JAMAICA PUBLIC SERVICE COMPANY LIMITED

2009-2014 TARIFF REVIEW APPLICATION

9 March 2009

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1 Application

1.1 Introduction

Jamaica Public Service Limited is a vertically integrated electric utility company licensed by the Government of Jamaica to generate, transmit and distribute electricity in Jamaica. The All Island Electric Licence, 2001 (The Licence) gives the Company the exclusive right to transmit and distribute electricity and the right to compete with other electricity producers for the opportunity to develop new generation capacity.

Since August 2007, JPS has been a subsidiary of Marubeni Caribbean Power Holdings who acquired an 80% ownership stake and operating control of the Company from Mirant Corporation. The remaining 20% is held between the Government of Jamaica (19.9%) and a number of individual and institutional investors (0.1%). In February 2009, Marubeni announced that it had entered into an agreement with Abu Dhabi National Energy Company (TAQA) of the United Arab Emirates to transfer 50% of its equity stake in its entire Caribbean portfolio, which includes JPS.

The Company serves approximately 590,000 customers; 525,000 (approximately 89%) of which are residential consumers. This customer group is responsible for approximately 35% of the billed energy sales. Small commercial customers make up 10% of the Company's customer base and consume 22% of the billed energy. The remaining customer base is made up of large industrial consumers making up less than 1% of the customer base, but consumes 43% of total billed energy.

The Company's electricity system is comprised of 24 generation plants, 52 substations and over 16,000 kilometres of transmission and distribution lines. The generating systems use a mix of technologies including steam, diesel, hydroelectric and gas turbines to produce electricity. The Company currently has an installed capacity of approximately 621 MW complemented by almost 200 MW of firm capacity purchased from Independent Power Producers (IPPs) under long-term Power Purchase Agreements (PPAs). This gives a total installed system capacity of 821 MW.

The transmission system, which transmits electricity at high voltages to substations across the island, consists of 1,264 kilometres of 138 kV and 69 kV transmission lines. This network primarily conveys electricity to distribution substations, but some large industrial customers are supplied from the 69 kV system. The distribution system that supplies all other customer groups operates at voltages of 24 kV, 12 kV and 4 kV levels.

1.2 Tariff Regulatory Framework

The Company generates revenues from electricity sales. The rates charged to customers must be approved by the Office of Utility Regulation (the OUR). The Company is regulated by the OUR under an incentive-based regulatory framework, known as a price cap regime, introduced through the 2001 Licence. The framework was implemented to ensure that consumers pay fair prices for electricity by simulating a competitive market environment. The Company, through a reward and penalty system, is incentivised to operate as cost efficiently as possible within the constraints of the macroeconomic environment.

Under the price cap mechanism non-fuel base rates are set once every five (5) years. The Company is allowed to make annual rate adjustments between review periods for inflation so rates can reflect changes in the real cost of providing electricity. A monthly adjustment is also made to rates based on indices of foreign exchange rate movements. Adjustments may also be allowed if events occur which are outside managerial control and which affects the costs of operations.

The tariff charged for electricity services consists of two components, the fuel rate and the non-fuel rate. The fuel rate represents the fuel cost to JPS and IPPs to generate electricity. It is recovered directly from customers through a Fuel and IPP Charge subject to adjustments for performance against heat rate and system loss targets. The cost of purchasing electricity under long-term PPAs is also recovered directly from customers with monthly adjustments for any variation between actual costs and the estimated costs embedded in the base rates.

The non-fuel base rate is used to recover costs associated with the operation and maintenance of the Company's regulated assets (the rate base) and its weighted average cost of capital.

The price cap regime also includes a performance based rate adjustment mechanism (PBRM) in which non-fuel rates are adjusted annually based on a productivity offset to inflation and performance against quality of service targets set by the regulator. Annual adjustments to its non-fuel base rates may be approved in keeping with the following formula: $\Delta I \pm X \pm Q \pm Z$, where:

- ΔI = the weighted average of US and Jamaican inflation (in a proportion equal to the split of domestic and foreign components of non-fuel costs);
- X = the offset to inflation resulting from expected productivity improvements (currently determined to be a 2.72% improvement per year);
- Q = price adjustment to reflect performance against the quality of service targets set by the OUR (currently a maximum of ± 0.5%); and
- Z = price adjustment for special reasons not captured by the other elements of the price cap mechanism including (**but not limited to**) costs and losses related to natural disasters and other *Force Majeure* events.

The targets, like the price cap, may be fixed for the five-year period of the price cap and adjusted at tariff resets.

1.3 Filing of Non-Fuel Tariff Application

The current non-fuel tariff rates, fixed by the OUR effective June 1, 2004 are set to expire on May 31, 2009. To obtain new non-fuel tariff rates, the Licence stipulates that JPS must submit a filing with the OUR by the succeeding fifth anniversary of the last submission. The Licence states that

> ***"This filing shall include an annual non-fuel revenue requirement calculation and specific rate schedules by customer class. The revenue requirement shall be based on a test year in which the new rates will be in effect and shall include efficient non-fuel operating costs, depreciation expenses, taxes, and a fair return on investment. The components of the revenue requirement which are ultimately approved for inclusion will be those which are determined by the Office to be prudently incurred and in conformance with the OUR Act, the Electric Lighting Act and subsequent implementing rules and regulations. The revenue requirement shall be calculated using the following formula unless such formula is modified in accordance with the rules and regulations prescribed by the Office.***
>
> ***Non-Fuel Revenue Requirement = non-fuel operating costs + depreciation + taxes + return on investment…"***

Additionally, Schedule 3 defines the test year and rate base as follows:

> ***"Test year" shall comprise the latest twelve months of operation for which there are audited accounts and the results of the test year adjusted to reflect:***
>
> ***Normal operational conditions, if necessary;***
>
> ***Such changes in revenues and costs as are known and measurable with reasonable accuracy at the time of filing and which will become effective within twelve months of***

the time of filing. Costs, as used in this paragraph, shall include depreciation in relation to plant in service during the last month of the test period at the rates of depreciation specified in the Schedule to this Licence. Extraordinary or Exceptional terms as defined by The Institute of Chartered Accountants of Jamaica shall be apportioned over a reasonable number of years not exceeding five years; and

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

"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 net investment made by the Licensee in the generation, transmission and distribution and general plant assets. The Rate Base shall include appropriate ratemaking adjustments to take into account known and measurable changes in the plant investment base and shall be increased or reduced by any positive or negative working capital requirement that may exist at such time. Working capital shall include, among other things, the cost of an appropriate level of fuel which is held in inventory, cost of appropriate levels of other inventories and an appropriate percentage of annual non-fuel operating expenses less any appropriate offsets.

In accordance with the Licence, JPS submits this filing of its application for new non-fuel tariff rates. The submission includes:

1. an application for the recalculation of the non-fuel base rate (ABNF);
2. a proposed *X*-factor for the next five year period;
3. a report on the quality of service provided by the Company during the last five years; and
4. proposed revisions to several PBRM components with justification;

The Company has also proposed adjustments to the methodology used to calculate the fuel rate.

The filing is organized as follows:

Section 1 presents a summary of the proposals contained within this submission.

Section 2 reviews the Company's performance since the last rate reset -2004 – 2008.

Section 3 presents the Company's outlook for the next five years, its forecast of the economic environment in which the business operates, its strategic objectives and the methodologies it will implement to achieve its corporate goals.

Section 4 provides the Company's calculations of the weighted cost of capital and all its components.

Section 5 presents the revenue requirement calculations using the test year financial data appropriately adjusted for known and measurable changes, with justification.

Section 6 provides the details and bases for setting the *X* and ***Q***-Factors for the price cap period. It also proposes to introduce a new Z-factor charge.

Section 7 details the new tariff design and explains the derivation of the new rates.

Section 8 proposes adjustments to the fuel efficiency measures (heat rate and system losses) and the calculation of the fuel rate.

Section 9 provides details of the various system losses initiatives, past and present.

Section 10 shows the calculation of the Reconnection fee, which has not been increased in five years.

Section 11 proposes revisions to the quality of service standards.

1.4 The Price Cap Regime

The 2009 – 14 Rate Case Submission by JPS is seeking to build upon the advances made in the 2004 – 09 tariff period while identifying and proposing solutions to new challenges that have emerged.

The 2004 – 9 tariff period was the first implementation of the price cap regime form of the Performance-Based Rate-Making Mechanism (PBRM) that was introduced under the operating licence granted to JPS at the time of privatisation in 2001. The 2009 tariff review therefore provides the first opportunity for an evaluation of the performance of the price cap regime.

The OUR's Determination of June 25, 2004, addressed a number of shortcomings with the existing tariff that JPS had identified at the time of its Submission. The determination provided greater predictability of cost recovery by adequately addressing certain areas of revenue leakage while challenging JPS to improve efficiency through the imposition of tough efficiency and service standard targets.

Highlights of the 2004 Determination include:

- Implementation of a global price cap (or a revenue cap) with the opportunity to rebalance customer rates in response to changing sales patterns at each annual inflation adjustment.
- Non-fuel costs separated from fuel costs in the application of the monthly foreign exchange adjustment. Full exchange rate protection was provided for fuel costs by allowing the monthly recalculation of fuel rates.
- Revision of the fuel rate calculation and reduction of the system heat rate target from 11,600 kJ/kWh to 11,200 kJ/kWh. This represented an OUR mandated 3.5% efficiency improvement in the conversion of fuel into electricity.
- Full recovery of IPP costs. IPP costs in excess of the non-fuel base rate could be recovered through an IPP surcharge included in the monthly fuel rate.
- Approval of JPS' request to start a self-insurance fund with funding of US$2M per annum from the non-fuel tariffs (the OUR subsequently approved increases in the annual funding rate to a current US$5M per annum at the 2008 annual tariff adjustment).
- An ***X***-factor target of 2.72%. This reflects a requirement for JPS to reduce tariffs in real terms by 2.72% per annum in years 2006 – 09.
- The inflation adjustment formula was changed to more accurately reflect the inflation cost incurred by JPS.
- The OUR established the basis for monitoring the quality of service delivered by JPS and later established specific ***Q***-factor targets. The targets required JPS to reduce the frequency and duration of customer outages by 8% between 2006 and 2009, or otherwise face a penalty that would be applied so as to reduce tariffs.
- Introduction of five (5) new Guaranteed Standards and four (4) new Overall Standards to regulate various customer services.
- Increase in customer compensation for breach of guaranteed standards from $150 to $1,000 for residential and small commercial customers and $8,400 for commercial and industrial customers.

1.5 Performance under Price Cap 2004 – 2009

The purpose of a PBRM, is to provide a utility with incentives to operate as efficiently as possible with the certainty that it will reap the benefits of efficiency gains for a set period. In the case of JPS, this would be the five (5) year reset period. The new levels of efficiency demonstrated by the utility then become the starting benchmark for the next tariff period, so allowing customers to share in the efficiency gains. In this way, the interest of all stakeholders is served.

At the time of the 2004 submission, JPS stated that the request for a new tariff was to achieve the following objectives in support of the goal of the PBRM to balance the interest of all stakeholders:

1. to further improve upon customer service and product reliability;
2. to provide the correct set of incentives for JPS to operate efficiently and to continue improving its productivity;
3. to provide a fair return to investors; and
4. to ensure that while the price cap regime imposes a restraint on the Company to pass on excessive costs to customers it does not unfairly impose on the Company risks that are outside of managerial control

JPS can demonstrate that it has made significant success with the first two of the objectives, those that are more directly within its control.

Operating Cost & Productivity Improvements

Consistent with the incentives provided in the price cap regime JPS has improved its cost efficiency since the last tariff period as reflected in the containment of operating and maintenance (O&M) costs over the period. This improvement in cost efficiency was confirmed by a benchmarking study of JPS' non-fuel cost performance conducted by international consultants Pacific Economics Group (PEG) and included at **Annex I** in this submission. PEG compared JPS' actual non-fuel costs with those predicted by the econometric model. They found that JPS' non-fuel cost was about 28% below the value predicted by the econometric cost model over the 2003 to 2007 period. This compares with a non-fuel cost for JPS that was only .7% less than the value predicted for the 1999-2002 period. Therefore, a comparison of JPS' benchmarking results for the 1999-2002 and 2003-2007 periods indicate that the Company has made substantial efficiency improvements in recent years. This benchmarking evidence is broadly consistent with the substantial TFP gains for the Company since 2003.

Another area that JPS continues to take steps to be cost competitive in is that of head count. Between 2001 and 2004 JPS reduced its head count by 15% and offered that saving to customers in the 2004 rate case. Since 2004, JPS has reduced its head count by a further 7.6% as it seeks to improve the organisation's efficiency.

These efficiency gains were achieved through the streamlining of operations, organizational restructuring, outsourcing of non-core activities and greater deployment and utilization of technology to automate processes that improved the Company's service delivery capabilities and lowered costs.

Improvement in Service Reliability

The JPS fleet of generators is operating at the highest average level of efficiency and reliability in near a decade.

Availability of generators, forced outage rates and heat rate (efficiency of conversion of oil to electricity), the three critical measures of performance have shown consistent and sustained gains over the 2004 – 08 period.

	2004	2005	2006	2007	2008
Heat rate (kJ/kWh)	10,832	10,985	10,174	10,627	10,215
Equivalent availability factor (EAF)	80.8%	81.2%	82.3%	83.7%	83.9%
Equivalent outage factor (EFOR)	12.7%	11.0%	13.4%	10.7%	8.5%

These statistics have translated into real quality of service improvements for customers as measured by the System Average Interruption Frequency Index (SAIFI) and the System Average Interruption Duration Index (SAIDI) for generation. These gains are evident of the Company's delivery on a commitment to invest in the rehabilitation of existing power plants, in tandem with its plans to transition to a modern mix of fuel-diversified power plants. JPS spent US$43 in capital expenditure and a further US$60M in O&M on the generation fleet over the review period with the objective of extracting the maximum MW output from each plant at the lowest unit cost. To this end JPS has retrofitted two of its gas turbines (GTs 6 & 8) to yield a further 8 MW and is currently retrofitting the Bogue combine cycle plant with air inlet cooling to extract an additional 10 MW net output.

Service Standards

Beyond power quality and reliability, the main indicators of JPS performance in customer service delivery are the Guaranteed and Overall Standards. In this area JPS has also made significant advances and now average a compliance rate of over 90% with the majority of the standards. Customers have enjoyed the benefit of the Company's commitment to quality service delivery. In some instances, JPS has opted to operate internally at an even more aggressive standard than mandated by the OUR. By way of example, in the case of reconnection of customers after the payment of overdue amounts, JPS adopted a universal policy of reconnection within 24 hours even as the mandated standard allowed up to 48 hours for some customers. For the few standards on which JPS is currently under-performing, the Company has committed, in this submission, to dedicate additional resources to become fully compliant during the 2009 – 14 period.

JPS has made it easier for its customers to do business with the Company by expanding and creating new channels for communication and transactions. Expansion of the 24 hour call centre, outsourcing of payment collection and the move to monthly meter reading in response to customer preference are all initiatives documented elsewhere in this submission that are aimed at improving the customer's experience with JPS.

In summary, JPS has responded positively to the urgings of the OUR to improve its efficiency and productivity through the imposition of incentives such as the 2.72% ***X***-Factor reduction of the allowed annual inflation-based adjustment and the heat rate and guaranteed standards. These are real gains for customers through improved service delivery and contained costs.

Returns to Investors and Risk Management

While the 2004 – 09 tariff regime has achieved considerable success in driving JPS towards the first two objectives of continued improvement in service and product reliability, as well as efficiency and productivity gains, it fell well short of adequately protecting investors' opportunity to earn a fair return on capital invested. The tariff regime also protected customers from excessive costs but left the Company vulnerable to risks outside its control.

For the 2004 – 08 tariff period for which audited financials are available, JPS made an accumulated net profit of $2.6 billion, with losses in three of the five years. The target profit for JPS allowed (not guaranteed) in the 2004 tariff Determination was $2.9 billion per annum, representing an allowed return on equity (ROE) of 14.85%. The average ROE over the period was 2.4% with a high of 8% in 2006.

This disappointing trend clearly does not augur well for the long-term prospects of the Company to continue to attract financing to the business in the very capital-intensive electricity sector. The trend not only bodes a negative outlook for JPS but constrains as well the IPP-based model of generation expansion favoured by regulatory policy. The performance of IPPs is inextricably linked to the financial fortunes of JPS, which pays for purchased power under long-term Power Purchase Agreements (PPA).

An analysis of the cause of reasons for JPS' underperformance on returns, points to two major factors: (i) under-recovery of expenses related to hurricanes and storms and (ii) under-recovery of fuel expenses due to the penalty/reward attached to the attainment/non-attainment of efficiency targets related to heat rate and system losses.

Hurricanes

At the time of the 2004 rate case submission, Jamaica had not experienced storm damage for the preceding 16 years. Since that filing, Jamaica has suffered damage of varying intensity from two Category 3 and above hurricanes and four tropical storms. JPS' T&D network suffered extensive damage from these weather systems. The Caribbean Basin and US South and Northeast seaboard utilities have not been able to obtain commercial insurance coverage for T&D networks due to the frequency of storm damage in the region since the early 1980s. Since 2004, JPS has incurred $3.1 billion in damage from weather systems.

In making its claim for damages from Hurricane Ivan in 2005, JPS proceeded on the basis that the ***Z***-factor provision of its operating licence provided cost recovery protection from *Force Majeure* events such as storms. The OUR in its Determination, however, disqualified the element of revenue recovery that would allow JPS to recover fixed costs that it is obligated to meet even when sales of electricity are adversely affected by events of *Force Majeure*. This type of protection is afforded to the IPPs through their 'take or pay' capacity payments but denied to JPS the power off-taker and energy sales collection agent for the electricity system.

JPS filed an appeal against the OUR's ruling in 2005 that remains outstanding today. Claims relating to two other major weather systems, hurricane Dean and tropical storm Gustav, are also outstanding at the time of this filing.

The very fact of the uncertainty of the right of recovery embodied in the OUR's ruling on hurricane Ivan and the protracted delay in obtaining a hearing, much less a ruling from the Ivan Appeal Tribunal in four years, has sharply raised the risk exposure profile of JPS.

The risk of hurricane recovery has been partially mitigated by the establishment of the Electricity Disaster Fund (or self-insurance fund) recommended in foresight by JPS in the 2004 rate case and approved by the OUR. Approved recovery costs for some smaller claims such as for Tropical storms Denis, Emily and Wilma and likely Gustav will be funded from the SIF, so avoiding any tariff impact to customers. However, with the frequency of tropical storm activity in the region over the past four years and the necessary draw downs on the fund, it is unlikely that the current funding rate of US$5M annually will be able to create a sufficiently large pool of accumulated funds to sustain the recovery cost of a major natural disaster in the near to medium term.

The risk of financial distress from an inability to recover legitimate costs due to Force Majeure events therefore remains a significant and unmitigated business risk outside of JPS' control.

Fuel Penalty

As part of the PBRM framework, the OUR has implemented a penalty/reward system to encourage JPS to operate its generating plants efficiently and also to keep total system losses (including theft) to 15.8% of net generation. The penalty is applied to the total monthly fuel cost JPS is allowed to recover from customers through the fuel rate.

Significant investment in plant rehabilitation, the introduction of 50 MWs of new capacity by one IPP and generally good plant performance across the system has led to improved heat rate performance over the last tariff period. The Company has therefore been able to meet the heat rate target with sufficient regularity to avoid material adverse impact on its earnings.

However, JPS has continued to under-perform against the 15.8% target for system losses, which remains the single most stubborn and pernicious threat to the viability of the electricity sector in Jamaica. At the end of 2008 losses, technical (10%) and non-technical (largely theft – 12.9%) stood at a total of 22.9%.

Over the 2004 – 08 period JPS was not allowed to recover $1.6 billion in fuel costs due to fuel penalties. The magnitude of the penalty varies with the price of oil and the risk exposure was amplified with the spike in the price of oil over the past two years. Fuel is by far the largest element of cost for JPS (2008 - $47.5B) and therefore has the most influential and immediate impact on JPS financial fortunes. It is for that reason, JPS believes, that the Licence contemplated full recovery of fuel costs subject to reasonable efficiency adjustments. The OUR, in the Company's opinion, recognized the potentially crippling effect of the fuel cost under-recovery to JPS, and ultimately to customers, in its 2004 decision to grant full foreign exchange risk protection to the fuel cost incurred by JPS by allowing costs to be recovered at the prevailing billing exchange rate.

Since the 2004 rate case filing, JPS has had two changes of equity ownership in the Company showing investor interest in the long-term potential of JPS. In addition, the Company in 2006 raised US$180M from internationally placed bonds, the largest placement by a local company.

However, JPS' financial performance 2004 – 2008 has demonstrated the magnitude of exposure to fuel penalties and its impact on the Company's financial viability in a context where fuel price volatility is increasing. Oil prices increased 52% in 2005, 20% in 2006 and 70% in 2008

JPS recognises that like the management of the Company, the OUR, at the time of the 2004 filing was unlikely to have foreseen the risk implication of the unprecedented rise in fuel prices to US$147 per barrel.

The Company has made a proposal in this submission to cap the real risk exposure to JPS of fuel cost under-recovery, while preserving the ability of the OUR to target efficiency improvements in heat rate and system losses.

1.6 Objectives of New Tariff Submission

The objectives of the 2009 – 14 tariff proposals are:

(i) To ensure fair and cost-reflective tariffs that send appropriate price signals but allow all customers affordable access to the product;
(ii) To ensure JPS remains viable and financially strong so as to continue to attract capital;
(iii) To continue the improvement in product quality and delivery to customers with particular focus on the T&D network and to reducing system losses; and
(iv) To mitigate the Company's exposure to risks outside its control.

JPS is mindful of the fact that, at the time of the filing of this tariff review, Jamaica and by extension electricity customers, are experiencing an economic contraction precipitated by global financial turmoil. The Company has experienced the impact of these economic conditions in the form of flat sales growth and illiquidity in the credit market that has forced the rescheduling of required financing and increased levels of system losses.

However, due to the capital intensive nature of the electricity sector and the long planning-to-commissioning cycle for projects, JPS has to continue to pursue its medium-term objective of investing in network and power plant replacement.

Generation expansion is not considered as a part of this tariff submission on the premise that under the regulatory policy promulgated by the OUR, all future expansion will be by way of IPPs and so any planned expansion is not contemplated in the cost or revenues of this filing.

Nevertheless, JPS believes keeping the Company financially strong so as to pursue generation expansion opportunities that will result in fuel diversification is key to its long-term objective of reducing the real cost of electricity. This is central to the Company's future capability to effect its obligation to serve.

Therefore, while JPS accepts the less than ideal environment in which the submission is made, the Company believes it important that it continues to invest in transforming the electricity infrastructure so as to support a robust economic recovery.

However, to support continued access to electricity service for the most vulnerable social group, JPS has proposed the introduction of a new tariff design that will result in only a marginal increase to both residential and small commercial enterprises that consume at the lowest consumption band. The new tariff design is reflective of the cost to serve the various rate classes. It will also begin to rebalance the proportion of revenue the Company earns from fixed charges and variable energy and so lead to a more stable revenue stream. Currently approximately 75% of JPS' non-fuel costs are fixed while only 15% of revenues are recovered through a fixed charge.

The continued assault on system losses, JPS' major challenge, is also a main feature of the tariff submission. The report of a study of 63 electricity utilities commissioned by JPS as to the socio-economic factors contributing to losses and the expected level of losses given Jamaica's socio-economic conditions is included in the filing. The Company is proposing radical new initiatives and requesting regulatory approval for additional economic sanctions for offenders. JPS, has also proposed a timetable for a five-year reduction in losses from the current levels to demonstrate its commitment to reduce the cost to customers and the Company of electricity theft.

JPS also plans to spend US$130M over the next tariff period to further improve the robustness, security and reliability of the T&D network. These investments will expand the T&D network to accommodate demand growth while maintaining a high quality of service reliably to all customers.

1.7 Summary of Proposals

1. **Global Tariff Price Cap (Revenue Cap)**

   JPS proposes that the global tariff price cap be maintained allowing the Company the flexibility to rebalance tariff baskets at the annual adjustment.

2. **Z- Factor Threshold**

   JPS proposes that the materiality threshold for the activation of the Z-Factor be set at $20 million representing the existing threshold of $13 million adjusted for inflation over the period 2004 – 9.

3. **Tariff Design (See Section 7.2 for complete details)**

   JPS is proposing a new tiered rate class structure for residential (rate10) and small commercial (rate 20) customers. Different service/ customer charges and energy charges will apply to the tiers. The redesign is a more cost reflective tariff structure that applies a minimal increase to customers consuming at the lowest levels in rates 10 & 20. With this structure JPS is attempting to keep electricity prices affordable to marginal and vulnerable customers. The new structure will introduce two tiers of service/customer charge for rate 10 customers and four tiers for rate 20 customers.

   The following tiered rate structure will result:

   - Rate 10 customer with monthly consumption less than 100 kWh/month (1^{st} tier)
   - Rate 10 customer with monthly consumption greater 100 kWh/month (^{2nd} tier)
   - Rate 20 customer with monthly consumption less than 100 kWh/month (1^{st} tier)
   - Rate 20 customer with monthly consumption between 101 – 1,000 kWh/month (^{2nd} tier)
   - Rate 20 customer with monthly consumption between 1,001 – 2,000 kWh/month (^{3rd} tier)
   - Rate 20 customer with monthly consumption greater than 2,000 kWh/ month (^{4th} tier)

   There are no proposed changes to the existing tariff design for Rate classes 40, 50 and 60.

4. **Cost of Capital (See Section 4 for complete details)**

   JPS proposes that the pre-tax WACC method be used in determining the WACC for the 2009 tariff review. This change will correct an error due to the post-tax WACC method used in the 2004 filing. The error resulted in the understatement of the cost of debt and hence the total allowed revenue requirement.

   JPS has determined that the pre-tax WACC to be applied to the revenue requirement is 23.08% (compared to 18% in 2004).

   This value was obtained following the same methodology used by the OUR in its 2004 determination to calculate the weighted average cost of capital with the noted exception of applying a pre-tax WACC as opposed to a post-tax WACC. The ROE was calculated using the CAPM methodology and the long-term debt cost reflects the embedded costs of debt for the utility plus the cost of acquiring an additional US$60M that the Company intends to obtain by June 2009. A summary of how the pre-tax WAAC of 23.08% was determined is provided below with a comparison to the adjusted pre-tax WACC for 2004. **Section 2.4.2** provides details on why the post-tax cost of debt is not appropriate.

		2004	2009
Cost of Debt	A	12.56%	11.47%
Rate of Return on Equity (ROE)	B	14.85%	21.63%
Tax Rate	C	33.33%	33.33%
Gearing Ratio	D=E/G	44%	44%
Long Term Debt (‘000)	E	15,420,557	26,537,000
Shareholder's Equity (‘000)	F	19,581,238	32,917,000
Total Capitalization (‘000)	G=E+F	35,001,795	59,454,000
Return on Equity	H=B*F	2,907,814	7,119,947
Taxation	I=H*0.5	1,453,907	3,559,974
Return on Investment	J=H+I	6,298,543	10,679,921
Interest Expense	K=A*E	1,936,822	3,043,794
Post-tax WACC	L=D*(1-C)*E+(1-D)*B	12.00%	15.39%
Pre-tax WACC	M=D*E+(1-D)*B/(1-C)	18.00%	23.08%

5. **Revenue Requirement (See Section 5 for complete details)**

JPS has determined the non-fuel revenue requirement is J$37.8B based on the audited financial statements of the test year 2008, appropriately adjusted to reflect normal operation conditions. The table below provides a summary of the components of the revenue requirement.

	‘000s
PPA Costs	5,661,990
Operating Expenses	13,483,971
Depreciation	4,696,840
Total Operational Expenses	23,842,801
Net finance costs (excl. long-term debt):	(17,717)
Other income	(104,844)
Self-insurance fund contribution + taxes	637,500
Cost of Long Term Debt	3,043,794
Cost of Equity	7,167,966
Taxation	3,583,983
Revenue Requirement, net of credits	38,153,483
Less Carib Cement Revenue	(310,521)
Adjusted Revenue Requirement	37,842,962

6. **Performance Based Rate Making Mechanism Components (See Section 6 for complete details)**

i. *X* – Factor

The Licence states that at the filing of application for new tariff rate the Company must include “a proposed ***X***-factor for the next five-year period including a total factor productivity study used in determining the appropriate level of the ***X***-factor”. The Licence further describes the calculation of the ***X***-factor in the following:

> ***“The X-Factor is based on the expected productivity gains of the Licensed Business. The X-Factor is to beset to equal the difference in the expected total factor productivity growth of the Licensed Business and the general total factor productivity growth of firms whose price index of outputs reflect the price escalation measure "dI".”***

Pursuant to the stipulations of the Licence, JPS retained PEG to provide such a total factor productivity (TFP) study and to make recommendations on an appropriate ***X***-factor.

The study calculated the expected TFP growth of JPS at 1.94% per annum based the Company's average TFP growth since 2001. The TFP growth trend of the US economy at 1.53% and estimated the TFP growth for the Jamaican economy at zero. Using the weights specified in the PBRM for U.S. and Jamaican inflation of 0.76 and 0.24, respectively. The overall TFP growth for firms whose output price indexes are reflected in the price escalation measure is 1.16% (*i.e.* 0.76*1.53% + 0.24*0% = 1.16%).

Using these values as inputs in the formula stipulated by the Licence, the recommendation for the appropriate level of the ***X***-Factor is:

$$X = 1.94 - (0.76*1.53+0.24*0) = 0.78\%$$

Accordingly, JPS proposes a ***X***-factor of 0.80% (0.78% rounded up) for the 2009 – 14 price cap period.

ii. *Q-Factor*

The ***Q***-factor should meet the following criteria:

- Provide the proper financial incentive to encourage JPS to continually improve service quality. It is important that random variations should not be the source of reward or punishment;
- Measurement and calculation of the ***Q***-factor should be accurate and transparent without undue cost of compliance;
- It should provide fair treatment for factors affecting performance that are outside of JPS's control, such as those due to disruptions by the independent power producers; natural disasters; and other *Force Majeure* events, as defined under the Licence; and
- It should be symmetrical in application, as stipulated in the License.

In the 2004 Determination the OUR stipulated that the ***Q***-factor should be based on 3 quality indices:

- SAIFI—this index is designed to give information about the average frequency of sustained interruptions per customer over a predefined area.

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

(expressed in number of interruptions per year)

- SAIDI—this index is commonly referred to as customer minutes of interruption and is designed to provide information about the average time that customers are interrupted.

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

(expressed in minutes)

- CAIDI— this index represents the average time required to restore service to the average customer per sustained interruption. It is the result of dividing SAIDI by SAIFI.

$$CAIDI = \frac{(\sum \text{Customer interruption durations})}{\text{Total number of interruptions}}$$

(expressed in minutes per interruption)

Additionally, the OUR proposed the addition of a fourth quality measure known as:

- MAIFI—this index is designed to give information about the frequency of momentary outages (those of durations of 5 minutes or less) per customer over a predefined area.

$$MAIFI = \frac{\text{Total number of customer interruptions (for durations of 5 minutes or less)}}{\text{Total number of customers served}}$$

(expressed in number of interruptions per year)

The actual targets set by the OUR for the three service quality indices and JPS' actual performance are shown below. It is important to note that targets were set under the assumption of continuous improvement during the period.

Year	Target SAIDI	Actual SAIDI	Target SAIFI	Actual SAIFI	Target CAIDI	Actual CAIDI
2006	3,428	3,436	36.65	33.88	93.52	101.4
2007	3,359	3,008	35.92	23.89	91.65	125.9
2008	3,257	2,518	34.82	24.45	88.84	103
2009	3,154		33.72		86.04	

JPS actually outperformed the SAIDI and SAIFI targets for most of the period, which is a testament to its commitment to improving its service. As it relates to CAIDI, JPS has highlighted in Section 6.2.6.1 the mathematical error in setting the CAIDI target. Since CAIDI is the result of dividing SAIDI by SAIFI, it was mathematically incorrect to assume that a 5% improvement in SAIDI and SAIFI would also lead to a 5% improvement in CAIDI. In fact, CAIDI would remain constant under those conditions; as such CAIDI should have been constant during the 2006 – 9 period. It is for this reason that JPS proposes that CAIDI be considered a being redundant service quality index and that only SAIDI and SAIFI should be used going forward (after 2009).

Additionally, in relation to MAIFI (please see Section 6.2.7 for further details), It is suggested that MAIFI not be included as part of the annual ***Q***-factor adjustment mechanism but rather that the OUR monitor our MAIFI results during the period 2009 – 14. This recommendation is supported by PEG, who stated:

> ***We also believe that there are significant uncertainties regarding an appropriate benchmark for MAIFI. We accordingly recommend that MAIFI simply be monitored, rather than subject to explicit penalties or rewards, in the next PBRM. We also believe more attention should be devoted to understanding customers' willingness to pay for quality improvements, including the willingness to pay for reductions in MAIFI. More knowledge of customer preferences can help JPS make appropriate investments and ensure that any quality improvements actually improve customer welfare.***

Accordingly, JPS requests that CAIDI be excluded from the ***Q***-factor measurement as of 2010 and that MAIFI be included in the Overall Standards.

iii. *Z- Factor*

The Licence describes the Z-factor as:

<u>Allowed (Z-Factor) Price Escalation Reflecting Special Circumstances</u>

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

- ***affect the Licensee's costs;***
- ***are not due to the Licensee's managerial decisions; and***
- ***are not captured by the other elements of the price cap mechanism.***

JPS has made five such Z-factor claims to date, as noted below.

Incident	Incident Date	Claim Date	Amount Claimed	OUR award Date	Amount Awarded
Hurricane Ivan Claim	Sep-04	Mar-05	$1.46B	Mar-05	$652.3M
2005 Tropical Storms	Jun - Nov-05	Mar-06	$193M	Jan-09	$90M
Hurricane Dean Claim	Aug-07	Mar-08	$1.21B	TBA	TBA
Tropical Storm Gustav	Aug-08	Dec-08	$256M	TBA	TBA
IDT Settlement (2008)	Jul-08	Mar-09	$3.5B	TBA	TBA

The Company highlights its concerns in **Section 2.5.1** about the risk it faces to hurricanes given the Determination of the OUR, which is under appeal.

In relation to the Industrial Dispute Tribunal (IDT) settlement made in 2008, the Company has made a separate **Z**-factor claim submission (March 2009) in relation to this matter. The current tariff submission does not specifically contemplate the impact of that separate claim. However, it should be noted that the amount being claimed for recovery over the two year period a special **Z**-factor adjustment amounts to 6.75¢ per kWh. This amount is included in the overall analysis of the tariff impact in **Annex M**. It is also assumed that the **Z**-factor charge in relation to Hurricane Ivan (currently 8.8¢ per kWh) comes to an end in June 2009. In summary, since the revenue requirement relates to normal operating expenses only, the **Z**-factor is designed conceptually to allow the Company to apply for the recovery of extra-ordinary costs that are legitimate operating expenses of the business, which were not contemplated in setting the tariffs.

7. Adjustments to the efficiency measures used in the fuel rate calculation (Section 8)

The mechanism used to calculate the fuel cost recovery on a monthly basis under the current tariff operates according to the following formula:

$$\text{Pass thru Fuel Cost} = \text{Fuel Cost Actual} * \frac{\text{Heat Rate Target}}{\text{Heat Rate Actual}} * \frac{(1 - \text{Losses Actual})}{(1 - \text{Losses Target})}$$

JPS proposes the introduction of a US$1 million cap on the fuel penalty/reward mechanism in conjunction with the application of the fuel efficiency measures, i.e. heat rate and system loss. The proposal is for the cap to be symmetrical thereby reducing the upside or downside exposure of JPS in relation to fuel costs.

8. TOU (See Section 8.3 for complete details)

JPS proposes a modification to the derivation of the monthly fuel rate, to take account of the fact that Time of Use (TOU) customers are not billed at the standard fuel rate. The proposed modification would be done by applying the weights of the respective TOU sale categories to the sales reported for these categories. This will ensure that the standard rate is properly adjusted for the discount/premium charged to TOU customers and that the full cost of the applicable fuel amount is properly recovered through the energy sales in the subsequent month in conjunction with the use of the volumetric adjustment mechanism (VAM).

