms of revenues based on an estimated level of scrap recovery;
c) The proposed decommissioning costs were not supported by any indicative scope of services and cost quotations from demolition contractors;
d) There were no projections on the land value before and after the proposed decommissioning works and site remediation. In cases where decommissioning is pursued through redevelopment strategies, land acquisition costs are generally equal to fair market value less structural demolition and remediation costs. However, as previously indicated, the proposed strategy was found to be deficient in exploring alternative options; and
e) The value of the land at the relevant plant sites was not factored into the proposed decommissioning costs. By not offsetting the decommissioning cost with the value of the land, creates a problem, in that, ratepayers are being asked to fully restore the plant sites, thus increasing their commercial value in favour of the utility. This is deemed unreasonable and not in the interest of the customers.

Salvage Value

19.30 JPS has estimated that the total salvage value for the OHPS and the HB B6 unit is US$2,473,474. Of this amount, US$1,986,928M is to be derived from the OHPS and $486,546M from the B6 unit.

19.31 Based on the proposal for each plant retired, the monetized salvage & scrap value is intended to offset the total decommissioning cost. However, no valuation documentation was provided to support the salvage value estimates. Further, it may be argued that the value of the plant as assessed in the last valuation could give an indication of this value, but that was not provided.

19.32 Notwithstanding, the Office has determined that as a temporary measure, JPS' proposed Phase I cost will be provisionally accepted. Consequently, the proposed salvage value shall be set-off against the total decommissioning cost allowed by the Office. However, JPS shall be required to get an independent valuation by an expert or through a competitive bidding process within eighteen (18) months of the effective date of this Determination Notice, which will allow the OUR to make the required adjustments to the tariff.

Decommissioning Schedule -2023

19.33 According to the Minister's Retirement Schedule, generating units from the HBPS, RF power plant and the BOPS (171.5MW) are slated for retirement at the end of 2023. While the timing for plant retirement is noted, this does not mean that decommissioning would immediately occur.

19.34 As a practical matter, due to load/generation uncertainties, commitments and timetable for new capacity additions, IRP projects implementation and system security requirements, the projected retirement dates may be delayed. Hence, even though it is necessary to plan ahead, it might not be prudent to put the decommissioning costs of these plants in the tariff at this point.

19.35 Further, the Application will be due by 2024 April, and at that juncture, there should be greater certainty regarding the retirement of these plants. As such, the OUR takes the view that it would be more appropriate to evaluate the decommissioning of these plants during the 2024-2029 Rate Review process. On that basis, no further consideration will be given to the Phase II decommissioning proposal in this Rate Review.

OUR's Position – Structural Demolition and Remediation

19.36 JPS' proposed cost for decommissioning 477.5MW of its generation plants is US$81.28M which translates to US$170,214 per MW. This proposed cost is almost six times the average cost of performing this exercise based on international benchmarks derived from Daniel Raimi's *"Decommissioning US Power Plants"* study, referred to by JPS in its Decommissioning analysis. The mean decommissioning cost for petroleum/gas plants in the Daniel Raimi's study of US plants is US$31,000.

19.37 Additionally, the Raimi study indicates that the maximum decommissioning cost petroleum/gas plants is US$103,000 per MW. JPS' proposed decommissioning cost of US$170,214 per MW exceeds this maximum by approximately 65%.

19.38 International best practice suggests that *"Planning properly for the decommissioning of these facilities is essential to minimize negative impacts to local environments, economies, electricity ratepayers, and taxpayers."*

19.39 Using the mean decommissioning works and environmental remediation benchmark cost of US$31,000 per MW, the OUR derived what would be a fair estimate of the expenses that JPS should incur for the HB B6 unit and the OHPS. As shown in Table 9.5 below, the total estimated decommissioning and remediation cost inclusive of project management fees would be US$9.052M.

19.40 It is worth noting that JPS prepared Decommissioning Plans for its HB B6 unit and the OHPS in 2013. The Decommissioning plans reveal that the decommissioning and environmental remediation costs associated with the HB B6 unit and the OHPS were US$2.702M and US$7.651M respectively as shown in Table 9.5 below. The total cost based on JPS' Decommissioning Plan is therefore US$10.353M or 14.4% more than the Daniel Raimi's benchmark study. This cost difference could be explained by conditions specific to the plant sites. However, the costs in JPS' Plan are reasonable.

19.41 The OUR takes the view that the JPS estimates of US$10.353M in its Decommissioning plans are a better guide to the cost of the exercise. However, given that JPS' Decommissioning plans were developed in 2013, they should be adjusted for inflation to translate them to 2018 US$. In this regard, it is estimated that the annual US inflation rate over the period 2013-2018 was 2% per annum. Hence, the inflation-adjusted decommissioning and remediation costs (inclusive of project management fees) using this approach is US$11.431M.

19.42 Given what is clearly a case of inadequate consideration for the prudent and cost-effective decommissioning of plants and the failure of JPS' Decommissioning study to explore other cost saving options, there is a high risk that customers would end up paying significantly more than what is required.

19.43 In light of this, the OUR has decided that JPS' decommissioning proposal as it relates to the decommissioning works and environmental remediation shall be based on its Decommissioning Plans adjusted for inflation. Accordingly, as shown in Table 19.5 below, the total approved decommissioning and remediation cost inclusive of project management fees is US$11.431M.

Table 19.5: OUR Approved Demolition & Remediation Costs (Inclusive of Project Management Fees)

Station	Plant	Capacity (MW)	Decommissioning Cost (US$)	
			International Benchmark (2016)	JPS 2013 Plan
Old Harbour	OH1	30	930,000	
	OH2	60	1,860,000	
	OH3	65	2,015,000	
	OH4	68.5	2,123,500	
Total -Old Harbour		**223.5**	**6,928,500**	**7,651,360**
Hunts Bay	HB6	68.5	2,123,500	
Total -Hunts Bay		**68.5**	**2,123,500**	**2,702,000**
Grand Total			**9,052,000**	**10,353,360**
Approved Grand Total @ 2018$US				**11,430,946**

OUR's Position – Inventory Spares

19.44 JPS has proposed the recovery of inventory spares costs amounting to US$4,136M and US$0.671M for the OH and HB plants respectively. JPS argued that these inventory spares will become stranded due to the retirement of the plants and should be recovered through the approved rates.

19.45 The OUR recognises that at any point in time, it is a good maintenance practice to have a minimum level of spare parts to optimize the operation of the generation plant. However, this proposal is difficult to justify given that from as far back as 2016, if not before, the company was fully aware that the OHPS and the HB B6 would be retired in 2019.

19.46 Consequently, appropriate winding-down operations and procedures should have been activated to reduce the possibility of the obsolescence of spares. Therefore, the extent and magnitude of cost associated with the purported stranded inventory spares, would appear to be sub-optimal and less than prudent.

19.47 In assessing the spare parts data provided by JPS, the OUR observed that some items referenced for other power plants were included in the data. Therefore, along with spares for the B6 unit, there were also spares for the GT4, GT5 and GT10 units in the inventory data. In this regard, the OUR's assessment indicates that the US$0.671M requested for the B6 unit should be reduced to US$0.403M.

19.48 With respect to the OHPS, the data submitted by JPS included (a) items that could not be classified as spares; (b) items referenced to other power stations; and (c) spares that were not specifically defined. Based on the OUR's analysis of the costs, it is concluded that of the US$4.136M stranded spare parts claim submitted by JPS, only US$2.655M is recoverable though the tariff.

19.49 In light of the above, and even though adjustments were not made for poor planning and inefficiency on the part of the utility, the OUR approves US$2.655M of the OHPS stranded spares, which together with US$0.403M allowed for the HB B6 unit translates to a total approval of US$3.058M of stranded spare costs to be passed on to customers.

19.50 Additionally, spares included in JPS' PPE are correctly addressed as accelerated depreciation, therefore, to award a recovery for the depreciation of spare parts as presented in JPS' proposal would be tantamount to regulatory double counting.

OUR's Review JPS' Proposed Staff Separation Cost & Study Cost

19.51 The OUR is cognizant that closure of a power plant will result in some amount of staff separation, for obvious reasons. Due to contractual labour arrangements between the company and the affected employees, some separation payments by the utility will be necessary. However, from a regulatory perspective, the separation costs incurred or to be incurred by the company, must be reasonable and prudent, and in accordance with relevant laws, regulations and labour contracts. This forms part of the context for the OUR's review of the proposed staff separation costs.

Separation Cost Calculations

19.52 Based on JPS' calculation schedules, the proposed separation costs include a redundancy cost and a "notice cost" component, as shown in Table 19.6 below. To reiterate, the Phase II costs will not be considered in this Determination Notice, consequently JPS' proposed separation cost scheduled for 2023 will not be assessed here.

Table 19.6: Breakdown of JPS' Proposed Power Plant Staff Separation Costs

Plant	Projected Retirement Date	Redundancy Cost (J$M)	Notice Cost (J$M)	Total (J$M)	Notice Cost % of Total	Comment
OHPS	-	729.04	55.00	784.04	7.0%	Plant retired 2019 Dec
HBPS B6 Unit	2020 Dec	245.90	19.09	265.09	7.2%	Initial Retirement Date – 2020 Jul
HBPS GT5&10	2023 Dec	96.90	8.02	104.92	7.6%	
RF Power Pant	2023 Dec	270.35	26.35	296.70	8.9%	

19.53 There were two components to JPS' staff separation cost; (1) redundancy cost, and (2) notice cost. The redundancy costs calculation was based on the following formulas:

- Years of service * annual basic pay * 8% (1-10years);
- Years of service * annual basic pay * 10% (over 10 years).

Notice Costs

19.54 The notice costs is applied in accordance with the provisions of section 3(1) of the Employment (Termination and Redundancy Payments) Act (ETRPA) in Part II: Minimum period of notice, and right to certain facilities, which states:

> *"3. - (1) The notice required to be given by an employer to terminate the contract of employment of an employee who has been continuously employed for four weeks or more shall be -*
> *(a) not less than two weeks' notice if his period of continuous employment is less than five years;*
> *(b) not less than four weeks' notice if his period of continuous employment is five years or more but less than ten years;*
> *c) not less than six weeks' notice if his period of continuous employment is ten years or more but less than fifteen years;*
> *(d) not less than eight weeks' notice if his period of continuous employment is fifteen years or more but less than twenty years;*
> *e) not less than twelve weeks' notice if his period of continuous employment is twenty years or more, and shall be in writing unless it is given in the presence of a credible witness."*

19.55 Regarding these legal provisions, JPS acknowledges that it has a duty to observe and abide by the relevant laws governing employee termination and redundancy payments and in respect of the OHPS staff separation cost estimates, notes that:

> *"In observing the ETRPA the company found it more prudent to issue payment in lieu of notice rather than issuing an actual notice. According to the company, a letter of notice allows the worker to have tenure over the period of the notice and benefit from monthly payments complete with basic pay and full benefits as well as any applicable increased rates for salary and benefits based on the recently concluded labour union negotiations while payment in Lieu of notice considers basic pay only. Hence, given the current state, it is more beneficial to customers for separation to be done for certain critical functions without notice."*

19.56 As shown in Table 19.6 above, notice costs account for over 7% of the total separation cost, which is a concern. The issue is that in the case of the OHPS, the company has been aware from the outset that the plant closure was imminent, and should have exercised greater diligence in administering the staff separation process, pursuant to the legal requirements. Instead, to compensate for not issuing timely termination notices, it unilaterally took the decision to adopt a ‘payment in lieu of notice arrangement’ without consultation with the OUR, which is unacceptable.

19.57 It is also worth noting that in recent times, there has been a trend in international dispute relations towards greater transparency in the handling of staff redundancies. The trend is towards a process of timely notification.

19.58 In light of the above, any action taken to incur notice cost by the company without prior approval by the OUR are deemed to be imprudent and are therefore disallowed from being recovered from customers in the tariff.

Separation Cost: Old Harbour Power Station

19.59 In the 2018 Annual & Extraordinary Rate Review Determination Notice, the OUR approved the recovery of 50% or J$296.7M (US$2.32M) of the staff separation costs for the OHPS. JPS in its Application is proposing the recovery of the remaining 50% of the staff separation cost which it adjusted upwards to J$784.04M (US$3.2M).

19.60 JPS in its Application, estimated that the entire OHPS would be separated by 2020 January, which is no different from what was deduced from the signals the company set out in its 2018 Annual Review Application. Since, the decommissioning of the OHPS was scheduled for 2019 December, the completion of the OHPS staff separation in 2020 January would be normal. The argument concerning extension of employees’ tenure in this case is invalid and the original determination that JPS should be awarded an additional J$296.7M over the Rate Review period still stands.

19.61 Additionally, the Office had approved the recovery of J$296.7M in relation to the OHPS over a 12-month period. Billed sales for the 12-month period immediately following the 2018 Annual & Extraordinary Rate Review Determination Notice (i.e. 2018 Oct – 2019 Sep.) amounted to 3,220 MWh, which means that JPS generated J$315.4M during that period for separation cost.

Separation Cost: Hunts Bay B6 Unit

19.62 Even though, JPS in its 2018 Annual Review Application had indicated that the separation cost for the HB B6 plant was US$3.3M (J$422.4M), in its Application the cost was reduced to J$265.09 (US$2.107M). This apparently is the result of a refinement, which correctly should be done given the proximity of the decommissioning event. The Office therefore accepts the J$245.897M redundancy cost in JPS’ proposal.

19.63 Based on the initial retirement date of 2020 July, which apparently has been shifted to 2020 December, this should have allowed ample time for the company to effect the relevant notices of contract termination in accordance with the ETRPA. On that basis, the notice costs of J$26.35M related to the staff separation has been disallowed.

Decommissioning Study Cost:

19.64 JPS also included the recovery of US$187,681 for the cost incurred in conducting the Phase 1 Decommissioning Study. This study like others done in relation to the JPS Rate Review is deemed to be a part of the cost of doing business, and would have been included in a general way in the last tariff.

19.65 Furthermore, unless there is a specific agreement concerning past expenditure, the existing forward looking tariff methodology has no scope for retrospective compensations. Against this background, the Office does not approve JPS' proposal for the recovery of the Decommissioning Study Fee.

Conclusion

19.66 In light of the various components of the proposed decommissioning cost the Office has approved at a Net Decommision Cost of US$14.067M (see Table19.7 below). This is comprised of:

- Decommissioning & remediation cost (including Project Mgmt Fees):US$11.431M
- Stranded inventory cost: US$3.058M
- Separation cost: US$2.052M
- Salvage value: -US$2.474M

19.67 The total decommissioning cost shall be recovered by JPS over the four (4) year period, 2020 – 2023.

Table 19.7: Decommissioning Cost Summary - JPS' Proposal vs. OUR's Approved

Activity/Item	Phase I			
	JPS Proposal		OUR Approved	
	US$'000	J$'M	US$'000	J$'M
Decomm. Remediation & Project Mgmt	20,296.4	2,597.9	11,430.9	1,463.2
Decommissioning Study	187.7	24.0	0.0	0.0
Sub Total	**20,484.1**	**2,622.0**	**11,430.9**	**1,463.2**
Stranded Inventory @ 2019 Mar	4,808.4	615.5	3,057.9	391.4
Depreciation - Stranded Assets	15,651.0	2,003.3	0.0	0.0
Sub Total	**20,459.4**	**2,618.8**	**3,057.9**	**391.4**
Staff Separation Cost	5,328.3	682.0	2,052.1	262.7
Total Decommissioning Cost	**46,271.8**	**5,922.8**	**16,541.0**	**2,117.2**
Estimated Salvage Value	-2,473.5	-316.6	-2,473.5	-316.6
Net Decommissioning Cost	**43,798.3**	**5,606.2**	**14,067.5**	**1,800.6**
Annual Decomm Cost Recovery (4yrs)	**10,949.6**	**1,401.5**	**3,516.9**	**450.2**

DETERMINATION #30

Based on the OUR's review of JPS' decommissioning proposals, the Office has determined that:

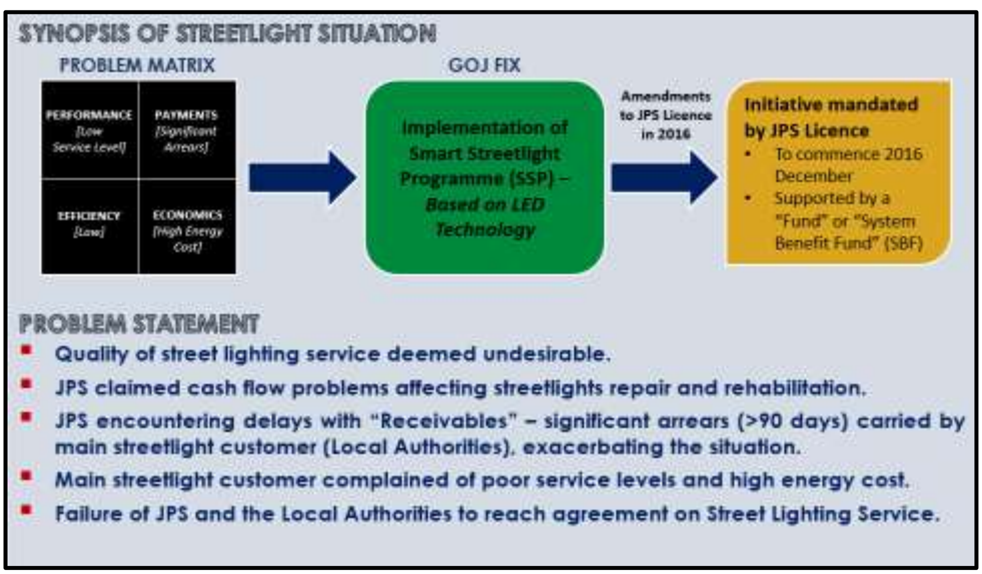
a) Given the uncertainties surrounding JPS' Phase II decommissioning and its proximity to the next Rate Review Process, the costs associated with that exercise shall be examined in the 2024 – 2029 Rate Review.
b) The total net decommissioning cost approved is US$14.067M (or J$1,800.6M), which shall be recovered in equal parts of US$3,516.9M (or J$450.2M) over the four (4) year period 2020 – 2023.