9. Heat Rate Target (See Section 8.1 for complete details)

Based on the planned mix of generating units, including IPPs, their projected availability and dispatch, and the possible variation in heat rate for reasons beyond JPS' control, JPS proposes a two stepped reduction (improvement) to the heat rate target for the rate cap period 2009 – 2014, as noted below:

- An initial 3.1% reduction to 10,850 kJ/kWh for the period July 2009 – June 2010;
- A further 1.4% reduction to 10,700 kJ/kWh for the period July 2010 – June 2014 (contingent on the 60 MW JEP Expansion).

The second step 150 kJ/kWh reduction in the heat rate target would be implemented only if the JEP 60 MW expansion was expected with certainty by August 2010. If not, it would be implemented in the month after the JEP 50 MW expansion is commissioned, or on a prorated basis for each 10 MW of capacity that is commissioned. So, if 30 MW were commissioned the target would be reduced by 30/60ths of 150 kJ/kWh or by 90 kJ/kWh.

The heat rate target should be set for the five-year tariff period. However, JPS would agree to the revision of the heat rate target if any major fuel diversification project (i.e. CNG or Petcoke) is commissioned into service during the price cap period (See Section 8.1.6).

10. System Losses Target (See Section 8.2 for complete details)

JPS has not been able to achieve a system loss reduction target in 15 years, reflecting the ingrained and pervasive nature of this crime that thrives in Jamaica's challenging socio-economic environment. Nevertheless JPS intends to intensify its battle against losses on both the technical loss and commercial loss sides. JPS expects to reduce system losses from 22.9% (at the end of 2008) to 18.3% over the rate cap period primarily as a result of its ongoing loss reduction initiatives. This represents almost a 1% point reduction per annum for the next five years as the result of a cumulative CAPEX and O&M spend of approximately US$45M. JPS therefore proposes a reset of the system loss target with a reduction over the tariff period as in the schedule below. Please note that the proposal includes the application of a stretch target of 2% on the projected losses outturn.

	Actual	Forecast					
	Dec-08	Jun-09	Jun-10	Jun-11	Jun-12	Jun-13	Jun-14
Projected System losses	22.9%	22.5%	21.5%	20.5%	19.7%	18.9%	18.3%
Stretch target		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Proposed Losses Target		**20.5%**	**19.5%**	**18.5%**	**17.7%**	**16.9%**	**16.3%**

The break-down of the system losses is provided below:

	Actual	Forecast					
	Dec-08	Jun-09	Jun-10	Jun-11	Jun-12	Jun-13	Jun-14
Non-technical losses	13.0%	12.9%	12.2%	11.4%	10.8%	10.2%	9.8%
Technical losses	9.9%	9.6%	9.3%	9.1%	8.9%	8.7%	8.5%
Total losses	**22.9%**	**22.5%**	**21.5%**	**20.5%**	**19.7%**	**18.9%**	**18.3%**

Please note that a 2% stretch target implies an annual fuel penalty for JPS of approximately US$9M per annum at today's fuel prices, or US$14M at the average fuel price for 2008. A larger stretch penalty would be excessive.

The Company has made suggestions regarding treatment of non-technical losses in an effort to deter the illegal abstraction of electricity. One suggestion, for example is the imposition of a penalty on the value of electricity stolen, which reflects actual loss and has a punitive component. JPS is committed to working with the GOJ and its affiliate organizations (such as the REP and the NWC) to encourage the development of proper housing infrastructure for such persons, to mitigate the need for the illegal access of water and light by these inhabitants. JPS recognizes that NWC has an even more uphill battle in their fight against unaccountable water (losses) which now stands at over 50% and will also be working closely together with them to see what synergies may be gained in our efforts to reduce non-technical losses.

Section 9 provides further details on the various initiatives JPS has employed as part of its loss reduction programmes and the details of a non-technical losses study which JPS commissioned to allow the proper benchmarking of non-technical losses (complete report included in **Annex L**).

11. Sales Forecast (See Annex D for complete details)

JPS forecasts sales growth for the tariff reset period (2009 – 14) at 0.8% per annum. This forecast is marginally lower than the average growth rate of 1.1% between 2004 – 8 and is a reflection of the negative economic outlook for the economy over the first half of the period.

12. Base Exchange Rate

JPS proposes a base-exchange rate of US$1 = J$85

13. FX Adjustment Factor (See Section 5.4 for detailed calculation)

JPS proposes that the FX adjustment factor be reset to 79% (formerly 76%) for the purposes of the monthly FX billing adjustment and the annual inflation adjustment factor.

14. Depreciation (See Section 5.2.8 for complete details)

The Company commissioned a study to compare the asset lives posited in Schedule 4 of the Licence with those used in other regulated territories.
The study confirms that the asset lives used by JPS in several instances were too long. A summary of the asset categories, the current useful lives in years, the mode of the sample and the excess is highlighted below.

Activity	Asset Category	JPS	Sample Mode	Difference
Generation	Hydro Production Plant	30	20	10
Distribution	Test Equipment	25	15	10
Distribution	Supervisory Control System	25	15	10
General Plant	Electronic Equipment	25	5	20
General Plant	Communication Equipment	15	5	10
General Plant	Computer Equipment	20	5	15
General Plant	Furniture & Office Equipment	20	10	10

Accordingly, JPS requests an adjustment specifically for assets that currently have a useful life that is 10 years (or more) over the sample mode of the Companies in the study.

15. Reconnection Fee (See Section 10 for complete details)

JPS is allowed to charge a reconnection fee to customers disconnected for non-payment based on the actual cost of reconnection activities plus a service charge. The fee currently being charged is $1441.
JPS calculated the unit costs of reconnections using 2008 data and proposes an increase in the reconnection fee to $2,036. JPS proposes that the revised fee be implemented on July 1, 2009 to coincide with the new tariffs.

16. Quality of Service Standards (See Section 11 for complete details)

JPS proposes the following modifications to the Guaranteed and Overall Standards in introduced in the 2004:

- GS02 - Complex Connections:

  a. Estimates within 15 days; connections within 35 working days after payment

  b. Estimates within 15 days; connections within 45 working days after payment

- GS10 - Billing Adjustments

  "Billing Adjustments: Timeliness of adjustment to customer's account - where necessary, customer must be billed for adjustment within 2 billing periods after conclusion of investigation of billing error.

- GS11 – Timeliness of repairs of streetlights

  GS11 measures the same performance target as Overall Standard OS11, is redundant and should be removed.

- OS2 (a) & OS2(b)

  Similar to GSO6, JPS adopted a non-discriminatory policy in respect of OS2 (a) and (b) and configured our operations to comply with the more aggressive 48 hour restoration standard for all our customers. It is therefore proposed that this standard be united at 48 hours.

- OS7 (b)

  In December 2005 the OUR/JPS and the Bureau of Standards Jamaica concluded a Protocol, "Electricity Meter Testing in Jamaica". The Protocol includes provision for the sample testing of meter lots and groups. It is proposed that the benchmark target for testing be linked to the targets established in the protocol.

- MAIFI

  JPS proposes that Momentary Average Interruptions Frequency Index (MAIFI) be included as an Overall Standard.

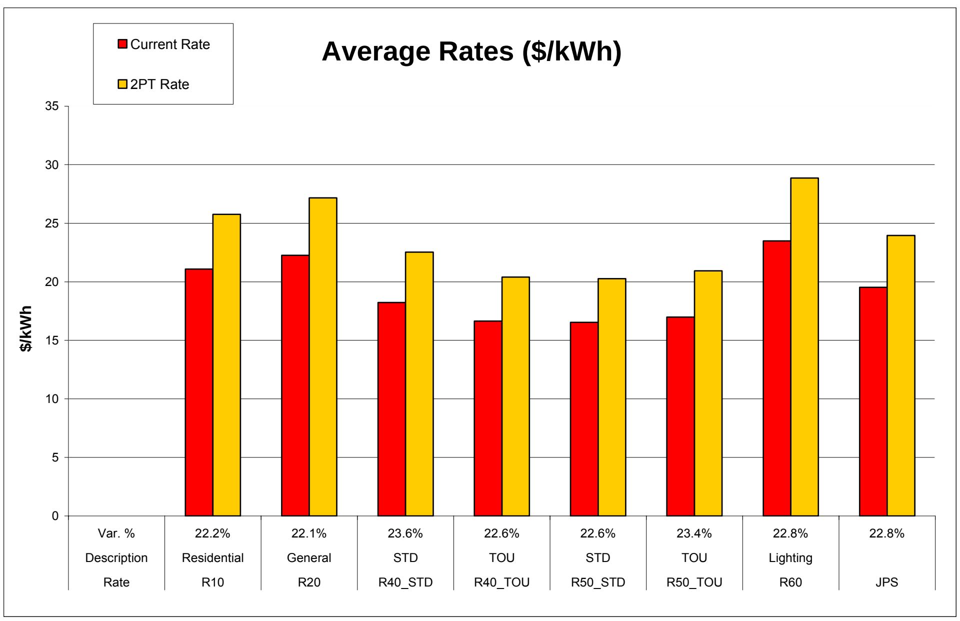
17. Proposed Rates and Charges (See Section 7.2 for complete details)

Summary of New Tariff Rates

Rates	Description	Customer Charge $/Month	Energy Charge $/kWh	Demand Charge $/kVA STD and On-Peak	Demand Charge $/kVA Partial-Peak	Demand Charge $/kVA Off-Peak
R10_1	0 - 100 kWh/month	190.00	6.20			
R10_2	100 - 500 kWh/month	475.00	17.65			
R10_3	> 500 kWh/month	475.00	17.65			
R20_1	0 - 100 kWh/month	475.00	8.38			
R20_2	100 - 1000 kWh/month	955.00	14.80			
R20_3	1000 - 3000 kWh/month	2,385.00	14.80			
R20_4	> 2000 kWh/month	4,775.00	14.80			
RT40 (STD)		10,956.03	5.23	1,444.91		
RT40 (TOU)		10,956.03	5.23	813.52	680.21	61.33
RT50 (STD)		10,956.03	4.94	1,369.44		
RT50 (TOU)		10,956.03	4.94	779.90	606.05	42.75
RT60	Streetlight	9,064.61	16.93			

Bill Impact

JPS proposes an overall tariff adjustment that will have an average bill impact of 22.8% on electricity rates as shown below.



This will result in an increase (total bill impact) from 4.3% for a tier 1 residential customer to 26.8% for a tier 4 commercial customer (see Annex M for the complete bill impact analysis).

2 Review 2004 – 2008

2.1 Macroeconomic Review

The Tariff period 2004-2008 was marked by spurts and ebbs in the fortunes of the Jamaican economy. Episodes of moderate economic expansion were offset by contraction and stagnation throughout the period. As a core input to economic activity, electricity services, and by extension the financial viability of JPS, is inextricably linked to the performance of the Jamaican economy. The Company conducts all its business activities in Jamaica and derives all its revenues from a local customer base. Therefore, its capacity for revenue maximization or cost optimization is entirely dependent on the business environment it faces locally. Specifically, Jamaica's macroeconomic variables such as interest rates, exchange rates, the growth of gross domestic product (GDP) and tax rates all significantly impact the Company's operating expenses, its cost of capital and its ability to collect revenues. Fluctuations in these variables will either augment the Company's efforts to improve financial performance or have a negative impact on said efforts.

Jamaica is a small open economy and thus susceptible to exogenous shocks. This fact, while evident during the entire 2004 – 09 tariff period, has been markedly pronounced since the second half of 2007 through 2008. A striking example of this was the recent slide in the value of the J$ which was precipitated by a sharp contraction in global financial markets in October 2008. Margin calls[1] by international banks that finance capital market transactions of many local financial institutions dramatically increased the demand for foreign currency at a time when supplies of foreign exchange were extremely limited. The ensuing scarcity resulted in a 10% depreciation of the dollar (J$) by year's end and caused Bank of Jamaica to intervene to stabilise the value of the local currency. The policy initiatives employed by the Bank resulted in interest rates increasing by 900 basis points by the end of the year. The depreciation of exchange rate and the subsequent rise in interest rates has had a direct negative impact on the cost of borrowing of JPS, which had long and short-term liquidity needs throughout the year. These developments delayed the acquisition of necessary funding for capital projects planned during the year and placed serious constraints on the Company's working capital and debt management efforts.

The foreign exchange crisis was the latest shock to an economy already recovering from spikes in world food and oil prices that resulted in an inflationary episode which averaged almost 2% per month for the first seven months (7) of 2008. During the year, point-to-point inflation peaked above 26% for the first time in 10 years. This inflationary environment put pressure on economic activity, industrial relations, and social welfare throughout the year. While inflation slowed by the fourth quarter of 2008, the lagged effect of inflation-indexed wage settlements, restricted credit markets, reduced economic activity, job losses and currency devaluation all indicate that the environment faced by businesses in the country will be negative for the near to medium term.

[1] ***A margin*** is collateral that the holder of a position in securities, options, or futures contracts has to deposit to cover the credit risk of his counterparty (most often his broker). When the margin posted in the margin account is below the minimum margin requirement, the broker or exchange issues a ***margin call***. The investor now either has to increase the margin that they have deposited, or they can close out their position. They can do this by selling the securities, options or futures if they are long and by buying them back if they are short. If they don't do any of this the broker can sell his securities to meet the margin call.

These developments also had a negative impact on government's fiscal position and led international rating agencies to downgrade the country's credit rating in November 2008. Moody's Investors Service, Standard and Poor's and Fitch all cited the country's debt to GDP ratio of above 130% and a deficit approaching 6% of GDP as important factors in their decision.

The impact of these developments on JPS' performance through the tariff period and in particular 2008, the test year, was to slow electricity demand growth, increase the cost of debt and hike the overall cost of production. Overall peak energy demand fell by 3%, total net generation remained relatively flat while the average consumption per residential customer fell by 4% to 164 kWh per month at year-end 2008.

The contraction in the latter half of the review period reversed the positive macroeconomic trend since 2003. In the five years prior to 2008 the economy grew by over 2%, compared to less than 1% in the previous 5 years. Interest rates stabilized at below 12% and inflation fell to 5%. During this period the Company made profits in consecutive years ('05 & '06) and reversed the J$1 billion loss made in 2003. This allowed the Company to attract capital, both debt and equity. In 2006 JPS reduced its cost of debt with an oversubscribed US$180M bond issue at a competitive interest rate of 11%. The Company also attracted new equity partners when majority ownership was acquired by Marubeni in 2007.

In this review, an examination of the outturn of the following selected macroeconomic variables is conducted over the review period:

(i) GDP growth
(ii) interest rates,
(iii) inflation
(iv) exchange rate,

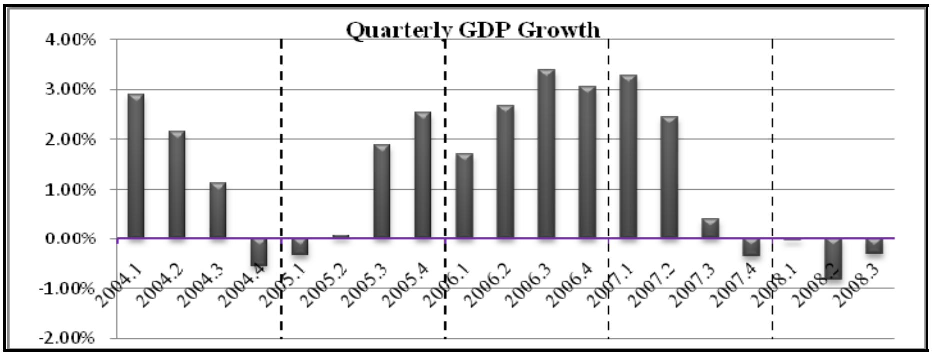
Throughout the analysis, the relationship between these variables and the financial performance of JPS will be emphasized. The historical performance of these variables were used to develop the economic forecast and the strategic business plan in **Section 3** and the Company's sales forecast in **Annex D**.

2.1.1 Gross Domestic Product

The Jamaican economy has been in a recession since the fourth quarter of 2007. After growing by 1.43% in 2007 the Planning Institute of Jamaica (PIOJ) estimates that the economy had contracted by 0.4% during 2008. The reduction in economic activity is a direct result of the ongoing global financial crisis that has negatively impacted each of the country's three main industries, bauxite, tourism and agriculture. This recession has also had an immediate impact on the demand for electricity as the Company's net generation was flat for 2008. Most significant was the fall in the average consumption per residential customer, which shrank by 4% over the past year.

As shown in **Figure 2.1,** since its recovery from Hurricane Ivan in September 2004, Jamaica had experienced ten (10) quarters of positive growth, half of which were above 2%. The figure also shows that in the quarters prior to Hurricane Ivan the economy experienced positive growth. The strong economy fostered a positive investment climate which resulted in greater foreign direct investment inflows into sectors that are traditionally heavy users of electricity such as the construction and the hotel industry. Both sectors grew by 20% during the period. This translated into higher demand by JPS' commercial customers as consumption by large customers grew by 10% over the period.

Figure 2.1: Quarterly GDP Growth



Source: Statin

The deterioration in the Company's financial performance coincided with the country's economic contraction that became pronounced in the last quarter of 2007. The downturn was precipitated by the impact of Hurricane Dean then exacerbated by spikes in oil and food prices. During the contraction, residential demand for electricity diminished while commercial demand trended flat. The Company as a result posted a 22.9% loss for the 2008 financial year.

Table 2.1: Annual GDP Growth

	GDP
2003	3.50%
2004	1.39%
2005	1.03%
2006	2.71%
2007	1.43%
2008(est.)	-0.4%

2.1.2 Inflation

A price cap regulation regime caps a utility's prices or revenues between rate review periods. The revenue requirement, that tariffs are set to recover, is fixed according to the level of expenses incurred in a specified test year. Between rate resets, real tariff rates are preserved through annual inflation adjustments.

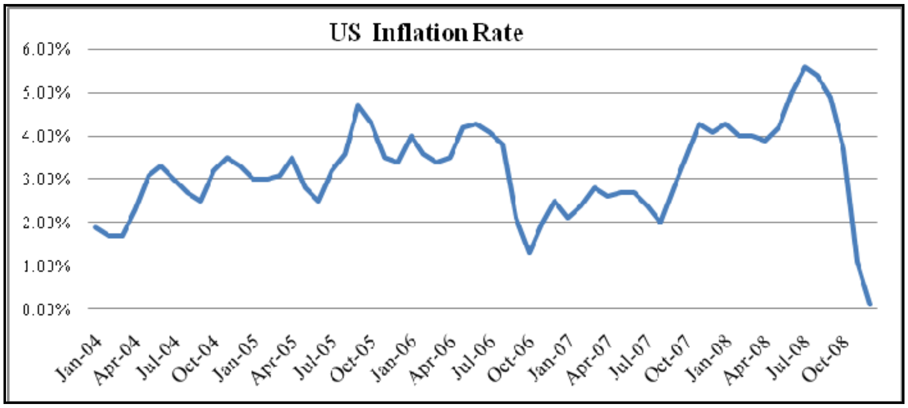
Although these adjustments compensate the Company for a rise in operating costs in one year by increasing tariffs in the following year, significant escalation of these costs during the year may expose the utility to significant business risks. Periods of especially high inflationary episodes put severe pressure on working capital; reduce sales growth and collections rates, deteriorating the utility's profitability in the process. This scenario manifested in 2008 when spikes in commodity and oil prices precipitated high inflation rates in Jamaica and globally.

2.1.2.1 US Inflation Rate

A large portion of JPS' costs are US$ denominated and thus influenced by US inflation. As illustrated in **Figure 2.2** prices in the US trended upwards during the first two and a half years of the review period, peaking at almost 5% point to point. This was due mainly to a buoyant economy and rising oil prices. Inflation spiked again in mid-2008 due to further sharp and sustained growth in commodity and oil prices.

The impact of the fluctuation in US inflation on JPS' performance during the period was minimal as the rates were still relatively low, the highest being 5% in 2008. However, the spike in oil prices in 2007-2008 did place significant pressure on the Company's working capital.

Figure 2.2: US Point-to-Point Inflation Rates



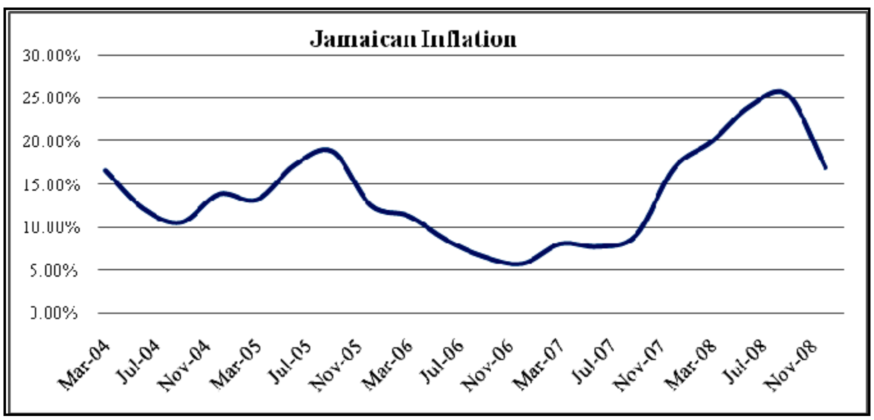
Source: US Dept of Labour

2.1.2.2 Local Inflation Rates

The average inflation rate in Jamaican between 2004 and 2008 was 13.72% per annum, which is much higher compared to US average inflation rates of 3.2% per annum during the same period. However, since most of the Company's operating expenses are US based, the impact on operating costs was largely minimal; yet, there was a noticeable impact in residential demand and energy sales. During most of the review period, inflation rates were moderate and sales growth modest. These trends were reversed by the inflationary upswing brought about by rising oil and international food prices. Sales growth has since trended flat and residential demand has fallen.

Inflation rates also had a brief upturn in 2005, that spike was similarly due to rising oil prices. **Figure 2.3** shows the point-to-point inflation rates between 2004 and 2008.

Figure 2.3: Jamaican Point-to-Point Inflation Rates

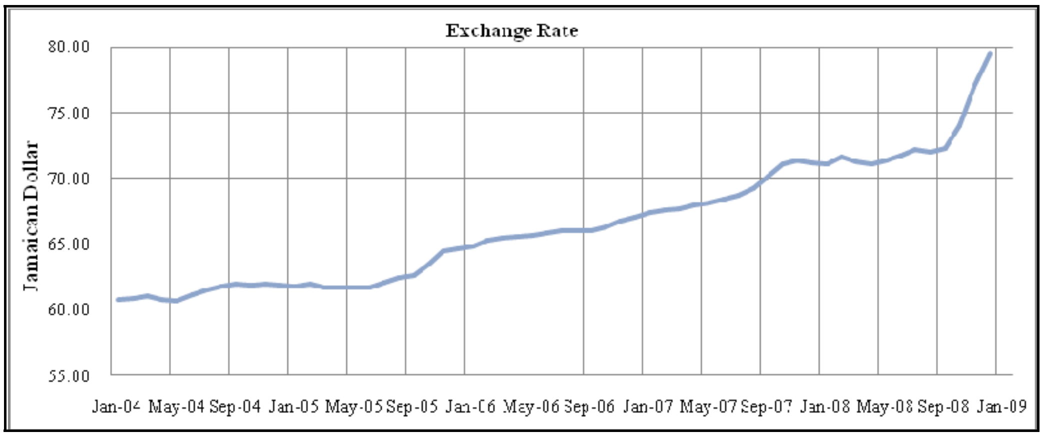


Source: Statin

2.1.3 Exchange Rates

Any depreciation of the exchange rate of the Jamaican dollar (J$) relative to the US dollar (US$) adversely affects the Company's ability to honour its foreign obligations. 90% of JPS' debt obligations are denominated in US dollars, while a significant portion of the capital plant is imported. JPS generates its revenues in Jamaican dollars, which must be converted at the current rate of exchange to service its obligations. Under the price cap regime, the Company's revenues are capped at test year levels with monthly adjustments for foreign exchange fluctuations. Although monthly adjustments of base billing rates in theory should compensate the Company for these fluctuations, a sharp devaluation of the currency during the adjustment periods may place severe pressure on working capital especially if the cost of short-term credit is very expensive. This was the case during 2008 as shown in **Figure 2.4**. The Jamaican dollar lost 10% of its value between September and December. Prior to 2008 the exchange rate depreciated by only 4% annually.

Figure 2.4: Foreign Exchange Rate



Source: Bank of Jamaica

2.1.4 Interest Rates

JPS typically accesses large multinational banks in the local debt market for its short-term US$ credit financing. Interest rates are usually influenced by global capital market interest rates, typically LIBOR, plus a spread by the bank(s) providing the funding. While the rates on short-term funds are mainly influenced by LIBOR, long-term financing required for capital projects are influenced chiefly by the pricing of the Government of Jamaica Global Bonds in the capital markets. Additionally, J$ interest rates tend to be influenced by local Treasury Bill rates, which in turn are influenced by international interest rates, expected currency depreciation and monetary policy

2.1.4.1 Long-term Debt Rates

The main factor affecting long-term interest rates is the sovereign bond rating given to Government of Jamaica issued global securities by international credit-rating agencies. Between 2004 and 2007 the typical rating of these bonds was a stable "B" which, allowed them to attract pricing that saw them trading at high single digit interest yields in the capital markets. In the third quarter of 2008, Fitch, Moody's & S&P all downgraded the bonds resulting in a lowering of their bond prices. As indicated in **Table 2.2** the bonds currently trade above 15% on average.

Table 2.2: Yield on Global Bonds

Bond	Coupon	29-Aug-08	26-Sep-08	30-Oct-08	28-Nov-08	23-Dec-08
2011 Bond	11.75%	5.14	5.55	10.37	9.42	9.36
2015 Bond	9.00%	8.12	8.40	11.66	13.75	13.78
2017 Bond	10.63%	8.27	8.48	13.62	12.98	13.00
2019 Bond	8.00%	8.32	8.95	11.90	13.74	13.77
2022 Bond	11.63%	6.35	6.96	10.22	9.59	9.59
2025 Bond	9.25%	8.63	8.79	11.72	13.11	13.90
2036 Bond	8.50%	8.45	8.69	12.35	14.38	14.38
2039 Bond	8.00%	8.53	8.86	12.49	13.30	14.46
2009 Euro Bond	10.50%	8.71	18.05	N/A	34.43	30.60
2012 Euro Bond	11.00%	8.29	10.74	N/A	18.21	19.10
2014 Euro Bond	10.50%	8.40	10.21	N/A	15.49	20.07

Source: Bank of Jamaica

The rates on 2015, 2017 and 2019 Global Bonds are the best indicators of the cost of long-term funding faced by JPS at its preferred tenure. As indicated in the table, those bonds were trading at yields of about 13% in December last year.

2.1.4.2 Short- term Interest Rates

Interest rates on short-term funds are mainly influenced by the rates on six (6) month Government of Jamaica Treasury Bills. Between 2004 and mid 2007, the gradual depreciation of the value of the J$ relative to the US$ and the downward trend in inflation rate allowed the central bank to maintain a relatively relaxed monetary policy regime. Interest rates fell below 12% in early 2007, a ten-year low. Since then rising inflation and the sharp depreciation of the local currency triggered a reversal of monetary policy sending benchmark interest rates on the six (6) month Treasury bill rate higher to almost 25%. **Table 2.3** shows the interest rate trend during the review period.

Table 2.3: Short-term Interest Rates

	Dec-03	Dec-04	Dec-05	Dec-06	Dec-07	Dec-08
3 month T-Bill	21.27%	14.41%	13.34%	12.26%	12.89%	22.01%
6 month T-Bill	22.05%	14.94%	13.55%	12.31%	13.34%	24.45%
Repo Rate	15.00%	13.80%	12.60%	11.65%	11.65%	14.00%
Weighted Average Loan Rate	19.32%	17.72%	17.32%	17.59%	17.11%	16.46%

Source: Bank of Jamaica

2.1.5 Conclusion

For the first three years since the last rate reset in 2004, with the exception of the period immediately after Hurricane Ivan, Jamaica's macroeconomic environment was fairly stable and positive. Specifically, inflation rates were relatively low and falling, and interest rates trended down throughout the period with moderate currency depreciation. This fostered a relatively positive economic climate which resulted in moderate economic growth. The Company capitalised on this environment by reducing its cost of debt and improving its financial performance. Since mid-2007 business conditions have changed adversely due in most part to external shocks. The Jamaican economy is estimated to have declined by about 0.4% in 2008. The ensuing higher rates of interest and inflation and significant currency depreciation in the last quarter of 2008 indicate a negative outlook for the Company's prospects over the near-term of the 2009-2014 tariff period.

2.2 Highlights of Company Performance 2004 – 2009

2.2.1 2004 – 2009: A platform for the Future

A major challenge for JPS in the immediate post privatization period (2001-2004) was to rapidly expand the Country's generating capacity to address a severe imbalance between electricity demand and supply. This challenge the Company successfully met with the installation of 120 MW of new capacity at the Bogue Power Station in Montego Bay and extensive refurbishment of existing plant.

This investment and the resulting improvement in service reliability and customer satisfaction were recognized at the 2004 tariff review. At the 2004 filing JPS committed to further improve customer service and reliability of supply and to grow the Company into a financially strong and investment-attractive business over the 2004-09 tariff period. Making JPS financially strong is central to the Company's ultimate goal of transforming the electricity system into a cost-competitive, modern and efficient one. The Company also pledged leadership in corporate social responsibilities. These responsibilities include operating in an environmentally sound manner, conforming to ethical business practices and supporting the social and economic development of communities and Jamaica. The improvement of the quality of life of our customers, communities and employees as the key to a sustainable business environment is and continues to be a core corporate philosophy of JPS.

In August 2007 majority ownership in JPS changed from Mirant Corporation to Marubeni Caribbean Power Holdings, a subsidiary, ultimately, of Marubeni Corporation. In March 2009 Marubeni entered into an agreement to transfer 50% of its equity in its Caribbean business (including JPS) to the Abu Dhabi National Energy Company (TAQA). These developments will undoubtedly assist JPS in achieving the objectives of the 2009-14 tariff period.

The 2004-09 tariff period has been a turbulent one marked by disappointing financial results with losses in three of five years; interruptions to operations from six storms (two major hurricanes); an unprecedented increase in fuel cost that sharply increased product price; a global credit crisis and a sharp contraction of the Jamaican economy. Nevertheless JPS made significant strides in living up to its commitments.

2.2.2 Power System Investments

North Western System Improvement

Jamaica has been experiencing strong growth in the leisure industry over the past five years. Several new resorts have been constructed adding thousands of rooms to the popular north western tourism corridor of the island. To meet the growing power demand and support the economic boom of this region, JPS invested US$4M to upgrade the electricity infrastructure in the region. Under the North Western System Improvement Project major a major upgrade was done to both the Rosehall and Greenwood substations and the associated transmission and distribution networks. The improvement work resulted in better fault containment, an increase in primary distribution voltage from 12kV to 24 kV and enhance in the reliability and quality of power delivered to customers in this important economic belt. The upgrades will facilitate demand growth in this region over the next 10-15 years.

2.2.3 Generation Re-Powering

The 2004 – 09 tariff period saw a sharp falloff in sales and peak demand. Most forecasts suggest that the economic contraction consequent on the global credit crisis, will carry this trend over into the 2009 – 14 tariff period. This depressed demand has led to a revision of the schedule for generation expansion for the country over the short-term. Nevertheless, JPS, in recognition of its obligation to serve embarked upon a number of re-powering projects with existing units even as it pursued development plans for baseload expansion in the medium-term. The projects not only provide efficiency gains in some instances but also provide an additional 22.8 MW of reserve margin to respond to changing market conditions and boost system security.

These projects include:

- An additional four (4) MW at the Rockfort Plant
- Eight (8) MW from new engine installations in GTs 6 & 8 at the Bogue Station
- Net output improvement of 10 MW on the Bogue 120 MW combine cycle plant from the installation of air inlet coolers. Project due for completion mid-year 2009.
- Restoration of the Constant Spring Hydro (0.8 MW) to be completed second quarter '09.

2.2.4 Renewable Energy

JPS, as a matter of policy, is pursuing the development of power from renewable energy. The initiative is a part of the Company's long-term goal to reduce electricity price through a diverse generation fuel mix. The policy also demonstrates the Company's commitment to reduce any environmental footprint of its operations.

JPS in October 2008 won a competitive bid and was awarded two projects by the OUR to do undertake a 6.4MW expansion of its existing hydro plant at Maggotty, St. Elizabeth as well a 3MW wind farm at Munro, St. Elizabeth. Commissioning of the Maggotty expansion is projected for Dec. 2012 and commissioning of the wind farm by Dec. 2010.

The Company will also complete installation of a 750kW wind turbine at Harbour View, St. Andrew along the Palisadoes Peninsula to gather wind data. The Peninsula is considered a possible site for offshore wind farm development.

2.2.5 System Reliability

Generation expansion was the focus of expenditure between 2001 and 2004 as the Company sought to address the shortfall in generation that caused inconvenience to customers and production loss from daily rolling blackouts. Three system-wide power outages between 2006-2007 underscored the urgent need to allocate additional resources to the grid to complement the investment in generation. The cause of the outages were extensively investigated by the Company, the OUR and a team of international investigators commissioned by the Government of Jamaica. Coming out of the recommendations JPS invested US$7M in upgrading components of the protection mechanisms and control systems on the Transmission and Distribution System, and improving communications and network stability. The programme of upgrades has resulted in a more robust and stable transmission network.

2.2.6 SCADA/EMS

The Company has spent US$7M installing a new Supervisory Control and Data Acquisition/Energy Management System (SCADA/EMS) that provides significant enhancement in system controllers' visibility and remote control over vital network functions. For the next phase of the project over the 2009 – 14 period, the SCADA/EMS system will be linked into other customer-dedicated systems to improve monitoring and response to customer supply interruptions.

2.2.7 Structural Integrity Programme & Asset Management

The unusually high incidence of tropical cyclones over the last tariff period has highlighted the importance of JPS' ongoing structural Integrity Programme. Through this programme s wooden poles in the distribution network are replaced with concrete poles thereby improving network resilience to storm and environmental damage and ultimately reducing the incidence of supply interruption to customers. Over the period 2004 to 2008 the Company has replaced approximately 16,000 wooden poles.

The Company also completed installation of a GIS-based asset mapping system (Phase One). Phase Two will provide the basis for company-wide knowledge and location of network assets and equipment. The technology will further enhance service delivery and responsiveness.

2.2.8 Improving Customer Experience

To complement the aim of the technical initiatives to provide a consistent, continuous and high quality product to customers, service initiatives were implemented over the tariff period intended to make customers' experience when doing business with JPS, convenient, easy and pleasant.

These initiatives include:

Customer Care Offices

The Portmore Customer care office was reopened in response to the request of customers living in this community. The Company also completed the renovation of four offices (May Pen, Savannah-la-Mar, Falmouth and Ruthven Road) to improve customer facilities at these locations.

Customer Care Centre

As the customer base grows JPS has increasingly relied on the Customer Care Centre to provide 24-hour access and service for customers. Since 2004 the Centre has expanded from 26 to 120 seats and has responsibility for a wider array of functions including complaint resolution and billing adjustments. The Centre now handles two (2) million calls per annum up from 500,000 with 86% of calls answered well within the industry standard of 20 seconds. This is the result of an investment of approximately US$2M in expanding the call centre and upgrading the technology.

Expansion of Payment Channels

As the number of customers doing business with the Company grows, JPS has opened up several new options to do payment transactions offering customers choice and convenience. To further improve operational efficiency, JPS outsourced the cashier function at its business offices and in response to customer preference, kept certain location fee-free payment locations. The Company has also introduced electronic payment options via, telephone and the Internet.

Monthly Meter Reading

Despite a worldwide trend away from reading meters monthly to reduce cost, the Company, in deference to customer preference introduced monthly meter reading to ensure bills are based on actual consumption readings.

Electronic Billing & Text Messaging

JPS introduced free electronic billing via email for customers preferring this option of bill delivery. The Company also introduced text message notification to customers with overdue balances. The Company now has a database of numbers for 62% of its customers on record.

Smart Meters

The Company rolled out Advanced Metering Infrastructure (AMI) or smart meters for commercial/industrial customers. Smart meters can help customers keep track of their energy usage patterns; and identify opportunities for savings from Time of Use (TOU) shifting of their energy use. The meters also provide remote disconnection/reconnection and monitoring capabilities for JPS.

Communication & Education Programmes

As oil prices spiralled during the tariff period customers took an increasingly keen interest in various aspects of our operations. JPS dedicated a large slice of its annual communication budget over the period to assist customers in managing their energy usage through the worse energy crisis in 20 years. Over the last four years JPS has spent over $210M on customer education programmes, utilising print, television, radio and through town hall meetings with customers.

2.2.9 Social Responsibility

More than just a Company of poles and lines, JPS takes its corporate social responsibility seriously. The Company considers it an important responsibility to contribute in time, money and talent to make a positive impact on the communities in which they live and work. Many employees enthusiastically volunteer for mentoring and teaching roles and annually help to raise money for charitable organizations.

The Company's efforts are primarily focused on education, health and sports at the national and community level. Many of the education programmes are designed to assist talented but needy students.

Some of the programmes include:

Education

- JPS/Kettering Scholarships
- JPS/UWI Scholarships
- Utech Education Fund
- Northern Caribbean University Fund
- Early Childhood Nutrition Support Programme
- Summer Employment Programme
- Science & Technology Expo
- Top CXC Students' Awards
- Old Harbour Bay Homework Centre

Health

- Cancer Relay for Life
- Sigma Corporate Run
- Jamaica Aids Support for Life

Community sports

- Community Netball League Competitions (West): St James, Hanover, Westmoreland
- Football League competitions: Old Harbour & Rockfort
- JPS/JNA President's League Netball Competition
- High Mountain 10K Road race
- Eastern Championships
- All-Island Basketball League Competition
- Eastern Cross Country

2.2.10 Awards

JPS has consistently won international acclaim for operational excellence. Over the last tariff period the Company has won an award and received recognition for outstanding performance from the Edison Electric Institute (EEI) - a peer group of over 200 US Utilities.

JPS will receive the 2009 EEI Emergency Recovery Award in recognition of the Company's exemplary response in restoring supply to customers after Tropical Storm Gustav wreaked havoc on the island in 2008.

This was the second occasion on which the EEI was recognizing JPS' hurricane recovery effort. In 2005 the EEI awarded the Company the Emergency Response Award for the outstanding recovery effort in the wake of Hurricane Ivan. The Company was also awarded the Emergency Assistance Award for sending assistance to the Grand Bahama Power Company in the wake of

JPS was also recognized by the EEI for the achievement of 1st quartile safety performance in 2008 relative to EEI's benchmark. This is an indication that JPS' safety performance in 2008 was comparable with the safest utilities in the US electric sector.

2.3 Financial Summary

JPS prepares its financial statements in accordance with International Financial Reporting Standards ("IFRS") and has a financial period that ends on December 31 in keeping with Conditions 5 (1) of the Licence. A selection of key financial information from JPS' audited financial statements for the 2004 – 08 tariff review period is highlighted in **Table 2.4** below.

Table 2.4: Income Statement

{J$ Millions}	2004	2005	2006	2007	2008	TOTAL
Operating revenues:						
Fuel revenues	14,732	21,198	26,923	31,628	47,659	142,140
Non-fuel revenues	15,667	19,055	21,222	22,567	23,760	102,271
Total operating revenues	**30,399**	**40,253**	**48,145**	**54,195**	**71,419**	**244,411**
Cost of sales:						
Fuel	(14,592)	(22,175)	(26,679)	(32,748)	(47,510)	(143,704)
Purchased Power (excluding fuel)	(3,570)	(3,954)	(4,784)	(5,156)	(4,887)	(22,351)
Total cost of sales	**(18,162)**	**(26,129)**	**(31,463)**	**(37,904)**	**(52,397)**	**(166,055)**
Gross profit	**12,237**	**14,124**	**16,682**	**16,291**	**19,022**	**78,356**
Operating expenses	(6,606)	(7,335)	(8,341)	(9,795)	(10,907)	(42,984)
EBITDA	**5,631**	**6,789**	**8,341**	**6,496**	**8,115**	**35,372**
Depreciation	(2,265)	(2,532)	(2,860)	(3,281)	(3,618)	(14,556)
Net finance costs	(1,977)	(2,409)	(2,779)	(2,694)	(5,121)	(14,980)
Other income/(expenses) net	(1,515)	78	(9)	(1,643)	(327)	(3,416)
Taxation	(15)	(480)	(718)	607	787	181
Net profit/(loss) after taxation	**(141)**	**1,446**	**1,975**	**(515)**	**(164)**	**2,601**

As can be seen from the Income Statement of **Table 2.4**, the Company made cumulative profits of $2.6 billion during the five-year period from cumulative sales of $244 billion. However, the Company actually made losses in three out of five years. This should be viewed against the targeted return on equity (or profit after taxation) based on the approved 2004 revenue requirement of $2.9 billion per annum. That is to say, if the 2004 tariff had performed to projection, the Company was expected to make annual profits amounting to $2.9 billion. Given that total revenues were $40 billion in 2005, the profit element of the total charge to customers was expected to represent less than 10% of the total cost of delivering electricity to customers.

In the Tariff Performance Review section to follow, the key areas of 'leakage' where the tariff did not perform to expectations are identified. The result was that the Company was unable to achieve the target profit after taxation as established in the revenue requirement. It is a fundamental principle of the price cap regime that the shareholders be given a reasonable opportunity to make a fair return on their investment. Failure to create such an environment would render it impossible for any utility to attract much needed capital in a highly capital intensive industry.

A review of the balance sheet (**Table 2.5**) demonstrates the significant capital investment that the Company has made in property, plant and equipment as well as the significant amount of working capital and debt required to operate the business. As at December 31, 2008, the Company had fixed assets in excess of $50 billion and total debt in excess of $25 billion, making it one of the largest private sector companies in Jamaica in terms of asset base. The same would be true in terms of revenues, with revenues exceeding $71 billion in 2008.

Table 2.5: Balance Sheet

J$'000	2004	2005	2006	2007	2008
Current Assets					
Cash & cash equivalents	1,462	1,736	2,703	1,530	1,165
Accounts receivable	6,866	9,180	10,572	14,409	13,929
Inventories	1,618	2,053	2,150	2,828	3,039
Other	148	164	168	177	195
	10,094	13,133	15,593	18,944	18,328
Current Liabilities					
Short-term loans	852	10,581	1,452	1,913	5,311
Accounts payable & provisions	3,609	4,755	5,299	10,519	6,303
Other	62	34	42		7
	4,523	15,370	6,793	12,432	11,621
Working capital	**5,571**	**(2,237)**	**8,800**	**6,512**	**6,707**
Non-current Assets					
Fixed Assets	34,751	37,601	40,302	44,659	54,091
Employee Benefit Asset	1,226	1,409	1,706	1,895	2,104
	41,548	**36,773**	**50,808**	**53,066**	**62,902**
Financed by:					
Shareholders' equity					
Share capital & reserves	19,952	21,239	22,304	24,175	28,696
Retained earnings	2,658	3,544	5,448	4,302	3,495
	22,610	24,783	27,752	28,477	32,191
Non-current liabilities					
Long-term loans	14,185	5,663	14,873	15,274	19,790
Customer deposits	2,125	2,055	2,185	2,363	2,501
Other long-term liabilities	2,628	4,272	5,998	6,952	8,420
	41,548	**36,773**	**50,808**	**53,066**	**62,902**

The financial information from **Tables 2.4** and **2.5** are extracted from the audited financial statements. For complete details of the 2008 Financial Statement please see **Annex C**.

As shown in the key performance indicators in **Table 2.6**, despite the financial challenges during the review period, JPS consistently invested more in the business each year in terms of capital expenditure, peaking at $4.3 billion in 2008. This highlights the Company's strong commitment to the industry and to improving the quality of the electricity service to our customers.

Table 2.6: Key Performance Indicators

	2004	2005	2006	2007	2008
Sales (gWh)	2,999.6	3,055.2	3,120.7	3,131.5	3,179.1
Net Generation (gWh)	3,717.0	3,878.0	4,046.4	4,078.8	4,123.3
System losses	19.3%	21.2%	22.9%	23.2%	22.9%
Heat rate (kJ/kWh)	10,832	10,985	10,174	10,627	10,215
Equivalent availability factor (EAF)	80.8%	81.2%	82.3%	83.7%	83.9%
Equivalent outage factor (EFOR)	12.7%	11.0%	13.4%	10.7%	8.5%
Gain/(loss) on fuel J$/US$	140	(977)	244	(1,120)	149
Average Fuel prices (US$)					
- No. 6 fuel	29.17	43.17	54.06	60.96	86.56
- No. 2 fuel	63.41	83.12	90.55	98.48	138.11
Annual non-fuel tariff increase (PBRM)	N/A	6.43%	6.58%	4.04%	8.94%
Avg. fuel tariff (J$/kWh)	4.9	6.9	8.6	10.1	15.0
Avg. non-fuel tariff (J cents/kWh)	5.2	6.2	6.8	7.2	7.5
Avg. exchange rate	61.39	62.60	65.99	69.17	73.36
Avg. fuel tariff (U.S. cents/kWh)	8.0	11.1	13.1	14.6	20.4
Avg. non-fuel tariff (U.S. cents/kWh)	8.5	10.0	10.3	10.4	10.2
Avg. monthly consumption per residential customer (kWh)	190	191	180	171	164
EBITDA margin	18.5%	16.9%	17.3%	12.0%	11.7%
Net profit margin	-0.5%	3.6%	4.1%	-1.0%	0.1%
ROE (Return on opening equity)	-0.7%	6.4%	8.0%	-1.9%	0.2%
Capital expenditure (J$ Millions)	1,970	2,149	2,450	3,236	4,372
Dividends paid (J$ Millions)	-	1,395	994	1,711	1,663
Year end exchange rate (J$:US$)	61.63	64.58	67.15	70.62	80.47
Total debt (US$ Millions)	244	252	243	243	312
Debt to equity ratio	40:60	40:60	37:63	38:62	44:56
Current ratio	2.2:1	0.9:1	2.3:1	1.5:1	1.6:1
Number of employees (permanent)	1,391	1,311	1,310	1,308	1,285

Indeed, one of the largest challenges that the Country and the Company have faced during the review period has been the rising price of oil, which coupled with the currency depreciation has driven up the average fuel tariff from $5 per kWh in 2004 to $15 in 2008, as reflected in **Table 2.6** above, an increase of 200%. This increase was unavoidable on the part of JPS and has resulted in customer conservation and increased levels of electricity theft. This is evident from the average consumption per residential customer falling from 200 kWh per month in 2003 to 164 kWh per month in 2008, which is extremely low by international standard and system losses rising to 23% despite numerous initiatives by the Company in its persistent efforts to contain losses. Moreover, energy sales have been virtually flat in the last three years (2006 – 2008).

Table 2.6 shows that the returns of the Company were generally far below expectation during the review period (2004 – 8), sales have been relatively flat, systems loses have been increasing and the Company has generally under recovered on its fuel costs. This has occurred despite the efficiency improvements made by the Company, which include the general improvement in the availability of the generating units while also reducing the forced outage rate and a 9% reduction in head count; among other things.

2.4 Tariff Performance Review

2.4.1 2004 Revenue requirement

The revenue requirement in the 2004 rate case determination was set based predominantly on the 2003 test year results with some adjustment for known and measurable changes. The details of the actual revenue requirement as determined by the OUR are set out below.

Table 2.7: 2004 Revenue Requirements

	J$'000
PPA Costs	3,002,542
Payroll costs	3,013,000
Non-payroll costs	3,631,580
Other Income, net	(178,208)
Self Insurance Fund	122,000
Operational Expenses	**9,590,914**
Depreciation	2,170,278
Amortization of redundancy costs	118,919
Depreciation & Amortization	**2,289,197**
Cost of Equity	2,907,814
Cost of Long-term Debt	1,291,215
Return on Investment	**4,199,028**
Taxation	1,453,907
Revenue Requirement	**17,533,046**
Less Carib Cement Revenue	(214,785)
Adjusted Revenue Requirement	**17,318,261**
Sales forecast (kWh)	3,075,800
J$ Rate per kWh	5.630
FX Rate	61.00
US ¢ Rate per kWh	**9.23**

As stated in the financial performance review for 2004 – 8, the Company did not achieve the target cost of equity (or net profit) in any single year during the five-year period that followed the 2004 rate case determination. This is primarily the result of fundamental deficiencies in the tariff regime, which will be highlighted in **Sections 2.3** to **2.4** that follow.

It is important to note that while JPS is **not** guaranteed a profit under the regulatory regime. It is in keeping with standard price cap regimes, entitled to be afforded a reasonable opportunity to make its target return as specified by the revenue requirement. Accordingly, the tariff structure should be cost reflective, providing an economic hedge against uncontrollable variables, such as inflation and foreign exchange risk which, as it does currently. Similarly, the tariffs should provide reasonable protection against unforeseen events that the utility could not otherwise protect itself against. JPS believes this protection was contemplated in the Z-factor clause of the Licence. However, given the interpretation of the clause to date by the OUR, the Company is of the view that a significant risk is created and that it is this risk that is the main reason for the Company being unable to recover certain legitimate operating costs, thereby making the return approved by the regulator. This is a critical issue in ensuring the continued viability of the provider of an essential service which by the very nature of the business, must expend billions of dollars per annum to provide electricity to the people of Jamaica.

2.4.2 Post-Tax WACC vs. Pre-Tax WACC

The 2004 revenue requirement was established using a post-tax WACC formula, as follows:

$$Pos\text{- } tax\ WACC = g * r_d * (1\text{-}t) + (1\text{-}g) * r_e$$

Where g is the gearing ratio; r_d is the cost of debt; r_e is the cost of equity; and t is the tax rate.

This incorrectly assumes that debt will provide some kind of tax shield relative to the return on equity included in the revenue requirement. However, given the nature of the calculation of the revenue requirement, debt should not be treated differently from any other expense included in the revenue requirement. Since a matching amount of revenue will be provided for each expense identified in the revenue requirement, the tax shield from expenses is irrelevant. That is why an additional amount is requested for the return on equity in the revenue requirement, which by itself represents the profit that would be generated from the revenue requirement calculation and therefore the only amount for which taxes need to be contemplated. As a result of the use of the post-tax WACC, the post tax cost of debt was included in the revenue requirement, which is lower than the actual cost of debt faced by the utility. If not recovered in some manner, the Company's revenue will consequently be understated by the amount of the assumed tax shield in the formula. This ultimately results in a lower return on equity for the investors, as will be demonstrated below.

The OUR's calculation of the rate of return on investment included in the revenue requirement was $4,199,028, as summarized in the **Table 2.8** below:

Table 2.8: OUR's Calculation of Return on Investment[2]

Parameters:	
Pre-Tax interest rate on Debt	12.56%
Return on Equity	14.85%
Tax Rate	33.33%
Gearing Ratio	44.00%
	(J$'000)
Long-term Debt	15,420,557
Shareholder's Equity	19,581,238
Total Capitalization	35,001,795
Cost of Debt	1,291,215
Return on Equity	2,907,814
Return on Investment	4,199,028

Note that the post-tax interest rate on debt used to obtain the cost of debt of $1,291,215 is equal to 8.37%[3], which differs from the pre-tax cost of debt due to the tax shield. The actual cost of debt faced by JPS is the pre-tax interest rate of 12.56%. Using this rate one can calculate the actual interest expense incurred by JPS, given the gearing ratio and the regulatory asset base, as being $1,936,822. This means that only $1.29 billion of the $1.94 billion of actual interest charges were included in the revenue requirement. This difference of $645.6 million represents the amount under-recovered on interest expense due to the methodology used. This under-recovery could have been avoided if the pre-tax cost of debt was used to calculate the rate of return on investment, as shown in **Table 2.9** below.

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[2] This table was replicated from Table 5.4 of the 2004-2009 Determination Notice.

[3] Post-tax interest rate on debt = $r_d * (1\text{-}t) = 12.56*(1\text{-}0.33)=8.37\%$

Table 2.9 : Revenue Requirement Comparisons

	OUR Determination	Pre-Tax Determination	Difference
	(J$'000)	(J$'000)	(J$'000)
Cost of Equity	2,907,814	2,907,814	-
Cost of Debt (Interest)	1,291,215	1,936,822	(645,607)
Return on investment	4,199,029	4,844,636	(645,607)
Operating Expenditure	9,590,914	9,590,914	-
Depreciation	2,289,197	2,289,197	-
Taxation	1,453,907	1,453,907	-
Revenue requirement	17,533,047	18,178,654	(645,607)

Table 2.10 shows how each treatment affects the actual net profit after taxation and rate of return on equity of the regulated business:

Table 2.10: Rate of Return on Equity Comparison

	OUR Determination	Pre-Tax Determination	Difference
	(J$'000)	(J$'000)	(J$'000)
Revenues	17,533,046	18,178,654	(645,607)
Operating Expenses	(9,590,914)	(9,590,914)	-
EBITDA	7,942,132	8,587,740	(645,607)
Depreciation	(2,289,197)	(2,289,197)	-
Interest	(1,936,822)	(1,936,822)	-
Earnings before taxation	3,716,113	4,361,721	(645,607)
Taxation @ 33 1/3%	(1,238,704)	(1,453,907)	215,203
Net Profit after taxation	2,477,409	2,907,814	(430,404)
Rate of Return on Equity	12.65%	14.85%	(2.20%)

Whilst the pre-tax WACC methodology preserves the rate of return ascertained in the cost of equity determination by the OUR, the post-tax WACC methodology, used in the 2004 determination, lowers the rate of return by 220 basis points. This omission specifically relates to what JPS considers was a flawed treatment of debt, which results in a $645,607,000 understatement of debt in the revenue requirement, which in turn lowers the profit by the same amount, and lowers the corporate tax, by 33 1/3% of this difference being $215,203,000[4]. Together, this would have resulted in a net understatement of $430,404,000 per annum[5] for the entire tariff review period 2004 – 2009.

JPS proposes that it would be more accurate for the pre-tax WACC methodology to be used in the 2009 rate case review to calculate JPS' rate of return on investment or a more appropriately adjusted post-tax WACC methodology.

[4] So $645,607 times 33 1/3% equals $215,203, which is the exact shortfall between the taxes included in the revenue requirement of $1,453,907 and the actual taxes calculated above of $1,238,704.

[5] Theoretically, this error would have grown each year by the amount of the annual inflation adjustment.

2.4.3 Self Insurance Fund

The 2004 revenue requirement was established taking into account a self-insurance fund (SIF) amount of $122 million (or US$2 million), which was increased in subsequent annual tariff adjustments to US$3 million in 2006 and then to US$5 million in 2008. However, there has been a deficiency as it relates to corporate taxes, as the SIF is embedded in the normal electricity rate and thus included in the taxable revenues of JPS. Since there is no offsetting expense, the monthly SIF savings should be either set aside net of taxes or be grossed up to account for the taxes

2.4.4 TOU Fuel Rate

It may be recalled that at the annual adjustment of 2003 it was agreed to move to a uniform fuel rate for all rate classes except the TOU class. The exception for the TOU class was based on the recognition that the Company's ability to influence consumption depended on price signals sent to customers through the non-fuel and fuel rates. Implicitly therefore, customers in this rate class would not be charged a standard fuel rate, but would pay a cost reflective rate that would be higher or lower than standard if consuming "on-peak", or "off-peak" respectively. To the extent that the rate class was designed to encourage peak shaving by shifting more customers into the off-peak and partial-peak consumption time bands, the majority of customers would enjoy savings, being the avoided cost to build new generation.

By letter dated August 12, 2003, JPS advised the OUR of the need to make adjustments to the fuel rate calculation to account for the difference between actual fuel costs recovered and the fuel cost that should be recovered – the volumetric difference. The OUR conveyed its understanding and acceptance of the need for the adjustment on October 2, 2003.

In September 2004, three months after the introduction of the new tariff regime, JPS wrote to the OUR seeking to modify the sales weights used in determining the TOU fuel rate to stem an incipient fuel revenue leakage. The change would allow the volumetric adjustment mechanism (VAM) to accurately capture the total fuel cost to be recovered net of efficiencies. In May 2005, JPS again raised the issue and the need for an urgent response to correct the error in fuel recovery. However, after further deliberation, the OUR denied JPS' request to modify the VAM for the TOU impact by way of its letter dated March 28, 2006, advising that JPS would have to bear the risk that its assumptions on the TOU weights might differ from reality during the tariff reset period (2004 – 9).

The deficiency in the VAM, as it relates to the TOU, was the result of the assumption that all fuel was billed at the standard fuel rate (or a weight of 1 when calculating the system fuel rate). However, TOU customers are billed at non-standard rates (i.e. weights not equal to 1 are applied to the standard fuel rate to derive the fuel rate for the TOU customers) and the VAM (while addressing the major aspect of the volumetric difference) still resulted in the under-recovery of the applicable fuel cost as a result. For JPS to recover the applicable fuel cost exactly, the distribution of sales between standard and TOU rates must be properly contemplated in the VAM itself. Accordingly, JPS contends that a revised VAM is required; one such that it properly adjusts for the volumetric differences between the sales distribution (and accordingly the weights) used to derive the fuel rate and the actual billed sales (and distribution) in the following month.

The under-recovery on fuel as a result of the TOU weights and the unavoidable volumetric differences for the review period is highlighted below. This negatively impacted the Company's profit during the review period.

Table 2.11: Fuel Cost Under-Recovery

	2004	2005	2006	2007	2008
US$	432,748	365,672	786,620	1,066,031	1,089,752

The problem is clearly the result of a mathematical error in the VAM that can be readily be remedied by an adjustment to the VAM included in the monthly fuel rate calculation.

JPS proposes that the VAM be modified to include the actual weights (or distribution) of the TOU billing. Alternatively, the TOU discount/premium could be removed from the fuel rate charge to customers completely, thus negating the need for any inclusion in the VAM and ensuring that there is no risk of fuel cost under-recovery as a result of the TOU discount on fuel rates. The latter, however, would reduce the effectiveness of the TOU option in smoothing out demand.

2.5 Increased Business Risks

2.5.1 Hurricanes

This represents a significant area of increasing risk for JPS that has negatively impacted the operating results in four out of five years since the last tariff reset. At the time of the last rate case filing, JPS had not experienced major hurricane damage in the preceding fifteen years, as the last major hurricane impacting Jamaica was Hurricane Gilbert in 1988. In spite this fact, in recognition of the exposure to hurricane damage and the unavailability of insurance for its T&D assets, the Company requested that the OUR approve a self insurance fund, to be funded through the tariffs at the rate of US$2 million per annum, this to augment the Z-factor protection provided under the Licence. The Company subsequently sought, and the OUR approved, that the funding rate be increased ultimately to US$5 million per annum, in direct recognition of the increased frequency of natural disasters since 2004.

Since 2004, JPS has experienced major damage due to two hurricanes: Ivan in 2004 and Dean in 2007. Additionally, JPS has suffered less severe but notable damages in 2005 (due to Tropical Storms Denis, Emily and Wilma) and in 2008 (from Tropical Storm Gustav). The **Table 2.12** below illustrates the financial statement impact as a resulting from these natural disasters during the period 2004 – 2008, net of any Z-factor award approved by the OUR:

Table 2.12: Hurricane/tropical storm damages

	2004	2005	2006	2007	2008	TOTAL
	(J$'000)	(J$'000)	(J$'000)	(J$'000)	(J$'000)	(J$'000)
Revenue:						
Z-factor award by the OUR	-	TBA	-	490,707	TBA	490,707
Restoration expenses:						
- Generation	(126,954)	(1,141)	-	(45,434)	(7,017)	(180,546)
- T&D	(584,194)	(85,689)	-	(571,257)	(119,250)	(1,360,390)
- Other	(48,997)		-	(71,846)	(14,990)	(135,833)
	(760,145)	(86,830)	-	(688,537)	(141,257)	(1,676,769)
Fixed cost under-recovery	(420,601)	(73,339)	-	(410,459)	(103,692)	(1,008,091)
Opportunity cost of capital	(285,000)	(32,704)	-	(135,064)	(11,229)	(463,997)
Total cost	(1,465,746)	(192,873)	-	(1,234,060)	(256,178)	(3,148,857)
Net financial impact	(1,465,746)	(192,873)	-	(743,353)	(256,178)	(2,658,150)
Capital:						
Z-factor award by the OUR	194,759	TBA	-	TBA	TBA	194,759

It is important to note that the total financial impact as a result of hurricanes during the period was $3.1 billion, while the OUR approved reimbursement of only $491 million, on the basis that $195 million should be capitalized and included in the rate base for recovery as of 2009. In fact, the only award granted by the OUR during the period was in relation to Hurricane Ivan in 2004 and determinations relating to the other three storms remain outstanding as at December 31, 2008. A Determination for the 2005 storms was handed down in February 2009 although a revised determination is expected.

It is important to note that the financial impact of Ivan and Dean, in particular, were individually in excess of $1 billion. Such significant costs clearly threaten the viability of the business in an environment where the Company is exposed to significant risk in relation to hurricanes; and especially if claims are not expeditiously reviewed and settled. Given that the target return on equity set in 2004 was $2.9 billion, it could not be considered reasonable for JPS to operate in a regulatory environment where its annual profits could be lost to one storm system, an event which it has no control over and minimal mitigative options outside of an adequate and effective recovery mechanism. Furthermore, the situation is adversely impacting the creditworthiness of the business in an increasingly risk averse global credit market. It is important to note that the business is extremely capital intensive, requiring routine capital expenditure in excess of $4 billion per annum and having net finance costs (in relation to debt service obligations) in excess of $3 billion per annum. Accordingly, the business must operate with a fair amount of leverage and it is therefore critical that its risk profile is not allowed to deteriorate due to exogenous factors outside its control to the point of threatening its creditworthiness. This highlights the importance of speedily discharging the Company's Appeal of the Hurricane Ivan award (and by extension the pending Hurricane Dean settlement and other storm claim determinations). It is indeed unfortunate that this Appeal, dating back to 2005, remains unresolved in 2009.

Unless the regulatory regime is adjusted such that it accounts for the all the aforementioned risks, JPS, in taking the necessary and prudent steps of risk mitigation as regards natural disasters, must, where possible through insurance coverage, now obtain business interruption insurance as a means of providing some form of fixed cost recovery. It is noteworthy that the position of the OUR (as evident from its denial of any fixed cost recovery) imposes a risk that the Independent Power Producers (IPPs) have mitigated through the capacity charge included in their Power Purchase Agreements (PPAs). This raises the question whether the regulator, having in principle approved the concept, would not so revise the tariff such as to provide a similar type of revenue protection for JPS, thereby ensuring that the Company is able to meet its fixed cost obligations under force majeure circumstances[6]. This is the very reason why a capacity charge exists for IPPs and its absence or differential treatment suggests that JPS, as a fully integrated utility, is a greater credit risk than the IPPs that provide power to JPS. This combined with the risk that JPS faces on system losses (another risk which the IPPs are not exposed on) would suggest that the credit of JPS is notably inferior to that of the IPPs, which is of great concern given that all future generation expansion will be done through IPPs. That is, JPS' credit position vis-à-vis IPPs, would continue to deteriorate as more IPPs emerge and there were no change in this regulatory approach.

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[6] Please note that this protection is being linked to force majeure conditions only and for fixed costs. JPS is not asking for its revenues or profits to be guaranteed, it is simply asking for protection similar to the capacity charge, which is a common practice in the electricity industry. Note that the IPPs themselves would have benefited from the capacity charge during the force majeure period resulting from the hurricanes, while JPS was not awarded similar protection.

2.5.2 System Losses

The reduction of system losses, more specifically non-technical losses, has been a top priority and a fundamental business goal for the Company, especially over the last three years particularly given the steep rise in fuel prices. JPS has spent hundreds of millions of dollars on various loss reduction campaigns with a strong technological focus. These efforts include the installation of approximately 2,000 smart meters (advanced metering infrastructure or AMI) for priority commercial customers in 2008, which allowed the Company to monitor on a real time basis approximately 25% of all demand on the electricity grid. This first phase of the AMI project cost approximately US$3 million and a similar amount will be spent in 2009 to install more smart meters, which will allow the Company the ability to monitor approximately 50% of all electricity demand on a real time basis. This effort will cover substantially all demand at the commercial and industrial level. The AMI implementation has significantly strengthened the Company's efforts to detect customer anomalies that result in non-technical losses. This combined with the Energy Rebalancing Project and the Customer-to-Feeder Mapping Project significantly enhances the Company's ability to systematically detect high loss areas, thus allowing it to prioritize the direction of field service investigations.

Other initiatives and work programmes include regular customer audits and the constant patrolling and removal of 'throw-ups' with assistance from the police force. A summary of the results achieved over the past three years is provided in **Table 2.13** below:

Table 2.13: Results from Loss Reduction Programmes

	2006	2007	2008
Customer account audits	13,000	15,900	16,400
Removal of throw-ups	7,000	25,000	42,000
Energy recovered/back-billed (kWh)	19,000	48,900	49,300
Revenues recovered (J$ Millions)	$200	$494	$750

Despite the Company's best efforts, the problem of increasing non-technical losses remains a significant and a constant challenge. One main reason for this is that the problem of electricity theft is socio-economic which like other crimes thrives in a society where the economic conditions are less than desirable. And, unfortunately, it appears as if this crime has become ingrained in the culture of the society. This is evidenced by how prolific the illegal abstraction of electricity has become. The problem has become endemic and pervasive, from deep rural communities to inner city communities to well-known businesses. Audits have detected anomalies with the power supply across all customer and social strata. The situation has been exacerbated by, the significant increase in the cost of electricity (primarily due to the sharp increase in fuel prices and the depreciation of the Jamaican dollar) in the last two years in particular, coupled with high inflation, high unemployment and generally worsening economic conditions. All together these have created a greater propensity for persons to steal electricity.

While JPS believes its accomplishments to date to be relatively successful, particularly given the significant increase in fuel prices between 2007 and 2008, the effort to monitor over 525,000 residential customers is enormous. Additionally, the Company must simultaneously monitor over 10,000 miles of distribution lines, as the illegal abstraction of electricity is relatively easy in an open network system.

As it relates to the review period (2004 – 2008), the challenges that the Company have faced in relation to the OUR determined System Losses Target of 15.8% and the ensuing financial penalty for the Company. This is against the background that fuel is generally meant to be a pass-through subject to two efficiency measures, yet JPS under-recovered its fuel cost by $977 million and

$1,120 million respectively in 2005 and 2007. This kind of exposure is enormous and unsustainable within the context of the target return on equity of $2.9 billion set back in 2004.

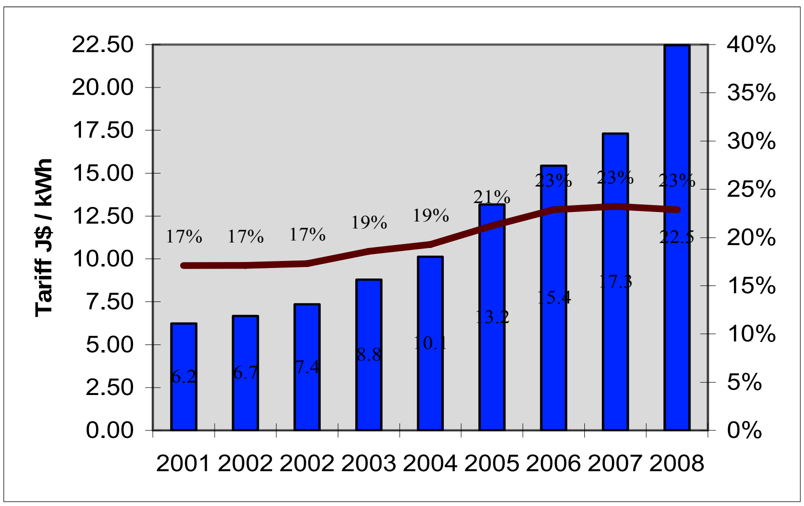
In fact, these penalties could have been worse had it not been for the efficient dispatch of JPS' generating units. To demonstrate the point on the exposure to losses, please see the quantum of the penalty that JPS faces for each 1% of excess over the regulatory target in the **Table 2.14** below. It should be noted that the penalty varies with the actual cost of fuel, though it is linear for each additional 1% of penalty at a given fuel price.

Table 2.14: Fuel Penalty Sensitivity

{Amounts in J$ Millions}	2004	2005	2006	2007	2008
Annual cost of fuel	14,592	22,175	26,679	32,748	47,510
Annual penalty for 1% excess	173	263	317	389	564
Annual penalty for 5% excess	867	1,317	1,584	1,945	2,821

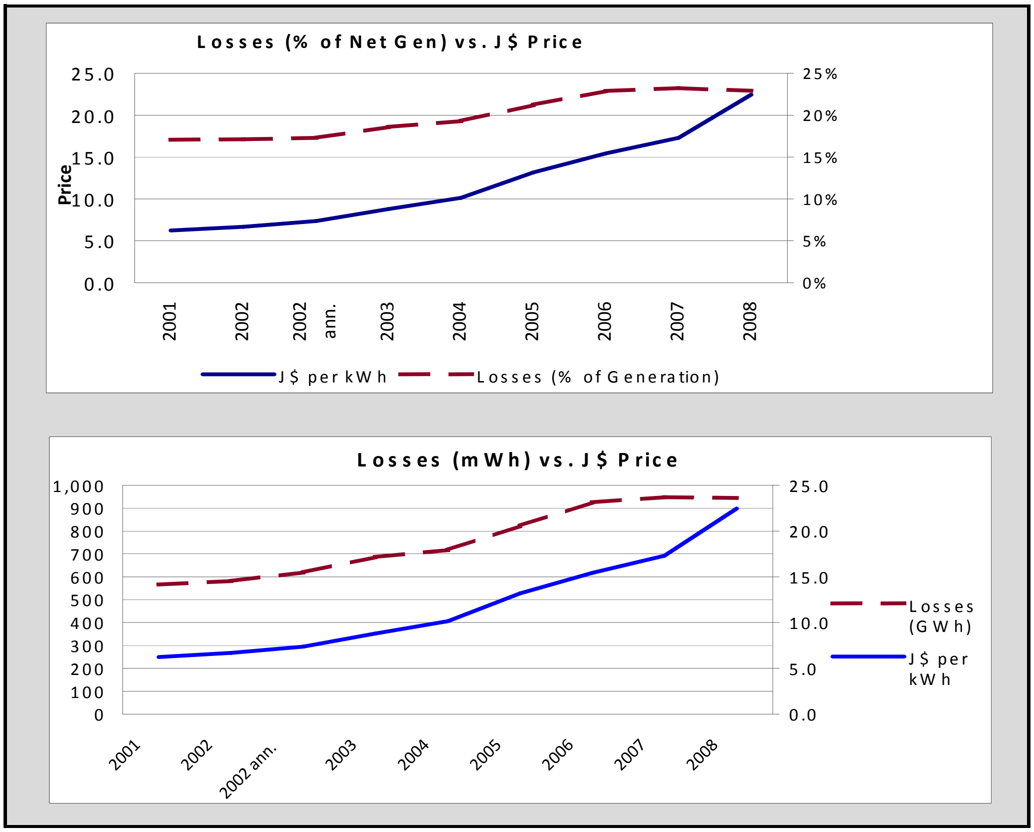
It is important to stress that while losses as a percentage of net generation has increased over the review period from 19.3% to 22.9%, when the unprecedented increase in tariffs over the period is considered, losses could have been as high as 30% were it not for the intervention of JPS. This is as shown in **Figure 2.5**.

Figure 2.5:System Losses



It cannot be that while losses as a percentage of net generation has increased during the review period, the rate of growth of losses in absolute terms has slowed down. That is to say, when one looks at the quantum of losses (kWh), one will observe that the growth in these losses has slowed down and, in fact, been relatively flat over the last three years, despite the significant increase in prices during the period. Please see **Figure 2.6** below which demonstrates this point.