19.2. JPS SMART LED STREETLIGHT PROGRAMME

19.2.1. Background

19.68 At the 2014-2019 Rate Review, JPS asserted that its performance in relation to streetlights repairs in previous years was undesirably low, which was primarily due to the unavailability of resources to fund the repair and rehabilitation of streetlights. JPS argued that over time its operation has been adversely impacted by significant arrears (more than 90 days on average) being carried by the primary customer of streetlight services. JPS also posited that public lighting is a valued and important service for the safety, security, and welfare of the public. The company indicated that it is committed to addressing the street lighting situation once the normal funding stream of streetlight service payment is resolved. From the perspective of the main streetlight customer (Local Government Authorities), the critical factors under consideration, were relatively poor service levels and high energy costs (Refer to Figure 19.1 below).

Figure 19.1: Streetlight Situation prior to Smart Streetlight Programme



19.69 Given the prevailing issues, in 2016, the Government of Jamaica (GOJ), in keeping with its broad energy sector objectives to promote energy efficiency (EE), economic service delivery and environmental sustainability, mandated JPS to implement the SSP based on advanced lighting technology across the country. This initiative was considered a practicable and feasible solution to address the problematic street lighting issues, including affordability, billing/receivables, performance levels and reliability.

Programme Objective

19.70 Broadly, the implementation of the SSP is in part fulfilment of the GOJ's overall grid modernization and EE objectives for the electricity sector, as outlined in the National Energy Policy (NEP) framework. Against that background, the main objective of the SSP is to ensure continued improvements in the operational efficiency of the electricity system and the provision of affordable and sustainable street lighting services in Jamaica. More specifically, the SSP is expected to realize improvements in EE, peak demand shaving, energy cost savings, and other system benefits. While these benefits are promising, given the scale and scope of the programme, strict regulatory oversight will be necessary to ensure that it is executed in a prudent, transparent and cost effective manner.

Smart Streetlight Programme Scope

19.71 As reported by JPS, the scope of the SSP encompasses the complete replacement of 105,000 existing grid-connected streetlight fixtures (according to 2013 JPS/Local Government Streetlight Audit), of mostly high pressure sodium (HPS) with smart LED types. Based on JPS' initial SSP implementation plan, the programme was scheduled to be executed in three (3) phases over the period, 2017 - 2020. To date, phases 1 & 2 have been reported as complete, with phase 3 ongoing.

19.2.2. Regulatory Review

19.72 This review involves JPS' proposed SSP activities, costs and performance requirements over the Rate Review period.As part of the review process, the OUR engaged JPS on certain aspects of its SSP proposal that were found to be deficient, and requested clarifications and additional information on various components. A response to the streetlight information request was submitted by JPS on 2020 February 14. Accordingly, the OUR's review of the SSP was based on all streetlight information submitted up to 2020 February 14.

19.73 To assess the merits and impact of the ongoing SSP implementation, the OUR conducted a comprehensive review and evaluation, including the relevant supporting data, documentation and schedules. The details of the OUR's review and findings are outlined in the sections below.

Licence Requirements

19.2.3. Obligation to Implement Smart Streetlight Programme

19.74 Condition 28 6. of the Licence, requires that by 2016 December 30, JPS commence a programme for the implementation of smart LED lighting technology that has intelligence capable of remotely reading the consumption of each lamp; provides a unique identifier; allows for identification of out-of-service lamps; provides for the dimming of lights when necessary; can accommodate video surveillance and other smart features and is designed in line with international best practices. According to the provisions of the Licence, the programme is designated the "Smart Streetlight Programme".

19.75 According to Condition 28 7. of the Licence, in the event that Licensee has not completed the SSP by the next rate review or extraordinary rate review following the 2016 January amendment of the Licence, it shall include the SSP in its Business Plan to guide the calculation of the Revenue Requirement necessary to allow the Licensee to recover the costs of the SSP.

19.2.4. Smart Streetlight Programme Funding

19.76 With respect to funding, pursuant to Condition 28, paragraph 6 of o the Licence , the Office shall utilize a Fund or the SBF, as defined in the EA, to allow the company to recover the costs of implementing the SSP. Subsequently, in 2017 August, the Minister of Science, Energy and Technology, issued an order authorizing the use of the SBF for JPS to recover the cost of implementation of the SSP. Notably, at the start of the SSP in 2016, the SBF was not yet established, however, JPS indicated that it secured financing from other sources, for phase 1 of the programme, so as to meet its Licence obligations.

19.2.5. Smart Streetlight Programme Implementation

19.77 As previously indicated, the SSP was scheduled to be executed in three (3) phases over the period 2017 - 2020. However, as the SSP progressed, the streetlight replacement schedule was altered several times by the company, and cited the following reasons:

- Challenges in securing capital for project funding; and
- Financial constraints due to arrears involving the primary customer for streetlight services.

19.78 Due to deviations from initial project timelines, the company in its Application has provided a revised schedule for the replacement of the remaining HPS streetlights, indicating full completion of the programme in 2021.

Smart Streetlight Programme Implementation Approach

19.79 Based on reports from JPS, the SSP implementation approach primarily involves the following activities:

1) Procurement/Selection of Suppliers and Contractors; and
2) Physical LED/HPS Streetlight Replacements.

Procurement

19.80 To achieve the project objectives, the company reported that it carried out a number of key procurement activities, including request for proposals (RFP) and selection of suppliers & contractors, starting 2016 September to 2017, prior to the commencement of phase 1 streetlight replacements in 2017 June.

19.81 Resulting from the procurement process, the suppliers and contractors selected by JPS to facilitate the implementation of phase 1 of the SSP are listed in Table 19.7 below.

Table 19.7: JPS Selected Suppliers and Contractors for SSP (Phase 1) Implementation

SSP: SELECTED SUPPLIERS, CONTRACTORS AND SERVICES	
SUPPLIER	**PRODUCT/SERVICE OFFERINGS**
LED Roadway Lighting	58W LEDs
Philips Lighting	108W & 161W LEDs
Cimcon Lighting	Smart Controller
Silver Spring Networks	Communication System
S&T Electrical	Installation works
M&O Traders	Installation works

Streetlight Power Rating and Luminous Intensity Equivalence

19.82 The estimated power rating (Watts) of the new LED streetlights to deliver the equivalent luminous intensity of the HPS type, were determined through field testing by JPS. The relative power ratings are shown in Table 19.8 below.

Table 19.8: Power Rating - HPS and Replacement LED Streetlights

POWER RATINGS: HPS VERSUS LED STREETLIGHTS	
HPS	**LED**
< 100W	58W
≤ 250W	108W
≤ 400W	161W or 162W

Streetlight Replacement Activities

19.83 Based on, a status report from JPS dated 2018 February 15, a schedule for streetlight replacements was presented, as shown in Table 19.9 below.

Table 19.9: JPS' Streetlight Replacement Schedule (2018 February 15)

SCOPE	YEAR 1 [PHASE 1]	PHASE 1 (Actual)	YEAR 2 [PHASE 2]	YEAR 3 [PHASE 3]	TOTAL	Remarks
Installation Target	35,000	36,440	16,500	52,060	105,000	Phase 1 completed – 2017 Dec
Schedule	2017 JUN – DEC		2018 JUN - DEC	2019 APR - DEC		

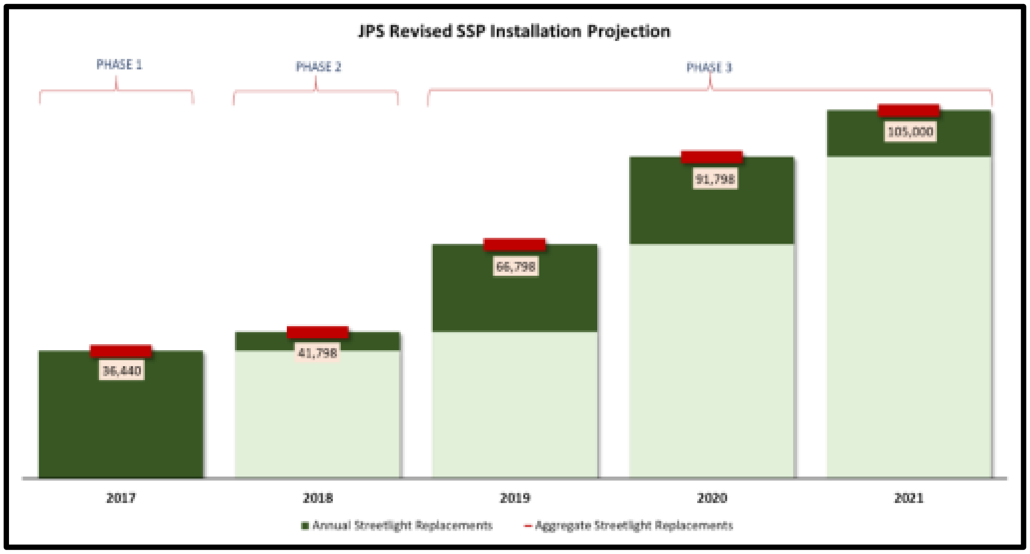
19.84 Subsequently, the projections for phases 1 & 3 were revised as shown in Table 19.10 below.

Table 19.10: JPS' Revised SSP Phases 2 & 3 Projections

Phase	Period of Activity	Target (No. of Lamps)	Capital Cost (US$M)	Remarks
2	2018 June - December	5,358	2.7	Cost based on 2019 Data
3	2019 February - December	25,000	8.4	Cost based on Rate Review Submission
3	2020 February – October	25,000	10.1	Cost based on Rate Review Submission
3	2021 January - June	13,202	6.5	Cost based on Rate Review Submission

19.85 The LED/HPS streetlight replacement target of 25,000 lamps in 2019, was found to be consistent with the streetlight schedule accompanying the Application. Based on the information provided in Table 19.10 above and the actual phase 1 replacement details provided in Table 19.9, the annual streetlight replacement trajectory is as shown in Figure 19.2 below.

Figure 19.2: JPS' Annual & Aggregate Projected Streetlight Replacements



19.2.6. Smart Streetlight Programme Achievements

19.86 Based on JPS' detailed LED/HPS replacement dataset for the period 2017 June 11 to 2019 December 12, ("the 2019 December SSP Dataset"), the number of streetlight replacements reported as at 2019 December 12, is <u>65,613,</u> representing approximately 62.5% of the 105,000 streetlight identified for replacement. The breakdown of the replacement over the period 2017 June – 2019 December, is presented in Figure 19.3 below.

<u>OUR's Observations and Comments</u>

1) As shown, the number of LED/HPS streetlight replacements in 2018 was drastically reduced from earlier plans, and in addition, the schedule for completion of installations was extended by approximately 18 months.

2) The reduction in the number replacements in 2018, was purportedly due to financial constraints impacting the company, at the time.

3) Streetlight replacement data provided in the SSP datasets (submitted 2020 June and 2020 February), and similar type information provided in Annex VII of the Application, show a number of discrepancies. The discrepancies observed, specifically relate to variations in the number of monthly and annual streetlight replacements for 2017 and 2018. It is not clear why these disparities exist between information sets, however, such differences reduce confidence in the accuracy of reported data.

4) In JPS' Business Plan, there are a number of references indicating that the total number of LED/HPS lamp replacements is 110,000, which contradicts the identified 105,000 existing streetlights widely reported elsewhere, including in the Application. This may require explanation from JPS.

5) The 2019 December SSP Dataset, captured the streetlight inventory information (47,735 LED/HPS replacements), which was previously submitted by JPS for the period 2017 June 11 to 2019 June 13 (“the 2019 June SSP Dataset”).

6) The 2019 December SSP Dataset indicates that:

a) All replaced lamps were of HPS type, with a power rating of either 100W, 250W or 400W;

b) The installed LED lamps were manufactured by either Philips or LED Roadway, with one of the following four (4) power ratings: 58W, 108W, 161W or 162W; and

c) Streetlight replacement occurred across all fourteen parishes during the subject period.

19.2.7. Streetlight Replacement Sequence and Cumulated Demand Impact

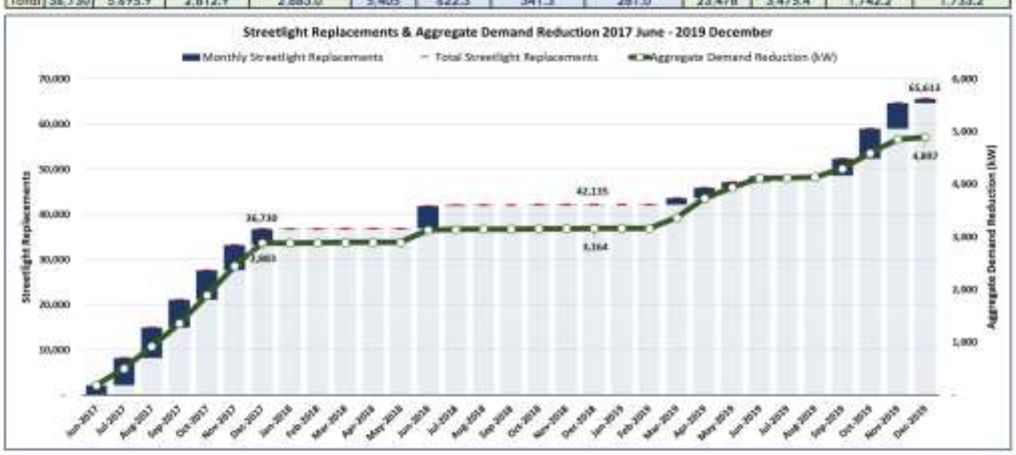
<u>Streetlight Replacement Trajectory</u>

19.87 Based on the information provided in the 2019 December SSP Dataset, the monthly LED/HPS replacements and the associated demand impact (kW) over the subject period, are as shown in Figure 19.3 below.

Figure 19.3: Monthly Streetlight Replacements and Demand Impact

MONTHLY STREETLIGHT REPLACEMENTS AND RESULTING REDUCTION IN DEMAND

	2017				2018				2019			
	#	Demand (kW)		Demand Reduction (kW)	#	Demand (kW)		Demand Reduction (kW)	#	Demand (kW)		Demand Reduction (kW)
Mth		Replaced HPS Lamps	Replacement LED Lamps			Replaced HPS Lamps	Replacement LED Lamps			Replaced HPS Lamps	Replacement LED Lamps	
Jan					8	2.0	0.9	1.1	0	0.0	0.0	0.0
Feb					32	8.0	3.5	4.5	6	2.4	1.0	1.4
Mar					72	15.6	7.0	8.6	1,430	356.6	154.7	201.9
Apr					1	0.4	0.2	0.2	2,367	643.4	274.8	368.5
May					3	0.9	0.4	0.5	1,248	353.3	149.6	203.6
Jun	2,158	361.6	174.8	186.8	5,013	507.2	303.0	204.2	1,306	321.6	140.0	181.6
Jul	6,000	700.5	381.9	318.6	179	24.1	12.5	11.6	31	3.4	1.9	1.5
Aug	6,748	878.8	460.2	418.6	24	6.0	2.6	3.4	74	28.4	11.6	16.8
Sep	6,205	888.7	450.9	437.8	0	0.0	0.0	0.0	3,706	378.7	217.7	161.0
Oct	6,501	1,043.1	510.6	532.5	40	16.0	6.4	9.6	6,651	686.6	393.0	293.6
Nov	5,557	1,044.1	486.5	557.6	3	0.3	0.2	0.1	5,674	600.3	340.1	260.2
Dec	3,561	779.1	347.9	431.2	30	11.9	4.8	7.0	985	100.9	57.9	43.0
Total	36,730	5,695.9	2,812.9	2,883.0	5,405	622.3	341.3	281.0	23,478	3,475.4	1,742.2	1,733.2



19.88 The streetlight replacements represented across service areas and by geographical dispersion are illustrated in Figure 19.4 below.

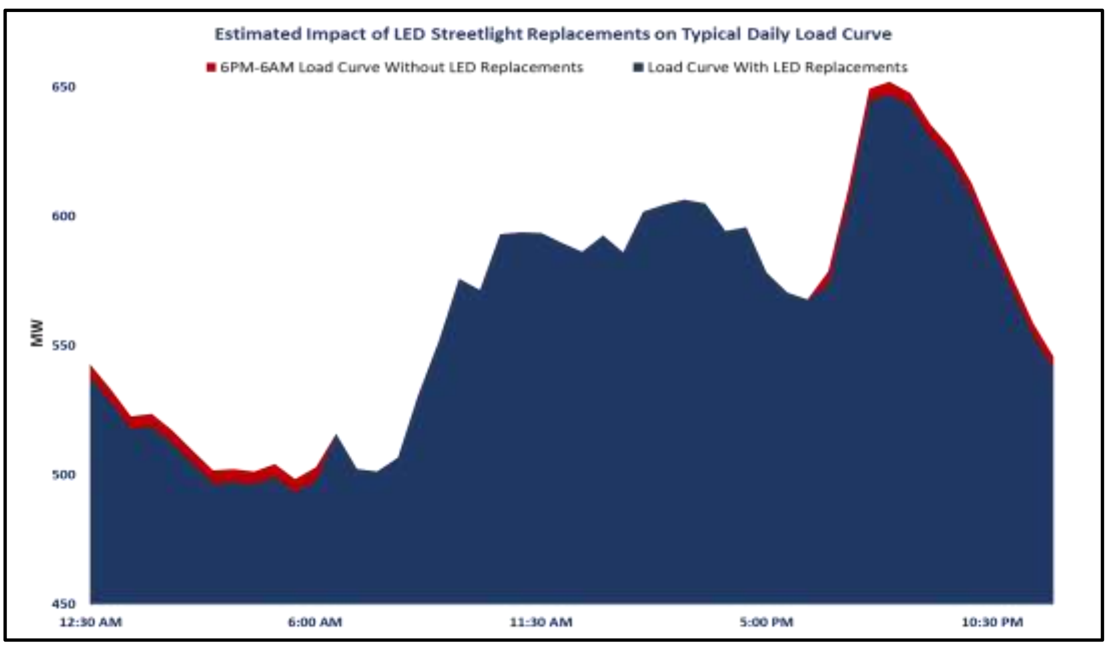
Figure 19.4: Streetlight Replacements per Parish 2017 June 11 to 2019 December 12

19.89 As shown, the service area with the largest number of replacements is St. Andrew (23,233), while the lowest level of penetration is observed in the parish of St. Thomas, with just 415 replacements at the end of 2019.

Estimated Demand Impact

19.90 As indicated in Figure 19.3 above, the estimated demand reduction, resulting from the 65,613 LED replacements up to 2019 December, is approximately 4,897 kW (4.9MW). The impact of this level of demand reduction on system average daily load curve, is illustrated in Figure 19.5 below.

Figure 19.5: Estimated Impact of LED Streetlight Replacement on Typical Daily Load Curve



19.91 Based on the available data, an extrapolation of the reported demand impact (based on the 65,613 LED/HPS replacements) for the total number of streetlights under the SSP (105,000) was performed. This generated an overall demand impact of 7.8MW for the entire programme.

SSP Related Capital Expenditure

19.92 In its Application, JPS provided information on both incurred and projected costs relating to the implementation of the SSP. The SSP costs details included the following:

- A detailed breakdown of SSP costs incurred for the years 2017 to 2019;
- A summary of budgeted costs for the 2019 to 2021;
- A document referred to as the "JPS SSP Agreed Upon Procedure Report" ('JSPR') which appears to provide a review by an independent consultant of accumulated SSP expenditure up to 2018 December 31.

JPS SSP Incurred Expenses

19.93 Based on the OUR's review of the SSP costs reportedly incurred by JPS, a generalized categorization of these costs for 2017 to 2019, is provided in Table 19.11 below. It should be noted that some of the transactions were not clearly described to permit accurate categorization.

Table 19.11: Categorization of JPS' SSP Incurred Costs for 2017-2019

APPROXIMATE CATEGORIZATION OF ANNUAL SSP COST BASED ON ITEMIZED COSTS PROVIDED BY JPS (2017 – 2019)			
CATEGORY	**2017**	**2018**	**2019**
Internal Labour (Capitalization) (US$)	177,638.83	409,153.99	195,232.56
Contracts & Services (US$)	1,452,525.63	353,876.29	1,097,892.13
Material Cost (US$)	8,926,994.19	1,836,720.87	6,953,722.32
Interest During Construction (IDC) & Commitment Fee (US$)	356,029.73	111,864.49	97,411.43
Total	**10,913,188.38**	**2,711,615.64**	**8,344,258.44**
Annual LED Installations (2019 Dec Dataset)	36,730	5,405	23,478
Average Total Cost/Installation (US$)	**297.12**	**501.69**	**355.41**
Approx. Material Cost/Installation (US$)	**243.04**	**339.82**	**296.18**

19.94 Issues emanating from the OUR's review, include:

1) Previous reports on the SSP submitted by JPS to the OUR, show significantly different programme costs for 2017 compared to that shown in Table 19.11 above;
2) The aggregate SSP expenditure for 2017 and 2018 in the JSPR, in comparison to that shown in Table 19.11 above, shows a variance of approximately US$17,833.61;
3) The costs attributable to Internal Labour during the 2018 period appear to be relatively high. As shown in the Table 19.11 above, the number of LED installations during 2018 was less than 25% of the reported number of installations in 2017 and 2019. However the costs attributable to "Internal Labour" was more than double that attributable to the same category in 2017 and 2019. This requires an explanation from JPS;
4) The average total cost per installation, and specifically, the approximate material cost per installation, shows significant increases in 2018 and 2019 relative to 2017. While the reported number of installations during 2017 was higher than the following years, which could in-part accounts for the lower per unit equipment cost, the magnitude of the increases still appears excessive. This is so, particularly in light of the fact that one of JPS' objectives in implementing the SSP in stages is that this approach may benefit from reductions in material/ equipment prices over time.

19.2.8. Smart Streetlight Programme Audit

19.95 Based on the described issues and discrepancies linked to the SSP, a full performance and financial audit of the programme, will be required after completion.

19.2.9. Completion of Smart Streetlight Programme Phase 3

19.96 As previously indicated, phase 3 of the SSP was initially scheduled to be executed during 2019 April to December. However, streetlight information submitted by JPS, indicates that this initial timeline was revised and extended by about eighteen (18) months, with full programme completion now scheduled for 2021 June.

19.97 This revised schedule for phase 3 was expected to result in the replacement of a total of 63,202 HPS lamps with LED fixtures. However, as indicated in the 2019 December SSP Dataset, up to 2019 December 12, 23,478 replacements had been completed for 2019. This indicates that 1,522 replacements were still outstanding for 2019, when compared to the revised schedule. With respect to the entirety of phase 3, based on the actual number of streetlight replacements completed as at 2019 December 12, 39,387 streetlight replacements are still outstanding under Phase 3. Based on this situation, an update on the progress of phase 3 since 2019 December 12 is required from JPS.

Proposed SSP Costs for Completion of Phase 3

19.98 Based on the Application, the total budgeted expenses for 2020 and 2021 are US$8.994M and US$6.984M respectively. However, the categorized SSP expense projections, which accompanied the Application, indicate that there are significant variations in these budgeted costs, as shown in Table 19.12 below.

Table 19.12: JPS' Categorization of Annual Budgeted SSP Expenses (2020 – 2021)

ELEMENTS OF PROJECT	ESTIMATE OF EXPENDITURE (US$)	
	2020	2021
Labour and Services	**1,493,526**	**1,092,115**
Internal Labour (Capitalization)	240,000	240,000
Third Party Labour Contracts	250,000	250,000
Contractor (Streetlight Installation)	1,003,526	602,115
Accommodation	45,000	45,000
ITRON (Smart Network)	**605,000**	**605,000**
Network Device Installation - hardware	500,000	500,000
Network Device Installation - labour	105,000	105,000
Tools and Equipment	**31,000**	**31,000**
Material	**7,318,621**	**4,397,787**
Lights (58W, 108W, 161W)	4,395,000	2,637,000
Controllers	2,625,000	1,575,000
Wires, connectors, etc.	298,621	185,787
SUB-TOTAL	**9,448,147**	**6,125,903**
Contingency (5%)	472,407	306,295
IDC and Commitment Fee	173,610	112,563
TOTAL PROJECT COST (Streetlight Budget 2019-2021)	**10,094,164**	**6,544,761**
TOTAL COST IN RATE REVIEW APPLICATION (TABLE 12-6: SSP FORECASTED CAPEX)	**8,994,000**	**6,984,000**
VARIANCE	**1,100,164**	**-439,239**

19.99 As shown, the variance for the 2020 and 2021 budgeted expenses from the two data sources are US$1.1M and (US$0.44) respectively. This requires clarification from JPS.

19.2.10. Integration of SSP Advanced Features

19.100 In addition to the replacement of HPS lamps with LED types, another important aspect of the SSP as specified in the Licence, is the integration of intelligence capabilities to allow for remote reading of each lamp and other smart features. Regarding the implementation of these SSP components, JPS in its 2018 September SSP Status Report to the OUR, reported that all LED streetlights installed up to that time, were being monitored by its "Streetlight Vision (SLV), Centralized Management System". According to JPS, this system has the capability of accomplishing a number of the Licence requirements for the SSP, including identification of out-of-service lamps (operational status), as well as the general control, monitoring and management of the inventory of streetlights.

19.101 Additionally, based on discussions with the OUR on this issue in 2019, the company conveyed that it was in the process of deploying a new communication platform across the electricity network, to facilitate the integration of all its smart devices and intelligent systems. To date, no further update on the implementation of these SSP design features has been provided by the company, which is a major concern. Furthermore, it is also evident from the submitted SSP Datasets of HPS/LED streetlight replacements that the reported LED energy consumption (kWh) is not being measured as required by the Licence.

19.102 Given this issue and its potential impact on the streetlight operations going forward, JPS shall submit a detailed report on the state of implementation of the required SSP intelligent features and their current functionality, to the Office within thirty (30) days of the effective date of this Determination Notice, for review.

19.2.11. Streetlight Performance Standard

19.103 Under Schedule 2 of the Licence, JPS is required to comply with the electricity Overall Standard (EOS12), relating to streetlight performance. This standard measures the effectiveness of street lighting repairs by JPS. It stipulates that 99% of all street lighting complaints must be resolved by JPS within fourteen (14) days. (See Figure 19.6 below).

Figure 19.6: JPS EOS12 – Effectiveness of Streetlights

SCHEDULE 2
OVERALL STANDARDS

CODE	STANDARD	UNITS	TARGETS JULY 2014 – MAY 2019
EOS12	Effectiveness of street lighting repairs	Percentage of all street lighting complaints resolved within 14 days	99%

19.104 With respect to JPS' performance on EOS12, the company has not provided any data addressing the outcome for the 2014-2019 regulatory period. Also, no performance projections were provided for the Rate Review period. However, based on historical EOS12 data reported by the company for 2013 and the first quarter of 2014, shown in Table 19.13 below, the performance on this overall standard relative to target, is highly unsatisfactory.

Table 19.13: JPS' 2013 Performance relative to EOS12 Target

	2013 Q1	2013 Q2	2013 Q3	2013 Q4	2014 Q1
Compliance	34%	41%	21%	15%	25.5%
Target	**99.0%**	**99.0%**	**99.0%**	**99.0%**	**99.0%**

19.105 It should be noted, however, that during the indicated timeframe, the approach employed by the company to identify "out-of-service" and defective lamps, was largely manual and not properly structured. In recognition of such defects, it could be inferred that some constraints would have been encountered, but not to the extent to cause such poor performance levels in relation to EOS12. While such performance is, in retrospect, the company should recognize that given the current streetlight developments, such performance cannot be maintained.

JPS Proposed EOS12 Performance Targets for 2019-2024

19.106 In the Application, JPS proposes the following changes to EOS12:

1) That the resolution time of street lighting complaints be increased to twenty (20) working days; and
2) The target be revised downward to 95%.

19.107 Based on the OUR's review of JPS' streetlight performance and proposal, the OUR does not approve of the proposed changes to EOS12, on the following basis:

Timeline to Resolve Streetlight Complaints

19.108 Based on recent process enhancements reported by JPS and planned developments to improve the company's operational processes via integrated information systems, intelligent/automated platforms over the Rate Review period, the company should possess adequate capacity to comply with the existing 14-day requirement for resolution of streetlights complaints. In that regard, the OUR is of the view that this target is reasonable and realistic, and therefore, shall continue to remain in effect.

EOS12 Performance Target

19.109 JPS would be aware that one of the key considerations of the GOJ in mandating the SSP was the issue of poor streetlight reliability, including repairs and maintenance deficiencies. To mitigate and minimize these effects, the Licence specified that the SSP should be designed with intelligent capabilities to allow for the identification of out-of-service lamps. Based on this feature, the company will have full visibility of the status of all installed smart LED streetlights (to be completed 2021 June), which is essential for ensuring acceptable reliability of street lighting services. This capability is expected to facilitate timely and optimal deployment of utility resources to comply with the existing performance target of EOS12. Taking into consideration these factors, the Office has determined that the existing target of 99% is reasonable and achievable and will remain in effect.

Office Determination – JPS' Smart Streetlight Programme

19.110 Based on the OUR's review of JPS' SSP activities and proposals, the Office determines as follows:

DETERMINATION #31

1) JPS' proposed changes to the requirements of EOS12 are not approved for the reasons described herein.
2) The existing Overall Standard (EOS12) shall remain in effect for the Rate Review period.
3) Based on the identified SSP issues and discrepancies, and the need to ensure reasonable and prudent programme expenditures, the Office will commission a full performance and financial audit after the completion of the programme.
4) JPS shall, within thirty (30) days of the effective date of this Determination Notice submit a detailed report to the Office on the state of implementation of the SSP intelligent features and their current functionality, for review.
5) After the effective date of this Determination Notice, JPS shall submit quarterly reports to the OUR on the progress of the SSP implementation. The report shall include the updated number of installations by region and incurred expenditure, an updated listing of each installation done showing date, location, rating of the replaced HPS lamp, and the rating and type of the replacement LED lamp. This report shall also include updates on the specified SSP intelligent features, indicating the number of streetlights that are currently controlled and monitored by this system, and the measured energy consumption for each smart LED streetlight.
6) Within three (3) months after the completion of the programme, JPS shall submit a schedule of all streetlight write-off assets, in the same format as the asset register to the OUR.
7) The company shall comply with all other related streetlight requirements in this Determination Notice.

20 Public Consultation

20.1. Overview

20.1 The OUR, consistent with its statutory mandate and by practice, conducts public consultations as part of the tariff review process. The public consultations, which normally include public meetings and town hall type engagements, are designed to provide an opportunity for comments and dialogue on the tariff application by all stakeholders. However, the hosting of public meetings during this tariff review exercise was significantly constrained by the Covid-19 pandemic.

20.2 Eight (8) public meetings and two (2) business meetings were scheduled to be held across the island between 2020 March 10 to 25. However, only the meetings in St. Elizabeth (2020 March 10) and Manchester (2020 March 11) were held before the other meetings had to be cancelled due to the health and safety concerns surrounding the Covid-19 pandemic and the restrictions imposed by the GOJ on public gatherings.

20.3 Consequently, the OUR deployed other methods to canvass the public's views on JPS' Application. These included an email campaign as well as the distribution of a short survey to gain insight into any local issues. The survey sought to assess customers' knowledge of the Guaranteed Standards and capture their views on the Application. The survey was distributed at the two public meetings (Manchester and St. Elizabeth) and online, with feedback being encouraged via social media. The OUR also invited feedback in writing from various stakeholders, including consumer groups and customers. The OUR received forty-nine (49) emails in addition to other written submissions from stakeholder groups, namely: The Private Sector Organization of Jamaica (PSOJ); the Consumer Advisory Committee on Utilities (CACU); Ambassador Anthony Hill and Professor Anthony Chen – University of the West Indies, Mona; the Montego Bay Chamber of Commerce and Industry (MCCI) and the United States Agency for International Development (USAID). See the responses included in the Appendices.

20.4 The OUR also attempted to schedule a virtual digital town hall meeting, but JPS declined the offer to participate indicating that the other means being pursued by the OUR should suffice to receive public comments on its Application.

20.2. Summary of JPS' Presentation

20.5 In its presentation at the two public meetings, JPS highlighted the areas where it would focus its efforts on service delivery. These included: grid reliability and power quality, ease of doing business, provision of innovative solutions, customer empowerment and reducing the cost of delivering service.

20.3. Highlights of Stakeholders' Concerns regarding the Application

Unreasonable and Unjustified Rate Increase Request

20.6 The review of the written submissions and the views of customers at the two public meetings indicated that the consensus among stakeholders was that JPS' request for a rate increase was unreasonable. One predominant concern expressed was the seemingly unreasonableness of an increase in electricity rates in light of the economic hardships caused by the Covid-19 pandemic, which has resulted in job losses and a reduction in customers' ability to pay. Accordingly, customers requested that the rate review process/increase in tariffs be deferred until the economy recovers from the adverse financial impact caused by the pandemic.

20.7 Customers in St. Elizabeth expressed the view that JPS failed to deliver a consistent and reliable supply of electricity, particularly since the last tariff increase. Customers' description of the poor quality of service issues being experienced included: frequent daily power outages, poor voltage quality and tardiness in responding to outage reports.

20.8 Stakeholders were also of the view that the JPS should implement a sustained plan, which should be actioned with alacrity to reduce electricity theft, as paying customers should not continue to bear the cost of illegal connections. Specifically, customers from Manchester suggested that the requested increase would not be necessary if JPS sought to reduce electricity theft/losses.

JPS' Response

20.9 In response to the customers' concerns at the public meetings, JPS advised that it was aware of the quality of service issues in St. Elizabeth, which was mainly due to vegetation overgrowth. The company committed to making investments in new technologies that will assist in reducing the frequency and impact of the quality of service issues. However, JPS also advised that given the nature of delivering electricity, customers should not expect an elimination of power outages, but should anticipate a reduction in the frequency of these incidents.

20.10 JPS advised of its efforts to reduce electricity theft/losses, but maintained that it is also a social issue which requires the involvement of all stakeholders in order to be resolved. Accordingly, JPS is advocating for the establishment of a national task force that will focus on fighting electricity theft.

Customer Service Concerns

20.11 JPS' customers complained about customer service issues which included: long wait time to speak with a customer service representative when contact is made with the call centre; delayed response to complaints; lack of payment arrangement facility and disconnection on weekends and/or public holidays.

JPS' Response

20.12 JPS, in response, advised that the long wait time to speak with a call centre representative may be caused from high call volumes. In relation to payment arrangements, JPS advised that the company has no such policy in place, however, payment arrangements may be extended on a case by case basis. JPS further advised that it was not the norm for disconnections to be done on weekends and public holidays.

Streetlights

20.13 Customers from the rural communities complained about the non-repair of malfunctioning streetlights and/or the lack of streetlights in their communities. This was a specific area of concern for customers at the Manchester and St. Elizabeth public meetings.

JPS' Response

20.14 JPS advised, that the installation and/or repair of streetlights was the responsibility of local government. The company also advised of the procedure to be followed to request the installation of streetlights for a specific area.

Lack of Information on Energy Efficiency & Consumer Energy Demand Management

20.15 The CACU's written submission noted a number of concerns with the Application, including the absence of information relating to demand-side management or EE programmes for consumers. It was noted that JPS had embarked on an EE competition in homes; however, there was no indication about the impact on demand and efficiency resulting from the competition on its tariff proposals.

20.16 The CACU also commended JPS on the establishment of its Customer Advisory Council and noted its interest in receiving further particulars about the Council's composition, role and mandate regarding stakeholder engagements.

Lack of Impact on Climate Change and Environmental Factors

20.17 In the written comments, among the concerns raised by stakeholders was the view that JPS' Application omitted the inclusion of several environmental factors, particularly those that are climate-energy related, that would ensure resilience in the energy sector and satisfy policy objectives.

Residential Lifeline Rate

20.18 Stakeholders purported that JPS' proposed changes to the lifeline rate would result in burdensome increases in the rates for customers. Consequently, stakeholders suggested that consideration should be given to allocating any financial shortfall for consumption in excess of 50 kWh/month to local government.

Net Billing

20.19 According to stakeholders, Net Billing is a critical regulatory tool that can be used to increase clean, sustainable energy, energy diversification and resilience on the grid. Although process flows were developed, issues such as unpredictability in its time-bound deliverables, responsible parties and costs were highlighted. The suggestion was made for Net Billing to be encouraged in the modern grid, along with the development of performance standards similar to the existing Guaranteed Standards Scheme, in order to improve transparency and accountability.

Electric Vehicle (EV) Tariff

20.20 Stakeholders commended JPS for its focus on promoting the use of EVs, which is in keeping with global trends. However, they opined that JPS' tariff proposal for EVs should be rejected at this time as it lacked sufficient details which include: the rate categories that would be charged the EV rate; how EV charges were to be formulated, and the context for defining what makes the charging stations 'public'.