Figure 2.6: Analysis of System Losses



The relatively high level of system losses (22.9% - 2008) belies the tremendous success the Company has had in keeping the absolute quantum of stolen energy relatively flat in the face of a deteriorating socio-economic environment and a high price to income ratio over the last three years. This success is attributable to the various aggressive loss reduction campaigns pursued over the past tariff period. A recent analysis of system concluded that the relatively high level of losses was due to the slow-down in the growth of net generation (or demand) over the past three years.

That is to say, net generation grew by 5% per annum on average during the period 1991 to 2001, when prices were relatively flat while system losses averaged 18% for that period and remained fairly stable at 17% during the period 1996 to 2001[7]. This implies that for the seven-year period (1996 to 2001) those losses in absolute terms actually grew at the rate of 5% per annum[8]. By comparison, in response to the unprecedented increase in prices during 2004 to 2008, which far outweighs the increase in prices experienced in the previous fifteen-year period, net generation grew by only 2.2% per annum on average. These unprecedented price levels have resulted in a reduction in demand (as evidenced by net generation), a reduction in the average consumption per customer and an increase in the propensity to steal electricity. However, despite these

[7] Please see Section 9 for a detailed analysis of system losses for 1991 to 2001.

[8] That is to say, if the net generation volumes (kWh) grew by 5% per annum, then in order for losses to remain constant at 17% of net generation, then the sales volume and volume of losses (in kWh) must have also grown by 5% per annum.

circumstances the actual incidence or volume of theft, measured in kWh, has remained relatively flat in the last three years as a result of the significant intervention by JPS.

Given that the cost of fuel for any given year is significant relative to the actual return that the utility makes and is beyond the control of the utility, the penalty/reward system should be revised to limit the exposure faced by the utility from an efficiency incentive perspective. The system should be restructured to be relevant to the target profit that the utility itself makes. That is, the utility should be penalized a percentage of its target profit in order to incentivise it to operate efficiently. It should not be exposed to penalties that could equal or exceed its entire target profit. This would not give the proper incentive but in fact threaten the viability of the business itself. Additionally, given the significant gap between the actual system losses and the regulatory target, the target should be revised to reflect the reality of higher levels of theft and crime including electricity theft, stemming from a deteriorating socio-economic environment to which the utility is particularly vulnerable but cannot insulate its operations.

Contained within this submission is a revised approach to the fuel rate calculation and the penalty/reward system in relation to the two main efficiency measures. It is important to note that the marginal costs of detecting losses exceeds the marginal revenues to be gained from those efforts. Simply put, the operational costs exceed the revenues to be gained. It is also an important fact that not all detected losses translate into future billable (or collectable) sales. **Section 9 (Systems Losses)** gives a detailed explanation of the various strategies employed by JPS and the cost of these initiatives.

2.5.3 The IDT Settlement

A job reclassification exercise arose out of a reorganization plan that commenced in 1999, which yielded a 20% reduction in the staff complement between late 2000 and early 2001. This was part of a deliberate effort by the then Government to improve the operational efficiency of the organization in preparation for its privatization on March 31, 2001. Further, as part of the privatization effort, JPS applied to the Minister of Mining and Energy (its then regulator) for an increase in non-fuel tariffs and the Minister requested that the OUR evaluate JPS' tariff application. The result was that a 9% increase on average was granted in the non-fuel tariffs in 2001. This represented the first rate review conducted by the OUR for JPS and the first non-fuel rate increase in tariffs for JPS in almost ten years. These two factors were critical to the privatization process, as was the establishment of an independent regulator and a clear and concise operating Licence.

Shortly after privatization, a dispute developed pertaining to the job reclassification exercise as the unions stated that the salaries had to be benchmarked to within the top 5-10 percentile of the benchmarked market to be consistent with the compensation policy/philosophy agreed on by the parties in a 1990/91 Heads of Agreement. In 2002 the Unions referred the dispute to the Industrial Disputes Tribunal (IDT).

In 2003 The IDT ruled in favour Unions and the Company disagreed with ruling on the basis that is was unclear, diluted managerial control over a significant cost driver and would impose significant and unquantified labour cost on JPS and by extension, rate-paying customers. The Company therefore took the decision to challenge the award through the courts. The Company's confidence in its case and the imprecise nature of the IDT ruling created uncertainty in the level, if any, of provision to be made in the audited financial statements over the period 2001 - 06.

In March 2007, the Court of Appeal essentially upheld the 2003 IDT award in favour of the unions, stating that

"the Salary structure that shall be implemented, consequent on the Job Evaluation and Compensation Review Exercise, is one which conforms with and maintains the established compensation policy/philosophy agreed on by the parties in the 1990/91 Heads of Agreement which is based on a formula of the top 5-10 percentile of the benchmarked market".

In accordance with the IDT award, JPS re-established the original Oversight Committee consisting of employee and employer representatives and also rehired the original consultants who had conducted the job reclassification exercise. The next twelve months were spent finalizing the salary structure and calculating the retroactive salary payments that were due to employees (in relation to total compensation) and culminated with the submission of a final report by the consultants to the Oversight Committee in May 2008.

On May 6, 2008, a Heads of Agreement brokered with the assistance of the Government, through the Ministry of Labour was reached with the unions. This long outstanding job reclassification exercise was finally brought to an end with a $2.3 billion (net) payment to employees and the adjustment of their current salaries based on a formula of the top 5-10 percentile of the benchmarked market as determined by the Consultants. Retroactive payments were made to employees in May 2008 (June 2008 for ex-employees).

A provision for $2.4 billion was initially made in the 2007 financial statements, which was increased to $3.5 billion during 2008. These amounts would have negatively impacted the operating profit of the business for both those years, although the cash flow impact did not occur until 2008.

It is important to note that the IDT settlement relates to genuine operating expenses impacting the business in 2008, since the amount was settled in 2008. As a result, a Z-factor claim was submitted to the OUR on March 2, 2009. Such a claim is consistent with Section 1.2, of the OUR's June 24, 2004, Determination Notice, where the OUR states:

"It is therefore the objective of the Office to ensure that the tariff determination will:

further improve upon customer service and service reliability;

provide the correct set of incentives for JPS to operate efficiently and to continue improving its productivity;

provide a fair return to investors; and

ensure that, while the price cap regime imposes a constraint on the Company to pass on excessive costs to the customers, it does not unfairly impose upon the Company risks that are outside of managerial control."

The above describes a PBRM revenue cap framework which, when fully developed, allows the Company the ability to meet its normal operating costs, which includes routine operating costs, the cost of capital invested by its shareholders and to ensure the Company is able to attract further capital when required. This framework restrains the annual price adjustment charged to customers to inflation less imposed allowances for productivity efficiency gains and quality of service targets. The framework, through the provision of a **Z**-factor clause, also seeks to mitigate the risk of undue financial distress on the Company for reasons beyond its control and which are not addressed normally under the tariff. The spirit of the **Z**-factor clause is that it allows the utility the opportunity to recover non-routine costs due to exogenous shocks that were not contemplated under the normal rate making process (i.e. which could not be foreseen) and which were not the direct result of mismanagement (or managerial behaviour).

The IDT payout are operating costs which meet the above stated three fundamental criteria established for a **Z**-factor claim, as it impacts costs, is outside of managerial control and is not addressed by any other element of the price cap mechanism. JPS's fundamental position as it relates to the IDT settlement is that baseline operating costs (specifically salaries) were unavoidably understated in the 2004 rate case submission. Had these costs been known with certainty they would no doubt have qualified for recovery under the regulatory framework, being genuine operating costs of the Company and therefore would have included in the rates since 2004. Given that, these costs were finally quantified and actually incurred during the 2004–9 tariff reset period (specifically 2008) they therefore qualify for recovery under the ***Z***-factor adjustment mechanism of the annual PBRM. More importantly, these costs were actually incurred during 2008; they should be claimed as part of a 2009 ***Z***-factor adjustment claim.

It is JPS' fundamental position that the costs included in the 2009 ***Z***-factor claim are the result of risks that are outside of its managerial control and that to deny the recovery of such costs would be to unfairly penalize the shareholders of the Company.

3 Outlook 2009-2013

3.1 Forecast of Economic Parameters

The Jamaican economy has been negatively impacted by a myriad of exogenous factors over the last five years. These include economic shocks due to hurricane and tropical storm systems, the spike in global oil prices, the global financial crises in 2008 and the significant devaluation of the Jamaican dollar, which collectively have caused a deterioration in the fiscal budget of the country.

This section looks at the economic projections for the period 2009 – 2013.

The outlook for the price cap period 2009 – 2013 is critical to JPS. While tariffs will be capped, JPS' operating costs have no ceiling and are dependent on the following key economic factors:

- GDP Growth Rate – which affects JPS' sales growth outlook and also determines the socio-economic conditions in Jamaica that contribute to electricity theft and system losses;
- Commodity prices and Inflation– which together affect the Company's operating costs inflation being the basis for the annual resetting of the tariffs.
- Interest rate policy – this is significantly influenced by U.S. treasury rates, the high Debt/ GDP ratio of Jamaica and the rating of Jamaican sovereign debt. JPS is heavily financed and incurs a significant amount of financing costs in the normal operation of its business.
- Foreign Exchange (FX) Rates – a significant portion of JPS' costs, both on the fuel and non-fuel, are US dollar denominated, while revenues are recovered in the local currency. As the FX movements pass down to customers, it affects the demand for electricity growth.

Mid-range forecasts of these factors over the five-year price cap period are shown in **Table 3.1**.

Table 3.1: Macro-economic Outlook 2009 – 2013 (Calendar Year)

	2009	2010	2011	2012	2013
GDP Growth Rates	-1.0	0.0	1.0	1.5	1.5
Inflation	12.0	9.0	7.8	7.4	7.0
Exchange Rates	92.5	98.0	102.6	106.9	111.1

3.1.1 GDP Growth

Since the second quarter of 2008, and in the context of the deepening global recession, the Jamaican economy has suffered a decline in its Real Sector performance. The main sectors are estimated to have either declined or recorded weak growth, among them, *Hotels & Restaurants*, *Mining & Quarrying, Transportation Services* and the area of *Remittances*. The overall GDP growth rate in 2008 was negative 0.4%. This negative growth will be carried over into 2009, and with momentum, the negative GDP growth for 2009 will exceed that experienced in the last half of 2008 with a projected outrun of negative 1.0%. This forecast is underpinned by the continued recession of the global economy into at least the last quarter of 2009.

Historical GDP growth, which averaged 1.2% over the last 5 years, has been constrained by a crowding out of the private sector, labour market rigidity, high security costs, and external shocks. All of these factors are still present in the Jamaican economy and therefore limit the prospect of rapid economic growth. With the economic downturn and recession currently being experienced by our main trading partners (U.S.A., U.K and Canada), global financial instability, a fall out in the productive sector and anticipated high levels of unemployment (in excess of 10%), one anticipates a decline in GDP for 2009 of at least 1.0% .

On the other hand, with the anticipated ease in the negative global crises and planned investment in infrastructure, tourism, education and the significant reduction in electricity prices in late 2008, it is expected that some recovery and growth will occur in the subsequent years, commencing in 2011.

Economic growth is projected at 1.0% in 2011 and 1.5% in both 2012 and 2013. In addition to the aforementioned reasons, the projected growth in GDP by 2011 reflects capacity expansion projections, which should be financed mainly by local and foreign direct investment. Growth will also be driven by gross fixed capital formation in the tourism, manufacturing, agriculture and mining sectors, as these sectors represent key productivity areas being targeted by the Government for development over the medium term. The economy is expected to be flat in 2010 as businesses realign themselves from the recessionary effects of 2009, thus no growth is expected in 2010.

However, one will appreciate that these projections of economic growth are surrounded by heightened uncertainty and risks under the current recessionary conditions and given the diverse global economy and financial marketplace in which JPS operates. Jamaica's responsiveness to these factors will be mainly dependent on the GOJ's ability to cushion the economy from exogenous shocks, and more so, its ability to stimulate the economy into the future.

3.1.2 Inflation

Inflation is projected to slow down from the 16.8% experienced in 2007 and 2008 to 12% in 2009, gradually declining to 9% by 2010, with continued moderate declines to 7% by 2013. This projected decline in inflation is against the backdrop of the Bank of Jamaica's high interest rate policy, the current economic slowdown and other anti-inflationary pressure present in the economy. The 16.8% inflation experienced in 2007 and 2008 was due to three key events, which are not expected to recur – significant currency devaluation, high commodity prices and inflated global oil prices. As detailed in **Section 3.1.3** below and, in the absence of exogenous shocks, the likelihood of the currency again depreciating by 14.0% in 2009 as it did in 2008 is remote, rather, one would expect a moderate level of currency depreciation going forward. Recently the economy has seen positive changes, including a reversal and subsequent stabilization of commodity prices, deceleration in the prices of some domestic agriculture commodities and weak domestic demand.

In the absence of the aforementioned three factors that drove the high inflation rate in 2007 and 2008, and in light of policies being implemented by the GOJ and the Bank of Jamaica to curb inflationary pressures in the economy, an increase in inflation over the medium term seems unlikely. The policies being implemented by the GOJ and the Bank of Jamaica are mainly based on monetary policy issues, evidenced by the issuing of high yield government bonds and the increase of bank reserve requirements in an attempt to reduce the money supply in the economy; the room for renewed high inflation seems slim. One can therefore expect a moderation of inflation next year, but not an immediate return to single digit rates. The likeliest path for the inflation rate, then, is a reduction between the ranges of 4 – 6% in 2009 (projections for 2009 is 12%), with a return to single digits of 9% in the following year, and an average rate of 7.4% over the next three years.

It should be noted, however, that the GOJ will face significant challenges in its quest to maintain a stable level of inflation. The largest economic challenge facing the GOJ is the size of the public sector debt. The Public Debt/GDP ratio has consistently been over 100% for the last ten years. The Debt Servicing alone for the financial year 2008/09 is estimated at $263.9 billion or 54% of the budget, comprising of $181.3 billion in domestic payments.

Given the above, the forecast range of possible outcomes for this variable is wide, possibly by as much as eight percentage points on the positive side, which means that an inflation rate of 20% is not unlikely over the medium term. This is due to the considerable risk that a more inflationary policy may be necessary if the government's debt dynamics do not respond to the corrective measures currently being implemented. The occurrence of any of the four inflationary variables again could also lead to higher inflation levels with the economy being particularly sensitive to exogenous shocks given the high Debt/GDP ratio.

3.1.3 Exchange Rates

The default assumption in exchange rate forecasting, in the absence of exogenous shocks or balance-of-payment corrections, is that the real exchange rate will be maintained. That would require a nominal depreciation equal to the differential between the inflation rates in the two currencies in accordance with purchasing power parity. Jamaican inflation is expected to remain significantly above U.S. inflation over the price cap period and consequently a continual depreciation of the Jamaican Dollar is expected. That differential for 2009 is expected to be approximately 15%, which would yield an exchange rate of $92.54 by year-end. This compares to the 5.5% annual depreciation experienced between 2004 and 2007 and the 6.0% depreciation in the first month of 2009. In 2008, the Jamaican Dollar depreciated by 12.2%.

Some of the concerns that drove the depreciation in the exchange rate have begun to subside. Supply to the market has increased in the first two months buoyed by remittances. Also, with the opening of the winter tourist season, a higher inflow of foreign currency is expected within the first quarter of 2009. The expectation of loan funds to sustain the availability of trade credit and capital would also have served to reduce uncertainty, and some US$300 million has been provided by the Inter-American Development Bank. The Bank of Jamaica continues to maintain sufficient reserves to fill short-term gaps in the market and to underwrite the integrity of foreign debts.

However, the nominal exchange rate in Jamaica will depreciate further in 2009, as the Jamaican currency is deemed overvalued and not sufficiently compensated by domestic interest rates. In addition, tourist arrivals to the Caribbean are expected to decline in 2008/09 and again in 2009/10, before recovering in the 2010/11-winter season. Remittances could also suffer, resulting in a deterioration of the balance of payments and falling exchange reserves, as the country encounters difficulty in refinancing its external debt obligations falling due.

With the liberalization of the financial sector, both credit and foreign exchange are freely traded in markets in Jamaica. With interest rates on government securities in Jamaica substantially higher than the corresponding US treasuries, lending in Jamaica should represent a relative bargain from an economic standpoint. This source should present some revaluation pressure on the currency, which could reduce the level of depreciation forecasted above through purchasing power parity.

Whether this revaluation pressure will manifest as actual currency movement depends simply on the Bank of Jamaica's policy decisions with regard to international reserve accumulation. With the NIR being eroded to US$1,772.9 million at the end of 2008, it would be the perfect occasion to absorb the capital inflows into rebuilding the reserves. Such a move would ameliorate, but not eliminate, the revaluation. This is, however, difficult to predict as the foreign exchange market reacts to influences external to Central Government's policy stance.

3.1.4 Interest rate policy

The GOJ and Bank of Jamaica have embarked upon the complex challenge of using monetary policy techniques, primarily interest rates, to help reduce the devaluation pressure on the Jamaica dollar. However, this high interest rate regime can only be a short-term measure since, while it mops up liquidity and helps to reduce the demand for U.S. dollars, it also creates financial hardship for the local productive sector, thus reducing their competitiveness in the global market.

It also raises the cost of borrowing for the GOJ itself, which also has a negative impact on the fiscal deficit. Thus, the GOJ must eventually reduce interest rates to bolster the local productive sector with the view of trying to increase exports (and reduce imports), while also reducing its cost of its borrowings. This is extremely important given that Jamaica's fundamental foreign exchange problem is the high import to export ratio, combined with a high Debt/GDP ratio.

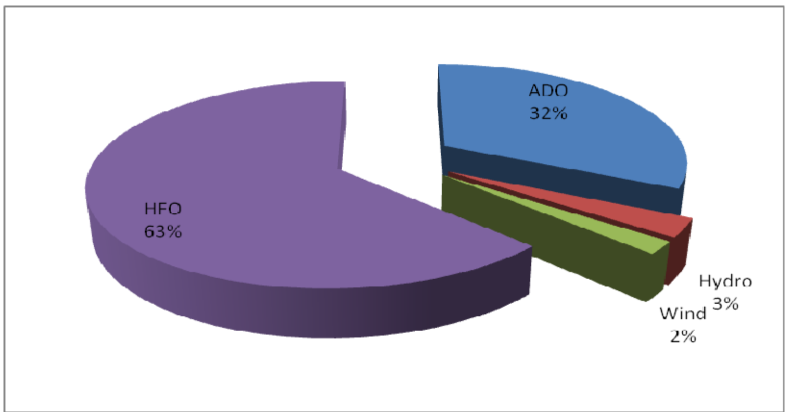
3.2 Strategic Objectives and Initiatives

The next five years will be crucial for JPS as it seeks both to consolidate the efficiency gains made over the last five years and to address the new challenges that have emerged. The primary goal of JPS is to provide a safe, reliable and efficient service, while also improving its financial strength. This is extremely important given that the viability of the Company is crucial to the development of the energy sector in Jamaica. Further, JPS recognizes that as an essential service provider, it provides a core service that is the backbone for economic growth in Jamaica. To this end, JPS has identified the following strategic objectives to pursue for the period 2009 – 13:

- Fuel Diversification
- Continued Improvement in Reliability
- Reduce Systems Losses
- Continued Improvement in Service Quality
- Maintain a Safe Operating Environment

3.2.1 Fuel Diversification

Figure 3.1 JPS Current Fuel Mix



It is vitally important for Jamaica to diversify the fuel consumed in its energy sector. Currently, 95% of the electricity generated in Jamaica emanates from oil-fired plants. Oil dependent generation resulted in significant fluctuation in the price of electricity over the last tariff period, reaching a record high of U.S. 38¢ per kWh in July 2008. Fuel diversification will mitigate any negative impact of future oil price fluctuations on the Company's operations as well as on the Country's macro-economy. Over the next ten (10) years the Company's strategic objectives for fuel diversification will include:

- Introduction of at least two other types of fuel to the generation (Coal, CNG (compressed natural gas) and/or Petcoke);
- A target limit of 40% of net generation from any single fuel source;
- A target of 10 – 15% contribution of net generation from renewable sources (hydro and wind).

To achieve these targets the Company will advocate a three-pronged generation expansion and diversification programme over the next five (5) years involving the following:

1. Expansion of renewable energy capacity;
2. Conversion of existing capacity at Bogue to CNG
3. Planning and preparation for long-term expansion and capacity replacement programmes involving the introduction of Petcoke and Coal.

3.2.1.1 Renewable Energy Sources

The GOJ is promoting the increased use of renewable energy for electricity generation and is targeting a 15% contribution to generation by 2015. JPS, by policy, will contribute to the attainment of that target.

The benefits of renewable energy in the fuel diversification mix are diverse, including:

- Environmentally friendly generation;
- Reduced fuel costs; and
- National savings in foreign exchange from the reduced use of imported fuel.

The Company responded to a 2008 request for proposal issued by the OUR for up to 70 MW of capacity from renewable energy projects. Approval has been granted for two projects and JPS will invest approximately US$37M to add 9.4 MW of wind and hydro generation to the grid by 2011, as shown in **Table 3.2**.

Table 3.2: Summary of Interim Expansion Projects

Project Name	Capacity (MW)	Estimated Costs (US$000)	Completion Date
Munro Wind Power	3.0	10,700	2nd. Qtr 2010
Maggotty Hydro Facility	6.4	26,000	1st. Qtr 2011

Additionally, JPS will work with the OUR and the GOJ to support other viable renewable initiatives that are identified.

3.2.1.2 Compressed Natural Gas

As part of its strategy in support of fuel diversification and the long-term reduction of electricity costs, JPS is pursuing the use of CNG as a fuel source for the Bogue power plant. This would include conversion of the existing 235 MW by 2011 and allow for future expansion of that plant.

The Bogue power plant is in the north-western end of the island and is a very important for the maintenance of a stable electricity grid. It is the only significant base-load generation facility outside the south-eastern belt of the island. This makes the future of the plant very significant as:

(i) The plant is situated within the second largest load centre, thus improving the efficiency of serving that load centre reliably;
(ii) The geographic location mitigates the risk of total generation loss due to natural disasters (an important consideration given Jamaica's vulnerability to hurricanes and earthquakes);
(iii) The site has significant land, infrastructure and transmission capacity to accommodate further generation expansion.

These advantages are partially offset by two important constraints: (1) The plant is located within the country's main tourism region and is subject to strict environmental regulations; (2) the plant's current fuel source is automotive diesel oil (ADO), the more expensive of the two liquid fuels used for generation. Due to the environmental constraints, cheaper solid fuel sources such as coal and petcoke are not options.

In order to preserve the long-term advantages of the Bogue plant, the Company is pursuing the introduction of CNG as the main fuel source while preserving the capacity to burn ADO in a back-up mode. CNG would provide the following benefits:

- Environmental
  - Reduced emissions and improved air quality in tourist area
  - Opportunity for carbon credit trading

- Short implementation time – could be completed within 18 months (by 2011)
- Reduced fuel costs and diversified fuel source
  - Reduction in generation fuel costs
  - Reduction in Jamaica's foreign exchange expenditure
- Increased reliability due to reduced maintenance cycles
- Local employment opportunities along the supply chain

Feasibility and safety studies have been completed. Gas procurement discussions have begun with potential suppliers. The project is well advanced but further statutory/regulatory approvals are required to move forward. The preliminary estimates of the project cost are US$50M.

3.2.1.3 Long-term Base Load Capacity Expansion

Effective March 2004, JPS no longer had the exclusive right to add generation to meet the incremental growth in demand for electricity. Future demand growth will be served by capacity obtained through open, competitive bidding approved by the OUR, in which JPS is free to participate. Further, since August 2007, the responsibility for planning the timely expansion of the system has also been transferred from JPS to the OUR.

JPS, to ensure its future growth and viability, will continue to aggressively pursue expansion opportunities that add value and meet the Company's long-term strategic objective of improving the price competitiveness of electricity service in Jamaica.

The Company is currently pursuing two projects that fit these criteria.

100 – 120 MW Petcoke Plant

The Petrojam refinery has embarked upon a US$720M project to upgrade the refinery's capacity by approximately 40%. The upgrade will utilize a new delayed coker process resulting in the production of a by-product, petroleum coke (petcoke).

JPS will utilize the petcoke produced as the inexpensive fuel source for a new 100 – 120 MW electricity plant in a joint venture partnership. The plant will utilize a circulating fluidized bed (CFB) boiler technology that has been proven to allow for the environmentally sound use of petcoke for the generation of electricity. The petcoke plant will be built in compliance with all environmental requirements.

Petcoke offers the following benefits:

- Reduced fuel cost to consumers with estimated fuel savings of US$70M p.a.;
- Reduce fuel imports, foreign exchange outflows, stable price;
- Opportunities to expand local limestone industry as a large amount of limestone will be used by the CFB boiler.
- The ash by-product can be used for road construction or making cement;
- Expanded employment opportunities during construction and operation.

The joint venture (JV) company will build, own and operate the CFB petcoke co-generating plant and provide 80 – 100 MW of energy to JPS' grid. An additional (18 – 20 MW), as well as the steam by-product, will be sold to the Petrojam refinery. The plant, to be sited at JPS' Hunts Bay power plant, is scheduled to commence commercial operations in December 2013 with an estimated cost of US$280M. The project is contingent upon the Petrojam Refinery expansion.

300 MW Coal Plant

One of the most significant energy sector challenges for Jamaica in the next ten (10) years is the orderly and timely replacement of the Old Harbour generating units that currently supply 240MW of power to the grid. The continued provision of a reliable service will be seriously challenged if proactive steps are not taken to plan, construct and commission base-load replacement capacity for this power plant. The OUR, in its Least Cost Expansion Plan (LCEP), recommends the retirement of the Old Harbour Generating plant by 2015.

To address this challenge, JPS is pursuing the construction of a 300 MW coal-fired generating facility in Old Harbour. JPS will develop and construct 4 x 75 MW CFB coal fired power plants at its Old Harbour Bay site to utilize low sulphur coal imported from Colombia/Venezuela. Limestone will be used as the sorbent to minimize the environmental impact. The projected Commercial Operation dates are:

- Phase 1 –2 x 75 MW -2015
- Phase 2 –2 x 75 MW - 2017

The construction of this plant is expected to cost approximately US$950M.

In 2006, the OUR granted approval for JPS to develop a 120 MW coal-fired facility. But the project was put on hold pending a clear decision by the government on the fuel of choice for diversification. Coal competes with Liquefied Natural Gas (LNG). With clear and unequivocal statements in 2008 from government, that, coal is the preferred fuel for base load expansion, JPS advised the OUR in December 2008 of its intention to resume engineering and development work on the project and of its intention to expand the plant to 300 MW.

3.2.2 System Reliability

3.2.2.1 Generation

JPS' capital expenditure for maintenance of the generating fleet from 2004 – 2008 totalled US$46M, an average of approximately US$9M per annum. This high level of capital investment over the past 5 years has begun to yield improvements. Forced outage rates improved significantly from 12.7% in 2004 to 8.5% in 2008, while the system availability also improved to 83.9% in 2008, up from 80.8% in 2004. Our customers have benefited significantly as the level of interruptions from the generating system continues to fall. **Table 3.3** summarizes the generation system performance from 2004 – 8

Table 3.3: Key Generating Performance 2003- 2008

	2004	2005	2006	2007	2008
Availability	80.8%	81.2%	82.3%	83.7%	83.9%
Force Outage	12.7%	11.0%	13.4%	10.7%	8.5%
Peak Demand (MW)	605	616	626	629	622
Reserve Margin (MW)	182	172	211	207	223
SAIDI (mins.)	564	1,052	483	403	194
SAIFI	21	23	13	8	7
CAIDI	27	45	36	53	27

Despite these achievements, JPS still faces a number of significant challenges including an aging generation fleet, the increased exposure to IPPs and the lack of much needed new base-load capacity.

The Company is targeting reliability improvements resulting in annual reduction of 3% in the level of system interruptions (SAIDI) and expects to realize this key performance measure by targeting an average system availability of 85% and a forced outage rate of 8% or less. The primary strategies for achieving these are:

- To continue implementation of a proactive maintenance programme driven by the OEM and best industry practices for Maintenance;
- Add incremental capacity, and restore derated generating capacity to maintain reserve margin.

The programmes to be implemented in 2009 include:

- Installation of an inlet cooling system on the Bogue Combined Cycle Plant, which will net a further 10MW of output.
- Restoration of the Constant Spring Hydro (0.8 MW)
- Upgrade of Rockfort Unit # 2 – 2MW
- An additional 60 MW of capacity is to be added by IPPs by 2010
- Construction and commissioning of two renewable energy plants – 9.4MW

The Company will spend US$68M between 2009 – 13 to maintain its generating fleet and achieve its key performance objectives. This will be a combination of OPEX (US$56.7M) and CAPEX (US$11.25M). US$41.1M or 60% of this will be spent on overhauling the key base-load steam plants.

3.2.2.2 Reduction in Service Interruptions

As JPS advances in its strategy to reduce the duration and frequency of system interruptions, the initiatives planned are expected to result in a 3% reduction in the outages experienced by customers. The effect will result in a continuing improvement in the system's reliability.

JPS has a three-fold strategy for the maintenance of a reliable service from its T&D network. This involves the:

- Continuous investment to improve the robustness of the T&D grids;
- Deployment and effective utilization of technology to operate and maintain the system;
- Increased utilization of live-line techniques for maintenance of the grid to reduce the necessity for outages.

3.2.2.3 Transmission Improvement Plans

Since 2007, there has been an increase in CAPEX to support necessary improvements to the transmission network. These improvements are, expected to impact the system reliability. Over the next five years, the Company will be allocating US$25.7M in CAPEX to effect planned improvements for the transmission network through the following programmes:

- Continuous transmission line upgrade and structural integrity programmes to replace aging transmission structures including 1,200 transmission poles and correct deficiencies. The total cost is US$16.7M. This programme will include rehabilitation and replacement of transmission line structures along the Old Harbour/Parnassus 138kV line;
- Replacement of all aged and obsolete breakers and reclosures throughout the system and upgrade and replacement of select substation transformers at a costs of US$6.9M;
- Upgrade of selected substation (US$1.3M);
- Improvements to the protection and control systems contributing to system stability and reliability, as identified in the recommendations from the system shutdown. (US$0.7M)

These programmes are expected to improve the system's SAIDI and SAIFI performances resulting in an improved customer service experience.

3.2.2.4 Transmission and Distribution Expansion

JPS' strategy to expand the transmission system is guided by two main concerns:

- The projected customer load growth; and
- the extent to which the system-wide generation expansion plan can be supported by the transmission network.

With over 100MW of new generating capacity planned over the five years there will be a need for reactive power support in the North Western region. Against this background, the Company will spend a total of US$7.4M to expand the transmission network and further improve the reliability of the system over the next five years. The transmission expansion plan will involve the following programmes:

- Installation of reactive support on the North West Coast of the island;
- Expansion to support customer load growth;
  - Upgrade to support for load growth at Constant Spring;
  - Upgrade and installation of interbus transformers (load growth support).

JPS has allocated US$104M in capital expenditure over the next 5 years to expand and improve the reliability of the distribution network. Almost 50% (US$48.1M) of this budget has been assigned to support the growth of the Company's customer base. A further 37% (US$38.4M) will be spent on improving distribution system reliability by way of:

- The Distribution Structural Integrity programme – Replacement of 20,000 wooden distribution poles and related equipment and updating the GIS database. (US$24.5M)
- Replacement of failed and aged pole-mounted transformers and the re-conductoring of sections of the primary and secondary distribution systems, while also improving voltage quality (US$13.9M).

For the period 2009 – 2014, the Company has committed to spending a total of US$19.9M in O&M funds towards recurrent maintenance activities impacting the reliability of both the T&D networks. On average US$1.7M will be assigned annually to emergency response activities while the remainder of the funds budgeted will go towards substation and distribution equipment maintenance

3.2.2.5 Protection and Control

A vital factor in the attainment of system reliability targets is the protection and control systems. The Company continues to treat this area with priority and over the next five years has designed a number of initiatives which complement other programmes being implemented to this end. Planned initiatives are summarized as follows:

- Provision of five (5) synchronising facilities for 138 and 69kV line circuit breakers. This should result in greater stability of the overall T&D System and faster restoration of the system following outages.
- Upgrade of under-frequency relays and several substations to maintain system stability.
- Modernisation and expansion of SCADA/EMS visibility using advanced communication protocols.
- Modernisation of remote relay maintenance to achieve greater efficiency in cost and relay operation.
- Reconfiguration of certain system-critical substations to achieve more discrete isolation of faults.
- Modernisation of protection infrastructure to reduce the probability of relay malfunction.

3.2.2.6 Technology

JPS continues the upgrading and integration of some its key technology systems. An upgrade to the SCADA/EMS started in 2007 and the first phase was completed in February 2009 at a cost of US$3.5M.

The new SCADA/EMS system will allow JPS to monitor its substations, generation facilities, and transmission and distribution system and to provide operators with remote control of various devices on the network. The new system will allow confirmation of customer power outages and the ability to issue manual controls to elements of power delivery infrastructure.

In addition, the SCADA/EMS system should confer the ability to leverage data gathered by the SCADA system throughout the Company by integrating the system with the customer related applications (CIS and the Call Centre) as well as the operational database (GIS) to facilitate improved customer experience. Data gathered from the system will be important in driving improvements to the T&D network and provide monitoring capability for the Momentary Average Interruption Frequency Index (MAIFI).

The Company completed implementation of the Enterprise Geographic Information System (E-GIS) application in 2008. It is currently involved in developing additional user interfaces to facilitate information sharing across the organization to augment customer responsiveness and service delivery.

3.2.2.7 Live-line work

In 2009 JPS will be training additional crews to expand its live-line operations. The advantage of live-line maintenance is to reduce the need for planned outages for routine maintenance activities. As a result customers will realize the benefit of improved system reliability due to fewer customer service interruptions.

3.2.3 Systems Losses

System losses represent the most significant operational challenge currently faced by the Company. Losses for the year 2008 were 22.9%, costing J$3.9B (US$54.8M).

Since 2001, the average price of electricity moved from U.S. 15.3¢/kWh to U.S. 23.4¢/kWh in 2006, representing an increase of 52%. During the same period, losses showed an increase of 39%. This indicates a strong correlation between system losses and electricity prices. Between 2006 and 2008 the price of electricity moved from U.S. 23.4¢ to U.S. 30.6¢, representing an increase of 23%. JPS estimates that this significant increase in prices could have resulted in the level of system losses increasing to approximately 25.3%, had it not been for the Company's sustained efforts to detect and reduce irregularities.

The Company realized success in its loss reduction efforts; however, the effort was masked and significantly offset by the pressures of the dramatic increases in electricity prices (due to fuel price movements). Recognizing the dangers of a price-driven acceleration in losses, the Company implemented additional initiatives in 2008, and intensified existing ones. Most of these initiatives targeted specific customer groups. For further details of system losses initiatives see **Section 9**.

One of the continuing strategic goals of JPS is to decrease energy losses in an effort to improve fuel efficiency. Presently, the aim is to reduce system losses down from 22.9% to 18.3% in 5 years, a 4.6% reduction over the five-year period. The Company's loss reduction strategies will be focused around four main areas. These are:

a. Improvement in the Company's measuring and analytical capabilities with the completion of the energy balancing project.
b. Technical loss reduction initiatives;

c. Non-technical loss reduction; and
d. Administrative controls and improvements.

3.2.3.1 Technical Loss Reduction Programmes

The technical loss initiatives to be pursued over the next five years target a reduction from approximately 10% at present to about 8.5% of net generation by 2014.

The largest technical loss reduction is expected from the rehabilitation of the secondary network, which will yield a reduction of one percentage point at a cost of US$2.1M. This will be achieved by replacing aged bare conductors especially where voltage violation is identified. US$2M will be spent on the VAR management programme with the procurement and installation of both fixed and switched pole mounted capacitor banks along with the associated accessories such as controllers, controller transformer, etc.