Guaranteed Standards Scheme

20.21 Stakeholders expressed the view that a comprehensive review of the current Guaranteed Standards scheme (GS scheme) is necessary in order to benchmark and align the Scheme with best practices. Additionally, some recommended that the number of GS be reduced and that the GS scheme be refocused to incentivize the utility towards a more efficient and smart delivery of customer service experience.

20.4. Summary of Survey Findings

20.22 In seeking broad input from JPS' customers regarding the Application and their quality of service experience, the OUR included the administration of a survey as part of its consultation activities. The survey sought to gauge customers' feedback on, inter alia: the reliability, quality and the cost of service provided by JPS.

20.23 The survey indicated that 63% of respondents were receiving bills based on actual readings and 68% were of the view that the charges were high in comparison to their usage. Further, 60% of the respondents indicated some knowledge of how their bills are calculated.

20.24 Generally, respondents indicated that they were somewhat satisfied with the reliability of their supply. 89% had experienced an outage in the past twelve months, lasting on average between one and three hours. Additionally, 51% of respondents expressed an unwillingness to pay more for improved quality of service. In response to whether they were receiving adequate power quality from JPS, 33% of respondents stated 'yes' and 33% 'no'. 20% of the respondents with a negative response were from KSAN and St. Catherine.

20.25 The respondents also indicated that bill payment and reporting an outage or emergency were the main reasons for contacting JPS. These were followed by querying a bill and making a complaint. In relation to the GS scheme, 57% of respondents indicated very little to no knowledge about the Scheme.

20.26 There were 212 respondents to the survey from 13 parishes as no response was received from Hanover. While it is recognized that the number of respondents is not representative of the generally accepted statistical sample size, the results typify the views of JPS' customers on the Application and their service delivery experience.

21 Guaranteed Standards and Overall Standards

21.1. Introduction

22.1 In keeping with the provisions of the OUR Act and the Licence, Quality of Service (QOS) standards have been established for JPS, which are comprised of the Guaranteed and Overall Standards. Under Condition 17, paragraph 5 of the Licence, the Guaranteed Standards (GS) as well as the related compensatory payment, can be reviewed periodically (normally between rate reviews) by the Office. Similarly, Condition 17, paragraph 7 of the Licence provides for the periodic review of the Overall Standards by the Office during the Rate Review. While the Licence provides for the GS review to be conducted between Rate Reviews, the practice of the OUR has been to include the GS review as part of the five year tariff review process.

21.2. Guaranteed Standards Performance Review

22.2 The GS scheme represents the aspect of the Quality of Service Standards that prescribes service levels to be met by the JPS in areas which include: billing, metering, disconnection, reconnection and complaints handling. The GS scheme also provides a mechanism for individual customers to be compensated where the JPS fails to adhere to any of the prescribed standards.

22.3 An assessment of JPS' quarterly reports on its performance against the GS indicates that it committed 293,720 breaches over the period 2016 January – 2019 December. As is shown in Table 21.1 below, despite the total number of breaches, JPS attained an average compliance rating of 95%.

Table 21.1: Guaranteed Standards Breaches, Compliance Rating & Compensation

Year	No. of Breaches		GS Compliance Rating	Compensation		
				Potential ($)	Actual Payment ($)	Actual/Potential Payments
2016	77,350	95%	187,814,077	117,300,000	62%	
2017	75,571	97%	151,800,000	151,800,000	100%	
2018	72,046	91%	148,000,000	148,000,000	100%	
2019	68,753	95%	142,500,000	142,500,000	100%	
Total	293,720	95%	630,144,077	559,600,000	89%	

22.4 For the 293,720 breaches committed, JPS paid out approximately $560 million in compensatory payments, which represent an 11,000% increase in the compensation paid over the previous tariff review period 2009 – 2014 (see Table 21.2 for further details). The significant increase seen in compensatory payments resulted from the OUR's decision in the 2014-2019 Determination Notice (Document Number: 2014/ELE/008/DET.004) that all GS compensatory payments be applied automatically. Prior to the 2014-2019 regulatory period, the compensation mechanism included the prescribed amounts being applied automatically to some breaches, while customers were required to submit a claim form for others.

Table 21.2: Summary of Guaranteed Standards Breaches and Payments for 2009 - 2014

Period	Approximate No. of Breaches	Potential Compensation	Actual Compensatory Payments
2009 October – December 2014	320,000	$1,000,000,000	$5,000,000

22.5 Estimated billing (EGS 7) at 87%, accounted for the highest incidents of breaches over the 2014 - 2019 tariff review period and 84% of compensation applied to affected customers' accounts. All other standards shared the remaining 13% of breaches and 16% of compensatory payments.

21.3. JPS' Guaranteed Standards Proposals

22.6 In its Application, JPS proposed that the following changes be made to the GS scheme:

Modification of Compensation Methodology

22.7 JPS requested that the compensation methodology be amended and proposed that the fixed monthly customer charge be used as the basis to calculate GS compensation for all rate classes. Under the existing construct, the compensation for residential customers is based on the value of the reconnection fee, while the customer charge is used as the basis for calculating the compensation for commercial customers. In support of its proposal, JPS expressed the view that:

a) The use of a single methodology will bring simplicity, consistency, and transparency to the compensation mechanism. Additionally, JPS cited the use of the single methodology in the local water and sewerage sector and other regional territories such as Barbados and Trinidad and Tobago;
b) The practice of linking the compensation methodology for residential customers to the value of the reconnection fee results in the compensation being determined by JPS' third party negotiations. JPS further argued that this association *"inhibits the Company's ability to make the reconnection fee cost reflective"*;
c) Given that the customer charge is reviewed annually, during the annual inflationary adjustment process, associating the compensation methodology to the customer charge would automatically result in it being reviewed on an annual basis.

Modification of Existing Standards

A. Conversion of EGS 3 – Response to Emergency to an Overall Standard

22.8 JPS requested that EGS 3 be converted to an Overall Standard as there are challenges to accurately monitor and measure its response under the requirements of the GS. Further, JPS argued that emergencies, by nature, are unplanned and are random events that can be triggered by third parties. JPS added that the tracking of its response to emergencies, is foremost and most importantly a matter of public safety that should be tracked as an Overall Standard. The company also indicated that it will continue to report its performance on its response to an emergency to the OUR.

B. Revision of Performance Target for EGS 15

22.9 JPS proposed that the performance target for EGS 15 – Transitioning Existing Customers to RAMI System, be modified as the requirement to not disrupt the supply of an existing customer for more than three (3) hours to facilitate transition to the RAMI system, is impractical and therefore not achievable. Accordingly, JPS proposed that the process to facilitate transition to its RAMI system be treated as one requiring a planned outage, for which adequate notice must be provided to customers.

Exceptions and Exemptions to the Guaranteed Standards

22.10 JPS proposed that, in addition to the provisions under the force majeure conditions, it should not be obliged to make GS payments in the following circumstances, which are outside of its control:

i. The customer informs JPS before a breach of the GS is committed that they do not want JPS to take any action or further action relating to the matter. This would be applicable to EGS 1, 2 and 6;

ii. Where information is required from the customer and (a) it is not provided using the appropriate telephone number, address and email address as indicated and published by JPS; or (b) it is not provided within the timeframe that would allow JPS to take action before a breach occurs. This would be applicable to EGS 1, 2 and 5;

iii. Where the information provided is erroneous or requires verification. This would be applicable to all standards.

21.4. OUR's Response to JPS's Proposed Guaranteed Standards Changes

22.11 The Office has reviewed JPS' proposals, along with the comments received from stakeholders, in relation to modifications to the GS. As is indicated in The OUR's 2020 – 2021 Corporate Business Plan, and stated in its letter to JPS dated 2020 June 19, the Office will conduct a consultation to undertake a comprehensive review and analysis of the GS scheme, which includes the standards established for JPS. Consequently, the Office has decided to defer any changes to JPS' GS until the aforementioned consultation is completed. Accordingly, the existing standards will be retained.

22.12 In light of the foregoing, the Office has determined that the Guaranteed Standards to be attained by JPS, pending the outcome of the aforementioned comprehensive GS review, are contained in Table 21.3 below.

Table 21.3: Guaranteed Standards for 2020 – 2022

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, includes connection to RAMI system **Automatic Compensation**
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 **Automatic Compensation**
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 **Automatic Compensation**
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**
EGS4	First Bill	Issue of First bill	Produce and dispatch first bill within forty (40) working days after service connection **Automatic Compensation**
EGS 5(a)	Complaints/ Queries	Acknowledgements	Acknowledge written queries within five (5) working days **Automatic Compensation**

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**
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**
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**
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**
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**
EGS 14	Compensation	Making compensatory payments	Accounts should be credited within one (1) billing period of verification of breach **Automatic Compensation**
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**

21.5. Compensation

22.13 The Office has determined that compensation for a breach of the GS shall continue as follows, pending the outcome of the aforementioned Comprehensive GS Review:

(i) General Compensation (this does not include compensation for Wrongful Disconnection);

a. Residential Customers – a breach of a GS shall result in a compensation payment which is the equivalent to the applicable reconnection fee.

b. Commercial Customers – a breach of the GS shall result in a compensation payment which is the equivalent of four (4) times the customer charge.

(ii) Compensation for Wrongful Disconnection (Special Compensation);

a. Compensation for wrongful disconnection (EGS11) will remain at the equivalent of two (2) times the applicable reconnection fee for residential customers and five (5) times the network access/customer charge for commercial customers.

b. Compensation for breach of the reconnection after wrongful disconnection GS (EGS12) will remain at the equivalent of two (2) times the reconnection fee for residential customers and five (5) times the network access/customer charge for commercial customers.

22.14 The Office continues to note that there remain instances where GS breaches are not corrected within the stipulated timeline and may occur for a protracted period. The undue delay in correcting a GS breach results in sustained inconvenience to the customer. Accordingly, the Office has decided to retain the eight (8) periods of non-compliance of a GS breach for which compensation is applicable. For clarity, where a breach of an individual GS is committed and is not remedied within the established timeline, then the compensation shall be payable for up to eight (8) periods of the breach occurring.

21.6. Guaranteed Standards Reporting Requirements

22.15 The Office is also retaining JPS' requirement to submit quarterly performance reports on its compliance with each GS. The report shall include an appendix that provides details on the number of breaches, the affected accounts and the compensation applied.

22.16 The GS performance report must be submitted within twenty (20) working days after the end of each reporting period.

Prepaid Metering System

22.17 During the previous tariff period, the Office sanctioned JPS' proposal to introduce Prepaid Metering service and establish GS for this service. The Office has decided to retain the GS for the prepaid metering service, as shown in Table 21.4 below, and will require JPS to submit quarterly performance reports on these standards. JPS will also be required to include information, in its quarterly report, on the number and nature of the complaints received regarding its Prepaid Metering service.

Table 21.4: 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 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 GER[35], there should be no disruption in customer's service.

21.7. Overall Standards

22.18 The Overall Standards (OS) represent prescribed technical and performance standards to be achieved by JPS in specified service areas that will have an impact on more than one customer. While performance targets are prescribed for each OS, unlike the GS, there is no compensatory mechanism attached when the targets are not met.

21.8. JPS' Proposals, OUR's Response and Determinations on the Overall Standards

22.19 The following are JPS' proposals and the OUR's response:

Revision of Performance Target for EOS 1 – Advanced Notification for Planned Outages

22.20 Under EOS 1, JPS is required to, in all instances (100%), advise customers of planned outages, allowing at least 48 hours' advanced notice. The company is requesting that the performance target of 100% be reduced to 95%.

22.21 In making this request, JPS highlighted the challenges the company has been experiencing in attaining the 100% performance target, which is mainly premised on the lack of an auditable process to verify certain aspects of its advance notification procedure. Specifically, JPS advised that the actual time of notification to individual customers via outage cards, which is an effective and time-honoured method, is not readily auditable for verification checks against the performance target.

22.22 The Office has reviewed JPS' request and is of the view that the basis proposed for the compliance target's reduction is inadequate. The Office is of the view that while JPS claims that the outage card method to provide advance notice of outages to customers is effective, there appear to be challenges in measuring the levels of effectiveness and by extension, the compliance rating against the performance target. It is therefore unclear how lowering the target would help to resolve this issue. The Office is therefore of the view that JPS needs

[35] Was previously Government Electrical Inspector (GEI) which has been replaced by the Government Electrical Regulator (GER).

to first verify the effectiveness of the outage card method, and then make a decision on whether it is practical to:

1. Continue its use;
2. Employ other, more reliable and verifiable methods to notify customers of planned outages as per the OS, in light of available technology; or
3. Devise and implement an auditable procedure to measure its performance against the OS, should the method be retained.

22.23 While the Office is mindful of the need for JPS to undertake maintenance works to enable the company's delivery of an efficient and reliable service, the Office is also mindful of the inconvenience that customers may experience due to outages. Further, the Office is of the view that it is only practical for JPS to develop a maintenance schedule for routine outages and would therefore be in a position to communicate these to its customers. Accordingly, the Office maintains that customers should be notified, at all times, of planned outages in an effort to give them an opportunity to make alternate arrangements, where necessary.

Revision of EOS 10 – Responsiveness of Call Centre Representatives

22.24 In relation to EOS 10, JPS has proposed that *"the standard be reworded to include the Interactive Voice Response system"* which provides customers with self-help options to effectively address their concerns. JPS is of the view that the Interactive Voice Response (IVR) system provides responses to a range of customers' issues/queries and should therefore be included as part of its Call Centre responsiveness.

22.25 The Office has reviewed JPS' request and is not averse to including the IVR system as part of the measure for Call Centre Responsiveness. Further, the Office agrees that the IVR system can provide customers with self-help options to address their concerns/queries. For instance, the Office is aware that a customer can be provided with information on outages and/or bill balances through the IVR system, which can be regarded as a response to the customer's query and by extension, a response from the customer's contact with the Call Centre.

22.26 However, the Office is of the view that including the IVR system as a part of the EOS 10 significantly changes the focus of the Standard. In its current form, the focus of the EOS 10 is for customers to be connected to a call centre representative within twenty (20) seconds. Additionally, this standard does not focus on the timeliness within which a response is provided to customers through the Call Centre. Based on a discussion with JPS regarding this proposal, the OUR confirmed that the inclusion of the IVR is intended to take into account customers' ability to be provided with a response from the suite of options.

22.27 To further assess this proposal, the Office conducted a number of timed test calls to JPS' Call Centre, by way of the toll free number, the last of which was done on 2020 June 25. From the test calls, the Office has identified that including the IVR in the EOS 10 measurement may pose a challenge to JPS' ability to achieve the compliance target of answering 80% of calls within twenty (20) seconds for the following reasons:

(a) The first option relating to bill balance, is provided in fifteen (15) seconds while the second option, which relates to information on current outages, is provided within twenty (20) seconds of the call being connected to the IVR;

(b) It requires forty-five (45) seconds from the call being connected to the IVR, to be advised of the entire suite of IVR options; and

(c) The time measurement for customers who may wish to speak with a Call Centre representative may need to begin when that option is selected from the IVR and not at the point of the call being connected to the IVR.

22.28 Given the foregoing, the Office is of the view that JPS' IVR is not currently configured to enable the company to meet the performance measurement for EOS 10. Accordingly, in order for the Office to grant this request to include the IVR and amend the focus of the Standard to Call Centre Responsiveness, JPS will need to demonstrate how it intends to ensure that the inclusion of the IVR will not impair its EOS 10 compliance rating and by extension, improve the customer experience through the Call Centre.

OUR's Determination of Compliance Target for EOS 11- Effectiveness of Call Centre Representatives

22.29 The OUR has consulted with JPS and the National Water Commission (NWC) in relation to establishing a performance target for the percentage of customer complaints that are addressed at the first point of contact. The establishment of this performance target is directly related to EOS 11 - Effectiveness of Call Centre Representatives for JPS.

22.30 Following the completion of the consultation process, the OUR outlined its decisions relating to EOS 11 in its *Determination Notice – Enhancing Customer Satisfaction through Customer Contact Centre Standards for the Jamaica Public Service Company Limited and the National Water Commission* (Document Number: 2020/WAS/005/DET.005) dated 2020 October 1. In summary, the OUR determined that the performance target for EOS 11 and First Call Resolution Rate shall be established by the OUR, in consultation with JPS and after its assessment of a trial period, and shall become effective within twelve (12) months of the date of said Determination Notice.

Revision of EOS 12 – Effectiveness of Street Lighting Repairs

22.31 In the Application, JPS proposed the following changes to EOS12:

1) That the resolution time of street lighting complaints be increased from fourteen (14) days to twenty (20) working days; and

2) The target be revised downward from 100 % to 95%.

22.32 Based on the OUR's review of JPS' streetlight performance and proposal, the OUR does not approve the proposed changes to EOS12, on the following bases:

- **Timeline to Resolve Streetlight Complaints**

  Based on recent process enhancements reported by JPS and planned developments to improve the company's operational processes via integrated information systems, intelligent/automated platforms over the Rate Review period, the company should possess adequate capacity to comply with the existing performance standards to resolve street lighting complaints within fourteen (14) days. In this regard, the OUR is of the view that this target is reasonable and realistic, and therefore, shall continue to remain in effect.

- **EOS12 Performance Target**

  JPS would be aware that one of the key considerations of the GOJ in mandating the SSP was the issue of poor streetlight reliability, including repairs and maintenance deficiencies. To mitigate and minimize these effects, the Licence specified that the SSP should be designed with intelligent capabilities to allow for the identification of out-of-service lamps. Based on this feature, the company will have full visibility of the status of all installed smart LED streetlights (to be completed 2021 June), which is essential for ensuring acceptable reliability of street lighting services. This capability is expected to facilitate timely and optimal deployment of utility resources to comply with the existing performance target of EOS12. Taking into consideration these factors, the Office has determined that the existing target of 99% is reasonable and achievable and will remain in effect.

OUR Establishing Overall Standard for Customer Service

22.33 Customer service, and the quality of its delivery, plays a critical role in the viability of any business/organization. Generally, Customer Service is referred to as, the assistance and advice provided by a business/organization to those who buy or use its products or services.

22.34 As the regulator for the provision of utility service in Jamaica, since 2017, the OUR has conducted Mystery Shopping (MS) surveys to assess, inter alia:

a) The current levels of in-store customer service provided by the regulated utility providers;

b) Customer satisfaction in relation to the provision of prescribed utility services, such as: service quality, specifically, customer experience;

c) The levels of improvements in the provision of in-store customer service;

d) The current levels of customer service provided by the operators' call centres; and

e) The overall customer satisfaction rating for each service provider.

22.35 The findings of the MS Survey, shown in Table 21.5 below, revealed that none of the utility service providers were delivering an above average customer service experience. While JPS and Cable & Wireless Jamaica Limited and Columbus Communications Limited (together trading as "FLOW") were the top performers in 2017, there was still a significant gap to be filled. The 2019 findings revealed a decrease in the total scores across utility service providers from 2017 to 2019, with the telecommunications providers showing larger declines in their scores. The study was expanded to include the Call Centre experience in 2019 and it was noted that the service delivery in the Call Centres helped to boost the overall performance in 2019 resulting in less overall declines.

22.36 The OUR recognizes that most of the utility providers in Jamaica are privately owned, with a mandate from their shareholders to provide a return on their investments. As a result, there tends to be a heavy focus on marketing as utility providers try to maximise the sale of their products and services. Often times, there is not enough focus on the quality of the customer service experience being delivered.

Table 21.5: Findings of the MS Survey

Utility	Total Score **This includes the score for customer service and their physical work environments (i.e. the stores)*		Customer Service Score	
	2017	**2019**	**2017**	**2019**
Digicel	69%	54%	68%	49%
FLOW	70%	69%	71%	56%
JPS	70%	68%	81%	72%
NWC	67%	62%	78%	61%

Source: OUR Mystery Shopping Reports 2017 -2019

22.37 The Office has therefore decided that in light of the survey findings and continued complaints to the OUR and via the media about the quality of customer service, it will be establishing an Overall Standard to monitor and measure the level of customer service delivered by the regulated entities. It is the view of the Office that establishing a customer service standard is important to:

- Allow the regulator to verify performance claims made by service providers;
- Establish minimum customer service quality levels to meet consumer and market trends, needs and expectations; and
- Provide information to the regulator and other interested parties as to the state of the delivery of said customer service standards.

22.38 The Office has further determined that the assessment and performance measurement for the Standard for Customer Service be conducted through the annual MS Survey.

22.39 In light of the foregoing, the Office has determined that the Overall Standards to be attained by JPS for the Rate Review period are contained in Table 21.5 below.

Table 21.5: Overall Standards for Rate Review Period

Code	Standard	Units	November 2020 -
EOS 1	No less than 48 hours prior notice of planned outages	Percentage of planned outages for which at least forty-eight hours advanced notice is provided	100%
EOS 2	Percentage of line faults repaired within a specified period of that fault being reported	Urban – 48 hours Rural – 96 hours	100% 100%
EOS 3	System Average Interruption	Frequency of interruptions in service	To be set annually
EOS 4	System Average Interruption 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	50%
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%
EOS 13	Effectiveness of Customer Service	Customer Service performance score obtained OUR's Mystery Shopping survey	To be determined

21.9. Additional Quality of Service Customer Concerns

22.40 During the 2014 -2019 tariff review period, the OUR received a noticeable number of complaints of high consumption charges over a prolonged period of consecutive estimated bills from customers on JPS' Residential Automated Metering Infrastructure (RAMI) system. In an effort to address this issue, the OUR conducted an investigation and had discussions with JPS to, inter alia:

(i) Ascertain the basis for the prolonged billing based on consecutive estimates; and

(ii) Decide on a methodology to be used by JPS to fairly reconcile the accounts of customers who have been affected by prolonged consecutive estimated bills.

22.41 A review of the information received from JPS indicated that one of the main issues plaguing the RAMI system relates to communication challenges. The RAMI system is designed to remotely provide JPS with monthly meter readings that are then used to bill customers' accounts. However, due to several factors, which include: technical problems, natural occurrences (such as lightning) and third party interference (such as illegal electricity abstraction), the communication aspect of the RAMI system becomes impaired resulting in JPS' inability to obtain the monthly readings remotely. Consequently, customers on the RAMI system may receive consecutive estimates for a prolonged period.

22.42 In spite of the reasons for the prolonged consecutive billing of RAMI customers, the OUR holds the view that JPS has sole responsibility for the maintenance of the RAMI system. As such, the challenges experienced ought to be remedied within a reasonable time; thereby reducing any adverse impact on customers. Additionally, the OUR deems unreasonable, the requirement for customers to pay significantly higher than normal charges when a meter reading is obtained after a prolonged period of underestimation of consumption by JPS. The OUR also deems unreasonable, the overpayment of amounts paid by customers due to periods of overestimation of consumption. Accordingly, the OUR and JPS agreed on the following methodology to be used to reconcile RAMI customers' accounts after a period of prolonged consecutive estimates:

(a) "In the case where a customer is ***under-billed and an actual reading is obtained****, the account is adjusted for a period not exceeding two (2) months;*

(b) In the case where a customer is ***overbilled and an actual reading is obtained****, the account is adjusted for the entire period of billing."*

22.43 Further the prolonged period of estimates is defined as a period greater than six (6) months.

DETERMINATION #32

The Office has determined that:

1. Any changes to JPS' Guaranteed Standards shall be deferred until the project to conduct a comprehensive analysis of all Guaranteed Standards Schemes are completed. Accordingly, the Guaranteed Standards to be attained by JPS are contained in Table 21.3 above.
2. The Guaranteed Standards for JPS' Pre-paid Metering service is as outlined in Table 21.4.
3. JPS shall continue to submit quarterly performance reports on its compliance with the Guaranteed Standard within 20 working days following the end of the reporting period. JPS is also required to report on its performance against the Guaranteed Standards for the Pre-paid Metering service in the quarterly performance report and shall include information on the number and nature of complaints related to the Pre-paid Metering service.
4. It will maintain the focus of EOS 10 for measuring the Effectiveness of Call Centre Representatives. If desired, JPS may resubmit its proposal to amend EOS 10 in the next Rate Review, clearly outlining how the inclusion of IVR will conform to the performance target to answer 80% of calls within 20 seconds.
5. The targets for EOS 11 shall be determined in accordance with Determination Notice – Enhancing Customer Satisfaction through Customer Contact Centre Standards for the Jamaica Public Service Company Limited and the National Water Commission (Document Number: 2020/WAS/005/DET.005) dated 2020 October 1.
6. The Overall Standards to be attained by JPS for the Rate Review period are contained in Table 21.5
7. The following methodology is to be consistently applied to reconcile the accounts of customers on JPS' RAMI system that have been affected by prolonged, consecutive estimated billing:
   - *(a)* *"In the case where a customer is* ***under-billed and an actual reading is obtained****, the account is adjusted for a period not exceeding two (2) months.*
   - *(b)* *In the case where a customer is* ***overbilled and an actual reading is obtained****, the account is adjusted for the entire period of billing."*

   The prolonged period of estimate is defined as a period greater than 6 months.

8. The existing Overall Standard (EOS12) shall remain in effect for the Rate Review period.

ANNEXES

23 ANNEXES

23.1 ANNEX 1: US and Jamaican Inflation Consumer Price Indices

a. U.S. Consumer Price Index

U.S. Consumer Price Index - All Urban Consumers

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

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

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual	HALF1	HALF2
2000	168.8	169.8	171.2	171.3	171.5	172.4	172.8	172.8	173.7	174.0	174.1	174.0	172.2	170.8	173.6
2001	175.1	175.8	176.2	176.9	177.7	178.0	177.5	177.5	178.3	177.7	177.4	176.7	177.1	176.6	177.5
2002	177.1	177.8	178.8	179.8	179.8	179.9	180.1	180.7	181.0	181.3	181.3	180.9	179.9	178.9	180.9
2003	181.7	183.1	184.2	183.8	183.5	183.7	183.9	184.6	185.2	185.0	184.5	184.3	184.0	183.3	184.6
2004	185.2	186.2	187.4	188.0	189.1	189.7	189.4	189.5	189.9	190.9	191.0	190.3	188.9	187.6	190.2
2005	190.7	191.8	193.3	194.6	194.4	194.5	195.4	196.4	198.8	199.2	197.6	196.8	195.3	193.2	197.4
2006	198.3	198.7	199.8	201.5	202.5	202.9	203.5	203.9	202.9	201.8	201.5	201.8	201.6	200.6	202.6
2007	202.4	203.5	205.4	206.7	207.9	208.4	208.3	207.9	208.5	208.9	210.2	210.0	207.3	205.7	209.0
2008	211.1	211.7	213.5	214.8	216.6	218.8	220.0	219.1	218.8	216.6	212.4	210.2	215.3	214.4	216.2
2009	211.1	212.2	212.7	213.2	213.9	215.7	215.4	215.8	216.0	216.2	216.3	215.9	214.5	213.1	215.9
2010	216.7	216.7	217.6	218.0	218.2	218.0	218.0	218.3	218.4	218.7	218.8	219.2	218.1	217.5	218.6
2011	220.2	221.3	223.5	224.9	226.0	225.7	225.9	226.5	226.9	226.4	226.2	225.7	224.9	223.6	226.3
2012	226.7	227.7	229.4	230.1	229.8	229.5	229.1	230.4	231.4	231.3	230.2	229.6	229.6	228.8	230.3
2013	230.3	232.2	232.8	232.5	232.9	233.5	233.6	233.9	234.1	233.5	233.1	233.0	233.0	232.4	233.5
2014	233.9	234.8	**236.3**	237.1	237.9	238.3	238.3	237.9	238.0	237.4	236.2	234.8	236.7	236.4	237.1
2015	233.7	234.7	236.1	236.6	237.8	238.6	238.7	238.3	237.9	237.8	237.3	236.5	237.0	236.3	237.8
2016	236.9	237.1	238.1	239.3	240.2	241.0	240.6	240.9	241.4	241.7	241.4	241.4	240.0	238.8	241.2
2017	242.8	243.6	243.8	244.5	244.7	245.0	244.8	245.5	246.8	246.7	246.7	246.5	245.1	244.1	246.2
2018	247.9	249.0	**249.6**												

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

b. Jamaican Consumer Price Index

Ja. Consumer Price Index

The Index numbers listed in the table: Consumer Price Index for 2007-2011, are based on the revised calculations using the new series that have been derived by using data from the HES conducted between June 2004 and March 2005. For the years prior to 2007 the data is linked to the 1988 series of the CPI using a link factor.

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

Consumer Price Index for 2003-2018

Month	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
January	64.80	74.60	84.10	94.70	101.00	119.40	136.00	152.60	167.80	178.90	193.80	211.80	223.00	231.30	237.30	248.60
February	64.40	75.00	84.50	94.80	101.30	121.50	137.10	155.90	167.10	180.30	195.00	211.90	221.50	229.60	237.80	248.30
March	64.70	75.40	85.30	94.90	102.50	122.90	138.20	156.60	168.90	181.20	197.70	**214.20**	222.70	229.30	238.70	**248.10**
April	65.70	75.70	86.90	96.00	102.90	124.80	138.80	158.70	169.70	181.90	198.50	213.60	223.10	228.40	239.40	
May	66.80	76.20	88.70	96.30	104.30	127.80	140.00	159.70	171.00	182.80	199.60	215.70	224.20	229.00	239.60	
June	68.50	76.80	90.00	97.60	105.10	130.30	142.00	160.70	172.30	183.80	199.90	215.90	225.30	231.00	241.20	
July	69.50	77.60	91.40	98.90	106.10	134.00	143.30	161.30	173.60	183.20	200.90	218.90	227.20	232.10	242.70	
August	70.40	78.60	91.50	99.20	107.20	135.60	143.90	162.00	174.60	184.10	201.60	221.30	229.00	233.10	243.40	
September	71.50	79.00	93.80	99.90	108.90	136.50	146.30	162.80	175.91	187.60	207.20	225.90	230.00	234.20	245.00	
October	72.70	81.60	94.30	99.80	110.40	136.90	147.50	164.00	176.70	189.40	209.00	226.10	230.70	234.80	245.80	
November	73.40	83.60	94.60	99.60	114.00	136.40	148.70	165.70	177.50	190.60	209.50	224.90	231.80	235.60	247.30	
December	73.90	84.10	94.60	100.00	116.80	136.50	150.40	168.10	178.20	192.50	210.70	224.10	232.30	236.30	248.70	
Annual Average	**68.90**	**78.20**	**90.00**	**97.60**	**106.70**	**130.20**	**142.70**	**160.68**	**172.78**	**184.69**	**201.95**	**218.69**	**226.73**	**232.06**	**242.24**	
Annual Inflation Rate	**13.80**	**13.70**	**12.60**	**5.70**	**16.80**	**16.80**	**10.20**	**11.80**	**6.00**	**8.00**	**9.45**	**6.36**	**3.66**	**5.44**	**7.06**	

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

Source: http://statinja.gov.jm/Trade-Econ%20Statistics/CPI/NewCPI.aspx

23.2 Annex 2: Estimated Bill Impact of OUR's Approved Rate Adjustment

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

Usage 90 kWh

Rate 10	**October 2020 Bill - Before**			**October 2020 Bill - After**				
Below 100kWh	**2018 - 2020 Rates J$**			**2020 - 2021 Rates J$**			**Change**	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		**J$**	**%**
	128.00	145.20		**145.00**	145.20			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy 1st	90	9.66	869.19	90	**7.24**	651.20	- 217.99	-25.08%
Energy 2nd	0	22.49	-	0	**20.79**	-	-	
IPP for kWh				90	**9.29**	835.70		
Customer Charge			445.39			**525.85**	80.46	18.07%
True-Up Adjustment				90	**-0.52**	**$ (47.05)**		
Sub Total			**1,314.58**			**1,130.00**	**- 184.58**	**-14.04%**
F/E Adjust		0.107	141.30		0.001	$ 2.38		
Fuel (formerly Fuel & IPP)	90	27.25	2,452.83	90	22.18	1,996.50	**- 456.33**	**-18.60%**
Bill Total			**J$ 3,908.71**			**J$ 3,964.57**	**55.86**	**1.43%**

3.2 Bill Comparison for a Typical Rate 10 Consumer with consumption 101kWh </= 150kWh

Usage 150 kWh

Rate 10	**October 2020 Bill - Before**			**October 2020 Bill - After**				
101 < /=150kWh	**2018 - 2020 Rates J$**			**2020 - 2021 Rates J$**			**Change**	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		**J$**	**%**
	128.00	145.20		**145.00**	145.20			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy 1st	100	9.66	965.77	100	**7.24**	723.55	- 242.21	-25.08%
Energy 2nd	50	22.49	1,124.38	50	**20.79**	1,039.47	- 84.91	-7.55%
IPP for kWh				150	**9.29**	1,392.83		
Customer Charge			445.39			**525.85**	80.46	18.07%
True-Up Adjustment				150	-0.52	**$ (78.42)**		
Sub Total			**2,535.54**			**2,210.45**	**- 325.08**	**-12.82%**
F/E Adjust		0.107	272.54		0.001	$ 4.32		
Fuel (formerly Fuel & IPP)	150	27.254	4,088.05	150	22.18	3,327.50	**- 760.55**	**-18.60%**
Bill Total			**J$ 6,896.13**			**J$ 6,935.10**	**38.98**	**0.57%**

3.3 Bill Comparison for a Typical Rate 10 Consumer with consumption 150kWh and above

Usage 200 kWh

Rate 10	October 2020 Bill - Before			October 2020 Bill - After				
Above 150kWh	2018 - 2020 Rates J$			2020 - 2021 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	128.00	145.20		145.00	145.20			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy 1st	100	9.66	965.77	100	7.24	723.55	- 242.21	-25.08%
Energy 2nd	100	22.49	2,248.76	100	20.79	2,078.93	- 169.82	-7.55%
IPP for kWh				200	9.29	1,857.11		
Customer Charge			445.39			525.85	80.46	18.07%
True-Up Adjustment				200	-0.52	$ (104.56)		
Sub Total			**3,659.91**			**3,223.78**	**- 436.14**	**-11.92%**
F/E Adjust		0.107	393.39		0.001	$ 6.06		
Fuel (formerly Fuel & IPP)	200	27.254	5,450.74	200	22.18	4,436.67		
Bill Sub-Total			**9,504.04**	**Bill Sub-Total**		**9,523.61**		
GCT		0.150	391.19		0.150	388.28	**- 2.91**	**-0.74%**
Bill Total			**J$ 9,895.23**			**J$ 9,911.89**	**16.66**	**0.17%**

3.4 Bill Comparison for a Typical Rate 20 Consumer with consumption

Usage 90 kWh

Rate 20	October 2020 Bill - Before			October 2020 Bill - After				
Below 100kWh	2018 - 2020 Rates J$			2020 - 2021 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	128.00	145.20		145.00	145.20			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	90	18.55	1,669.50	90	8.93	803.34	- 866.16	-51.88%
IPP kWh				90	15.56	1,400.10		
Customer Charge			992.24			1,121.23	128.99	13.00%
True-Up Adjustment				90	-0.52	$ (47.05)		
Sub Total			**2,661.74**			**1,877.52**	**- 784.22**	**-29.46%**
F/E Adjust		0.107	286.10		0.001	$ 3.96		
Fuel (formerly Fuel & IPP)	90	27.25	2,452.83	90	22.18	1,996.50	**- 456.33**	**-18.60%**
Bill Sub-Total			**5,400.67**			**5,278.08**	**- 122.59**	**-2.27%**
GCT		0.150	810.10		0.150	791.71		
Bill Total			**J$ 6,210.78**			**J$ 6,069.79**	**- 140.98**	**-2.27%**

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

Usage 1000 kWh

Rate 20	October 2020 Bill - Before			October 2020 Bill - After				
101 - 1000kWh	2018 - 2020 Rates J$			2020 - 2021 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	128.00	145.20		145.00	145.20			
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	1000	18.55	18,549.97	1000	8.93	8,925.98	- 9,623.99	-51.88%
IPP kWh				1000	15.56	15,556.65		
Customer Charge			992.24			1,121.23	128.99	13.00%
True-Up Adjustment				1000	-0.52	$ (522.81)		
Sub Total			**19,542.21**			**9,524.40**	- **10,017.81**	**-51.26%**
F/E Adjust		0.107	2,100.54		0.001	$ 31.65		
Fuel (formerly Fuel & IPP)	1000	27.25	27,253.68	1000	22.18	22,183.37	- 5,070.32	-18.60%
Bill Sub-Total			**48,896.44**			**47,296.07**	- **1,600.37**	**-3.27%**
GCT		0.150	7,334.47		0.150	7,094.41	- 240.06	-3.27%
Bill Total			**J$ 56,230.91**			**J$ 54,390.48**	- **1,840.43**	**-3.27%**