Finally, the third technical loss reduction project will be directed at the primary distribution network. The primary upgrade and phase balance programme is aimed at shaving 0.4% off technical losses between 2009 and 2014, at a cost of US$3.1M.

3.2.3.2 Non -Technical Loss Reduction Strategies

JPS plans to reduce non-technical loss by 2.6% over the next five (5) years. This will be achieved through a combination of capital projects (focusing on line and metering infrastructure upgrade) as well as intensified auditing and investigation of accounts and the maintenance of effective controls. The non-technical loss reduction programme over the last two years directed a significant amount of effort and resources at large account audits (Rate 40 & 50 primarily). During 2007/8 the introduction of the AMI metering project facilitated real-time continuous monitoring of these accounts, thus freeing resources for utilization in other initiatives.

Starting in 2008, residential consumers have been receiving significantly more attention. The consumption of residential customers (Rate 10) has declined consistently over the last 3 years and there is increasing evidence that this customer category is a significant contributor to the growth of system losses.

Theft Resistant Network Programmes

The company launched its theft resistant network programme in 2007. The strategy involves identifying high-energy loss sources via energy balanced meters on distribution transformer circuits and implementing theft resistant network and metering solutions to effectively reduce energy losses on a sustained basis. It is estimated that over 100,000 illegal residential electricity users exist island-wide, who contribute to approximately 5% of net generation or US$20M in lost revenues per annum. In addition, a further 4% of energy is estimated to be lost to our 525,000 residential customers.

The target is to realize 0.5% of net generation or an annual savings of US$2.5M with an investment of US$5M in the first year. This will involve the regularization of over 10,000 illegal customers per annum. In addition to the recovery of losses, this project will also facilitate automatic meter reading and remote disconnection capabilities for these high-risk customers.

The theft resistance programme targets illegal users and, to a lesser degree, the irregularities among residential customers. A new aspect of the program will focus on legitimate residential customers through the auditing of 10,000 customers per month, thereby allowing for coverage of approximately 20% of customers each year, starting with low and the zero consumption grouping.

AMI for Priority Accounts will focus on the remaining rate large customers for 2009. That is, the procurement and installation of an additional 2,500 Smart Meters including spares, support infrastructure and software to the AMI system already implemented in Phase 1 of this Project.

Phase 1 of the project saw the installation of approximately 1,900 meters and support infrastructure in early 2008.

Administrative Controls and Improvements

As the Company continues to implement and expand the loss reduction initiatives, it plans to carry out a number of activities aimed at improving internal controls and processes, including but not limited to:

- Improving meter reading quality and efficiency by recycle training/outsourcing;
- Upgrading to the billing system; and
- Improving controls around bill estimation and the adjustment of accounts.

The Company expects to make significant improvements over the next five years and is committing US$28.3M in CAPEX and US$16.6M in OPEX.

3.2.4 Service Quality

The Company continues to make service quality improvements a major objective. Over the last five (5) years, the primary measure of service quality is the OUR guaranteed standards and JPS has made steady improvements in this regard. Despite these improvements, the Company has faced several challenges primarily in the areas of complex connections, billing adjustments, and responses to emergency calls. JPS will be embarking on a number of key strategies to proactively improve the quality of service offered to its customers. These include the implementation of an automated service management system, which will streamline the customer service provision process as well as the implementation of specific programmes, which will target the three areas mentioned.

3.2.4.1 Automated Service Order Management

Currently, customer-related field activities such as meter installations, meter connections, meter inspections, disconnections and reconnections are done through the generation, execution and closing of service orders. Analysis has shown that delays in closing service orders are a contributor to timely service delivery. The strategy going forward is to automate the process so as to improve efficiency and reduce the time taken to complete this process through a Service Order Management System (SOMS).

Development and deployment of SOMS for new installations and meter inspections (Phase 1) has been completed and been in use since 2008. The implementation of SOMS provides JPS the ability to improve compliance with certain Guaranteed Standards.

3.2.4.2 Customer Connection Improvement

Over the last five (5) years the Company has implemented several programmes that have improved the efficiency with which new customers are connected to the network. These include:

- Changes in the organization structure to have a dedicated GS2 implementation group.
- Business process improvements in relation to scheduling of field activities, material acquisition, scheduling of live line crews and reporting; and
- Improved IT infrastructure support.

Although improvements have been made, the Company's goal is to be fully compliant with the OUR standards by 2014. However, due to challenges external to JPS, the Company is requesting a modification in the OUR standards (See **Section 10.1**) to read:

GS(2) (a) Estimates within 15 days; connections within 35 working days after payment

(b) Estimates within 15 days; connections within 45 working days after payment.

To achieve this modified standard the Company will implement a number of other initiatives over the next 5 years. These include:

- Modifying the Complex Connection Management Application (CCMA);
- Better classification of applications for service to ensure that those jobs are properly classified and resources allotted accordingly.
- Ensuring the availability of materials for connecting customers through better coordination with the materials inventory management.

In addition the Company has budgeted to spend US$56.4M over the next five years on customer expansion, load growth and service installation activities. JPS is therefore confident that it can significantly improve customer responsiveness on new service installation

3.2.4.3 Response to Emergency Calls

Over the last three (3) years there have been steady improvements in the average response time to emergency calls. However, the Company is still not satisfied with its performance in this area and will dedicate more resources over the next five (5) years. As part of its commitment, the Company has set a strategic goal to restore service within 6 hours in 95% of all cases.

To achieve this, a number of strategies will be implemented within the next two (2) years, many of them intending to reduce the necessity for emergency calls thereby providing optimal deployment of available crews and resources. These include:

1. Organizational restructuring to improve 24-hour response capability.
2. Implementation of continuous bushing management to reduce incidence of call outs.
3. Conducting lightning mitigation activities (install adequate grounding equipment and lightning arresters) in areas of high ground resistivity to again reduce call out incidences.
4. Infrared scanning of all feeders to ensure live-line correction of "hot joint" before they create outages.
5. Improving fuse coordination on feeder laterals in order to prevent large 'section outages" whenever faults develop on the distribution system.
6. Increased "live line" preventative maintenance. A capital budget of US$1.8M has been earmarked to acquire additional equipment in 2009.
7. Complete structural integrity projects prior to the beginning of the Hurricane season to reduce possible service disruption during the storm season.

3.2.5 Safe Operating Environment

A core objective of JPS is the provision of a safe, reliable and affordable product. The process of generating, transmitting and distribution involves significant potential environmental and safety challenges. JPS has therefore made Environmental, Health and Safety (EHS) a primary focus of it day-to-day operations with the two major strategic goals. These are:

- Maintain visible leadership in environment, health and safety stewardship in the industry, the workplace and the communities served; and
- Maintain compliance with internal and regulatory requirements and continual improvements in its EHS performance.

The primary objective of JPS' Environment Health and Safety program is to create and maintain a safe and healthy work environment. This safety culture translates to the safe delivery of our products to the homes and businesses of our customers. Over the last three years, the Company has intensified its environmental and safety programmes, which have resulted in substantial improvements and achievements including a reduction in the number of job injury cases.

For 2009-14, the strategic focus will be to build on the success of these programmes in order to continue to meet and/or exceed international industry best practice and to comply with all statutes and regulations.

4 Cost of Capital

4.1 Introduction

The non-fuel revenue requirement JPS is allowed to recover through the tariff includes a component for the return on investment. This return is compensation to JPS' investors for capital costs they incur by investing in the utility's regulated asset base. Schedule 3 (Section 2(C)) describes this return in the following manner:

> ***"This component is calculated based on the approved Rate Base of the Licensee and the required rate of return which allows the Licensee the opportunity to earn a return sufficient to provide for the requirements of consumers and acquire new investments at competitive costs….***
>
> ***The return on investment shall be calculated by multiplying the allowed rate of return by the Licensee's total investment base (Rate Base) for the test year. The allowed rate of return is the Licensee's Weighted Average Cost of Capital (WACC). The WACC ("K%") will balance the interests of both consumers and investors and be commensurate with returns in other enterprises having corresponding risks which will assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital. The WACC will be based on the actual capital structure or an appropriately adjusted capital structure which adjustment is required to keep parity of the interests of the consumers and investors and at the time of the filing such capital structure and WACC shall be adjusted by any known and measurable changes which are expected to occur during the test year.***
>
> ***Return on Investment = K% * (Rate Base)"***

The overall rate of return is calculated as the weighted cost of the capital structure components: long-term debt, preferred stock and equity. The costs associated with debt and preferred stock are, for the most part, already established as per audited financial statements for the test year since these forms of capital are generally issued with defined coupon and dividends rates that are known and can be validated. The costs of any additional borrowing or preferred stock issues would be estimated at current market levels. The costs associated with equity on the other hand must be estimated by evaluating quantitative and qualitative factors that measure investors' expectations. These costs are determined in the financial markets and are correlated with the risks associated with the investment.

The weights assigned to each element of the WACC are determined by the capital structure of the utility as indicated by its gearing ratio. As stated by the Licence, the ratio may be actual or adjusted to reflect the trade-off between the interest of the ratepayers and the Company's shareholders.

The principle on which any calculation of the return on investment is based is the risk return trade-off principle. The risk return trade-off principle states that, assuming risk averse investors, potential return on investments must rise with an increase in risk. Therefore, if it can be ascertained that the environment in which JPS will operate between 2009 and 2014 is inherently more volatile than the previous rate review period, ex ante, then the allowed rate of return should be higher. In other words, the rate of return on investment authorized in the previous determination should be adjusted commensurate with the changing risk environment faced by investors in the utility, which in JPS' case will be measured primarily by the country risk premium.

According to the 2004 Rate Case Determination Notice, the OUR determined the following relating to the calculation of JPS' return on investment:

- Cost of Debt - The OUR accepted the weighted cost of outstanding debt of 12.56% as per the test year's audited financial statements.
- Real Cost of Equity – The OUR approved a real rate of return on investment of 14.85% based on the CAPM Methodology
- Capital Structure – The OUR accepted a gearing ratio of 44% as per the audited financials.
- WACC – The OUR approved a post-tax WACC of 12.00%, which implies a pre-tax WACC of 18%.

Since 2004 the business environment in which JPS operates has changed dramatically. JPS currently faces an extremely risky economic environment and will continue to do so in the medium term. The Company must operate in an environment characterized by domestic and global contraction, global financial crisis, inflationary spiral and volatile foreign exchange market. The events that precipitated these risks began in late 2007 and as a result JPS investors have lost value on their investment in the Company. Some of the factors contributing to the increased business risk faced by the Company include:

- Macroeconomic environment – Planning Institute of Jamaica estimated that the economy contracted by 0.4% last year. Due to the ensuing global financial crisis the outlook remains negative with a significant risk that the recession will continue into 2010.
- Electricity Demand – Demand for electricity has been flat since 2007, actually contracting for residential customers. JPS expects demand to continue to be weak, growing by approximately 1.1% per annum on average over the next five years.
- Financial Markets – The local credit markets have been in flux since the second quarter of 2008 due to the meltdown of the US financial markets. There is little indication that the credit markets will stabilize before 2010.
- Power Purchase Agreements (PPAs) - The source of these risks come mainly from contractual performance risks due to the PPA structure and performance guarantees. The new 60 MW plant to be commissioned by JEP in 2011 will expose JPS to even greater risks from PPAs.
- Interest Rate – Short-term interest rates have become very volatile since June 2008. Long-term interest rates which are based on the prices the GOJ Global bonds trade have increased 500 basis points, from 8% to 13% in the same three months. These are a result of the impact of the global financial crisis on the local credit markets and are forecasted to continue rising as long as the crisis persists

These developments indicate that JPS will operate in a riskier environment than was anticipated in the 2004 Determination and the additional risk should be reflected in the return on investment the OUR authorizes in the current rate case. The Company's capital structure and the actual cost of debt are similar to the levels in 2004, thus the risk premium should be reflected in the allowed return on equity (ROE).

4.2 Capital Structure

According to the Licence, the cost of capital the utility is allowed to recover should be based on either the actual capital structure or *"an appropriately adjusted capital structure which adjustment is required to keep parity of the interests of the consumers and investors"*. In the 2004 determination, the OUR indicated that in its view an appropriate gearing for JPS was 48%, despite the actual level being 44%. The OUR nonetheless accepted the actual gearing for use in calculation of the JPS' WACC.

The Company's capital structure for the test year, as reflected in its gearing ratio of 39%, represents a sub-optimal level of debt currently used to finance the Company's regulated asset base. According to PEG's Cost of Capital Study included in **Annex B** of this submission, the average gearing of energy companies that are similar to JPS is 48%. However, JPS has been constrained in its efforts to obtain additional credit financing due to the ensuing global financial crisis, which has frozen lending in the capital markets especially for governments and companies in emerging markets. Consequently it has been virtually impossible for JPS to find reasonably priced credit at preferred tenures. Instead the Company has reluctantly resorted to obtain short-term financing with the option to refinance at longer tenures when the crisis recedes. **Table 4.1** outlines the components of the current structure (please see **Table 5.18** in **Section 5.2.9** for further details)

Table 4.1: Rate Base Capital Structure

J$ Million	2008 Audited Financials	Reclassification	Additional Borrowing	FX Adjustment	2008 Adjusted
Current Assets	18,328		402	246	18,976
Current Liabilities	(11,621)	504	3,622	(345)	(7,840)
Net current assets	6,707	504	4,024	(99)	11,136
Non-Current Assets	56,195			3,044	59,239
Other Long-term Liabilities	(10,921)				(10,921)
	51,981	504	4,024	2,945	59,454
Shareholder's equity	32,191		(805)	1,531	32,917
Long-term Loans	19,790	504	4,829	1,414	26,537
	51,981	504	4,024	2,945	59,454
Gearing ratio	38%				45%

JPS proposes that the capital structure be modified to increase the level of debt by US$60M (or J$4.829B) and reduce equity by US$10M (or J$805M). The adjusted capital structure would increase the gearing to 45% equal to the level in the last rate submission. JPS intends to have the additional financing in place by June 2009. The full details of the additional financing and the intended use of funds are provided in section 5.2.3. This represents actual planned financing activities that were delayed in 2008 and does not merely represent a subjective adjustment to the gearing ratio.

4.3 Cost of Debt

In its calculation of the Company's return on investments, the OUR accepted JPS' methodology of using the actual cost of debt in the test year's audited financial statements to estimate the cost of debt included in the 2004 rate case WACC. JPS has employed the same methodology to estimate the current cost of debt for the 2009 rate review but has included an estimate for the cost of additional borrowing to compute the weighted average cost of debt. This approach was necessitated due to the instability in the credit markets in 2008 that forced JPS to delay the acquisition of US$60M in long-term financing until 2009 in order to avoid incurring significantly higher interest costs due to market volatility.

The cost of borrowing the additional $60M is estimated at 13%. This estimate was deduced from the average yield that the 2017 and 2019 GOJ Global Bonds currently trade for on the capital markets which is 12.5%, plus the transaction costs. Those bond rates set the floor for the interest rate of any long-term loan currently being negotiated in Jamaica. That rate is also reflective of the quotes obtained from the financial institutions interested in offering JPS a long-term credit facility.

Table 4.2 shows JPS' actual cost of debt, by lender, principal balance outstanding at December 31, 2008, the coupon rate and the 'all-in' cost of borrowing. The weighted average interest rate is 11.47%

Table 4.2: JPS Actual Cost of Debt

Lender	Principal	Interest Rate	Issuance Cost	All-in Rate	Weighted Avg. Interest Rate
	US''000				
KFW Loan - DM 14M	422	7.00%	0.45%	7.45%	0.01%
KFW Loan - DM 7M	5,029	7.00%	0.45%	7.45%	0.12%
Int'l Finance Corporation	35,000	9.12%	0.75%	9.87%	1.09%
AIC Merchant Bank	1,627	8.75%	0.50%	9.25%	0.05%
Credit Suisse	180,000	11.00%	0.45%	11.45%	6.50%
FCIB Syndicated - US$	35,000	9.46%	1.00%	10.46%	1.15%
Additional Borrowing	60,000	13.00%	0.50%	13.50%	2.55%
	317,078				11.47%

JPS proposes that a cost of debt of 11.47% be included in the calculation of the weighted average cost of capital authorized in the revenue requirement. This represents a reduction from the cost of debt authorized in the 2004 rate review of 12.56%.

4.4 Return on Equity

In its 2004 rate case determination, the OUR established a real, allowed return on equity (ROE) for JPS of 14.85%. This allowed ROE had two components. The first was a real cost of equity determined through the capital asset pricing model (CAPM), equal to 9.535%. The second was a country risk premium (CRP) to reflect the differential risks of investing in Jamaica versus the US, equal to 5.315%. PEG was retained to advise JPS on the appropriate value for its cost of equity for the current 2009 rate review. The Consultant's full report is presented in **Annex B** of this submission.

PEG reports that recent developments in financial markets since the initial 2004 determination have serious implications for cost of equity faced by JPS investors. They indicate that the world is currently in the midst of its worst financial crisis in decades and it is uncertain whether a resolution is imminent in the near future. As financial markets will be characterized by greater uncertainties, and probably higher capital demands than in the recent past, PEG believe these factors point to a higher required cost of equity for JPS.

In developing the allowed ROE recommendation, PEG adhered closely to the framework that the OUR used in its last determination. They based their recommendation entirely on the CAPM. In most instances, they also relied on the same data sources that were previously used to select values for the parameters of the CAPM formula.

PEG recommended a real ROE for JPS of 21.6%. This recommendation is, in turn, founded on recommended values for the risk-free rate of return of 0.32%; an equity beta of 0.95; a market risk premium of 11.66%; and a country risk premium of 10.23%. All of these values support an increase in JPS' cost of equity compared to 2004. PEG concludes this adjustment in JPS' allowed ROE is reasonable given the most recently available data, ongoing developments and uncertainties in the world's capital markets. **Table 4.3** summarizes the key aspects of the ROE with comparative information for 2004.

Table 4.3: JPS ROE Calculation

	2004 Determination	2009 PEG Calculation
Real, Risk Free Rate of return	2.70%	0.32%
Equity Beta	0.87	0.95
Market Risk Premium	8.20%	11.66%
Real Cost of Equity before CRP	9.535%	11.40%
Country Risk Premium	5.315%	10.23%
Total real Cost of Equity	14.85%	21.63%

JPS accepts PEG's recommendations and proposes that the OUR uses the above parameters in their calculation of the cost of equity in the determination of the WACC for JPS.

4.5 Calculation of JPS' Weighted Average Cost of Capital

The two most common techniques used to calculate a utility's weighted cost of capital, the pre-tax and post tax methodologies differ in their treatment of the Company's tax liabilities. A pre-tax approach includes an allowance for tax as part of the WACC, a tax wedge is introduced which increases cost of equity sufficiently to cover corporate tax charge. Under a post-tax approach, tax is included in expenditure cash flow rather than the WACC, a corporate tax charge is included as a part of the efficient operating costs that the utility is allowed to recover. The decision of which method to employ depends on the relative complexity of applying either methodology given local tax laws and the accuracy of estimating tax liabilities from cash flow forecasts.

4.5.1 Post Tax WACC Methodology

The post-tax WACC formula is given by:

$$Post\ tax\ WACC = g * r_d * (1-t) + (1-g) * r_e$$

Where g is the gearing ratio; r_d the cost of debt; r_e the cost of equity; and t is the corporate tax rate.

In this methodology a tax shield is introduced in the calculation of the cost of capital. Since interest is deducted from the Company's profits prior to calculating its corporate tax charge the Regulator must ascertain the extent of the Company's taxes by applying the corporate tax rate to earnings before taxes (EBT) are calculated but after interest is deducted. The Company is then allowed to recover this tax charge through revenues.

The problem with this method is the manner in which debt is treated. The tax shield on debt in the formula is intended to reduce the Company's tax liability. However, under the current tariff regime as explained in **Section 2.4.2**, debt is already deducted from income before taxes are calculated. The shield instead simply reduces cost of debt the Company is allowed to recover through tariffs to a level below the actual costs associated with debt. Since the Company incurs the actual cost of debt, the impact of the tax shield is to diminish the effective rate of return on equity allowed in the revenue requirement. This may be corrected by grossing up the return on equity to compensate for the tax shield but this step is often overlooked as was the case in 2004 Rate Case Determination when debt was understated by J$624M (see **Section 2.4.2** for additional details on this matter).

4.5.2 Pre-Tax WACC Methodology

The formula used in this treatment for cost of capital is:

$$Pre\ tax\ WACC = g * r_d + (1\text{-}g) * 1/\ (1\text{-}t) * r_e$$

Where g is the gearing ratio; r_d the cost of debt; r_e the cost of equity; and t is the corporate tax rate.

In the calculation of the rate of return in this methodology a tax wedge, *1/ (1-t)* converts the post tax cost of equity to a pre-tax cost of equity. When this formula is applied to the regulated rate base it provides sufficient revenues to meet tax liabilities without impacting the return on equity.

As previously stated in **Section 2.4.2**, JPS recommends that the pre tax WACC methodology be used in the 2009 rate review to calculate JPS' rate of return on investment in part to avoid the error that occurred in 2004 but also to eliminate the risk of over or underestimating the level of taxation included in the revenue requirement.

4.5.3 Calculation of JPS WACC

Given the increased risks facing investors in JPS, the risk/ return principle implies that investors should expect a higher rate of return to be authorised in the 2009 non-fuel tariff revenue requirement compared to 2004. In this context JPS proposes that the following estimates of the components of the weighted average cost of capital be included in the calculation:

- A weighted average cost of debt of 11.47% - This is calculated using the actual cost of the long-term debt in the JPS 2008 audited financial statements and an estimate of the cost of borrowing an additional US$60M;
- A cost of equity of 21.63% - This value recommended by PEG represents an increase of 675 basis points over the ROE authorised in 2004 following the same methodology prescribed by the OUR then. This is due mainly to an increase in the volatility and the negative medium-term outlook for the business environment in which JPS operates; and
- A gearing of 44% - This reflects an adjustment of the capital structure indicated in the 2008 audited financial statements to include the US$60M in additional debt which JPS intends to acquire in 2009.

These parameters and the rate base determined in Section 5.2.9 should result in following calculation of the return on investment, as shown in the **Table 4.4.**

Table 4.4: Return on Investment

		2004	2009
Cost of Debt	A	12.56%	11.47%
Rate of Return on Equity (ROE)	B	14.85%	21.63%
Tax Rate	C	33.33%	33.33%
Gearing Ratio	D=E/G	44%	45%
Long-term Debt ('000)	E	15,420,557	26,537,000
Shareholder's Equity ('000)	F	19,581,238	32,917,000
Total Capitalization ('000)	G=E+F	35,001,795	59,454,000
Return on Equity	H=B*F	2,907,814	7,119,947
Taxation	I=H*0.5	1,453,907	3,559,974
Return on Investment	J=H+I	4,361,721	10,679,921
Interest Expense	K=A*E	1,936,822	3,043,794
Post-tax WACC[9]	L=D*(1-C)*E+(1-D)*B	12.00%	15.39%
Pre-tax WACC	M=D*E+(1-D)*B/(1-C)	18.00%	23.08%

[9] The post tax WACC is only shown for informational purposes and is not appropriated as explained in Section 2.3.2.

5 Revenue Requirement

5.1 Rate Base and Revenue Requirement

The Licence, in Schedule 3, Section 2, defines the Rate Base as:

> ***"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 net investment made by the Licensee in the 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 and shall be increased or reduced by any positive or negative working capital requirement that may exist at such time. Working capital shall include, among other things, the cost of an appropriate level of fuel which is held in inventory, cost of appropriate levels of other inventories and an appropriate percentage of annual non-fuel operating expenses less any appropriate offsets."***

The Licence further explains how the revenue requirement should be calculated:

> ***"This filing shall include an annual non-fuel revenue requirement calculation and specific rate schedules by customer class. The revenue requirement shall be based on a test year in which the new rates will be in effect and shall include efficient non-fuel operating costs, depreciation expenses, taxes, and a fair return on investment. The components of the revenue requirement which are ultimately approved for inclusion will be those which are determined by the Office to be prudently incurred and in conformance with the OUR Act, the Electric Lighting Act and subsequent implementing rules and regulations. The revenue requirement shall be calculated using the following formula unless such formula is modified in accordance with the rules and regulations prescribed by the Office.***
>
> ***Non-Fuel Revenue Requirement = non-fuel operating costs + depreciation + taxes + return on investment…"***

Finally, the Licence defines the test year as follows:

> ***"Test year" shall comprise the latest twelve months of operation for which there are audited accounts and the results of the test year adjusted to reflect:***
>
> ***Normal operational conditions, if necessary;***
>
> ***Such changes in revenues and costs as are known and measurable with reasonable accuracy at the time of filing and which will become effective within twelve months of the time of filing. Costs, as used in this paragraph, shall include depreciation in relation to plant in service during the last month of the test period at the rates of depreciation specified in the Schedule to this Licence. Extraordinary or Exceptional terms as defined by The Institute of Chartered Accountants of Jamaica shall be apportioned over a reasonable number of years not exceeding five years; and***
>
> ***Such changes in accounting principles as may be recommended by the independent auditors of the Licensee."***

5.2 Known and Measurable Changes

The test year results will be based on the 2008 audited financial statements with adjustments for known and measurable changes, as allowed under the Licence. The details of these adjustments are highlighted in the sections that follow. All 2008 financial statement amounts mentioned throughout **Section 5.2** are taken from the audited financial statements. Please refer to **Annex C** (Audited Financial Statements) for the details of the 2008 operating expenses.

5.2.1 2008 Base Salaries

This represents the adjustment for salaries and benefits in relation to the outstanding Collective Labour Agreements (CLA) for 2008 and 2009. The CLA for unionized employees expired at the end of 2007 and while negotiations are ongoing they have not yet been finalized. Accordingly, the Payroll & Benefits expense included in the 2008 audited financial statements does not include an adjustment in relation to the salary increase that the unions are seeking for 2008. The four unions have submitted claims for their 2008 salary adjustment, which would result in an overall increase in the Payroll & Benefits expense of between 30% and 40%, if their claims were agreed to by the Company. A similar salary adjustment will also be required for 2009 (effective January 1, 2009). It is important to note that the 2007 salaries were not finalized until May 2008, consequent on the implementation of the IDT award and retroactive salaries for the period 2001 – 2007 were paid to employees between May and July 2008.

Since the 2008 and 2009 salary increases are outstanding, it is appropriate that an adjustment be made to the test year. The Company believes that the inflation rate for 2008 plus half the projected inflation rate for 2009[10] is the appropriate adjustment. For the non-unionized employees, who have already received their 2008 salary adjustment, one needs only include an adjustment for half the CPI in 2009. Both of these adjustments are shown in the **Table 5.1** below.

Table 5.1: Analysis of Employee Costs

{Amounts in J$'000s}	2008	CPI – 2008 (16.87%)	½ CPI - 2009	2008 (Adjusted)
Unionized employee costs	4,740,847	799,781	332,438	5,873,066
Non-unionized employee costs	566,800	-	34,008	600,808
TOTAL	5,307,647	799,781	366,446	6,473,874

It is important to note that if the actual salary adjustments turn out to be higher than expected that the Company would deem this to be outside of managerial control and would expect to include same in a Z-factor adjustment. Similarly, if the salary adjustments turn out to be lower than anticipated, the Company would refund same through the annual Z-factor adjustment. This is, in JPS' view, the most reasonable approach to take, given that, these costs are significant and there will not be an opportunity to capture these costs until the next rate review in five years. Any other approach requires the Company to bear the risk on the tariff adjustment for the next five years without any recourse to adjust prices to account for that cost. JPS' proposal is consistent with its commitment to negotiate fair settlements with the Unions while minimising the costs to customers. The Company has held to this principle, cognisant of the fact that a delay would put the settlement outside the test year. The alternative would be to prioritise reaching a settlement within the test year at the risk of a far more costly resolution.

[10] The assumed inflation rate for 2009 is 12%, so the adjustment for the ½ year is 6%.

5.2.2 Insurance

This represents the adjustment to the insurance expense for 2008 as a result of the imminent increase in the 2009 insurance premiums. A significant portion of insurance coverage is secured overseas and that insurance policy is renewed on May 31each year. JPS' insurance broker has given formal notice that the insurance premiums will be increased at the next renewal as a result of the current global economic crisis. The Company's broker typically obtains quotes from numerous insurance service providers around the world to ensure that our insurance premium is competitively priced. Premiums are trending upwards mainly as a result of the financial crisis, the economic recession and the fall in interest rates overseas. The financial crisis has resulted in large credit insurance claims on reinsurers, while the recession has negatively impacted the amount of business that insurance companies are underwriting, and the fall in interest rates has negatively impacted the quality of their earnings, since most insurance companies invest the premiums received and rely heavily on the earnings (interest income) from those investments. These factors combined have contributed to the near bankruptcy of one of the largest reinsurance companies in the world (e.g. American Insurance Group or AIG), which will also negatively impact the insurance industry.

Table 5.2 below provides an analysis of our test year insurance expense and provides the basis for the known and measurable adjustment.

Table 5.2: Analysis of Test Year Insurance Expense

	Expiry date	2008 Actual US$ Premium	2008 Actual J$ Premium	J$ Equivalent Exps in 2008
		('000s)	('000s)	('000s)
Property damage (all risk)	31-May-09	5,305	-	429,412
Public/Employer's liability	30-Apr-09	612	-	44,124
Excess liability	31-Jul-09	297	-	21,495
Motor contingent liability	30-Jun-09	-	55,280	31,903
Group Life & Personal accident	31-Jan-09	-	15,413	14,072
Other miscellaneous		-	6,601	6,601
TOTAL		6,214	77,294	547,607

It must be noted that 90% of the insurance cost is actually incurred in US$. It is also important to note that the Company achieved a 10% reduction on average on its 2008 premiums relative to 2007, which were renewed in the main just before the hurricane season.

For the purpose of calculating the applicable insurance expense, the Company will use the actual 2008 premiums, adjusted for any known and measurable changes. As it relates to the US$ premiums, the first adjustment will be to restate the premiums to the new base foreign exchange rate of $85. The second adjustment will be to incorporate any impending increases in the actual premiums, for instance, the increase expected for the property damage premium. As it relates to the local insurance premiums, an increase is expected for the Group Life & Personal Accident premiums, which are reset quarterly based on employee salaries. Since employee costs will be increasing effectively by 23.8% ((1.168) (1.06)-1) then the premium will also need to be adjusted by 23.8%.

The appropriate adjustments to the insurance expense for inclusion in the revenue requirement are shown in the **Table 5.3**.

Table 5.3: Insurance Expense Adjustments

	2008 Actual US$ Premium	2009 US$ Increase	2008 Actual J$ Premium	2008 J$ Increase	J$ Equivalent at base FX rate
	('000s)	('000s)	('000s)	('000s)	('000s)
Property damage (all risk)	5,305	1,061	-	-	541,110
Public/Employer's liability	612	-	-	-	52,020
Excess liability	297	-	-	-	25,245
Motor contingent liability	-	-	55,280	-	55,280
Group Life & Personal accident	-	-	15,413	3,668	19,081
Other miscellaneous	-	-	6,601	-	6,601
TOTAL	6,214	1,061	77,294	3,668	699,337

The increase to the property damage premium of 20% is consistent with the renewal advice received from the insurance broker. The Company also further advised that premiums were increasing globally by region as follows:

- U.K./Europe - 10 – 25%
- Caribbean - 15 – 30%
- U.S. Market - 15 – 50%

5.2.3 Additional Borrowing Requirement

The fall-out of the U.S. capital markets and the subsequent ripple effect throughout the financial sector worldwide made it impossible for JPS to raise its desired level of capital funding in 2008. This resulted in a greater level of shareholder reinvestment in the business, in a sub-optimal level of cash resources at year-end, an increased reliance on accounts payable and a sub-optimal debt to equity ratio. It is for this reason, that JPS had approximately US$53 million in short-term debt at December 31, 2008, which is significantly higher than the US$20 million level maintained in 2006 – 2007. It is important to note that JPS invested $4.4 billion (or US$60M) in capital expenditure in 2008, of which US$30 million should have been funded through debt. Additionally, JPS had a one-off expense of $3.5 billion (or approximately US$47M) for retroactive wages (and the related taxes), which also should have been financed through additional debt.

JPS sought to raise US$100 million in long-term debt in 2008, including the refinancing of $30 million of short-term debt. However, the Company only obtained US$40 million in the last quarter of the year, with approximately US$7 million being for a tenure of one-year. As a result, JPS is actively seeking to obtain US$60 million in additional borrowings in relation to its 2008 activities and the need to refinance US$37 million of short-term debt. **Table 5.4** shows the impact of the additional borrowing on the balance sheet, with the intended use of funds analysis. It is important to note that this additional borrowing will also help to favourably adjust the debt to equity ratio from a revenue requirement perspective. The column to the far right of the table shows the use of funds in US$. In the column marked ‘Reclassification’ The current maturity of long-term debt is reclassified to long-term or short-term debt respectively.

Table 5.4: Adjusted Balance Sheet after Additional Borrowing

J$ Million	2008	Reclassification	Additional Borrowing	2008 (Adjusted)	Additional Borrowing (US$'000s)
Cash	1,165		402	1,567	5,000
Receivables	14,151			14,151	
Inventories	3,039			3,039	
Other	195			195	
Current Assets	18,550		402	18,952	5,000
Accounts Payable	6,303		(644)	5,659	(8,000)
Short-term loans	4,285	522	(2,978)	1,829	(37,000)
Current maturity	1,026	(1,026)		-	
Other liabilities	7			7	
Current Liabilities	11,621	504	(3,622)	7,495	(45,000)
Net Current Assets	6,929	504	4,024	11,457	
Property plant & equipment	54,091			54,091	
Other non-current assets	2,104			2,104	
Total Net Assets	63,124	504	4,024	67,652	50,000
Shareholder's equity	32,413		(805)	31,608	(10,000)
Long-term Loans	19,790	504	4,829	25,123	60,000
Other Long-term Liabilities	10,921			10,921	
Total Shareholder's equity	63,124	504	4,024	67,652	50,000
Year end FX Rate	80.4713			80.4713	
Debt to equity ratio	39:61			44:56	

From **Table 5.4** above one can now fully contemplate the impact on the revenue requirement, which includes the fact that the new debt will likely be raised at the rate of 13% for a five-year tenure and the short-term debt being replaced currently has an interest rate of approximately 9.44%[11]. While the Company endeavours to raise debt at longer tenures, those efforts are currently constrained and frustrated by the lack of available credit in global markets as a result of the financial sector crisis. Additionally, a further interest-rate premium would be required to raise debt for tenure longer than five (5) years. This is in recognition of the fact that U.S. interest rates are forecasted to trend upwards over the next two (2) to three (3) years, given the unusually low levels of U.S. treasury rates now. This situation places a significant amount of refinancing risk on the Company, since recovery of the cost of capital expenditure through the depreciation charge is typically over a twenty-five year period. Lastly, the loans are restated to reflect the fact that the base foreign exchange rate will be $85:1. This will be done under **Section 5.2.7** – Adjustment for Foreign Exchange Movement and for Local Inflation.

Finally, it should be noted that the adjusted debt to equity ratio of 44:56 excludes the short-term debt. The ratio would be 46:54 if those loans were included, which is probably the more realistic way to look at JPS' gearing since most loan covenants currently include short-term debt as a part of the debt covenant calculations.

[11] It is typical that long-term debt attracts a higher interest rate than short-term debt; just as a long-term investment (e.g. a 1 year Treasury Bill) yields a higher return than short-term investment (e.g. a 30 day Treasury Bills). However, in the case of a utility (or any business for that matter), it is a fundamental principal that long-term assets should be backed by long-term liabilities to ensure the viability of the business.

5.2.4 Interest on Short-term Loans and Customer Deposits

This represents the adjustment to the test year interest expense to reflect the refinancing of short-term loans and the proposed changes to the interest rate for interest on customer deposits. The amounts included in the test year expense are shown in the **Table 5.5**.

Table 5.5: Analysis of Loan Finance Costs

{Amounts in J$'000s}	2008
Interest on long-term loans	1,872,641
Interest on short-term loans	364,734
Loan finance fees	122,220
Interest on customer deposits	133,261
Interest - other	20,808
	2,513,664

The amount for interest on short-term loans should be adjusted downwards to reflect the imminent refinancing of short-term loans at the new base foreign exchange rate. JPS had US$53 million in short-term loans at year-end but will seek to reduce this to US$22.7 million after the loan refinancing is complete. As a result, the appropriate amount of short-term interest in the revenue requirement should be US$22.7 million at 9.44% or US$2.15 million. This translates into J$182.38 million at the base foreign exchange rate of $85:1, as shown in the **Table 5.6**

Table 5.6: Adjusted Interest on Short-Term Loans

	Loan Balance			Interest Expense	
	US$'000s	FX rate	J$'000s	Rate	J$'000s
Short-term loans	22,729	85.00	1,931,965	9.44%	182,377

The second adjustment relates to interest on customer deposits. The interest rate applied in 2008 was 8.88%, being the average Treasury Bill rate for the previous year less a 3.6% administration fee. Using this same methodology the applicable interest rate for customer deposits for 2009 will be 11.93%. This would form the basis for an adjustment to the test year expense as shown in the **Table 5.7**.

Table 5.7: Interest Adjustment Based on Treasury Bill Rates

J$'000s	2008 (Actual)	Actual Interest rate	Revised Interest rate	2008 (Restated)
Customer Deposits	133,261	8.88%	11.93%	179,032

However, JPS wishes to propose a different basis for determining the interest rate to be paid on customer deposits. There are three main considerations for this recommendation:

(i) the use of the average savings rate for commercial banks would be more reflective of the economic benefit to the Company and the opportunity cost of capital to the customer;

(ii) the use of the Treasury Bill rate is excessive, subject to significant variation and does not reflect the economic reality of the transaction; and

(iii) no other utility in Jamaica currently pays interest on customer deposits

It should be noted, that, JPS is not investing the customer deposits in Treasury Bills, but is use this amount as working capital support. This working capital requirement originates from the fact that the Company averages 45 days on collections but has to pay its main suppliers (primarily IPPs and Fuel) in 30 days. Therefore, any cash on hand is typically being held for very short periods, typically benefiting from overnight call interest rates. Furthermore, any interest earned from such investments is treated as a credit to the revenue requirement (i.e. they are effectively refunded to the customer). Finally, if JPS did not require a customer deposit, it would simply require additional debt funding to fill the working capital need and the cost of this debt would be included in the revenue requirement as a reasonable and prudently incurred cost.

In summary, if any interest is to be paid on customer deposits, it should be based on the BOJ average domestic savings rate. If agreed, this would form the basis for an adjustment to the test year expense as shown in the **Table 5.8** below

Table 5.8: Interest Adjustment Based on Domestic Savings Rates

J$'000s	2008 (Actual)	Actual Interest rate	Revised Interest rate	2008 (Restated)
Customer Deposits	133,261	8.88%	5.16%	77,435

5.2.5 Bad Debt Expense

This represents the adjustment to the bad debt expense included in the 2008 financial statement to reflect the actual collections to billing ratio. The accounting basis for the doubtful debt provision is more conservative and does not permit the use of general provisions. However, an analysis of the actual collections compared to billings over the last five years, shows that JPS collects 97.9% of its billing on average. This average has improved slightly (see **Table 5.9** below), with the average collections for the last two years being 98.0%. This implies a bad debt expense ratio of 2% of billings.

Table 5.9: Billings to Collections Ratio

{J$ Millions}	**2004**	**2005**	**2006**	**2007**	**2008**	**TOTAL**
Billings	30,435	38,676	47,436	52,169	71,318	240,034
Collections	29,274	37,851	46,638	50,220	70,965	234,948
Collections ratio	96.2%	97.9%	98.3%	96.3%	99.5%[12]	97.9%

This can be compared to the doubtful debt provision made in the financial statements, as shown in the **Table 5.10** below, which reflects a bad debt expense ratio of 0.8%. This position is far more conservative based on the accounting and tax rules.

Table 5.10: Bad Debt to Sales Ratio

{J$ Millions}	**2004**	**2005**	**2006**	**2007**	**2008**	**TOTAL**
Bad Debt Provision	134	211	329	630	547	1,851
Revenues	30,399	40,253	48,145	54,195	71,419	244,411
Bad Debt % of sales	0.4%	0.5%	0.7%	1.2%	0.8%	0.8%

[12] Please note that "Collections" includes arrears and recovery of theft. The amount in 2008 includes an unusually high amount ob back billing in relation to theft recovery as reflected in Table 2.13. Results from Losses Reduction Programmes

However, the economic reality is that amounts billed and not collected will have a negative impact on the Company's cash flows. Accordingly, the revenue requirement should be adjusted to reflect the true economic recovery of billings, and that adjustment is made below to gross up the bad debt expense from 1.1%, as shown in the financial statements, to 2% of revenues, based on the average collection to billing ratio. It should also be noted that the OUR itself allows for a 97.5% collection ratio in relation to the administration of the Electricity Disaster Fund (or self-insurance fund), that is, it is assumed that only 97% of billings are actually collected and this represents the amount of cash that is actually set aside in the self-insurance fund each month. JPS recommends that that factor be increased from 97.5% to 98% as well, to reflect the average collection ratio for the past five years

Table 5.11: Adjustment to Bad Debt Expense

J$'000s	2008	Adjustment (from 1.1% to 2%)	2008 (Adjusted)
Bad debt expense	769,245	659,124	1,428,369

5.2.6 Other Income/ (Expense)

This represents the adjustment to exclude one-off items included in Other Income/ (Expense) that should be excluded from the revenue requirement. **Table 5.12** below provides the analysis of the amounts included in the test year financial statements.

Table 5.12: Analysis of Other income/ (Expense)

J$'000s	2008 (Actual)	Adjustments	2008 (Adjusted)
Post retirement benefit obligation (PRBO) - write-back	737,700	(737,700)	-
Rental Income	45,379	-	45,379
Cable & Pole attachment fees	59,465	-	59,465
Credit balances - written-back	31,784	(31,784)	-
Insurance Proceeds & other miscellaneous	38,514	(38,514)	-
	912,842	**(807,998)**	**104,844**
IDT Job Reclassification	(1,103,501)	1,103,501	-
Tropical storm restoration costs	(135,458)	135,458	-
	(1,238,959)	**1,238,959**	**-**

Table 5.12 details all Other Expenses that were one-off[13] and should be excluded from the revenue requirement. There are two items in Other Income that are normal recurring activities that should be treated as a credit to the revenue requirement. These are rental income and cable & pole attachment fees, which both represent incidental earnings from assets included in the rate base. The post retirement benefit obligation (PRBO) that was previously included in the balance sheet but excluded from the rate base was written-off during the year, as this obligation no longer exists. There is a similar adjustment for some miscellaneous accounts payable balances. Finally, the insurance proceeds relates to damages incurred in a prior period.

[13] These one-off expenses are the subject of a 2008 and 2009 Z-factor adjustment claim.

5.2.7 Thirty One(31) Day Billing Directive:

The OUR has directed JPS to ensure that customers are billed for not more than 31 days of service (DOS) in each bill, effective January 2009. In order to meet this directive, meter reading must take place regularly on weekends. In 2009, the meter reading schedule that is necessary to meet this directive requires meter readings on 43 Saturdays and 10 Sundays in the year. The Company anticipates a similar pattern going forward each year. The overtime cost associated with this effort, based on current salaries, is estimated to be $50.86 million annually (see **Table 5.13**).

Table 5.13: Estimated Increase in Meter Reading Costs

	Contract	Permanent	TOTAL
Number of meter readers	101	22	123
Approximate daily cost (J$)	4,500	6,700	
Saturday over-time multiple	1.5	1.5	
Sunday over-time multiple	2.0	2.0	
No. of Saturdays required for meter reading	43	43	
No. of Sundays required for meter reading	10	10	
Estimated overtime cost at 2008 Costs (J$)	38,405,250	12,455,300	50,860,550
Adjustment for 2008 Salary increase	N/A	1.168	
Adjustment for 2009 CPI/Salary increase	1.06	1.06	
Estimated overtime cost at 2009 Costs (J$)	40,709,565	15,420,658	56,130,223

The cost estimates are done based on overtime costs instead of simply rostering our meter readers on shift for the following reasons:

- To meet the Directive, meter reading must take place almost continuously for the first 3 weeks of the month. Under shift work arrangements, employees are required to work 40 hours in every seven-day week. Meter reading schedules that require 6 – 7 days of reading within each week must either incur overtime costs or the costs of hiring part-time workers to cover 1-2 days a week.
- The latter option of hiring part-time workers is not practical. It takes a fairly long period to gain the experience to locate on a route. Part-time meter readers who are required to work only 4–5 days each month and who cannot be guaranteed the assignment of the same route each time will have difficulty acquiring the knowledge quickly enough to be effective.
- Reliance on overtime costs appears to be the most practical solution.

5.2.8 Depreciation

This represents the adjustment to the test year depreciation expense in relation to plant in service at the end of the test period and JPS' request to modify depreciation rates for certain asset categories.

In the first instance, because JPS had capital expenditure during the year amounting to $4.4 billion and, due to the nature and timing of capitalization, a full year's depreciation would not be reflected on such assets. So the appropriate amount of depreciation for the test year is the depreciation charge for the last month of the year multiplied by twelve. Since fixed assets were substantially revalued at the year-end foreign exchange rate ($80.47) this depreciation charge should also be revalued to the new proposed base foreign exchange rate of $85. These two adjustments are shown in the **Table 5.14**.

Table 5.14: Full Year Depreciation on Plant in Service as at December 31, 2008

J$'000s	Dec'08 (1 month)	Annualized Amount	Year-end FX Rate	Base FX Rate	Adjusted Amount
Depreciation	339,779	4,077,344	80.47	85.00	4,306,875

The second adjustment relates to a request by JPS to adjust the asset lives included in the Licence. JPS commissioned a depreciation study to compare the asset lives that it has compared to that used in other regulated territories. The complete details of that study are included in **Annex H**.

The study confirms that the asset lives used by JPS in several instances were too long. Accordingly, JPS requests an adjustment specifically for assets that currently have a useful life that is 10 years (or more) over the sample mode of the Companies in the study. A summary of the asset categories, the current useful lives in years, the mode of the sample and the excess is highlighted below.

Table 5.15: Asset Lives Comparison

Activity	Asset Category	JPS	Sample Mode	Difference
Generation	Hydro Production Plant	30	20	10
Distribution	Test Equipment	25	15	10
Distribution	Supervisory Control System	25	15	10
General Plant	Electronic Equipment	25	5	20
General Plant	Communication Equipment	15	5	10
General Plant	Computer Equipment	20	5	15
General Plant	Furniture & Office Equipment	20	10	10

Please note the following in relation to the relevance of the useful lives:

(i) Return of capital and financing of assets – depreciation represents the return of capital and establishes the period over which the utility may recoup the cost of its investment. Since financing is a very important aspect of all utility investments (where the utility seeks to leverage its investment as much as is prudently acceptable) the utility should try to finance its long-term assets with long-term loans (and over similar periods). If the useful lives are too long, then this will be unattractive to investors. Additionally, if the utility cannot finance its loans over similar (long) tenures then it faces financing risk since the depreciation charge provides the returns to pay back the debt.

(ii) Regulatory asset base – the depreciation rate determines the net book value of assets included in the regulatory rate base. If the useful lives are too long then it results in an overstatement of the value of the assets included in the rate base.

(iii) Depreciation as a proxy to Capital Expenditure (CAPEX) – in the current price cap regime, depreciation also acts as a proxy to the allowed level of capital expenditure during the rate reset periods. That is, the utility foregoes the repayment of debt in favour of capital expenditure (CAPEX). Again, if the useful lives are too long, it results in an inadequate level of depreciation and does not provide an adequate basis for CAPEX for the utility during the reset periods.

For the reasons noted above, JPS requests that the useful lives of the above assets be adjusted to reflect their true economic value and to be in keeping with best industry practices as stated in the Depreciation Study.. For all of the items listed above it would be impossible for the business to obtain project financing for the tenures suggested by the current economic useful lives. These useful lives are therefore inappropriate for investment purposes.

If the useful lives were adjusted prospectively, then the adjustment to the test year depreciation would be as shown below.

Table 5.16: Additional Depreciation due to Asset Life Adjustment

Asset Category	Current Asset Life	Requested Asset Life	Book Value @ $80.47	Book Value @ $85	Additional Dep'n Charge
			J$'000s	J$'000s	J$'000s
Hydro Production Plant	35	20	3,370,467	3,560,205	76,290
Test Equipment	25	15	423,236	447,062	11,922
Communication Equipment	15	10	2,290,125	2,419,046	80,635
Computer Equipment	20	5	1,321,001	1,395,366	209,305
Furniture & Office Equipment	20	10	223,663	236,254	11,813
			7,628,492	8,057,933	389,965

This adjustment would increase the test year depreciation charge from $4,306,875 shown in **Table 5.14** to $4,696,840.

5.2.9 Adjustment for FX Movement and Local Inflation

The foreign exchange adjustment represents the adjustment to the non-fuel costs included in the revenue requirement that are denominated in US$. This excludes interest expenses, which will be adjusted for separately. The average exchange rate for 2008 was $73.36:1, while it is proposed that the base foreign exchange rate for 2009 be reset to $85.0:1. This will necessitate the restatement of all US$ non-fuel costs in J$ terms to the base foreign exchange rate, since the 2008 US$ costs would effectively be stated in the financial statements at the average exchange rate.

The inflationary adjustment represents the adjustment to the non-fuel costs included in the revenue requirement that are denominated in J$, which need to be adjusted to reflect the impact of inflation for January – June 2009. The inflationary adjustment shown in **Table 5.17** excludes payroll and related expenses, insurance expenses, interest on customer deposits and bad debt expense, which were all addressed separately. This adjustment is necessary, given the significant impact of inflation on costs in 2008, where inflation for the calendar year was 16.87%. The inflation adjustment for half of 2009 is 6%, which will be incorporated into the revenue requirement for applicable J$ denominated costs

Table 5.17: US$ vs. J$ Cost Components

{Amounts in J$'000s}	Actual Costs[14]	Cost component US$ Costs	J$ Costs	% of cost US$	J$
Purchased power (excluding fuel)	4,886,630	4,886,630	-	100%	0%
Operating expenses:					
Payroll, benefits & training	5,307,647	-	5,307,647	0%	100%
Third party services	1,670,736	584,758	1,085,978	35%	65%
Materials & equipment	832,754	832,754	-	100%	0%
Office & Other expenses	1,032,591	826,073	206,518	80%	20%
Transportation expenses	746,485	662,485	84,000	89%	11%
Insurance expense	547,607	518,878	28,729	95%	5%
Bad debt write-off	769,245	-	769,245	0%	100%
	10,907,065	3,424,948	7,482,117	31%	69%
Depreciation and amortization	3,618,059	3,618,059	-	100%	0%

Using the cost components shown in the **Table 5.17** and the known adjustment factors for (i) US$ costs – to adjust them to the base foreign exchange rate of $85:1; and (ii) J$ costs – to reflect half of the 2009 CPI, one can derive the necessary adjustments for the two cost components in the **Table 5.18** below.

Table 5.18: Adjustment for US$ and J$ Cost Components

{All amounts in J$'000s}	1/2 CPI or FX Adjustment US$	J$
Purchased power (excluding fuel)	775,360	-
Operating expenses:		
Payroll, benefits & training	-	N/A
Third party services	92,783	65,159
Materials & equipment	132,133	-
Office & Other expenses	131,073	12,391
Transportation expenses	105,116	5,040
Insurance expense	N/A	N/A
Bad debt write-off	-	N/A
	461,105	82,590
Depreciation and amortisation	N/A	-

No adjustment is made above for FX or CPI to the categories marked “N/A” as an appropriate adjustment has already been made in a previous section.

A similar adjustment is required to the US$ denominated costs in the rate base, to restate them from the year end exchange rate of $80.47 to the base rate of $85:1, as shown in the **Table 5.19.**

[14] All actual costs are extracted from the audited financial statements for 2008.

Table 5.19: Balance Sheet Adjustments

{Amounts in J$ Millions}	2008 (Adjusted)	US$ Component %	Adjustment on US$ Cost Component	2008 (Final)
Cash	1,567	85%	75	1,642
Receivables	13,929	0%	-	13,929
Inventories	3,039	100%	171	3,210
Other	195	0%	-	195
Current Assets	18,730		246	18,976
Accounts Payable	5,659	76%	242	5,901
Short-term loans	1,829	100%	103	1,932
Other liabilities	7	0%	-	7
Current Liabilities	7,495		345	7,840
Net Current Assets	11,235		(99)	11,136
Property plant & equipment	54,091	100%	3,044	57,135
Other non-current assets	2,104		-	2,104
Total Net Assets	67,430		2,945	70,375
Shareholder's equity	31,386		1,531	32,917
Long-term Loans	25,123	100%	1,414	26,537
Other Long-term Liabilities	10,921	0%	-	10,921
Total Shareholder's equity	67,430		2,945	70,375
Year end FX Rate	80.4713			85.00
Debt to equity ratio	45:55			45:55

5.3 Revenue Requirement Calculation

A summary reconciliation of the amounts included in the test year expense and the adjustments made to derive the amounts included in the revenue requirement is shown in **Table 5.20** below.

Table 5.20: Reconciliation of Test Year Expenses

{All amounts in J$'000s}	Ref-erence	Actual Costs	Exclusions	Rate Increase	FX	CPI	Interest rates	Bad debt	Cost of Capital	Adjusted Costs
Purchased power	5.2.9	4,886,630			775,360					5,661,990
Operating expenses:										
Payroll, benefits & training	5.2.1	5,307,647		799,781		366,446				6,473,874
Payroll, benefits & training	5.2.7	-		56,130						56,130
Third party services	5.2.9	1,670,736			92,783	65,159				1,828,678
Materials & equipment	5.2.9	832,754			132,133					964,887
Office & Other expenses	5.2.9	1,032,591			131,073	12,391				1,176,055
Transportation expenses	5.2.9	746,485			105,116	5,040				856,641
Insurance expense	5.2.2	547,607		151,730						699,337
Bad debt write-off	5.2.5	769,245						659,124		1,428,369
		10,907,065	-	1,007,641	461,105	449,036	-	659,124	-	13,483,971
Depreciation & amortization	5.2.8	3,618,059	-	389,965	688,816	-	-	-	-	4,696,840
Net finance costs:										
Foreign exchange losses		2,905,439	(2,905,439)							0
Interest - long-term loans		1,872,641							1,171,153	3,043,794
Interest - short-term loans	5.2.4	364,734					(182,357)			182,377
Loan finance fees		122,220	(122,220)							0
Interest-customer deposits	5.2.4	133,261					(55,826)			77,435
Interest - other		20,808								20,808
Finance income		(298,337)								(298,337)
		5,120,766	(3,027,659)	-	-	-	(238,183)	-	1,171,153	3,026,077
Other income	5.2.6	(912,842)	807,998							(104,844)
Other expenses	5.2.6	1,238,959	(1,238,959)							-
		326,117	(430,961)	-	-	-	-	-	-	(104,844)
TOTAL NON-FUEL EXPENSES		24,858,637	(3,458,620)	1,397,606	1,925,281	449,036	(238,183)	659,124	1,171,153	26,764,034

A reference is included in the table above to the section that explains the adjustments in greater detail.

Please note that the foreign exchange losses and loan finance fees have both been excluded as these amounts are contemplated under the cost of capital adjustment.

The revenue requirement can now be derived from the **Table 5.20**, which is based on the test year expenses, the known and measurable changes presented in **Section 5.2** and the cost of capital developed in **Section 4.** This is shown in the **Table 5.21** below.

Table 5.21: 2009 Non-Fuel Revenue Requirement

	J$'000
PPA Costs	5,661,990
Operating Expenses	13,483,971
Depreciation	4,696,840
Total Operational Expenses	**23,842,801**
Net finance costs (excl. long-term debt):	
Interest on short-term loans	182,377
Interest on customer deposits	77,435
Interest – other	20,808
Finance income	(298,337)
	(17,717)
Other income	**(104,844)**
Self-insurance fund contribution	425,000
Gross up for taxes on SIF	212,500
	637,500
Cost of Long-term Debt	**3,043,794**
Cost of Equity	**7,119,947**
Taxation	**3,559,974**
Revenue Requirement, net of credits	**38,081,455**
Less Carib Cement Revenue	(310,521)
Adjusted Revenue Requirement	**37,770,934**

In accordance with the Licence, the revenue requirement shown above represents the last twelve months of operations, adjusted to reflect normal operational conditions. These adjustments are summarized in **Table 5.16** and are considered absolutely necessary to reflect what normal operational conditions will be at the time the new rates are put into effect. This is due principally to macroeconomic conditions that are outside of the control of management. The same fundamental drivers (foreign exchange movement and inflation) are incorporated in the annual PBRM adjustment formula. In fact, JPS has been very conservative in its estimation of these primary drivers, as the foreign exchange rate has already surpassed the proposed new base foreign exchange rate of $85 and the inflation trend in the last two years is far higher than the assumed inflation for the first six months of 2009.

Additionally, note that the self-insurance fund contributions have been grossed up for taxes as explained in **Section 2.4.3**. Should the OUR opt not to gross-up for taxes then JPS should be directed that the actual monthly contribution to be remitted to the SIF should be made net of taxes.

Finally, the total revenue requirement amount shown in **Table 5.21** above does not include the expected Z-factor adjustment in relation to the IDT settlement. These costs currently amount to $3.5 billion, as explained in **Section 2.5.3**. However, there remains residual exposure from this issue as the unions still contend that additional payments are still outstanding. JPS anticipates that these costs will be included in the tariffs through a Z-factor adjustment.

Additionally, please note that the self-insurance fund contributions have been grossed up for taxes as explained in **Section 2.4.3**. Should the OUR opt not to allow the gross-up for taxes then JPS should be directed that the actual monthly contribution to be remitted to the SIF should be made net of taxes.

Finally, the total revenue requirement amount shown in **Table 5.21** above does not include the expected Z-factor adjustment in relation to the IDT settlement. These costs currently amount to $3.5 billion, as explained in **Section 2.5.3**. However, there remains residual exposure from this issue as the unions still contend that additional payments are still outstanding. JPS anticipates that these costs will be included in the tariffs through a Z-factor adjustment.

5.4 Calculation of the Foreign Exchange Adjustment Factor

The data in the **Table 5.22** below, which is taken from the revenue requirement shown in **Table 5.20**, indicates that the foreign exchange adjustment factor should be increased from 76% to 79%. That is to say, 79% of all non-fuel costs included in the revenue requirement are denominated in US$. When the impact of the 2008 fuel expenses is included, you will observe that 91% of all of the Company's costs are incurred in US$.

Table 5.22: 2009 Non-Fuel Revenue Requirement

	Actual Costs		US$ component of Actual Costs	
		% of Total	(J$ Equivalent)	
	J$'000	Expense	%	J$'000
Purchased Power (non-fuel)	**5,661,990**	**6%**	**100%**	**5,661,990**
O&M Expenses	**13,483,971**	**15%**	**29%**	**3,972,549**
Payroll, benefits & training	6,530,004	7%	0%	-
Third party services	1,828,678	2%	35%	640,037
Materials & equipment	964,887	1%	100%	964,887
Office & Other expenses	1,176,055	1%	80%	940,844
Transportation expenses	856,641	1%	89%	762,410
Insurance expense	699,337	1%	95%	664,370
Bad debt write -off	1,428,369	2%	88%[15]	1,256,965
Depreciation	**4,696,840**	5%	**100%**	**4,696,840**
Net Finance Costs	**3,026,077**	**3%**	**100%**	**3,023,907**
Finance Income	(298,337)	0%	75%	(223,072)[16]
Interest on customer Deposits	77,435	0%	0%	-
Interest on Short-term debt	182,377	0%	100%	182,377
Interest on Long-term debt	3,043,794	3%	100%	3,043,794
Other Net Financing costs	20,808	0%	100%	20,808
Rental Income	**(104,844)**	0%	**0%**	-
Sinking fund contribution	**637,500**	**1%**	**100%**	**637,500**
Return On Rate Base	**10,679,921**	**12%**	**100%**	**10,679,921**
Return on Equity	7,119,947	8%	100%	7,119,947
Taxation	3,559,974	4%	100%	3,559,974
Total Non-Fuel Expenses	**38,081,455**	**43%**	**79%**	**29,929,671**
Total Fuel Expenses	**47,510,274**	**53%**	**100%**	**47,510,274**
Total Expenses	**89,151,702**	**100%**	**91%**	**80,999,919**

[15] Bad debt expenses relate to sales, whereby the ratio of fuel to non-fuel revenues at today's fuel prices is 50:50. Given that fuel costs are 100% denominated in US$ and non-fuel costs were previously designated as being 76% US$ denominated, the weighted average US$ component is 0.5 X 100% + 0.5 X 76% = 88%.

[16] Finance income includes interest income (primarily interest earned on overnight call deposits which is used as an off-set to interest paid on customer deposits) and AFUDC. The latter is treated as 100% US$ denominated since it represents the capitalization of interest on long-term debt.

Therefore, the Company requests that the FX adjustment factor be reset to 79% (up from 76%) for the purposes of the monthly billing adjustments.

6 Performance Based Rate-Making Mechanism

6.1 X-Factor

6.1.1 Introduction

The non-fuel rates of Jamaica Public Service (JPS) will be subject to a performance based ratemaking mechanism (PBRM). The main features of this PBRM are detailed in the Schedule 3., Exhibit 1 of the Licence. According to Licence, the PBRM will restrict the growth in JPS' non-fuel base rates according to the following formula:

$$dPCI = dI \pm X \pm Q \pm Z \qquad [1]$$

Here, dPCI refers to the maximum allowed change in non-fuel electricity prices, dI is the annual growth in an inflation and exchange rate devaluation measure, 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 reflect changes in the quality of service provided to customers, and Z is the allowed rate of price adjustment for special cost pressures not captured by other elements of the formula.

The Licence further describes how the ***X***-factor is to be calculated. It says

> ***"the X-Factor is based on the expected productivity gains of the Licensed Business (i.e. JPS). The X-Factor is to be set to equal the difference in the expected total factor productivity growth of the Licensed Business and the general total factor productivity growth of firms whose price index of outputs reflects the price escalation measure dI."***

The current dI measure applies a 24% weight to a Jamaican inflation index and a 76% weight to US inflation and corresponding changes in the US-Jamaica exchange rate. Appropriate measures of total factor productivity (TFP) growth for JPS, the Jamaican economy and the US economy are therefore critical for calibrating the terms of the PBRM. Indeed, the Licence mandates that a filing supporting the application of the PBRM must include "a total factor productivity study used in determining the appropriate level of the ***X***- factor" (Schedule 3, Par. 3 (B)).

JPS retained PEG to provide such a TFP study and to make recommendations on appropriate X and for JPS. PEG is the leading US consultant on performance-based regulation (PBR) for energy utilities and provider of energy industry productivity studies. Their personnel have testified many times on productivity and related benchmarking issues in North America. They also prepared a TFP and benchmarking study for JPS in conjunction with the initial PBRM approved for the Company in 2004. The results of their research for JPS are briefly summarized in this section. Their full report is included in **Annex I** of this submission.

6.1.2 TFP for JPS

A total factor productivity ("TFP") index is the ratio of an output quantity index to an input quantity index. It is used to measure the efficiency with which firms convert production inputs to outputs. The growth trend of a TFP trend index is the difference between the trends in output and input quantity indexes.

PEG calculated the TFP trend of JPS in the provision of power generation, transmission, distribution and retailing services. The output quantity index they developed for JPS included trends in the number of customers served, MWh volumes delivered, and MW of peak demand. They constructed an input quantity index which summarized trends in capital and operation and maintenance (O&M) inputs JPS used to provide these outputs. All fuel and purchased power costs were excluded from costs and inputs since the PBRM applies only to non-fuel base rates, so only non-fuel inputs should be included in TFP studies used to set the terms of the PBRM.

Established methods and the best available data were used to estimate TFP trends for JPS. The sample period was 1990-2007. This represents the longest period for which the consultant could estimate the Company's TFP, given the available data from JPS. PEG estimates that JPS' TFP in the provision of non-fuel, bundled power service grew at an average rate of 0.74% per annum over the 1990-2007 period. However, TFP grew at a more rapid rate of 1.94% over the more recent 2001-2007 period, primarily because JPS has been more effective at restraining input quantity growth in recent years.

6.1.3 TFP for US and Jamaican Economies

The US government regularly measures TFP growth in the US economy. The most comprehensive of such measures is the multifactor productivity (MFP) index of the US private business economy, as computed by the Bureau of Labour Statistics (BLS) of the US Department of Labour. The BLS updates this MFP measure annually. From 1990 through 2007, US non-farm, private business sector MFP grew at an average annual rate of 1.04%. The comparable growth rate over the 2001-2007 period was 1.53%.

There are no comparable, official estimates of TFP growth for the Jamaican economy. PEG developed estimates of TFP growth in Jamaica until 2002 using a standard growth accounting framework and data developed both within and outside of the country. PEG's research shows that TFP growth in Jamaica has been extremely variable. This, in turn, reflects the sharp fluctuations in the Jamaican economy over the past four decades. For example, the country experienced steady economic and TFP growth in the 1960s and early 70s, but economic performance was severely impacted by the 1970s' oil price shocks. The economy generally recovered in the 1980s, except for a recession in 1984-85, but economic and TFP growth since 1990 have been weak. Recent reports by other analysts also indicate that Jamaica's recent TFP growth has been weak, but it was not possible for PEG to estimate TFP for the country after 2002 because of the lack of available data.

These economic gyrations complicate the estimation of Jamaica's long-term TFP trends and the country's expected productivity growth during the term of the PBRM (2004-2009). Given the country's recent poor performance for TFP growth, the consultants believe a reasonable estimate for Jamaica's TFP growth over the term of the PBRM is zero percent. This is actually greater than the TFP declines the country has recently experienced, but they do not believe it is reasonable to forecast that TFP will continue to decline indefinitely.

6.1.4 Benchmarking JPS' Non-Fuel Cost Performance

The PBRM should be calibrated on the basis of "expected" productivity growth, and future TFP growth may differ from past TFP trends. This would especially be expected if a utility has been relatively inefficient in the past. A Company would then have more ability to boost TFP growth by eliminating inefficient practices. PEG evaluated JPS' non-fuel cost efficiency using econometric cost modelling. This benchmarking approach compares JPS to *average* efficiency levels in the electric power industry.

Guided by economic theory, PEG developed an econometric model in which the cost of non-fuel, bundled power services is a function of some quantifiable business conditions. The parameters of the model were estimated statistically using data on the historical costs of 41 US investor-owned US electric utilities and the business conditions they faced. The sample period used to estimate the econometric cost model was 1991 to 2006. All key parameters were plausibly signed and, in most cases, highly significant.

PEG used the model to predict the average non-fuel cost of bundled power services for JPS given the business conditions that it faced. The Company was found to face some challenging conditions in its efforts to contain cost. For example, JPS is not a combined gas and electric utility. JPS has very low volumes per customer served. The Company also faces high prices for capital services.

PEG compared JPS' actual non-fuel costs with those predicted by the econometric model and found that JPS' non-fuel cost was about 28% below the value predicted by the econometric cost model over the 2003 to 2007 period. This compares with a non-fuel cost for JPS that was only .7% less than the value predicted for the 1999-2002 period. Both differences were not statistically significant; the reason is that JPS differs substantially from the average US electric utility, and these differences in business conditions tend to increase the confidence intervals around any cost prediction for the Company, thereby making it more difficult to obtain statistically significant results. Nevertheless, a comparison of JPS' benchmarking results for the 1999-2002 and 2003-2007 periods indicate that the Company has made substantial efficiency improvements in recent years. This benchmarking evidence is broadly consistent with the substantial TFP gains for the Company since 2003. The large efficiency gains that JPS has already made suggest that there is limited ability for the Company to make significant *incremental* TFP gains during the next PBRM.

6.1.5 Proposed *X*-Factor

The ***X***-Factor in the PBRM is to be equal to the difference in expected TFP growth for JPS and the general TFP growth of firms whose price index of outputs reflects the price escalation measure dI. PEG believes the best estimate for JPS' long-term TFP growth rate is 1.94% per annum, or the Company's average TFP growth since 2001. Since the inflation measure *dI* is based on economy-wide inflation trends in the US and Jamaica, the latter TFP growth rate is a weighted average of TFP growth trends for the US and Jamaican economies. PEG estimates that the long-run TFP growth trend of the US economy for the 2001-07 period is 1.53% and the best estimate for TFP growth for the Jamaican economy is zero. The weights specified in the PBRM for US and Jamaican inflation are 0.76 and 0.24, respectively. Overall TFP growth for firms whose output price indexes are reflected in the price escalation measure is therefore 1.16% (*i.e.* 0.76*1.53% + 0.24*0% = 1.16%). The "baseline" TFP differential based on historical TFP experience is therefore 0.78% (1.94% - 1.16%).

PEG's research also shows that JPS has made substantial improvements in its non-fuel cost performance in recent years and has a limited ability to make incremental TFP gains. When setting X factors, regulators often add "stretch factors" to historical TFP differentials in the expectation that productivity growth will accelerate when companies become subject to stronger performance incentives under PBR. The average stretch factor in North American index-based PBR plans is 0.5%. Given PEG's evidence that the Company has registered substantial productivity gains in recent years, they believe the maximum stretch factor that should be approved for JPS is 0.5%. However, since there is always an element of judgment involved in selecting a stretch factor, the consultants suggested that a stretch factor value between 0 and 0.5% would be reasonable for the next PBRM. When these stretch factors are added to the estimated TFP differential, this leads to an appropriate range of ***X*** factor values of between 0.78% and 1.28% which may be rounded up to 0.8 and 1.3 respectively.

JPS concurs with the consultant's analysis that 0.8 (0.78 rounded up) is an appropriate baseline TFP differential based on methodology employed and should be considered in the range of appropriate ***X* –** factor values to be included in the PBRM. However, given the sales forecast of only 0.8% per annum reported in **Annex D** of this submission and the company's high level of fixed cost JPS believes that stretch factor is inappropriate at this time. PEG's benchmarking study had concluded that the Company made large efficiency gains during the last Tariff period and there is limited ability for the Company to make any significant additional TFP gains during the next PBRM. With low sales growth expected over the tariff period it would be even more difficult for the Company extract production efficiencies from its operations as it seems to be close to the production possibility frontier given the results of PEG's study. Therefore JPS proposes that 0.8 be used as the appropriate inflation offset from expected productivity improvements in the 2004 – 2014 PBRM.

6.2 Q-Factor

6.2.1 Introduction

The third element under the PBRM is the Q-factor, i.e., the allowed price adjustment to reflect changes in the quality of service provided to customers. Specifically:

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

JPS and the OUR have agreed in principle that the Q-factor should meet the following criteria:

- The Q-factor should provide the proper financial incentive to encourage JPS to continually improve service quality. It is important that random variations should not be the source of reward or punishment;
- The measurement and calculation of the Q-factor should be accurate and transparent without undue cost of compliance;
- It should provide fair treatment for factors affecting performance that are outside of JPS' control, such as those due to disruptions by the independent power producers; natural disasters; and other *Force Majeure* events, as defined under the Licence; and
- It should be symmetrical in application, as stipulated in the License.

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

- SAIFI—this index is designed to give information about the average frequency of sustained interruptions per customer over a predefined area.