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

Usage 5000 kWh

Rate 20	October 2020 Bill - Before			October 2020 Bill - After				
1001 - 7500kWh	2018 - 2020 Rates J$			2020 - 2021 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	128.00	145.20		145.00	145.20			
		.						
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	5000	18.55	92,749.85	5000	8.93	44,629.92	- 48,119.94	-51.88%
IPP kWh				5000	15.56	77,783.26		
Customer Charge			992.24			1,121.23	128.99	13.00%
True-Up Adjustment				5000	-0.52	$ (2,614.05)		
Sub Total			**93,742.10**			**43,137.09**	- **50,605.00**	**-53.98%**
F/E Adjust		0.107	10,076.10		0.001	$ 153.34		
Fuel (formerly Fuel & IPP)	5000	27.25	136,268.42	5000	22.18	110,916.83	- 25,351.59	-18.60%
Bill Sub-Total			**240,086.62**			**231,990.52**	- **8,096.09**	**-3.37%**
GCT		0.150	36,012.99		0.150	34,798.58	- 1,214.41	-3.37%
Bill Total			**J$ 276,099.61**			**J$ 266,789.10**	- **9,310.51**	**-3.37%**

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

Usage above 8000 kWh

Rate 20	October 2020 Bill - Before			October 2020 Bill - After				
Above 7500kWh	2018 - 2020 Rates J$			2020 - 2021 Rates J$			Change	
Description	Base F/X Rate	Billing F/X Rate		Base F/X Rate	Billing F/X Rate		J$	%
	128.00	145.20		**145.00**	145.20			
		.						
	Usage kWh	Rate (J$)		Usage kWh	Rate (J$)			
Energy	8000	18.55	148,399.77	8000	**8.93**	71,407.86	- 76,991.90	-51.88%
IPP for kWh				8000	**15.56**	124,453.22		
Customer Charge			992.24			**1,121.23**	128.99	13.00%
True-Up Adjustment				8000	-0.52	**$ (4,182.48)**		
Sub Total			**149,392.01**			**68,346.61**	**- 81,045.40**	**-54.25%**
F/E Adjust		0.107	16,057.77		0.001	$ 244.61		
Fuel (formerly Fuel & IPP)	8000	27.25	218,029.47	8000	22.18	177,466.93	- 40,562.54	-18.60%
Bill Sub-Total			**383,479.25**			**370,511.36**	**- 12,967.89**	**-3.38%**
GCT		0.150	57,521.89		0.150	55,576.70	- 1,945.18	-3.38%
Bill Total			**J$ 441,001.14**			**J$ 426,088.07**	**- 14,913.07**	**-3.38%**

3.8 Bill Comparison for a Typical Rate 40 Consumer

Usage 35,000 kWh

Demand 100 kVA

Description	Unit	Usage	Current Rate	New Rate	Current Charge	New Charge	Change	
			J$/Unit	J$/Unit	J$	J$	J$	%
Base Exch. Rate	J$	1	128	145	128	145	17.00	13.28%
Billing Exch. Rate	J$	1	145.20	145.20	145.20	145.20	-	-
Customer Charge	**Month**	**1**	**6,990.81**	**7,899.62**	**6,990.81**	**7,899.62**	**908.81**	**13.00%**
Demand (STD)	kVA	100	1,790.05	3,935.24	179,005.00	393,524.28	214,519.28	119.84%
Demand (PK)	kVA				-	-	-	-
Demand (PART-PK)	kVA				-	-	-	-
Demand (OFF-PK)	kVA				-	-	-	-
Total Demand	**kWh**				**179,005.00**	**393,524.28**	**214,519.28**	**119.84%**
Energy (STD)		35000	5.77	1.92	201,950.00	67,133.15	(134,816.85)	-66.76%
Energy (PK)					-	-	-	-
Energy (PART-PK)					-	-	-	-
Energy (OFF-PK)					-	-	-	-
Total Energy		**35000**			**201,950.00**	**67,133.15**	**(134,816.85)**	**(0.67)**
True Up Adj	kWh	35000	-	-0.52	-	-18,298.36	(18,298.36)	-
Sub-Total Non-Fuel	**kWh**				**387,945.81**	**450,258.69**	**62,312.88**	**16.06%**
Sub-Total + Fx Adj	**kWh**				**429,645.38**	**450,750.81**	**21,105.43**	**4.91%**
IPP Fixed (STD)	kVA	100		664.67		66,466.62		
IPP Fixed (TOU)	kVA	-		1,003.76				
IPP Variable (STD)	kWh	35000		1.19		41,824.34		
IPP Variable (TOU)	kWh	-		1.48				
Total IPP (Fix + Variable)						**108,290.95**		**0.00%**
Total IPP Fx Adjusted						**108,438.90**		
Fuel	kWh	35000		20.77		726,950.00	726,950.00	-
Fuel - TOU (PK)	kWh	0		28.17		0.00	-	-
Fuel -TOU (PART-PK)	kWh	0		22.60		0.00	-	-
Fuel -TOU(OFF-PK)	kWh	0		17.31		0.00	-	-
Total Fuel	kWh					726,950.00	726,950.00	-
Fuel & IPP	kWh	35000	26.16		915,723.76			
Fuel & IPP (PK)	kWh	0	35.47		0.00			
Fuel & IPP (PART-PK)	kWh	0	28.46		0.00			
Fuel & IPP (OFF-PK)	kWh	0	21.80		0.00			
Total Fuel & IPP	**kWh**				**915,723.76**	**835,388.90**	**(80,334.86)**	**-8.77%**
Fuel & IPP + Fx Adj	**kWh**	**0**			**915,723.76**	**835,388.90**	**(80,334.86)**	**-8.77%**
Total Bill	**J$**				**1,345,369.14**	**1,286,139.71**	**(59,229.43)**	**-4.40%**

3.9 Bill Comparison for a Typical Rate 50 Customer

Usage 500,000 kWh

Demand 1,500 kVA

Description	Unit	Usage	Current Rate	New Rate	Current Charge	New Charge	Change	
			J$/Unit	J$/Unit	J$	J$	J$	%
Base Exch. Rate	J$	1	128	145	128	145	17.00	13.28%
Billing Exch. Rate	J$	1	145.20	145.20	145.20	145.20	-	-
Customer Charge	**Month**	**1**	**6,990.81**	**7,899.62**	**6,990.81**	**7,899.62**	**908.81**	**13.00%**
Demand (STD)	kVA	1,500	1,603.66	2,812.29	2,405,490.00	4,218,438.86	1,812,948.86	75.37%
Demand (PK)	kVA		895.30	1,622.89	-	-	-	-
Demand (PART-PK)	kVA		697.81	1,202.59	-	-	-	-
Demand (OFF-PK)	kVA		71.51	429.11	-	-	-	-
Total Demand	**kWh**				**2,405,490.00**	**4,218,438.86**	**1,812,948.86**	**75.37%**
Energy (STD)		500,000	5.57	2.14	2,785,000.00	1,067,649.69	(1,717,350.31)	-61.66%
Energy (PK)			5.57	1.96	-	-	-	-
Energy (PART-PK)			5.57	1.76	-	-	-	-
Energy (OFF-PK)			5.57	1.71	-	-	-	-
Total Energy		**500000**			**2,785,000.00**	**1,067,649.69**	**(1,717,350.31)**	**(0.62)**
True Up Adj	kWh	500000	-	-0.52	-	-261,405.17	(261,405.17)	-
Sub-Total Non-Fuel	**kWh**				**5,197,480.81**	**5,032,582.99**	**(164,897.82)**	**-3.17%**
Sub-Total + Fx Adj	**kWh**				**5,756,148.28**	**5,038,083.43**	**(718,064.84)**	**-12.47%**
IPP Fixed (STD)	kVA	1500		1,745.29		2,617,940.93		
IPP Fixed (TOU)	kVA	-		831.79				
IPP Variable (STD)	kWh	500000		2.14		1,070,317.94		
IPP Variable (TOU)	kWh	-		1.34				
Total IPP (Fix + Variable)						**3,688,258.87**		**0.00%**
Total IPP Fx Adjusted						**3,693,297.79**		
Fuel	kWh	500000		21.30		10,648,015.54	10,648,015.54	-
Fuel - TOU (PK)	kWh	0		28.87		0.00	-	-
Fuel -TOU (PART-PK)	kWh	0		23.17		0.00	-	-
Fuel -TOU(OFF-PK)	kWh	0		17.75		0.00	-	-
Total Fuel	kWh					10,648,015.54	10,648,015.54	-
Fuel & IPP	kWh	500000	26.16		13,081,768.02			
Fuel & IPP (PK)	kWh	0	35.47		0.00			
Fuel & IPP (PART-PK)	kWh	0	28.46		0.00			
Fuel & IPP (OFF-PK)	kWh	0	21.80		0.00			
Total Fuel & IPP	**kWh**				**13,081,768.02**	**14,341,313.34**	**1,259,545.32**	**9.63%**
Fuel & IPP + Fx Adj	**kWh**	**0**			**13,081,768.02**	**14,341,313.34**	**1,259,545.32**	**9.63%**
Total Bill	**J$**				**18,837,916.29**	**19,379,396.77**	**541,480.48**	**2.87%**

3.10 Bill Comparison for a Typical Rate 70 Customer

Usage 500,000 kWh

Demand 2,000 kVA

Description	Unit	Usage	Current Rate	New Rate	Current Charge	New Charge	Change	
			J$/Unit	J$/Unit	J$	J$	J$	%
Base Exch. Rate	J$	1	128	145.00	128	145	17.00	13.28%
Billing Exch. Rate	J$	1	145.20	145.20	145.20	145.20	-	-
Customer Charge	**Month**	**1**	**6,990.81**	**7,899.62**	**6,990.81**	**7,899.62**	**908.81**	**13.00%**
Demand (STD)	kVA	2,000	1,526.30	3,106.16	3,052,600.00	6,212,318.79	3,159,718.79	103.51%
Demand (PK)	kVA		864.33	1,861.95	-	-	-	-
Demand (PART-PK)	kVA		672.78	1,215.26	-	-	-	-
Demand (OFF-PK)	kVA		68.33	436.23	-	-	-	-
Total Demand	**kWh**				**3,052,600.00**	**6,212,318.79**	**3,159,718.79**	**103.51%**
Energy (STD)		500,000	3.71	2.66	1,855,000.00	1,330,035.06	(524,964.94)	-28.30%
Energy (PK)			3.71	2.00	-	-	-	-
Energy (PART-PK)			3.71	1.79	-	-	-	-
Energy (OFF-PK)			3.71	1.75	-	-	-	-
Total Energy		**500000**			**1,855,000.00**	**1,330,035.06**	**(524,964.94)**	**(0.28)**
True Up Adj	kWh	500000	-	-0.52	-	-261,405.17	(261,405.17)	-
Sub-Total Non-Fuel	**kWh**				**4,914,590.81**	**7,288,848.29**	**2,374,257.48**	**48.31%**
Sub-Total + Fx Adj	**kWh**				**5,442,850.96**	**7,296,814.75**	**1,853,963.79**	**34.06%**
IPP Fixed (STD)	kVA	2000		424.14		848,272.50		
IPP Fixed (TOU)	kVA	-		92.71				
IPP Variable (STD)	kWh	500000		0.59		293,373.37		
IPP Variable (TOU)	kWh	-		0.14				
Total IPP (Fix + Variable)						**1,141,645.87**		**0.00%**
Total IPP Fx Adjusted						**1,143,205.59**		
Fuel	kWh	500000		20.77		10,385,000.00	10,385,000.00	-
Fuel - TOU (PK)	kWh	0		28.17		0.00	-	-
Fuel -TOU (PART-PK)	kWh	0		22.60		0.00	-	-
Fuel -TOU(OFF-PK)	kWh	0		17.31		0.00	-	-
Total Fuel	**kWh**					**10,385,000.00**	**10,385,000.00**	**-**
Fuel & IPP	kWh	500000	26.16		13,081,768.02			
Fuel & IPP (PK)	kWh	0	35.47		0.00			
Fuel & IPP (PART-PK)	kWh	0	28.46		0.00			
Fuel & IPP (OFF-PK)	kWh	0	21.80		0.00			
Total Fuel & IPP	**kWh**				**13,081,768.02**	**11,528,205.59**	**(1,553,562.43)**	**-11.88%**
Fuel & IPP + Fx Adj	**kWh**	**0**			**13,081,768.02**	**11,528,205.59**	**(1,553,562.43)**	**-11.88%**
Total Bill	**J$**				**18,524,618.98**	**18,825,020.35**	**300,401.37**	**1.62%**

23.3 ANNEX 3: Stakeholders Written Submissions on the Application

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/WhatsApp: (876) 322-9301
E-mail: cacu2@our.org.jm

Office of Utilities Regulation (OUR)
3rd Floor, PCJ Resource Centre
36 Trafalgar Road
Kingston 5, Jamaica.

Dear Sir/Madam,

RE : JPS Tariff Review 20219-24

The Consumer Advisory Committee on Utilities (CACU) is grateful for the opportunity to contribute to the regulatory consultation process regarding the subject matter.

Having discussed and considered the information in the application of a revised five-year electricity tariff in Jamaica, the CACU offers the following comments/observations in response to the OUR's request for comments, views and feedback.

A. General Comments

How does the revenue cap regime work if JPS goes below or above the approved target? Does it get worked out over the 5 years?

Capital costs for the two latest investments – Eight Rivers Solar Farm and South Jamaica Power Company (SJPC) and its impact on the rate.

The CACU is pleased to learn of the existence of JPS' Customer Advisory Councils and is just curious to learn about the composition, role and mandate the Councils play in terms of stakeholder engagement.

The application does not speak directly to demand side management or energy efficiency programmes for customers. In the past, the company had an interesting energy efficiency competition in homes; it would be of interest to learn about the impact on demand and efficiency which was realized through the programme.

The concept for energy efficiency should be encouraged across all stakeholder groups, possibly looking at offering a rebate structure on electricity bills considering the new tariff structure being proposed where consumers, especially since those falling in the lower rate classes, will be asked to pay higher charges.

A. Proposed Tariff Rates

Page 51 – CACU believes that the recommendation for the lifeline tariff may be viewed as burdensome and as such, consideration should be given to shifting this burden to local government for streetlights and traffic signals.
How significant is the projected income on EV in the overall projected 5-year revenues?

Heat Rate

Page 16 - The proposal states that JPS plans to reduce its overall heat rate during the 2019 – 2024 period, due mainly to the retirement of inefficient plants. Considering the cost for fuel is passed directly through to customers, JPS must ensure that the best possible heat rate is achieved especially since newer technologies are being utilized, i.e. improvement at Bogue and the new combined cycle plant at Old Harbour - SJPC.

The heat rates stated seem to be marginally better than previously reported. However, these heat rates are typical of ageing plants and do not appear to consider investments made in new plant at both the combined cycle plant at Old Harbour and improvements in the Bogue power plant, both of which utilize natural gas. Why are the improved heat rate benefits not considered at the beginning of the period 2019 – 2024 as opposed to the latter part of the said period?

Non-Technical Losses (NTL)

Page 175 - The report outlines that 22% of JPS customers had smart meters installed (~$28.4 M CAPEX) over the last few years, and the report shows a 0.73% reduction in NTL. What has been the economic impact of the smart meter programme? This programme had been financed through the energy efficiency improvement fund (EEIF) which customers paid (0.4 c USD/ kWh), as such, how has the customer benefitted from this investment made?

Page 181-183 – A capital expenditure of US$82M is being proposed for their Smart ANSI Meter Programme during the review period, which would contribute to a 1.7% reduction in system losses. What has been the impact of the smart meter programme and the generation of estimated bills to customers?
It is not apparent in the tariff request that the public education programme on meter reading for customers will continue, in order to allow customers to better understand their bills, especially since JPS is transitioning to a more digital platform for its customers. The disadvantaged customers, particularly the elderly and those without continuous internet access, should be encouraged to use the other communications and bill payment means available. It is incumbent on all stakeholders to ensure that there is a consistent and continuous public awareness and education programme on meter reading and billing.

Page 331 - The average household consumes between 100-120 kWh per month, the report indicates that 45% of the consumers are using less than 100 kWh, and 22% are using less than 50 kWh. Those who use less than 50 kWh will see a 7% reduction in their bill. However, the vast majority of JPS residential customers will see a 41% increase in their bills non-fuel tariff and a 17% increase in their overall bill. This means 22% of JPS customers would now benefit vs. 45% previously. Customers that fall within the rate 10: 51-500 kWh, could conceivably migrate to self-generation.

2

- How does reducing the first block from 100kWh to 50kWh benefit the lowest rate class?
- Reducing the first tranche to 50kWh may result in an increase in the non-technical losses category (theft), considering customers in this class will be required to pay a higher rate.
- What are the plans for public education on energy efficiency or a demand-side management program to help with conservation?

DER Tariff

Page 357 - The rate review application is seeking to apply capacity charges to those customers who self-generate but remain grid-tied. The CACU has no issue with the DER tariff across all rate classes, given that the Company would have had to provision the stand-by power regardless of whether or not the customer actually uses the reserve power

Page 59 – What are "Quad logic and YPP/ENT upgrades"?

Page 53 – JPS proposes a decoupling mechanism for power purchase cost and its treatment as a direct pass through on customers' monthly bills. CACU believes there is a need to provide a clearer explanation to customers on what this means.

Page 103 – Guaranteed Standards: The CACU agrees with the proposal to review and reduce the number of guaranteed standards currently in force. We have consistently and continuously encouraged and recommended a comprehensive review of the current standards, in order to benchmark and align them with smart and best practices in other comparable markets globally. Additionally, the standards should be re-focused to incentivize the utility towards a more efficient and smart delivery of the customer service experience. We view the current number of eighteen (18) standards - all of which come with automatic compensation – to contain irrelevant and repetitive standards and more importantly, are onerous from an operational and regulatory perspective. Reviews of markets in the Caribbean, Europe, Australia, U.K. and Africa show a trend toward 'categories' of guaranteed standards e.g. metering, thereby reducing the number and treatment of standards relevant to the smart environment of today's utility. In the Caribbean, the maximum number of standards noted stands at nine (9) while in more developed jurisdictions, they are as low as four (4).

The CACU is again encouraging the OUR to **prioritize** the review of guaranteed/overall standards for **ALL** utilities and look forward to participating in what we expect to be wide-scale consultation in the very near term among stakeholder groups and customers of the utilities sector.

The CACU looks forward to further engagement with the Office of Utilities Regulation (OUR) on this and other matters of regulatory importance.

Sincerely yours,
CONSUMER ADVISORY COMMITTEE ON UTILITIES

Private Sector Organization of Jamaica (PSOJ)

THE PSOJ REVIEW OF THE JPS TARIFF APPLICATION

The Private Sector Organisation of Jamaica (PSOJ) thanks the OUR for the opportunity to provide comments on the JPS Tariff application. In conducting the review, the PSOJ took the following points into consideration:

a. The interest of PSOJ Members, to include JPS and other SMEs that operate in the renewable, fossil fuels and distributed generation sectors; contractors and service providers, and large commercial demand entities;
b. Government of Jamaica Energy Policy;
c. Government of Jamaica Energy Priorities;
d. The Electricity Act;
e. The OUR Act;
f. Jamaican Consumers at all respective tariff rate categories; and
g. Jamaican citizenry at large.

1. Heat Rate (H-Factor)

Targeted reduction in Heat Rate and the emphasis on End to End Efficiency targets is commendable.

PSOJ Comments

JPS should not be penalized when IPP's underperform when their underperformance is not caused by the JPS.

There should be adjustments in JPS' favor if the actual dispatch negatively impacts the efficiency of the respective plant operated at suboptimal load output. Proper mechanisms should be in place to ensure transparency.

We are concerned that SJP's HR is not factored in the JPS HR target as SJP is considered an IPP. Our concern extends to the penalty highlighted above as the application of the principle has inherent conflicts, since JPS is both an IPP with a PPA and is also the utility.

2. System Losses (Y-Factor) – Non-Technical

JPS asserts that there is no clear and consistent mechanism for determining NTL categorization between JNTL and GNTL, however this does not seem to be the case as in the 2018-2019 Annual Review Filing, JPS agreed with how the OUR described and allocated responsibility for NTL. Further the review indicated that the following sources of NTL were within JPS' control or ability to meter, monitor and manage the continuation of losses from the categories of customers:

- Rate 60 - Streetlight/Stoplight/Interchange;
- Rate 40, 50 & 70 - Large customer class; and
- Rate 20 – Medium customer class;

The above suggests that a clear mechanism does exist for determining the NTL categories and allocation of responsibility for such losses.

The Responsibility Factor was previously set at 20% however JPS has requested that 10% of the RF should be assigned to the Government for the portion of the GNTL experienced.

PSOJ Comments

We believe that some NTL is attributable to the socio-economic issues resulting from government policies. As such, we are supportive of the breakout of non-technical losses (NTL), into components within JPS' control (JNTL) and those substantially under the Government's control (GNTL).

1

The 10% of RF should be approved initially and adjusted annually to signal that some of this electricity theft is a social-economic problem and not the fault of the utility.

We do not support any increase attributable to JNTL (from 4.22% - 6.98%) between 2018 and 2023 and the company should be challenged to put better numbers on the table for JNTL.

We believe that JPS should allocate the appropriate resources to enable a sharper decline in JNTL over time but be allowed to recover the associated costs in the tariff.

3. Grid Defection

The general attempt made to rebalance the tariff structure to offer the manufacturing and industrial sector more cost competitive power is acknowledged.

JPS in their application has stated that their intent for a request of changes to the Tariff structure is primarily to disincentivize commercial customers from installing their own generation sources and defecting from the grid.

However, we noted that defection from the grid might not be widespread, as JPS is forecasting a 1% growth in demand and a 4% growth in energy consumption over the 5-year Tariff period.

The net effect of the requested adjustment to the Tariff and DER proposal is to reduce tariffs for commercial customers and shifting those costs to residential customers. This against the background that:

a. JPS is actively installing distributed generation solutions for clients. See page 180 of the Tariff Application (5 x 2 MVA LNG fired cogeneration plant).

b. As part of JPS' proposed *"Behind the Meter Energy Services and Solutions"* program, JPS is seeking to participate in the emerging lucrative roof top solar lease program (see page 89 of the JPS Tariff Application).

It should be noted that large commercial and industrial customers are not considering pure financial justifications only from defection from the grid, in which case a lower tariff will be redundant as a deterrent.

Some self-generation by large commercial and industrial customers may also seek to achieve efficiency objectives (using technologies such as co-generation) to avoid additional/auxiliary equipment for thermal demands (e.g. process heat for sterilization and manufacturing or food processing, etc.) and electrical demands. Some commercial & Industrial (C&I) decisions may be based on the National Energy Policy, Government Energy priorities as stated in Table 4-1 of the Application, owner sentiments, global, industry or association trends which are desired by shareholders and management.

JPS' presupposition will not satisfy these non-financial decisions, and therefore it is probable that JPS would in the future revert to its original intent to shift costs to burden residential and other categories of users.

Note that Government of Jamaica Energy Priorities (Table 4-1 of the Tariff Application) specifically seeks to achieve the following:

a. **Competition**

With emerging technologies and the rapid decline in the price of Solar, cogeneration and trigeneration solutions, there is a rise in SMEs providing real energy solutions to Jamaican businesses and saving them upwards of 25% in their energy costs.

This activity is providing significant employment opportunities, growth in the MSME business sector and an increase in the government's tax base. Further, this type of indirect competition incentivizes cost containment in a monopolistic regulated sector.

b. **Modernization**
Jamaica is realizing growth in modern and smart technology on the large scale as provided by JPS and the smaller scale by entrepreneur in the SME sector.

c. **Diversification**
Solar, wind, trigeneration and cogeneration solutions along with LNG are bringing diverse energy sources to the Jamaican market.

d. **Energy Efficiency**
Cogeneration and trigeneration solutions are reducing boiler and air-conditioning related costs and driving up energy efficiencies of some business on an average of 65%. This translates into energy cost reduction of an average of 30%.

e. **Carbon Footprint**
Solar, wind, cogeneration and trigeneration solutions, by virtue of increasing operational efficiencies reduce fuel and energy consumption reduces the carbon footprint of those facilities that employ these technologies.

f. **Demand Reduction**
Demand reduction occurs in a variety of ways to include but not limited to large scale energy conservation, installation of rooftop PV solar, cogeneration and trigeneration.

g. **Green Economy**
Renewables, cogeneration and trigeneration solutions contributes to a green and modern economy.

By increasing the tariffs on residential customers and lowering the tariffs on commercial customers, JPS is primarily seeking to limit competition in the cogeneration, trigeneration and renewable energy market segments with the protection of the Regulator. This contradicts Government's Energy Policy and Energy Priorities.

PSOJ Comments
We are of the opinion that Grid Defection is not widespread and that JPS' approach is short sighted. JPS should instead explore creative ways to work with local energy developers (SMEs) and Self Generating customers (microgrid) to add value to the Grid to include among other things, using microgrids for voltage and frequency stability or to support select communities in the event of localized utility outages.

Since the requested Tariff changes are hinged on this expressed concern of Grid Defection by JPS, as we have articulated throughout this document, we cannot support these tariff changes and related increases.

4. Consumer Rate Categories
Rate-10
100 kWh/month approximates to the household equivalent of;

- 1 small refrigerator;
- 2 x 40 W light bulbs; and
- 1 small iron.

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The 100 kWh/month therefore equates to an under-privileged household/person under financial stress. An energy inefficient refrigerator alone exceeds the proposed 50 kWh/month.

JPS should have to substantiate any suggestion that those on PATH and those stealing are in anyway linked or one and the same, hence suggesting PATH as a socio-economic solution.

This financial obligation for the balance of electricity consumption (> 50 kWh/month) should <u>not</u> be transferred to the financially stressed citizen or the public who pay taxes (held by the State), through PATH or other programmes, especially of the 'lifeline' citizen is already able to pay at this time. The application/extension of an additional social security net also burdens and complicates the administration and distribution of social resources from the State.

<u>PSOJ Comments</u>

The lifeline tariff rate in RT-10 should remain at 100 kWh/month. As such the proposed **Electricity Affordability Assistance Programme** is not recommended.

More thought is required to achieve a more gradual transition to a cost reflective tariff structure.

Time-of-use (TOU)

TOU proposal for residential customers is not sufficiently clear on how easy it will be for customers to understand a fractured and more complex bill (considering current misunderstandings). It is also unclear how TOU will be applied across the 3 proposed tiers of RT10 tariffs.

TOU may be a good signal to encourage more Energy efficiency, however JPS needs to propose their simplified rules on such a TOU charge application.

In addition, while C&I businesses have means to increase revenue for sustainability, residents will unlikely have such flexibility. Residents may likely experience/pursue any of the following options:

- Grid defection using renewable to generate power.
- Increase GNTL via electricity theft.
- Delay or non-payment of bills.
- Decline or reverse living standards.

<u>PSOJ Comments</u>

The proposed overall net bill increases of 17.14 % on RT-10 consumers is **<u>inequitable and unacceptable.</u>**

When contrasted with the <u>14.06% reduction</u> for the proposed MT50X (TOU) and <u>3.96% reduction</u> for MT 70 - MV Power Service (TOU) customers, residential RT-10 is already at a disproportionate disadvantage. Currently RT-10 already pays the highest overall costs per (a) KVA, (b) energy costs and (c) marginal costs among all categories. See Tables 14-24 and 14-25 below.

Table 14-24: Marginal Cost Charges[89]

Tariff Category	Demand (USD/kVA/month)				Energy (USD/kWh)			
	Standard	On-Peak	Partial-Peak	Off-Peak	Total	On-Peak	Partial-Peak	Off-Peak
RT 10 LV Res. Service	223.7	107.1	71.0	45.5	0.024	0.026	0.023	0.022
RT 20 LV Gen. Service	175.9	61.1	98.1	16.8	0.023	0.025	0.022	0.021
RT 60 LV Street Lighting	110.9	79.4	0.2	31.2	0.052[90]	0.018	0.016	0.016
RT 40 MV Power Service All	150.2	58.8	71.5	19.9	0.017	0.018	0.016	0.016
RT 50 MV Power Service All	132.5	52.0	63.2	17.3	0.016	0.017	0.015	0.015
RT 70 MV Power Service All	143.4	59.6	63.8	20.1	0.016	0.017	0.015	0.015
RT 20 LV Gen. Service (Other)	175.9	61.1	98.1	16.8	0.023	0.025	0.022	0.021
RT 50 MV Power Service (Cement Company)	167.3	73.3	70.9	23.0	0.016	0.017	0.015	0.015

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Table 14-25: Average Marginal Costs

Tariff Category	Average Marginal Cost (JMD/kWh)	Adj Existing Average Tariff (JMD/kWh)
RT 10 LV Res. Service	28.41	28.35
RT 20 LV Gen. Service	21.27	23.64
RT 60 LV Street Lighting	9.06	29.08
RT 40 MV Power Service All	12.71	10.52
RT 50 MV Power Service All	11.05	9.8
RT 70 MV Power Service All	9.38	7.5
RT 20 LV Gen. Service (Other)	11.47	22.06
RT 50 MV Power Service (Cement Company)	11.36	7.39
Total	18.95	18.95

5. DER (Distributed Energy Resource) Tariff

PSOJ Comments

We believe the existing standby tariff is reasonable and fair and should remain in place in lieu of the proposed DER which is punitive and serves only to discourage defection from the grid.

6. Electric Vehicle (EV) Tariff

JPS has not clearly defined the measurement and tariff parameters.

- How is a public charging infrastructure defined – i.e. is the infrastructure 100% or only a partial JPS investment?
- Users of such public charging infrastructure may be unknown, random, sporadic, and occasional or scheduled, so how will they be billed?
- For public sector or private sector public charging infrastructure, who is to be charged – the user or the provider?
- If public charging infrastructure is supplied purely with renewable energy power and not from the grid, how will this tariff be calculated and would charges continue after full ROI/payback period of the SPV system has been achieved?
- How and when will the "customer" be billed.
- Will JPS metering and charges discern between industry Level 2 and Level 3 chargers?

PSOJ Comments

The focus on promoting the use of Electric Vehicles is commendable, especially as globally this is the direction many countries are taking.

Additionally no TOU mechanism is being proposed for EVs even though this could go a far way to changing the shape of the load curve.
This tariff class should be rejected until clarity on the issues raised can be provided.

7. Wheeling Tariff

PSOJ Comments

We are generally supportive of a Wheeling Tariff. However, we believe the components of this tariff especially the component "Wheeling Fuel Charge" warrants a more thorough evaluation.

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8. Recovery of Stranded Assets

PSOJ Comments

JPS should be limited in which assets it is permitted to include under an alternative mechanism to recover stranded asset costs. For example, smart meter assets which are purchased by JPS to determine its outputs and revenues for different customers should NOT be included as they are owned by JPS in perpetuity and consumers have no cost saving options for selecting smart meter assets. Other assets may however fall in this category.

9. Integrated Resource Plan

PSOJ Comments

Though the delivery of an IRP was delayed by the Government of Jamaica and thus not in time for the Rate Case filing at end-2019. The IRP is now available since February 2020. The opportunity should therefore be sued for the IRP findings to be reflected in the current review if only being indicative on the way forward.

10. Non-payment/Late Payment:

JPS asserts that only about 50% of customers pay bills in full and on time, thereby affecting its cash flow.

PSOJ Comments

JPS should be allowed to charge a percentage of the billed amount (e.g. 1%) or a fixed amount for penalties for non-payment or late payment after (say) 15 days, based on the applicable rate tariff category.

11. Net Billing

PSOJ Comments

For the stages of approval and licensing under the full control of JPS, performance and guarantee standards should be established as JPS consistently been responsible for extended delays in approvals and signing of a SOC. Performance Standards with compensations should include:

a. Access to interconnection to supply if declared electrically safe by the competent authority.
b. Timely inspection of sites and reporting on-site inspection.
c. Timely installation of JPS NB equipment.
d. Timely connection upon SOC approval.
e. Timely provision of data requirements upon request.
f. Adherence to NB sequence and procedures.
g. Response time to emergencies (each event).
h. Response to Customer queries/Customer Complaints Response.
i. Advance notice to customers of planned outages.
j. Keeping appointments of inspections and reports.
k. Payment punctuality under SOC.
l. Timely publications of the gross number and capacity of all NB and Auxiliary Connections.
m. Timely publication of short-run avoided costs for NB customer payments

12. Guaranteed Standards

PSOJ Comments

A review of the Guaranteed Standards is certainly necessary a few of the proposals need to be re-thought.

One such example is the proposed modification of the Call Center responsiveness to be just answered within the time and not interfaced by an agent. This doesn't provide a reliable assessment of the Call Center efficiency as once answered by an automated agent you could be put "on hold" for a prolonged time after; which would not for part of the assessment.

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13. Q-Factor:

PSOJ Comments

OUR should reasonably not object to the exclusion of sustained forced outages caused by approved Force Majeure events - not in the control of JPS - from the derivation of the Q-Factor indices

14. FX Rates

No Base Exchange Rate (BER) appears to have been set in the 2019-2024 tariff application. In fact, the revenue requirement for each year computed by JPS has been submitted using an exchange rate of JMD$127.98 to USD$1

JMD to USD rates are one of the single largest cost drivers of electricity prices from the grid. Considering that average electricity price in 2014 was USD$0.33/kWh declining to USD$0.28/kWh in 2018 a reduction of 16%.

However, in JMD$ terms the price was unchanged as a result of currency devaluation over the same time period (averaging JMD$37.00/kWh in both 2014 and 2018). The JPS business plan that accompanies the Tariff application states that the JPSCo sees the JMD devaluating against the USD to reach $157.81: $1 in 2023.

While JPSCo is not in control of the FX Rate it does seem that the assumption of an overall increase in electricity prices of 4.6% is being presented in JMD not USD and would be more accurate if presented in USD as the JMD increase is likely to be considerably larger

Our Position

A BER should be established for the Tariff Review period, adjusted at a frequency determined by the OUR.

15. Moving RE Power purchases to Fuel Cost Pass through

PSOJ Comments

We agree with JPSCo that power purchased from IPPs should fall under Fuel & IPP whether these IPPs supply fuel powered or non-fuel powered energy.

16. Bill Impact Analysis

PSOJ Comments

We are of the opinion that the evaluation of the impact of the proposed tariff on future bills can be misleading when the fuel component is factored in. This because fuel being a pass through coupled with its volatility will skew the real impact of the requested increases.

17. Weighted Average Cost of Capital – 12.12%

PSOJ Comments

a. **Cost of Debt – 7.45%.**
   With cheaper debt (< 4% on US$ and <7% on J$) now available, JPS should consider refinancing those debts without punitive refinancing restrictions.

b. **Gearing Ratio of 50%**
   With inexpensive debt (< 4% on US$ and <7% on J$) relative to Return on Equity (ROE) rate of 11.20%, JPS should consider adjusting its gearing ratio and use cheaper debt to lower the cost of energy.

If the cost of debt is reduced and the gearing ratio adjusted where the company reduces equity and increase its debt (cheaper), the company might attain its ROE while maintaining tariffs at reasonable levels.

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c. **EBITDA**

With the exception of 2016 and 2017, we noted that JPS' EBITDA has increased by 28% between 2013 and 2019 (see Table 2-3 on page 61). JPS's cashflow is robust and the stated risk of the company going out of business without the requested tariff should be challenged.