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

  (expressed in number of interruptions per year)
- SAIDI—this index is commonly referred to as customer minutes of interruption and is designed to provide information about the average time that customers are interrupted.

  $$SAIDI = \frac{(\sum \text{Customer interruption durations})}{\text{Total number of customers served}}$$ *(expressed in minutes)*
- CAIDI— this index represents the average time required to restore service to the average customer per sustained interruption. It is the result of dividing the duration of the average customer's sustained outages (SAIDI) by the frequency of outages for that average customer (SAIFI).

  $$CAIDI = \frac{(\sum \text{Customer interruption durations})}{\text{Total number of interruptions}}$$ *(expressed in minutes per interruption)*

6.2.2 The Benchmark SAIDI, SAIFI and CAIDI

The OUR has determined that until the next price review that the verified set of SAIFI, SAIDI and CAIDI indices for 2005 will be used as the benchmark quality level. Furthermore, the OUR determined that SAIFI, SAIDI and CAIDI should be improving by 2% in 2007 relative to the 2006 performance level and by 3%, relative to the 2005 performance level, in each subsequent year until 2009. Accordingly, the target set by the OUR is shown in the **Table 6.1** below.

Table 6.1: The OUR Targets for the Q-factor 2006 – 2009

Year	Target SAIDI	Target SAIFI	Target CAIDI
2006	$SAIDI_{2005}$	$SAIFI_{2005}$	$CAIDI_{2005}$
2007	$SAIDI_{2005}$*(1 – 0.02)	$SAIFI_{2005}$*(1 – 0.02)	$CAIDI_{2005}$*(1–0.02)
2008	$SAIDI_{2005}$*(1 – 0.05)	$SAIFI_{2005}$*(1 – 0.05)	$CAIDI_{2005}$*(1– .05)
2009	$SAIDI_{2005}$*(1 – 0.08)	$SAIFI_{2005}$*(1 – 0.08)	$CAIDI_{2005}$*(1– .08)

The OUR has stated, that, generally in PBRM, penalties are increased as performance worsens and are capped when a maximum penalty is reached and further, that, rewards for good reliability can be implemented in a similar manner. The OUR is of the view that this would provide an incentive for JPS to enact reliability improvement measures even after they have surpassed the poor reliability threshold for a year, before the year comes to an end.

The OUR has determined that the quality of service performance should be classified into three categories, with the following point system:

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

The OUR further stated, that, if the sum of Quality Points for:

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

Since the performance in each of the three performance measures can either be above target, below target or on target (dead band) there are twenty-five (25) possible outcomes as shown in **Table 6.2** below:

Table 6.2: Possible Q-factor Scores

SAIDI	SAIFI	CAIDI	Total	Adjustment Factor
3	3	3	9	0.50%
3	3	0	6	0.40%
3	0	3	6	0.40%
0	3	3	6	0.40%
3	0	0	3	0.25%
0	0	3	3	0.25%
0	3	0	3	0.25%
3	3	-3	3	0.25%
-3	3	3	3	0.25%
3	-3	3	3	0.25%
0	0	0	0	0.00%
3	0	-3	0	0.00%
-3	3	0	0	0.00%
0	-3	3	0	0.00%
-3	0	3	0	0.00%
0	0	-3	-3	-0.25%
0	-3	0	-3	-0.25%
-3	0	0	-3	-0.25%
3	-3	-3	-3	-0.25%
-3	-3	3	-3	-0.25%
-3	3	-3	-3	-0.25%
-3	0	-3	-6	-0.40%
0	-3	-3	-6	-0.40%
-3	-3	0	-6	-0.40%
-3	-3	-3	-9	-0.50%

This design of the Q-factor adjustment as a component of the PBRM is symmetrical and all possible outcomes are properly defined based on the PBRM point system. The design is balanced as it provides equal opportunity for either a positive or negative adjustment to the PBRM.

6.2.3 2008 SAIDI, SAIFI and CAIDI Performance

The **Table 6.3** below outlines JPS' performance for 2008 in the three main qualities of service measures: SAIDI, SAIFI and CAIDI. The data shown here is for the complete system performance and includes interruptions due to generation, transmission and distribution outages. Additionally, the distribution interruptions include both feeder level and sub-feeder level outages. All the computations are based on the 2007 customer base of 581,056, as previously provided in the annual tariff adjustment submission for 2008. It shows a peak in all three indices in January, which is the month when JPS experienced a total system shutdown.

Table 6.3: 2008 JPS Outage Data

Month	*SAIDI*	*SAIFI*	*CAIDI*
January	326.04	2.38	136.99
February	98.18	1.41	69.63
March	130.18	1.56	83.45
April	214.46	2.25	95.32
May	171.15	1.28	133.71
June	230.50	3.21	71.81
July	272.04	3.19	85.28
August	310.44	2.51	123.68
September	263.00	2.20	119.55
October	162.38	1.60	98.27
November	228.11	1.87	101.49
December	111.10	0.99	87.57
Grand Total	**2518**	**24.45**	**102.98**

The 2008 target is based on data supplied in the 2008 Annual tariff submission, which was 3,257 for SAIDI; 34.82 for SAIFI; and 88.84 for CAIDI.

JPS' performance in 2008 would be classified into the above average performance range when compared to the 2008 benchmark target, as noted in the **Table 6.4** below:

Table 6.4: Actual 2008 Q-Factor Performance vs. the 2008 Target

SAIDI was 24% better than target equalling	3 Quality Points
SAIFI was 30% better than target equalling	3 Quality Points
CAIDI was 16% worse than target equalling	3 Quality Points

Since the sum of the quality points on SAIDI, SAIFI and CAIDI is 3, then Q would have been equal to 3 if the Company had a 2009 annual tariff adjustment. This would have resulted in an overall 0.25% positive adjustment to the annual tariff reset, reflecting the fact that JPS' performance was overall better than the target.

Please note that the 2008 customer count, which will be used as the basis for the calculation of the 2009 indices, is provided in **Annex J**. It reflects a customer base of 587,507.

6.2.4 Data Collection Methods

The calculation of SAIDI, SAIFI and CAIDI indices requires key information to be collected. Namely:

- Outage starts and end times;
- System total number of customers; and
- Number of customers affected by each outage.

In 2004 it was agreed that the following methods be used to capture the above-mentioned data.

6.2.4.1 Outages Start and End Times

Feeder level outage

At the feeder level all planned and forced outages were to be collected and stored in a Microsoft Access-based outage-logging database (developed in-house) located at its System Control Centre. This information would contain all the start and end times associated with the individual outages. These outage times were to be derived from the SCADA system and in the event of communication failure the outage start times be derived from the customer call log, when the first affected customer called.

Sub feeder level outages

- Planned outages—for planned outages at the sub-feeder level, data was to be made available primarily from Outage Log Database at the System Control Centre. The outage times were to be derived from actual switching times logged by the System Control Engineer.
- Forced outages—the central call centre logs would be used to provide outage start times. The start time would be derived from the time the first affected customer called. The outage end time would be determined by the recloser or switch closing time as reported to the system control engineer or dispatch technician by the field personnel and also recorded in the call centre log.

6.2.4.2 Number of Customers Interrupted

Feeder Level Outages

To determine the customer count per feeder, an extensive customer to feeder GPS mapping exercise was completed in 2006 where 95% of all customers were mapped with their GPS coordinate to respective feeders island-wide. The remaining 5% were assigned to feeders based on their address and meter reading route. This more accurate and reliable method to determine the number of customer at the feeder level was introduced in 2007.

Where outages (planned and forced) are concerned at the feeder level, it was therefore accepted that the estimated number of customers on each feeder be determined from this derived customer count listing. This list was updated at the end of the tariff year and used in the following years' calculations

Sub-feeder level outages

JPS did not have customer count data at the sub-feeder level so therefore, a method of utilizing the fuse sizes and derived average customer demand per feeder was used to approximate the number of customers interrupted. . This method is shown below;

$$\text{Average customer utilization (MW/customer)} = \frac{\text{feeder peak loading per month}}{\text{Number of customers on the feeder}}$$

The number of customer interrupted was to be computed as follows:

$$\text{Number of customers to be interrupted} = \frac{\text{Estimated load (kW) interrupted}}{\text{Average Customer Utilization (kW/Customer) for that feeder}}$$

Where neither the kW loading nor customer utilization was provided the discounted rating of the isolating fuse (amperes) to be opened was used as a proxy to estimate the load on the line section. The fuse rating was discounted using the transformer utilization factor to approximate the typical peak load on the section.

- Load on branch = transformer utilization x fuse factor x branch kVA
- Where branch kVA = fuse size (amperes) x phase voltage
- fuse factor = feeder connected kVA / total main branch fuse kVA

JPS has since used a discount factor of fifty (50) percent to determine the load and the number of customers interrupted for outages at the sub-feeder level.

6.2.5 Improvements in Data Collection

Consistent with the Company's commitment to improve the accuracy and reliability of the customer count significant investment and efforts were expended in 2007/8 to achieve this objective. This includes the following;

- Staffing – 1 GIS Administrator and 3 GIS Technicians
- Data Infrastructure – Acquire ESRI Arc Server and Desktop v9.3
- GPS Mapping and Field Data Capture of asset attributes
  - 280,000 poles
  - 31,000 transformer locations
  - 10,500 switch location
  - 8,000 km of secondary circuits to which customers are connected.
- Established Geometric Network – Mechanism used to develop and maintain the connectivity of 580,000 customers to transformer locations to line switches and to feeder reclosers.

The Geometric Network was completed on a phase-by-phase basis as outlined below.

Phase I – Map All Customer Meters

This phase involved the GPS mapping of all customer meters and superimposing them on the feeder route. It was completed in the fourth quarter of 2005 and a concise database was created which incorporates this new customer data into the CIS and the Outage Logging System. As a result of these advances the methodology employed in determining feeder customer count was replaced with a more accurate technique. Estimated counts were replaced by actual counts from mapped customer meter locations on each feeder.

Phase II – Map All Line Switches (Isolating and Interrupting Device) Locations

Phase II of the project involved the GPS mapping of junction and main line switch locations. This was completed in 2007

Phase III – Map All Transformer Locations Including Secondary Dead-End Points

This phase involves the GPS mapping of all pole mounted and pad mounted transformer locations and their associated secondary dead-end points. Phase III commenced February 2007 and was completed during the third quarter of 2007. This data provides information on the extent of any transformer secondary circuit. With this information, customers can be linked to transformers and transformers to switch locations giving a more precise indication of the number of customer served by each transformer and switch location.

Since the completion of the mapping of transformer locations and the tying of customers to transformer, JPS undertook the creation of an electrical geometric network. This geometric network uses as input, the data collected in all three phases and allows for the modelling of the entire distribution system from the substation to the customer service locations. This geometric model was completed in the first quarter of 2008 and provides the backbone of improvements made and future improvements.

The data required for calculating SAIDI, SAIFI and CAIDI values will build upon JPS' improved methodology of determining customer count, as described in more detail below.

Since the completion of the geometric network JPS has modify its existing outage logging system at the System Control location as well as the Central Call Centre logs. The objective of this exercise was to replace the current estimated customer counts on sub-feeder outages using fuse size and loading data, with accurate customer counts from the GIS database.

With the geometric network completed, each switching device currently has a unique Name/Identifier and attributes data, which includes the number of customers served via the switch. Whenever a switch operates this unique identifier is captured as a part of the outage information, which now results in each outage being assigned to a unique switch identifier, and in turn an accurate customer count.

Feeder Level Outages

These outages will continue to be captured at the System Control Centre outage-logging database and will be time stamped using the data provided by the SCADA system. As indicated earlier the revised mapped customer count data has been implemented and tied to the individual feeder recloser providing accurate registering of customers affected.

Sub-Feeder Level Outage

- Planned outages—for planned outages at the sub-feeder level, all outages are currently tied to a switching point, which in turn is mapped to a customer count. The start and end times are recorded and captured in the Outage Log Database at the System Control Centre.
- Forced outages— for forced outages JPS will continue using the start time of outages as that reported by the first customer and the end time as that determined by the recloser or switch closing time.

6.2.6 JPS Proposal Data Capture Proposal

JPS intends to utilize the improved data capture mechanism with actual customer count to compute system reliability indices for 2009. After preliminary comparisons between both methods of estimating customer counts it was observed that on average the customer counts using the information from the GIS database was 70% higher than that using the fuse method of calculation. Further research revealed that according to an EEI survey conducted in 2005 among 24 utilities, 17 of the 24 utilities recorded an increase in outage statistics after improvements in data gathering techniques. It can therefore be concluded that a transition between customer estimation methods will inevitably result in increases in SAIDI, SAIFI and CAIDI levels.

In order to track and quantify this possible increase, JPS proposes to continue calculating the reliability indices using both techniques (use of fuse size data and the use of GIS data) for the remainder of 2009. After this point a comparison can be made between both methods to establish a benchmark performance for settings reliability targets for 2010 and beyond.

As submitted in previous years a total system customer count is submitted along with the individual feeder counts. However, in order to provide a clear means of auditing, this year JPS have included a switch customer count (please see **Annex J**). This data is pulled from the GIS database and is being used in the comparative calculation of the reliability indices.

6.2.6.1 Future Data Collection Improvements

With the completion of the geometric network JPS has undertaken the task of procuring/building an Outage Management System. At present there are several different software that captures outage data for reporting purposes. These applications will be replaced with a single solution that will log and record, outage start and end times, interrupting devices, fuse sizes, customer information on all feeder and sub feeder outages.

JPS is currently embarking on the implementation of AMI meters in residential communities. These meters will be outfitted with communication capabilities and will report kWh readings, tamper flags as well as outages to a central database. With the implementation of this technology JPS will use the data from these meters to accurately define the outage start and end times.

With almost real time graphical monitoring of system outages and modifications a proposal will be made to move from a static feeder count system to a dynamic count to facilitate system reconfigurations including partial load transfers between feeders.

It should be noted that JPS is investing a significant amount of resources in its efforts to improve its data collection capabilities. The combined spend on the GIS project, along with the acquisition of additional SCADA and communication system upgrades to ensure proper monitoring of all substations, is approximately US$3 million. Additionally, JPS' total expenditure between 2007 – 09 on the installation of smart meters (AMI) at 5,000 plus commercial and industrial customer locations to augment its ability to detect outages at the sub-feeder level on some secondary circuits will total US$6 million upon completion later this year.

6.2.6.2 Adjustments to Reliability Indices

As stated in the current tariff, the performance targets for 2009 shall be based on the 2005 actual adjusted for 8% improvement for the indices (SAIDI, SAIFI and CAIDI). For the calendar year 2010 and subsequent years JPS proposes that CAIDI be removed from the PBRM.

CAIDI, the average duration of a sustained interruption experienced by a customer, has been monitored and reported to the OUR since 2004 when the PBRM was made operational. It has long been viewed that the monitoring of SAIDI and SAIFI and in particular CAIDI presented some ambiguity due to the mathematical relationship between the indices and as such the expertise of an outside consultant was sought.

The report presented by the consultant confirms the views held by JPS and suggests the discontinuance of the use of CAIDI as a benchmark, while upholding the use of SAIDI and SAIFI.

In the report [17]X Factor and Q factor Recommendations for JPS, October 2008 presented by PEG the reasons for CAIDI exclusion are outlined as:

- " The metric is redundant when SAIDI and SAIFI are already included in the metrics"
- " It can be demonstrated mathematically that SAIDI and SAIFI are ultimately what matters to customers"; and
- "Using SAIDI, SAIFI and CAIDI to measure quality can lead to anomalous and unwarranted penalties or rewards in a service quality mechanism" [18]

An incident of the anomalous penalties was observed in the submission of the 2008 annual tariff submission, where SAIDI bettered the target by 10% and SAIFI bettered the target by 33%, however CAIDI worsened by 37%. The poor performance in CAIDI was as a result of the mathematical relationship between CAIDI and the other two indices. Because there was a greater reduction in SAIFI than the reduction in SAIDI this caused the measured value of CAIDI to be greater, resulting in a worsened CAIDI. This CAIDI value does not accurately indicate a reduction in the quality of service to customers, as both SAIFI and SAIDI demonstrated that the frequency and the duration of outages were reduced. Nevertheless, JPS was penalized with the awarding of –3 quality points for the 'worst than target' CAIDI value.

It is important to note, therefore, that **Table 6.1** had an inherent mathematical error in it as it relates to the derivation of the CAIDI target for 2006 – 2009. Since CAIDI represents SAIDI divided by SAIFI, if SAIDI and SAIFI were expected to improve by the same percentage each year, then CAIDI should have been held constant[19].

6.2.7 Definition of MAIFI as a Reliability Index

MAIFI—this index is designed to give information about the frequency of momentary outages (those of durations of 5 minutes or less) per customer over a predefined area.

$$MAIFI = \frac{\text{Total number of customer interruptions (for durations of 5 minutes or less)}}{\text{Total number of customers served}}$$

(expressed in number of interruptions per year)

Momentary interruptions are defined in IEEE Std. 1366 as those that result from each single operation of an interrupting device such as a recloser. MAIFI measures data on momentary interruptions that result in a zero voltage. For example, two circuit-breakers open operations are equivalent to two momentary interruptions.

6.2.7.1 JPS Operations and Momentary Interruptions

JPS' distribution network is comprised of 110 feeders, predominantly overhead lines, which emanate radially from 52 substations. The major drivers of momentary interruptions on any

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[17] A copy of the report can be viewed in Annex K

[18] Please see Appendix three of the *X factor and Q factor recommendations for JPS, October 2008*, for mathematical proof of what matters to customers.

[19] That is to say if SAIDI is assumed to be 2,500 and SAIFI is 100, then CAIDI must be 25 (2,500/100). If we assume a 10% improvement in SAIDI and SAIFI, to 2,250 and 90 respectively, it stands to reason that CAIDI must remain constant at 25 (2,250/90). Therefore, to assume that CAIDI will also improve by 10% is mathematically incorrect. This explains why the inclusion of CAIDI is redundant and why the assumption that CAIDI will also improve each year is incorrect.

exposed outdoor distribution system include lightning strikes or other weather related effects, lines making contact, tree interaction with lines and animal contact (e.g. birds) with lines.

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

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

On the event of a lockout, field personnel will be dispatched to find the source of the fault and effect isolation and repairs. The unaffected parts of the feeder will be returned to service when isolation is effected by closing back the breaker. Each incident of a breaker lockout will almost always exceed the five minute threshold for MAIFI and will thus be captured in SAIFI and SAIDI. In instances when the source of the fault is not permanent (e.g. lightning strikes), there can be one or two cycles of the feeder not leading to a lockout. These instances would be captured in MAIFI.

Apart from the typical momentary outage drivers, other operations can lead to breaker open and close operation of less than five minutes duration. During switching activities to effect isolation for planned maintenance or fault repairs, feeder sections may be required to be de-energized for short periods for safe operations. Likewise, during a planned maintenance of a breaker (i.e. injection tests) the breaker may be placed on bypass and operated numerous times and these instances will register as breaker cycling or customer interruptions if not extracted. These examples are normal and necessary activities in electric utility operations

Also, in many systems like JPS' power grid, under-frequency schemes are a necessary part of protecting the system from collapsing in the case of events that can lead to a frequency reduction on the system. In JPS' case, there are four (4) stages of under-frequency that operate to restore load-frequency balance. Feeders are assigned to these four (4) stages and are shed automatically when the frequency reaches the required frequency set point.

This under-frequency scheme complements the spinning reserve margin (30 MW presently) criteria set to balance the need for reliability and the need to minimize the variable operating cost to JPS and its customers. When under-frequency loads are shed, quick start generators are started and the feeders restored in a short timeframe, oftentimes in less than five (5) minutes.

Based on the configuration of JPS' distribution system, section outages would not normally fall in the category of momentary interruptions and can be ignored for MAIFI calculations since operations on a feeder beyond the recloser are predominantly manual. Likewise, JPS does not now have the capability to measure momentary outages at an individual customer level.

6.2.7.2 Current Data Collection Systems for MAIFI

JPS collects data on all sustained interruptions due to permanent trips in the Outage Database at the System Control Centre. These include interruptions due to under-frequency, planned and forced transmission and distribution outages.

JPS also stores on the SCADA historian server, all the recloser cycling for substations that are monitored. However, not all the substations are monitored by SCADA and, therefore for recloser cycling, data from such substations will not be available for MAIFI computation. Similarly, whenever there is a break in communication to a substation's Remote Terminal Unit (RTU) the recloser cycling operation is not captured.

6.2.7.3 Guiding Principles for calculating MAIFI

Given the various scenarios that can lead to momentary interruptions, JPS is of the view that the target set for MAIFI, as is the case with the other reliability indices, should provide fair treatment for factors affecting performance that are outside of JPS' control. Thus, the baseline data used to set MAIFI targets must be confined to instances initiated by JPS controllable factors. In that respect, it is our considered view that the following incidences should be excluded:

- Normal switching activities required during maintenance, load transfers, fault isolation or post fault restoration etc., that may cause momentarily interrupt customers;
- Under-frequency operations which act to protect the system from collapse;
- Cycling operations which eventually lead to a lockout of the recloser and hence restoration times exceeding five minutes since this incident will already be accounted for in SAIFI;
- Third party initiated incidences which cause momentary interruptions to customers where such third party is not acting as an agent of JPS; and
- Acts of GOD (i.e. lightning or other weather related effects, natural disasters etc.) or other force majeure provisions presently applied to the other indices (SAIDI, SAIFI and CAIDI) under the current Q-Factor mechanism.

The remaining incidences will be driven by factors that JPS is either directly responsible for or has some means of controlling or mitigating. This will ensure that the Q-factor is satisfying the criteria of providing the proper financial incentive to encourage JPS to continually improve service quality.

6.2.7.4 2006 – 2008 MAIFI Data Analysis and Q Factor Proposal

Annex K summarizes the number of breaker cycling data required for the calculation of MAIFI for the JPS system for the period 2007 – 2008. JPS' research on the use of MAIFI as an index for reliability measure has shown that this index has waned in popularity over the years. Oftentimes utilities have found it difficult to extract the information to calculate this index accurately and have abandoned the measure in preference to SAIDI and SAIFI.

JPS has also had significant difficulty in extracting the information solely related to the calculation of MAIFI. The old SCADA system (ABB Ranger) along with the limitations of other database management and communications systems provided significant challenges to extracting incidences less than five minutes in duration and consistently classifying them as MAIFI related according to the principles outlined above. This is not uncommon to many utilities across the world. Consequently, the MAIFI data presented for 2007 to 2008 has not been cleaned of all the momentary outages caused by the above-mentioned factors which are outside of JPS' control.

Nevertheless, the Company has used its best efforts to provide a breakdown of the 2008 MAIFI related outage data in **Annex K**. This should provide some high level guide to the breakout of the effects of the causative factors. Statistically, the 2008 breakout data indicates that 9,643 pairs of breaker open and close operations were recorder by the SCADA system. Of that amount, 695 were found to have associated outages whose duration would result in them being classified under SAIFI. The remaining 8,948 breaker operations include 1,044 with a duration between 6 seconds and five minutes. These 1,044 breaker operations would for sure include the majority of under-frequency operations, switching operations, operations caused weather related factors and other factors mentioned before. The 7,904 breaker operations left include all cycling operations of less than 6 seconds duration caused either by JPS controlled (planned maintenance or forced events), acts of God and weather related factors, third party incidences, etc. Using the non-SAIFI related breaker operations (8,948) to calculate MAIFI gives a result of 117.29 minutes.

For JPS to effectively, accurately and consistently measure and report MAIFI will require vast improvement in its data capture, reliability and verification capabilities. JPS is currently improving its communications infrastructure as well as implementing a new SCADA system with improved data capture and processing capabilities. While some of the MAIFI causative factors (maintenance, switching, under-frequency etc.) can be possibly be tracked and eventually extracted, the tracking of many of the main MAIFI drivers (acts of GOD and weather related causes etc.) require infrastructure and systems that JPS currently does not have.

Importantly, given the current configuration of the T&D network and the lack of inter-connectivity, particularly in many rural areas, it would require significant capital investment to implement redundant systems and automatic switching equipment to enable the Company to be able to control or improve MAIFI

As a result of all of the above factors and consistent with PEG's recommendation in **Section 1.2.5** of their X-Factor and Q-Factor Study included in **Annex I**, JPS proposes that MAIFI not be included as part of the annual Q-factor adjustment mechanism but rather that the OUR monitors the MAIFI results during the period 2009 – 14. PEG further states the following in their report:

> ***We also believe that there are significant uncertainties regarding an appropriate benchmark for MAIFI. We accordingly recommend that MAIFI simply be monitored, rather than subject to explicit penalties or rewards, in the next PBRM. We also believe more attention should be devoted to understanding customers' willingness to pay for quality improvements, including the willingness to pay for reductions in MAIFI. More knowledge of customer preferences can help JPS make appropriate investments and ensure that any quality improvements actually improve customer welfare.***

Notwithstanding, JPS is prepared to continue to improve its systems to refine the data required for the assessment of momentary interruptions consistent with the principles outlined in this submission to facilitate the inclusion of an appropriate index in the determination of service quality.

JPS proposes that MAIFI be included as a part of the overall standards and be monitored on an annual basis. This will facilitate a continuous dialogue with the OUR on the matter while the Company improves its monitoring capabilities, attempts to better understand and categorize the data with respect to the causative factors and further analyze the relative performance of some feeders vs. others.

Additionally, JPS proposes that once the base-line data is collected for SAIDI and SAIFI for 2009 on the improved basis (as outlined in **Section 6.2.6**), that the targets and penalty/reward scoring system be revised as part of the 2010 annual adjustment submission. The Q-factor adjustment for 2009 would therefore be calculated on the previously determined basis as outlined in **Section 6.2.2**, preferably with the appropriate correction to CAIDI. While the Company does not believe it prudent to include MAIFI as part of the Q-factor adjustment mechanism going forward as of 2010, given the significant challenges and concerns noted previously, if the OUR were to include this measure going forward, the weighting of MAIFI in the point score system and its resultant tariff impact should be appropriately adjusted (diminished).

6.3 Z-Factor Claims

In Schedule 3, Exhibit 1, of the Licence, it describes the Z-factor as:

> ***Allowed (Z-Factor) Price Escalation Reflecting Special Circumstances***
> ***The Z factor is the allowed percentage increase in the price cap index due to events that:***
> - ***affect the Licensee's costs;***
> - ***are not due to the Licensee's managerial decisions; and***
> - ***are not captured by the other elements of the price cap mechanism.***

JPS has made five such **Z**-factor claims to date, as noted in the **Table 6.5** below:

Table 6.5: Summary of Z-factor Claims

Incident	Incident Date	Claim Date	Amount Claimed	OUR Award Date	Amount Awarded
Hurricane Ivan Claim	Sep-04	Mar-05	$1.46B	Mar-05	$652.3M
2005 Tropical Storms	Jun - Nov-05	Mar-06	$193M	Jan-09	$90M
Hurricane Dean Claim	Aug-07	Mar-08	$1.21B	TBA	TBA
Tropical Storm Gustav	Aug-08	Dec-08	$256M	TBA	TBA
IDT Settlement (2008)	Jul-08	Mar-09	$3.5B	TBA	TBA

In **Section 2.5.1**, the Company highlighted its concerns about the risk it faces to hurricanes. As a result of not having received decisions regarding the Z-Factor claims made by the Company, it is unable to determine the full extent of costs that may be deemed as enhancement costs to be included in this submission. Consequently, the Company has decided to defer all claims in relation to enhancement costs until the dispute has been resolved. Should there be the need for any costs to be capitalized and recovered through the rate base, then a special adjustment would need to be made in the 2010 annual tariff adjustment. This includes any enhancement costs in relation to:

- determination notice Ele 2005/5, which stated $194.8 million should be capitalized and included in the rate base;
- determination notice Ele 2009/01: Det/01, which stated $29.1 million should be capitalized for future recovery; and
- the pending determination in relation to the Tropical Storm Gustav claim made in December 2008.

In relation to the IDT settlement made in 2008, the Company has made a separate Z-factor claim submission (March 2009) in relation to this matter. This current tariff submission does not specifically contemplate the impact of that separate claim. However, it should be noted that the amount being claimed for recovery over two years through a special Z-factor adjustment amounts to 6.75¢ per kWh. This amount is included in the overall analysis of the tariff impact in **Annex M**. It is also assumed that the current Z-factor charge in relation to Hurricane Ivan (currently 8.8¢ per kWh) comes to an end in June 2008.

7 Non-Fuel Tariff Rates

7.1 Load Characterization Study

7.1.1 Principles

In order to be able to develop a tariff review it is necessary to be aware of the consumption patterns that each of the customer classes of the Company. The load characterization studies are devised in order to obtain specific information of the market served, which allows identification of the responsibility that each of these customer classes has concerning delivery costs. Therefore, a fairer allocation of costs is achieved. The data required to determine the responsibility is based on power logs and energy consumptions of the different network users, which is usually not available for all the user classes, due to the type of meter they have. Consequently, given this restriction, a load characterization study is used in order to gather crucial data for an adequate allocation of costs of each of the activities involved in the business: generation, transmission and distribution.

In addition, the data obtained from the load characterization studies is not only useful for the tariff review, but also for the other areas that the Company are involved in. In order to be able to estimate the need of future investments due to system expansion, the engineering and investment planning departments require power and load flow demand forecasting of the different voltage levels and areas served by the Company. Therefore, it is critical to obtain representative parameters of the consumer patterns belonging to the different customer classes the Company has, such as load factors, internal and external coincidence factors, which are calculated through load characterization studies.

7.1.2 Case Presentation

The study considered 2008 data. The load characterization study is based on the processing of a database considering consumption data for individual consumers.

Generally, medium and large consumers have electronic meters with mass memory that can be interrogated remotely, so a 100% census can be carried out upon these customers.

The Street lighting category shows a unique behaviour. The curves in this class have a flat profile that presents a practically instantaneous demand at sunset and a drop to zero at sunrise. Given the particularity of this class, it does not justify its inclusion in a measurement campaign to estimate the typical consumption behaviour. The consumption pattern of this category is calculated by choosing a city as a geographic centre and downloading the sunrise and sunset data. This data together with the annual energy from the base year allows the calculation of the parameters.

For the small consumers, due to the quantity of customers and the type of meters they generally have, a sample is selected to study their consumption behaviour.

JPS 2008 market is composed as follows:

Table 7.1: Customer Consumption

	2 008	
Rate	Average Customers	MWh
RT10	527 575	1 084 674
RT20	61 444	638 265
RT40	1 566	789 468
RT50	123	599 294
RT60	277	68 028
Total	**590 984**	**3 179 728**

According to the quantity of consumers and the type of meters each in category, the optimum design for JPS is:

- RT10: Stratified Sample
- RT20: Stratified Sample
- RT40: Stratified Sample
- RT50: 100% Census

After a thorough analysis and considering the existence of diverse constraints (financial, manpower and time), a methodology for achieving the initial goal was developed. This methodology combined with the available data allows the Company to estimate the behaviour of its customers with a minimum error.

The methodology that is described below considered the following data for calculating the parameters and load profiles by voltage level and category:

- Total energy generated and purchased
- Energy losses by voltage level (%)
- Energy sold by category
- System load profile
- Consumption data from AMI (advanced metering infrastructure) meters

– RT50: ***112*** curves
– RT40: ***560*** curves
– RT20: ***1195*** curves

With the data related to total energy generated and purchased,

Energy losses by voltage level (%), and Energy sold by category, an energy movement was built for the year 2008.

Table 7.2: Energy Losses by Voltage Level

Concept	MWh	Losses / Net Generation (%)
Net Generation	**4 123 288**	
Gen / Tr Losses	16 493	0.40%
Energy entered in Tr	**4 106 795**	
Tr Losses	74 219	1.80%
Energy entered in Tr/MV	**4 032 576**	
Tr/MV Losses	16 493	0.40%
Energy entered in MV	**4 016 082**	
MV Losses	94 836	2.30%
RT 50 (Power Service)	599 294	
Energy entered in MV/LV	**3 321 953**	
MV/LV Losses	98 959	2.40%
Energy entered in LV	**3 222 994**	
LV Technical Losses	123 699	3.00%
Total LV Demand w/o Tech. Losses	3 099 295	
Non Technical Losses	518 861	12.58%
RT 60 (Street Lighting)	68 028	
RT 40 (Power Service)	789 468	
RT 20 (General Services)	638 265	
RT 10 (Residential)	1 084 674	

This movement is an input for the energy movement that is carried out by hour and type of day, and allows identifying the responsibility of each category to the maximum power of each voltage level.

The calculation of the energy movement was performed through a Top-down process starting at the level of net generation, where subtraction of energy losses and sales of the corresponding voltage level allowed calculation of the load profile of the levels below until reaching the Low Voltage level. At this level, the information available finally allowed us to estimate the Residential load profile, which is the only category in which there wasn't enough information to calculate its profile in a direct way.

7.1.3 Methodology of Parameters Calculation

The basic information consisted of load curves with registries of 15' (15 minutes). Each one contains the date, hour and energy (kWh) during a period of approximately 3 weeks.

The registries received were added in a data base where the date and hour of each one was uniquely stored:

- DOW code (Day of the Week). Takes values from 1 to 7. The number 7 corresponds to Sundays.
- Code of the hour in blocks of 15' (From 1 for the hour 00:00, to 96 of the hour 23:45)

The curves were standardized in 7 days. Each block of every day results from the average energy of the registries of that block (E.g.: if for day 1 (Monday) there are two registries with different dates and the same hour block of 15', a simple average is generated to represent the energy of that moment.

7.1.3.1 Study Groups

The study groups were as follows:

- Residential Class (RT10) LV: This category was analyzed as a whole, and its behaviour was obtained in an indirect way as was explained in point in **Section 7.1.2**.
- General Class (RT20) LV: A post-stratified sample was conducted:
  - Stratum 1: Consumption between 0 – 100 kWh/month
  - Stratum 2: Consumption between 100 – 500 kWh/month
  - Stratum 3: Consumption between 500 – 1000 kWh/month
  - Stratum 4: Consumption between 1000 – 1500 kWh/month
  - Stratum 5: Consumption between 1500 – 2000 kWh/month
  - Stratum 6: Consumption between 2000 – 2500 kWh/month
  - Stratum 7: Consumption between 2500 – 3000 kWh/month
  - Stratum 8: Consumption between 3000 – 4500 kWh/month
  - Stratum 9: Consumption greater than 4500 kWh/month

1. Power Service (RT40) LV: A post-stratified sample was conducted:
   - Stratum 1: Consumption between 0 – 10000 kWh/month
   - Stratum 2: Consumption between 10000 – 25000 kWh/month
   - Stratum 3: Consumption between 25000 – 50000 kWh/month
   - Stratum 4: Consumption greater than 50000 kWh/month
2. Power Service (RT50) MV: This category was analyzed as a whole.
3. Street Lighting (RT60) LV: This category was analyzed as a whole.

7.1.3.2 Curves Received by Group

The number of curves received and validated by group is as follows:

Table 7.3: Sample Size by Rate Class

Rate	Stratum	Range	Sample Size
RT20	1	0 - 100 kWh/month	25
RT20	2	100 - 500 kWh/month	39
RT20	3	500 - 1000 kWh/month	38
RT20	4	1000 - 1500 kWh/month	38
RT20	5	1500 - 2000 kWh/month	51
RT20	6	2000 - 2500 kWh/month	48
RT20	7	2500 - 3000 kWh/month	79
RT20	8	3000 - 4500 kWh/month	262
RT20	9	> 4500 kWh/month	577
RT40	1	0 - 10000 kWh/month	109
RT40	2	10000 - 25000 kWh/month	147
RT40	3	25000 - 50000 kWh/month	119
RT40	4	> 50000 kWh/month	156
RT50			109

7.1.3.3 Sample Validation

In the case of RT20 and RT40, a post-stratification process was carried out and the representativeness of the sample in each stratum was validated.

The variable analyzed was the energy consumption of the sample versus the population, checking the representativeness through hypothesis tests carried out upon the average consumption (Student) and its variance (Fisher) in each stratum.