Table 2-3: JPS Historical Income Statement 2014-2018

[US$ Thousand]	2013	2014	2015	2016	2017	2018	Total 2014-2018
Operating revenues:							
Fuel revenues	683,010	633,472	345,209	299,048	395,812	483,714	2,157,254
Non-fuel revenues	416,373	389,768	414,610	413,486	441,057	424,540	2,083,461
Total operating revenues	**1,099,383**	**1,023,240**	**759,819**	**712,534**	**836,869**	**908,254**	**4,240,716**
Cost of sales:							
Fuel	(728,745)	(651,880)	(367,291)	(306,389)	(390,892)	(477,553)	-2,194,005
Purchased Power (excluding fuel)	(104,270)	(97,318)	(105,771)	(121,064)	(157,270)	(141,480)	-622,904
eStore	-	(968)	(569)	(339)	(805)	(560)	-3240
Total cost of sales	**-833,015**	**-750,166**	**-473,631**	**-427,792**	**-548,967**	**-619,593**	**-2,820,148**
Gross profit	**266,368**	**273,074**	**286,188**	**284,742**	**287,902**	**288,661**	**1,420,567**
Operating expenses	(143,265)	(137,063)	(142,093)	(142,729)	(148,969)	(130,384)	-701,238
EBITDA	**123,103**	**136,012**	**144,095**	**142,013**	**138,933**	**158,277**	**719,330**
Depreciation	(49,168)	(54,077)	(57,949)	(77,607)	(76,589)	(80,666)	-346,888
Net finance costs	(61,775)	(55,198)	(42,478)	(39,814)	(34,932)	(35,843)	-208,265
Other income/(expenses) net	83	(4,578)	(12,840)	8,400	2,619	(1,882)	-8281
Taxation	(3,054)	847	(4,323)	(8,941)	(5,444)	(8,848)	-26,709
Other Comprehensive Income Net of Taxes	-2,211	0	0	4,469	3,534	1,490	9,493
Net profit/(loss) after taxation	**6,978**	**23,006**	**26,505**	**28,520**	**28,121**	**32,528**	**138,680**

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UWI Mona, Physics, Professor Anthony Chen & Ambassador Anthony Hill

HILL Comment - CLIMATE ENERGY – JPS Tariff 2019-2024 Application

To comment on the JPS and OUR documentation for the Tariff rate to be applied for electricity consumption over the years up to 2024 is not easy for the layman, not steeped in the process. In fact, it is limited by the technical criteria set by the Office and the Objectives set out by JPS.

I believe the Tariff Rate Application, seeking regular increases in electricity charges to the public, has a direct bearing on the social and economic transformation of the society. The JPS has a customer base of a 630,000 customers of a total population of some 2.8 million persons. There are considerable illegal connections across all segments of the society.

The JPS Tariff design objectives are limited to supporting grid retention and economic development, increasing fixed cost recovery, and rates reflective of costs. It is noted that in its application the JPS has not explicitly committed itself to reducing tariffs to its customers. The OUR is not limited only to regulating revenue matters but also to service standards. Yet as will be indicated below a number of relevant issues are not within its mandate.

On several environmental factors, in particular climate-energy related, the JPS omits any reference to them in its application as agreed with the OUR. These are important for ensuring resilience in the energy sector and to meeting policy objectives in closely related fields set by government.

The JPS as a limited public company with private shareholders is nevertheless a Utility operating within one of the most critical sectors of the society. It therefore has a responsibility to do, and be more than a company serving its customer base and returning profit to its shareholders.

What emerges from the periodic reviews is essentially an exercise, important as it is, of improving efficiency, energy resource diversification and rewards and insufficient focus on the imperatives of national energy security, resilience and price reductions in line with the relative low incomes in the society.

The JPS is after all a profitable commercial enterprise guaranteed the revenue to make this possible. It is the public monopoly for GRID transmission and distribution of electricity, and though not so for generating capacity, its control of the grid gives it special advantages.

warming fossil fuels. It operates as a profit-making entity; pays dividends to Preference shareholders (including Accountant General) and only recently to Ordinary shareholders.

It is regulated by the Office of Utility Regulation (OUR), now overseen by an Office (Board) appointed *de jure b*y the Executive (government). JPS and OUR has drawn on the limited pool of expertise in the country and the Consultancies advising them.

OUR Regulation - JPS submits its claim for operational revenue to the OUR on the basis of the **total revenue the company projects in its five-year business plan, including a surplus to provide returns on its equity, Preference and Ordinary shares.**

The Our gives an indicative range for IPP of renewable energy and the JPS negotiates directly with each IPP for their output. The JPS then negotiates with the OUR, the rates the company proposes to charge each category within its growing disaggregated group of consumers. This is based on two components – the **fuel rate** and the **non-fuel rate**. The former on the basis of negotiations between JPS and the supplier; the latter, less than 40% of the combined total is influenced by the ever-devaluing J$/US$ exchange rate) negotiated between the JPS and the OUR.

This non-fuel rate is most crucial in securing the profitability of JPS. With the ever-devalueing J$/US$ exchange rate, this indexed part of the overall rate guarantees the company against any market losses. Notwithstanding this, the company is cautious in not making any explicit undertaking to reduce its charge to the consumer. Thus there is an increasing own-account power generation by private consumers in an effort to reduce the cost of energy in their production.

JPS is guaranteed a surplus to cover all its costs that it can get the OUR to agree – such as direct subsidies by government, New Investment in Plant, decommissioning of old stock, Revaluation of Capital Assets via accelerated depreciation, inefficiencies due to heat loss, outages, theft, poor risk/uncertainty judgements such as 'take or pay' contracts), high debt charges, profit seeking private equity funding, bureaucratic fudging by *ad hoc* government bodies, and the list is long.

And as power plants are big consumers of **water,** is this scarce resource being properly priced as **a 'public good'? Pollution** too and the cost-free aspect passed on to a 'respiratorily' challenged, ageing population**?** One such Policy seems to be ignored or at least downplayed, namely, the **National Energy Conservation and Efficiency Policy 2010-2030 – Securing Jamaica's Energy Future.** Therein are 16 Indicators and targets, which, if appropriately modified, would ensure that there is real commitment to a Renewable Energy Future. Certainly, for Jamaica it is an imperative by 2045. **For this the energy sector requires additional investments in storage capacity and wheeling technologies.**

Granted these are aspects beyond the legal mandate of the OUR. It does underscore the relatively free hand the JPS and IPP have. An exception seems to be regulation by the National Environment Protection Agency (NEPA).

There is some confusion here – JPS claims it loses revenue when fuel prices are low and vice versa (how does this work?). This should be clarified.

Jamaica's several (too numerous to mention) Policy documents, the Integrated Resource Plan (IRP), the Fiscal and Monetary Frameworks should now be more closely linked in the review processes.

Concluding Remarks

The JPS is justifying its Application for a substantial increase in Revenue on the grounds that it seeks to balance the interests of its customers, support national development while satisfying its private equity shareholders. It requires judicious rebalancing, given the transformative impact on the Jamaican society of the COVID-19 (global) pandemic.

The company's 22-page Executive Summary is a model of clarity. It sets a macroeconomic stage for its operations as one supportive of national development through modernizing the country's energy infrastructure. It is a rate increase application set within a broad macroeconomic framework without delving into details beyond its purview.

The OUR in turn, may wish to indicate to what extent some of the issues raised in this Note are important in the impact that 'price signals' have on decisions in the allocation of budgets – for instance - does a high price for electricity translate into increased efficiency? Does it increase awareness of climate change and influence on householders' recourse to 'net billing'? Does it encourage the distributed supply and if so, is this not positive given the comparative advantage of such for renewable energy generation across the country.

The exercise is not intended to be adversarial but consultative. It would be most informative for comparison and analytical purposes to see the fuel and non-fuel rates over the past 20 years, starting at the turn of this century and projected over the next 10-year intervals, say to 2030 and 2040. By 2050 there may be several fossil-fueled plants 'stranded' by the migration to distributed renewable energy supplies and reliance on those technologies.

In the circumstances, both the OUR and government's approval for the JPS to use current rate charges for the company's capital investments (past, and projected) creates bad precedent and in any event seems improper, given there is no return to the consumer for such investments made by them. Further, the company leverages this capital through depreciation, accelerated or otherwise.

2. With the constant, steady, rate increases and the J$ devaluations, there can be no getting away from the ever-higher prices sought by the monopoly service provider. The only solution is for an over 95% reliance on indigenous renewable energy with entrenched national investment in national currency. This must be obvious as the country's net international investment position (NIIP) is deepening into ever-increasing negative territory. With capital flowing mostly out of the country, including by way of perfectly legal means of returns on portfolio and direct investments, the store of income Wealth being the US dollar, the country is facing difficult times.

The logic of incorporating inescapable, operating costs of public utilities into the macroeconomic frameworks, both monetary and fiscal, is a must.

3.With private equity and its reliance on debt, as the preferred *modus operandi* of investment in Jamaica as in the Anglo-American spheres, it is difficult to see how the government can escape digging a deeper dependency hole for the economy as a whole.
-- The lack of reliable public information about the incorporation of LNG in the fossil fuel mix and the long-term high-priced contract, absolute clarity and full openness is required.
-- the OUR indicates that the JPS is requesting a 17.14% increase for residential consumers in a certain category.
--Considering the company feels hard done by in not securing its target profit of 16%! 16% when US and Euro risk-free rates are near and below zero %.
---And this for a monopoly public utility! The computational methodology to arrive at an overall Bill Impact of an average 4.69% requires explanation.
--- The OUR states "**JPS's detailed application includes a raft of proposals, with the company seeking approval of an annual average revenue requirement of J$62.1 billion (US$485.2 million) in real terms over the five-year review period**".
---- Imagine if JPS went the way of government's ideological 'privatisation' of its minority holdings!!!

1. **Energy Security** – the supply of external fuel supplies and foreign currency availability exceeding threshold volumes should be set for the Utility and related energy-using sectors. This should be related to energy use of and for Water and Irrigation distribution, Municipal and other public street lighting; Health, Policing and Productive sectors.

2. **The Climate-Energy nexus** must be explicitly stated and built into the fiscal revenue aspects of rate setting. There are a number of quantitative targets that should be set, over and above those now used –
For Climate: electricity production/consumption and Carbon emissions (CO2)/$GDP;
For the Environment/Health: trend in emissions of pollutants;
For Water use: (thousands) cubic meters/MW electricity;
For efficiency: energy supply/GDP and electricity consumption.

3. **Risk/Vulnerability/Fragility Indexes –** the JPS Risk analyses should be extended , not necessarily at their cost, to incorporate the ecosystemic fragilities, vulnerabilities and hazards. The recent virus-pandemic indicates that the usual disaster risk analyses and modeled stress tests are inadequate. They do not reflect the socio-economic disruption from the cascading risks to any one part of the system with their feedback loops.

Montego Bay Chamber of Commerce and Industry

MONTEGO BAY CHAMBER OF COMMERCE & INDUSTRY

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May 22, 2020

To: The Office of Utilities Regulations (OUR)

RE: Proposed increase for JPS

The Montego Bay Chamber of Commerce and Industry (MBCCI) is against any increase being granted to the Jamaica Public Service at this time.

We believe that JPS cutting the life line consumption will have significant negative impact on low income employees and residents.

1. The Lifeline Rate, which represents a subsided rate, **which is meant to provide relief to low consumption users who are presumably low income earners** (our assumption), will be applicable to only the first 50 kwh of consumption, whereas this currently is applicable to the first 100kwh. (page 9 see extract below).
2. JPS is also proposing to increase the energy charge for consumption above the lifeline, 50 to 500 kwh from $22.49 to $29.33 or 30% per kwh and for consumption above 500 kwh the proposed rate is 27.78 per kwh or a 23.4% (*page 341 and extract below*)
3. The customer charge is increasing from $445.39 to $853.74 or 91.7%
4. This is likely to increase the energy cost section of the electricity bill of a residential customer who uses 100 kwh by 96% (from $1,411.39 to $2,767,74). See table below. Note that this does not include the Fuel and IPP charge and GCT applicable to the 100 kwh hours).

5. We also extracted the rate 20 proposed rate below to show the small increase for the category, which is good for business, however at the expense of lower income/ lower consumption residents.

Lifeline Rate
Current tariffs present a first block of 100 kWh that reflects a level of subsidized service associated with basic consumption. Consumption data shows that a large percentage of its rate 10 customers (approximately 44%) consuming at or below 100 kWh monthly. This offers an opportunity to reduce the lifeline consumption to 50 kWh, without doing injury to genuine lifeline

consumers. While JPS recognizes the need to maintain a lifeline rate to protect vulnerable customers, reducing the first block to 50 kWh reduces the amount of revenue to be recovered from other customers within the class and therefore supports a reduction in the rate of customers consuming above lifeline while still maintaining the principle of equity

Overall, our members feel that in light of the current pandemic JPS is not deserving of any increase at this time. There is also concern expressed, regarding inaccurate billing via estimates that they are required to pay in full. This is another matter that needs to be addressed.

Many people are of the opinion that with lower fuel cost this should be evidenced in the electricity bills. In the absence of the use of office spaces, they were of the opinion too that there would be a decrease in their bills, but this remains the same.

This is a time for the company (JPS) to do something that shows they care about the country, states a number of our members.

In particular, shop operators at The Shoppes at Rose Hall say they are facing many difficulties at this time and are asking that the Demand Charge be removed from their JPS bills especially now with the presence of a pandemic that has devastated businesses in western Jamaica. The shopping centre has been closed and their Demand Charge is half of the bill, which is unreasonable, given the fact that there is no income at this time. They are requesting this charge be removed and that they be billed as per KW used.

As an essential service, JPS should at least waive the interest, if they cannot defer the payment. We agree that GOJ tax add on is a point of note, but at the same time they too should waive some portion of their profit. Whenever, they are hit by a hurricane, they add on and pass those charges, this should be an option during this time of crisis.

A number of members say that JPS has switched to Natural gas at its Bogue facility which was supposed to be cheaper and more efficient for the Jamaican public, why is this not being reflected on their bills.

In fact, there has only been marked increases. Jamaican people are now being held ransom every so often to rate increase because the country does not own the plant.

We made a collective decision that JPS should not be favored in their request made, at least not until the country comes out of this crisis.

We ask that our concerns are taken into consideration.

Thank you for providing the platform for us as business operators to voice our opinions, we are happy our input matters.

USAID

USAID FEEDBACK ON JPS TARIFF REVIEW APPLICATION 2019-2024

USAID has been a partner of the Government of Jamaica in development for decades. Current shared priorities include power sector resilience with attention to grid modernization, distributed energy for energy diversification and the establishment of renewable energy in the generation marketplace.

USAID is also deeply involved in matters of citizen security which is affected by and affects access and utilization of electricity for improvement of overall standard of living.

In the recent past USAID through the Caribbean Clean Energy Programmed (USAID CARCEP) and other interventions has levied expert capacity to further advance the technical electricity code and to support grid connection for impoverished communities through its Ready Board programme, among other outcomes.

For these reasons USAID is pleased to receive an invitation, and to submit comments on the 2019-2024 Tariff Application submitted by JPS to the OUR.

Comments on JPS Tariff Review Application

Grid Defection

JPS has proffered that by reducing tariffs for the manufacturing and industrial sector, its significant power clients, it can reduce the rate of defection from the grid for self-generation and protect its revenues. JPS also indicated that if there is defection by these large energy users, the other rate categories will of necessity face higher charges to support fixed operational charges for generation and the grid.

With this objective, it appears JPS has front-loaded the cost for preventing grid defection by large commercial and industrial clients to other rate categories;

- ☐ an estimated 222,531 low income residential clients who would experience an average tariff increase of 17%; and
- ☐ Rate 20 customers with consumption below 7,500 kWh who would experience an increase of 15% in their tariff.

This would allow JPS to reduce the tariffs to some rate 40 and 50 clients by 1%

Considering that electricity theft in impoverished communities is in some measure due to socio-economic needs, rising the tariff for the rate 10 category seems counter intuitive to the desire to reduce GNTL, and would likely increase the burden of unpaid for electricity on the utility and the GoJ. JPS should be implored to revisit this request for a more equitable and viable option.

Regarding energy resilience, whereas the utility desires to maintain (or increase) its shares in the generation sector (and increase grid dependence) , it should consider that energy resilience across the grid especially during disaster events such as earthquakes and storm events, may be enhanced by some amount of self-generation (using renewable sources in particular) by large commercial and industrial customers. Resilience can also be enhanced by lowering dependence on imported fossil fuels for generation through greater use of renewable. A greater number of well-located generation sources effectively decentralizes generation to the grid and reduces the risk of catastrophic failure, if some utility generation fails. In addition the injection of generation along intervals over large distances also helps to reduce line losses. USAID suggests that OUR facilitated some self-generators to remain with the grid through implementation of option such as Power Wheeling, and Net Billing or other mechanisms. The utility can then reduce its spend on new infrastructure and maintenance, increase generation diversification and increase energy resilience, in accordance with the National Energy Policy and the State's priorities to enable competition, grid modernization and diversification, while achieving energy efficiency and a greener energy sector.

Consumer Social Programmes

JPS proposes to increase the residential rate by 17% and also shift the cost for GNTL to the government supposing that existing social programmes such as PATH could be used to alleviate the additional burden on the State or citizens. Currently PATH as a social security net covers diverse financial needs and would become complex to administer if electricity is added. For this reason USAID does not recommend the proposed Electricity Affordability Assistance Programme.

USAID has however been instrumental in social efforts such as the successful Ready Board Distribution and Installation programme which could be enhanced to increase the expansion of new safe and legal electricity service with JPS. Other social interventions as this one could be considered to mitigate an increase in rates to residential communities and reduce line losses.

Non-Technical System Losses (NTL)

JPS experiences loss of energy on their grid due to various sources; losses caused by and which are under the control of the utility JNTL and other general losses which may or may not be controlled by the utility including electricity theft.

JPS proposes a Responsibility Factor (RF) in the 2019-2024 tariff and that 10% of that RF should be assigned to the Government for the portion of the GNTL experienced.

Some of the NTL is has socio-economic roots where hundreds of householder often in inner-city communities, are seeking to improve their opportunities for education, comfort and better living conditions. Supporting this transition is reasonably the effort of the Government. As such USAID supports the RF in principle, allowing the utility to be alleviated of this social practice, but cannot opine on the proportion of the NTL which the RF would cover. USAID stands ready to explore with the GoJ, the opportunities to support more legitimate grid connectionsfor impoverished communities.

Electric Vehicle (EV) Tariff

USAID is supportive of tariff interventions which encourage the generation of clean power and utilization ofclean emission vehicles, particularly EVs. JPS however was unclear in the required details of who would be charged this rate, how charges were to be formulated, and the context for defining what makes a charging station "public". Residential EV owners could also benefit from a favourable time of use tariff when charging at home during off-peak.

USAID recommends that JPS close this information gap before a new tariff is applied.

Integrated Resource Plan (IRP)

Considering that the IRP is now available it should be a critical part of guiding the tariff review application.

Net Billing

Net Billing is a critical regulatory/policy tool to increase clean sustainable energy, and energy diversification and resilience on the grid. Even though there have been process flows have been developed over the life of the programme, there have however been complaints that the programme has variability and some unpredictability in its time bound deliverables, responsible parties and costs. Net Billing should be encouraged in the modern grid and to do so it may be necessary to create some performance standard for transparency and accountability.