The validation results are in the following table:

Table 7.4: Statistical Analysis

Average consumption validation

Hypothesis Test
Null Hypothesis (Ho): μ = x
Alternative Hypothesis (H1): μ ≠ x
Statistical Significance 95%
Upper Limit (Z_{LS}) 1.96
Lower limit (Z_{LI}) -1.96

Rate	Stratum	μ	x	σ / √n	Z_{exp}	Decision
R20	1	38.47	45.87	10.79	0.69	OK
	2	241.81	255.72	20.75	0.67	OK
	3	712.47	751.90	29.56	1.33	OK
	4	1 221.69	1 270.59	26.68	1.83	OK
	5	1 736.19	1 757.36	22.26	0.95	OK
	6	2 236.53	2 266.87	20.87	1.45	OK
	7	2 736.92	2 767.47	16.93	1.80	OK
	8	3 647.36	3 660.00	26.64	0.47	OK
	9	10 488.98	10 381.67	388.42	-0.28	OK
R40	1	5 468.42	5 748.99	280.32	1.00	OK
	2	16 833.12	16 700.01	343.75	-0.39	OK
	3	34 709.04	34 770.41	631.50	0.10	OK
	4	108 882.00	110 776.34	6 349.14	0.30	OK

Validation of the average consumption variance

Hipothesis Test
Null Hypothesis (Ho): $\sigma^2 = S^2$
Alternative Hypothesis (H1): $\sigma^2 \neq S^2$
Statistical Significance 95%

Rate	Stratum	σ^2	S^2	S^2 / σ^2	F(n1,n2)	Decision
R20	1	1 165	1 238	1.06	1.83	OK
	2	11 622	16 956	1.46	1.53	OK
	3	20 098	24 783	1.23	1.55	OK
	4	20 650	20 454	0.99	1.52	OK
	5	20 809	22 698	1.09	1.44	OK
	6	20 039	21 247	1.06	1.42	OK
	7	20 920	22 487	1.07	1.31	OK
	8	178 814	154 699	0.87	1.25	OK
	9	84 184 290	65 086 628	0.77	1.24	OK
R40	1	8 329 382	7 492 290	0.90	1.29	OK
	2	17 369 936	16 103 452	0.93	1.28	OK
	3	47 058 052	48 793 404	1.04	1.29	OK
	4	6 207 987 178	7 021 307 115	1.13	1.29	OK

7.1.3.4 Parameter Definitions

From the study of the emerging load curves, the consumption parameters will be estimated per group of study. The parameters are defined as follow:

1. ***KonPK***: is defined as the percentage of energy consumed by a typical customer of ***k*** category in the on-peak hour block. The consumption of all ***k*** category customers times this factor allows us to know the quantity of energy consumed by the ***k*** category during the peak hour block. It is calculated from the Energy Data for the 96 Code of the hour blocks (i.e. 15' intervals), multiplied by a time matrix that decomposed them between the different blocks. This block includes the hours from 6:00 pm to 10:00 pm for Weekdays (i.e. Monday to Friday).

2. ***KpaPK***: is defined as the percentage of energy consumed by a typical ***k*** category customer in the partial-peak hour block. The consumption of all ***k*** category customers times this factor allows us to know the quantity of energy consumed by the k category during the partial peak hour block. It is calculated from the Energy Data for the 96 Code of the hour blocks, multiplied by a time matrix that decomposes them between the different blocks. This block includes the hours from 6:00 am to 6:00 pm for Weekdays and the hours from 6:00 pm to 10:00 pm for Weekends.

3. ***KoffPK***: is defined as the percentage of energy consumed by a typical ***k*** category customer in the off-peak hour block. The consumption of all k category customers times this factor allows us to know the quantity of energy consumed by the ***k*** category during the off peak hour block. It is calculated from the Energy Data for the 96 Code of the hour blocks (i.e. 15' intervals), multiplied by a time matrix that decomposed them between the different blocks. This block includes the hours from 10:00 pm to 6:00 am for Weekdays and all the hours of Weekends except from 6:00 pm to 10:00 pm.

4. ***UFK***: is defined as the use factor or load factor of a typical ***k*** category customer. It provides information concerning the existing relationship between the demanded average power of a customer for a certain period of time and the maximum power usage over the same period.

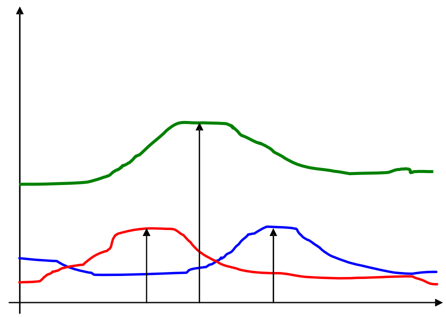
$$\boxed{\hat{UF}_k = \frac{\overline{et}_k}{T \times \overline{\hat{P}}_k}}$$

where:

- $\hat{UF}_k$: Use Factor of the group ***k***
- $\overline{et}_e$: Average total energy consumption of clients of Stratum e that belongs to the group ***k***
- T: Period of time of measurement of curves (24 hours)
- $\overline{\hat{P}}_k$: Average maximum power of clients of Stratum e that belongs to the group ***k***

5. ***ICF$_K$***: is defined as the internal coincidence factor of category ***k***. The internal coincidence factor or simultaneity factor is bound to each category; that is, only data pertaining to the category of interest is required for its calculation. This factor is the ratio between the maximum power of ***k*** category and the sum of all the non-coincidental maximum powers of the customers in the ***k*** category.

Figure 7.1: System Curve



The figure above shows the load curve of 2 ***k*** category customers, where these curves, when added to the curves of the rest of the ***k*** category customers leads to the aggregate curve of ***k*** category. Therefore, the category maximum power and the other ICF component are made up by the sum of all individual maximum powers of ***k*** customers. The equation is presented below:

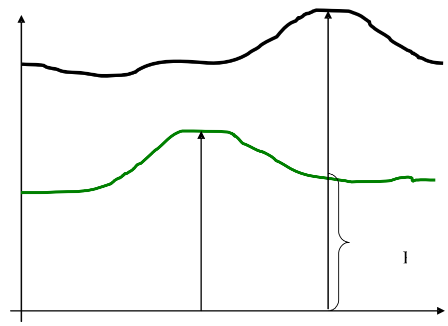
$$\hat{ICF}_k = \frac{\dfrac{\sum_{i=1}^{n_k} P_i^{Coin\,k}}{n_k}}{\dfrac{\sum_{i=1}^{n_k} \hat{P}_i}{n_k}}$$

where:

- $\hat{ICF}_k$: Internal Coincidence Factor of the group k
- $P_i^{Coin\,k}$: Power of client *i* coincidental with the maximum power demand of the selected sample of group *k*.
- $\hat{P}_i$: Maximum power of client *i* of the selected sample of group *k*.
- nk: sample size of group ***k***

6. $\boldsymbol{ECF_K^J}$: is defined as the external coincidence factor of ***k*** category with the maximum voltage level ***J*** (J = LV, MV, Tr or G) Given the ***J*** level, the factor is defined as the quotient between the category ***k*** power coincidental with the maximum power of ***J*** voltage and the maximum power of category ***k***.

Figure 7.2: Coincidence Curve



The formula of the ECF is:

$$\hat{ECF}_k^J \equiv \frac{\sum_{i=1}^{n_k} P_i^{Coin\,J}}{\sum_{i=1}^{n_k} P_i^{Coin\,k}}$$

where:

- $\hat{ECF}_k^J$: External Coincidence Factor of the selected sample of group k with the maximum power demand of the voltage level J
- $P_i^{Coin\,J}$: Power of client i coincidental with the maximum power demand of the voltage level J
- $P_i^{Coin\,k}$: Power of client i coincidental with the maximum power demand of the selected sample of the group k.

7. ***TCF$_K^J$***: is defined as category ***k*** total coincidence factor with the maximum power of voltage level ***J*** (J = LV, MV, HV or SIN). It is the result of ICF_K times the ECF_K^J. From the maximum power measured in a category k customer, this factor allows us to know its contribution to the maximum power of voltage level ***J***. The formula is:

$$\hat{TCF}_k^J \equiv \frac{\sum_{i=1}^{n_k} P_i^{Coin\,J}}{\sum_{i=1}^{n_k} \hat{P}_i}$$

where:

- $\hat{TCF}_k^J$: Total Coincidence Factor of the group ***k*** with the maximum power demand of voltage level J
- $P_i^{Coin\,J}$: Power of client i coincidental with the maximum power demand of voltage level J
- $\hat{P}_i$: Maximum power of client i from the selected sample of group k.

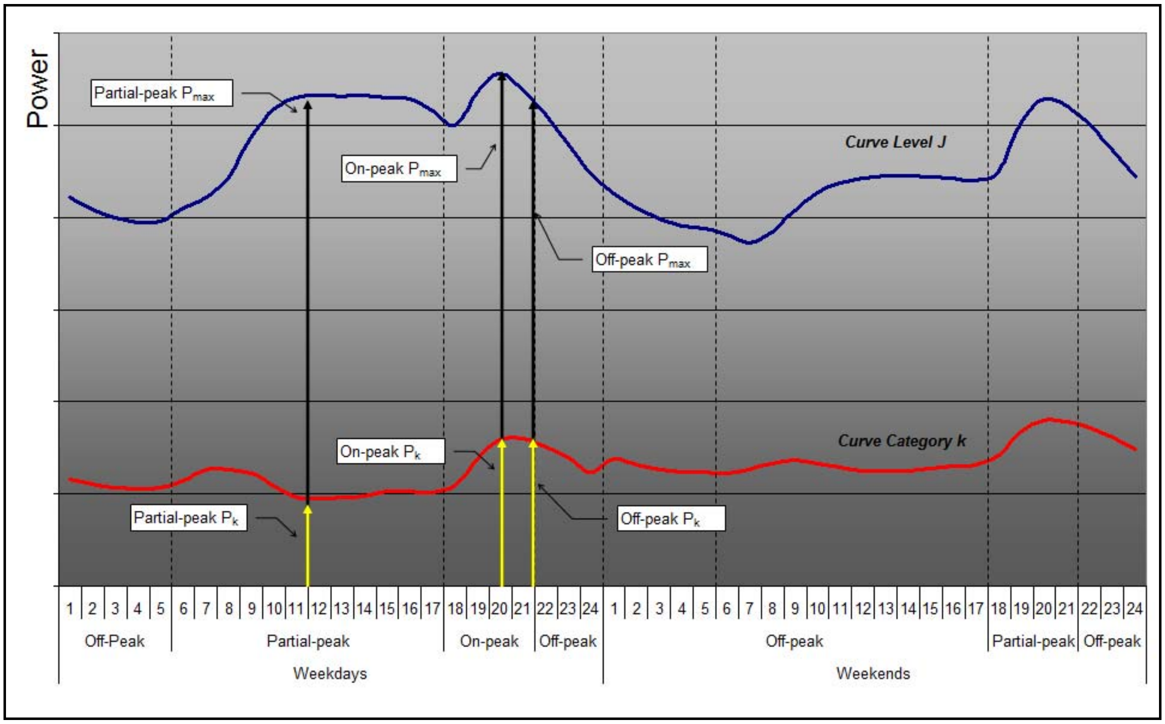
Currently, JPS only has Power Charges for different blocks of hours (On Peak, Partial Peak and Off Peak) for two rate categories (RT40 and RT50). Consequently, it is necessary to estimate the TCF in those blocks, in order to obtain one result for each block, and be able to calculate the responsibility that each category has in the maximum power demand of the correspondent block. If capacity costs are linked to the maximum power demand that occurs in each block, then these parameters allow determination of the portion of each cost that has to be paid by each category.

In the case of categories with Time-of-Use tariff, Power charges by block are directly calculated, for the other tariff options theses charges are reorganized according to the variable that is measured for the customers (Energy or Maximum Power).

According to the 2008 Rate Schedule document, and as was stated before, the current blocks are:

- On-peak hours: Monday-Friday 6:00 p.m. to 10:00 p.m.
- Off-peak hours: Monday-Friday 10:00 p.m. to 6:00 a.m., and weekends and Public Holidays all hours except 6:00 p.m. to 10:00 p.m.
- Partial-peak hours: Monday-Friday 6:00 a.m. to 6:00 p.m., and weekends and Public Holidays 6:00 p.m. to 10:00 p.m.

Figure 7.3: Weekday and Weekend Load Curves



For clients with Standard billing demand (Measurement of the maximum power regardless the hour block), the TCF by block and voltage level is:

$$\hat{TCFOnP}_k^J \equiv \frac{\sum_{i=1}^{n_k} P_i^{OnPJ}}{\sum_{i=1}^{n_k} \hat{P}_i} \qquad \hat{TCFOffP}_k^J \equiv \frac{\sum_{i=1}^{n_k} P_i^{OffPJ}}{\sum_{i=1}^{n_k} \hat{P}_i} \qquad \hat{TCFPaP}_k^J \equiv \frac{\sum_{i=1}^{n_k} P_i^{PaPJ}}{\sum_{i=1}^{n_k} \hat{P}_i}$$

where:

- $\hat{TCFOnP}_k^J$: On-Peak Total Coincidence Factor of group k with the maximum power demand of level J in the On-Peak block.
- $\hat{TCFOffP}_k^J$: Off-Peak Total Coincidence Factor of group k with the maximum power demand of level J in the Off-Peak block.
- $\hat{TCFPaP}_k^J$: Partial-Peak Total Coincidence Factor of group k with the maximum power demand of level J in the Partial-Peak block.

- P_i^{OnPJ} : Power of client i coincidental with the maximum power demand of level J in the On-Peak block.
- P_i^{OffPJ} : Power of client i coincidental with the maximum power demand of level J in the Off-Peak block.
- P_i^{PaPJ} : Power of client i coincidental with the maximum power demand of level J in the Partial-Peak block.
- $\hat{P}_i$: Maximum power demand i from the selected sample of group k.

For clients of the Time-of-Use Option billing demand (a maximum Power lecture on each block), the TCF by block and voltage level is:

$$\boxed{T\hat{C}FOnP_k^J \equiv \frac{\sum_{i=1}^{n_k} P_i^{OnPJ}}{\sum_{i=1}^{n_k} \hat{P}_{i,OnP}}} \quad \boxed{T\hat{C}FOffP_k^J \equiv \frac{\sum_{i=1}^{n_k} P_i^{OffPJ}}{\sum_{i=1}^{n_k} \hat{P}_{i,OffP}}} \quad \boxed{T\hat{C}FPaP_k^J \equiv \frac{\sum_{i=1}^{n_k} P_i^{PaPJ}}{\sum_{i=1}^{n_k} \hat{P}_{i,PaP}}}$$

where:

- $TCF\hat{O}nP_k^J$: On-Peak Total Coincidence Factor of group $\boldsymbol{k}$ with the maximum power demand of level J in the On-Peak block.
- $TCF\hat{O}ffP_k^J$: Off-Peak Total Coincidence Factor of group $\boldsymbol{k}$ with the maximum power demand of level J in the Off-Peak block.
- $TCF\hat{P}aP_k^J$: Partial-Peak Total Coincidence Factor of group $\boldsymbol{k}$ with the maximum power demand of level J in the Partial-Peak block.
- P_i^{OnPJ} : Power of client i coincidental with the maximum power demand of level $\boldsymbol{J}$ in the On-Peak block.
- P_i^{OffPJ} : Power of client i coincidental with the maximum power demand of level $\boldsymbol{J}$ in the Off-Peak block.
- P_i^{PaPJ} : Power of client i coincidental with the maximum power demand of level $\boldsymbol{J}$ in the Partial-Peak block.
- $\hat{P}_{i,OnP}$: Maximum power of customer i of group k in the On-Peak block.
- $\hat{P}_{i,OffP}$: Maximum power of customer i of group k in the Off-Peak block.
- $\hat{P}_{i,PaP}$: Maximum power of customer i of group k in the Partial-Peak block.

7.1.4 Load Curves by Category

As stated previously, based on the standardized load curves for the 96 code of the hour blocks, the curve or load profile of a typical client of each category and stratum was determined.

The construction of these typical curves was done in the following way:

- Standardization of all the observed client curves into 96 blocks of consumption in Weekdays and Weekends.
- The average consumption was calculated for each block by adding the consumption of the sample units and dividing by the size of the sample (this was done by stratum in those categories where the sample was stratified).

- The average curves were extrapolated to the population multiplying by the number of customers that each category-stratum had.
- The data allowed the estimation of two curves:
  - Weekday Curve
  - Weekend Curve

The two curves by category are presented below in the same graph to facilitate comparison and to show the behaviour of each category within the different hour blocks:

Figure 7.4: RT20 General Service

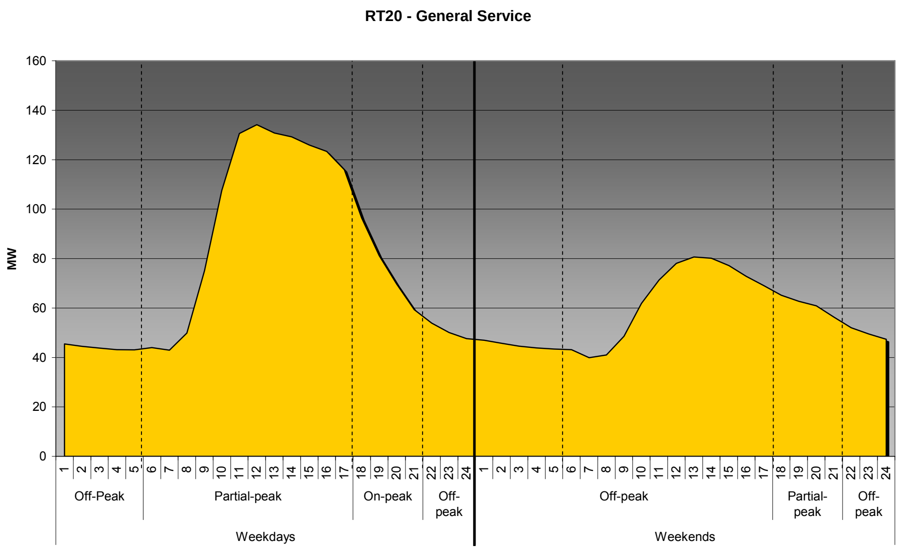


Figure 7.5: RT40 Low Voltage Power Service

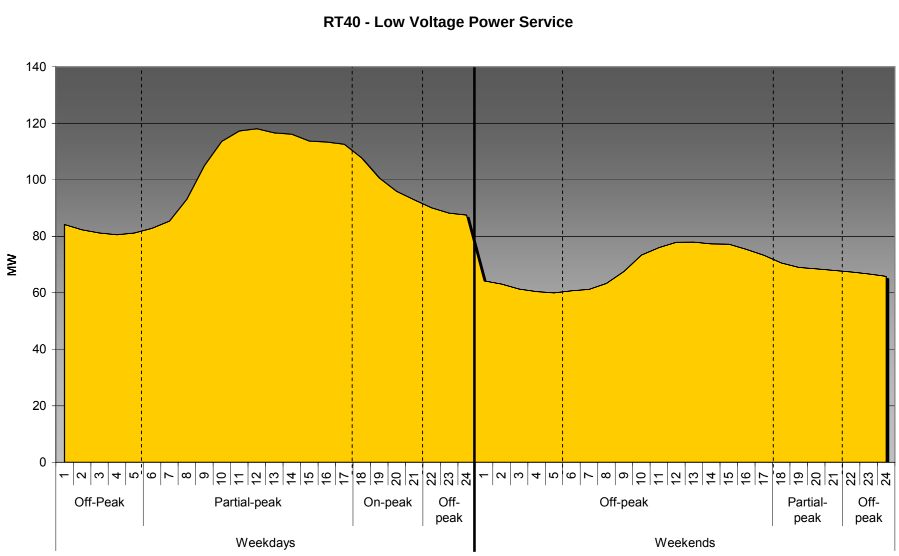
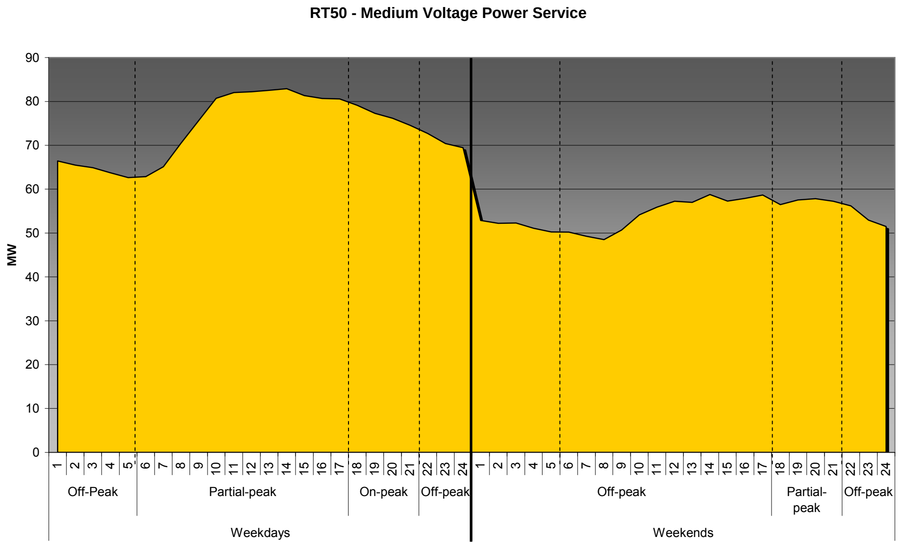


Figure 7.6: RT50 Medium Voltage Power Service



7.1.4.1 RT60 Street Lighting

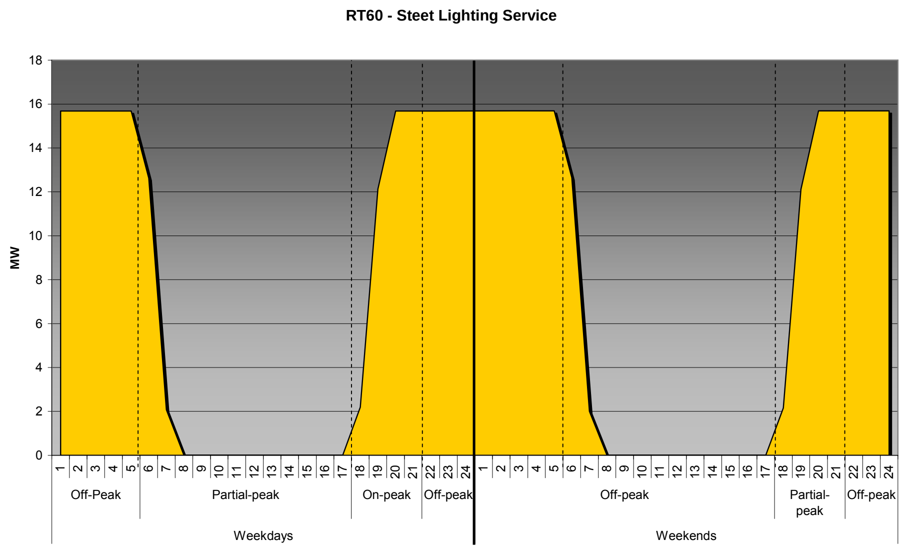
The streetlight class (RT60) shows a unique behaviour. The curve in this class has a plateau or flat profile which presents a practically instantaneous demand at sunset and a drop to zero at sunrise.

Given the particularity of this class, their consumption patterns were calculated by taking the data of sunrise and sunset hours of the capital city of the country, that it is considered as the greater demand centre. This data is used to distribute the annual street lighting energy from the base year, in order to obtain the efficient curve of this category.

The category load curve was treated in the following way:

- Selection of the city to be considered as the geographic centre of the concession area. This city was Kingston, specifically its harbour, and its position is: West longitude 076º 47' and North latitude 17º 57'. Time zone: 5 Hours the West of Greenwich. (Consulted Source: USNO Astronomical Application Department)
- From the total annual energy of 2008 (68,028 MWh) and the times of sunrise and sunset of every day of the year, the 365 curves of street lighting was calculated.

Figure 7.7: RT60 Street Lighting



7.1.4.2 RT10 Residential Service

RT10 was the last category for which the load curve was calculated. As stated previously, the lack of data related to this category determined the necessity for carrying out an estimation of the load profile by subtracting the known data (curves of the other categories and losses) from the JPS Total System curve.

The percentages of energy losses (referred to Net Generation) used were:

Table 7.5: Breakdown of System Losses

Losses	%
Gen / Tr Losses	0.40%
Tr Losses	1.80%
Tr/MV Losses	0.40%
MV Losses	2.30%
MV/LV Losses	2.40%
LV Technical Losses	3.00%
Non Technical Losses	12.58%
Total	**22.88%**

The profile of JPS' Total System curve and its composition is as follows, with the RT10 curve being determined as the residual.

Figure 7.8: Average System Curve

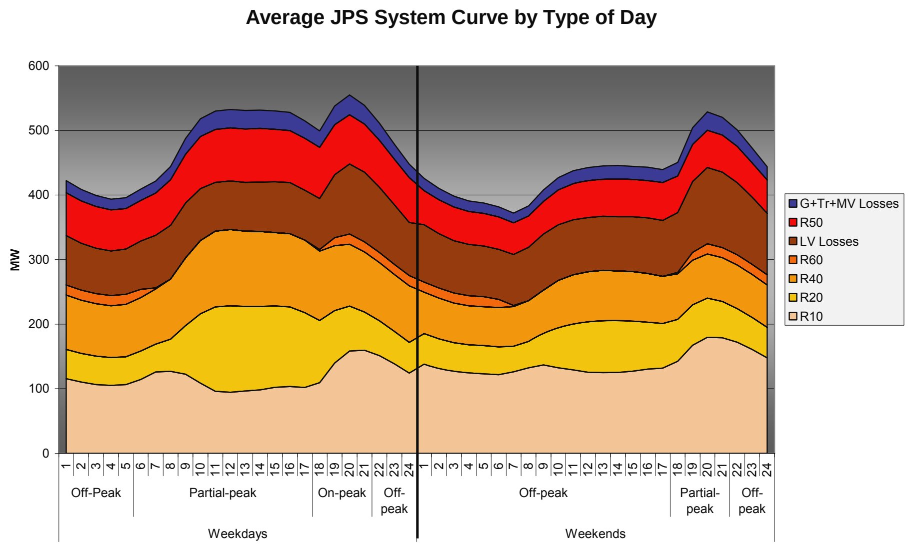
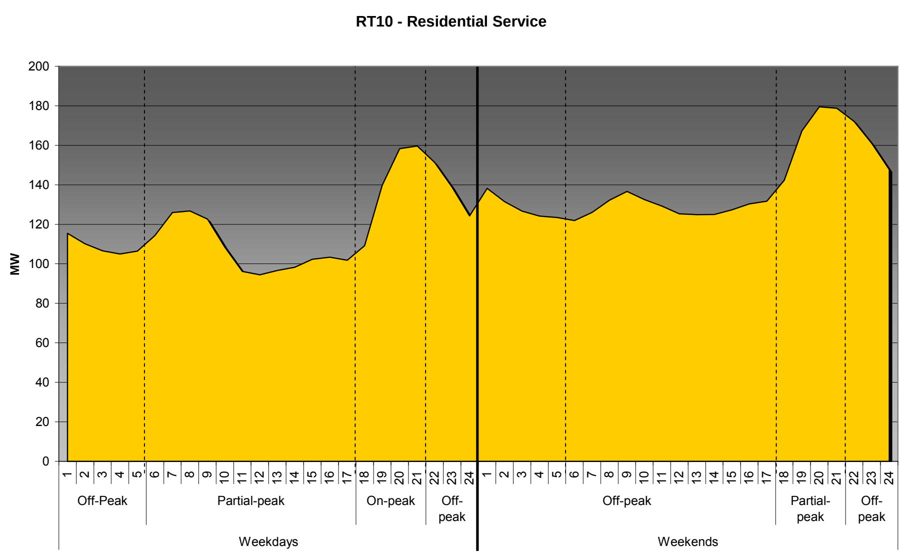


Figure 7.9: Rate 10 System Curve



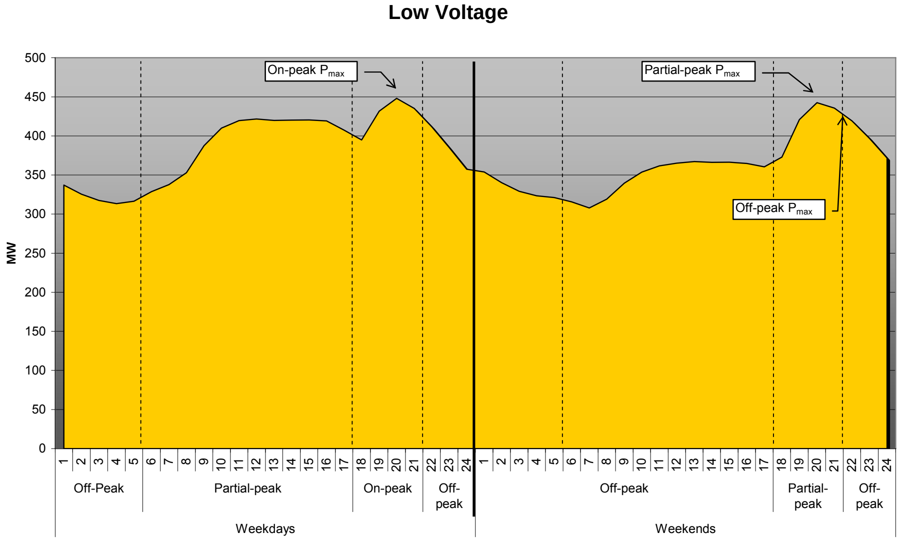
7.1.5 Parameter Calculation

The parameters $\boldsymbol{KonP_K}$, $\boldsymbol{KpaP_K}$ and $\boldsymbol{KoffP_K}$ that are the percentages of energy consumed by each category $\boldsymbol{k}$ in the peak, partial peak and off peak blocks respectively were estimated using the data for each category only. This is also the case for the $\boldsymbol{UF_K}$.

For calculating the Total Coincidence Factors, a curve of each voltage level has to be built to identify the moment of the day in which the maximum power occurs.

The following graphs show the moments of the maximum power for the 3 blocks for each voltage level.

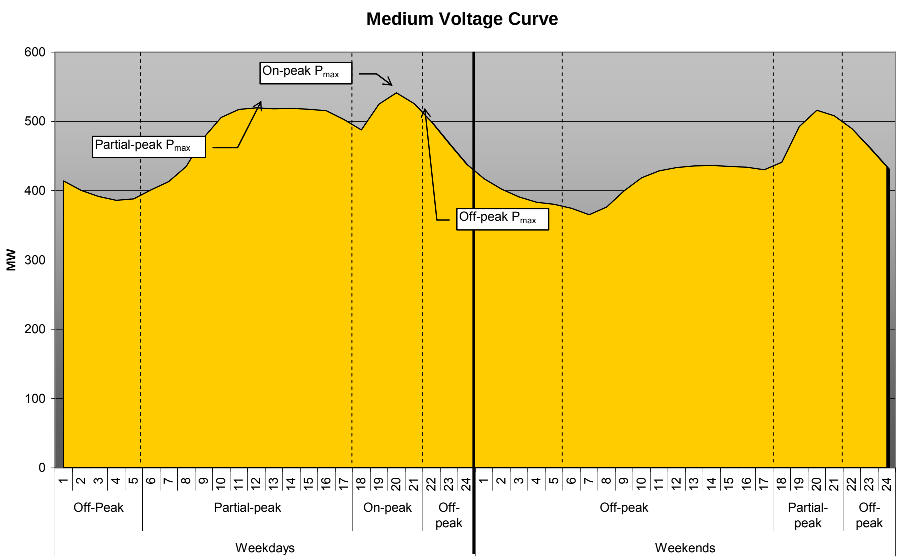
Figure 7.10: Low Voltage Load Curves



Notes:

- The maximum power demand for On-Peak hours takes place at 8:00 p.m. on Weekdays.
- The maximum power demand for Partial-Peak hours takes place at 8:00 p.m. on Weekends.
- The maximum power demand for Off-Peak hours takes place at 10:00 p.m. on Weekends.

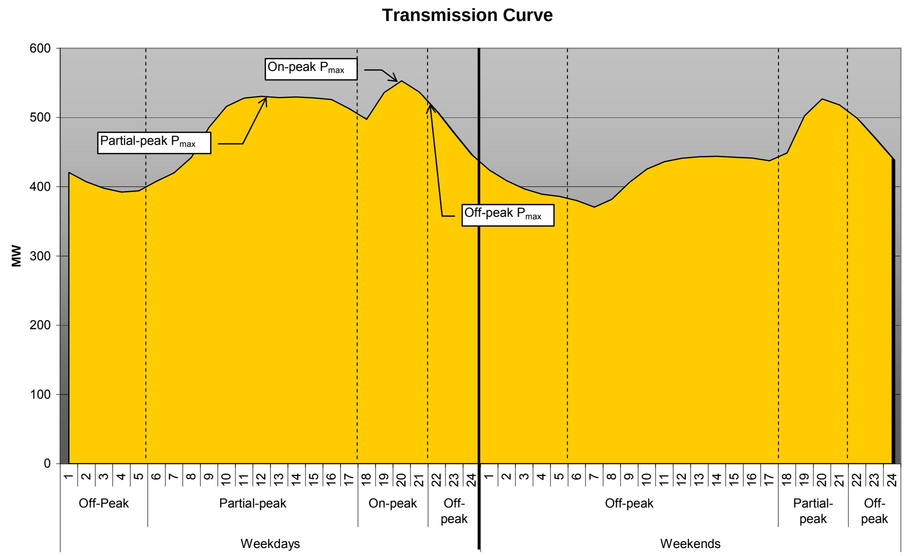
Figure 7.11: Medium Voltage Load Curves



Notes:

- The maximum power demand for On-Peak hours takes place at 8:00 p.m. on Weekdays.
- The maximum power demand for Partial-Peak hours takes place at 12:00 p.m. on Weekdays.
- The maximum power demand for Off-Peak hours takes place at 10:00 p.m. on Weekdays.

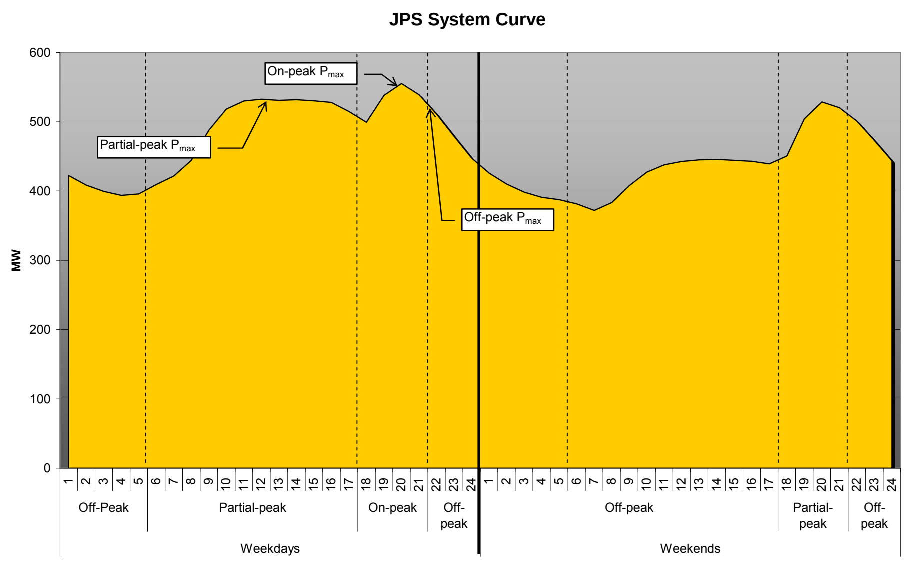
Figure 7.12: Transmission Curve Load Curve



Notes:

- The maximum power demand for On-Peak hours takes place at 8:00 p.m. on Weekdays.
- The maximum power demand for Partial-Peak hours takes place at 12:00 p.m. on Weekdays.
- The maximum power demand for Off-Peak hours takes place at 10:00 p.m. on Weekdays.

Figure 7.13: JPS System Load Curve



Notes:

- The maximum power demand for On-Peak hours takes place at 8:00 p.m. on Weekdays.
- The maximum power demand for Partial-Peak hours takes place at 12:00 p.m. on Weekdays.
- The maximum power demand for Off-Peak hours takes place at 10:00 p.m. on Weekdays.

After having determined the moment of each maximum power, it was determined for each element of the sample its coincidental powers, in order to allow the estimation of the different Total Coincidence Factors.

7.1.6 Parameter results

Based on the information processed, the following parameters shown below were estimated, along with the variance and estimation error for those categories where a sample was taken. Generally, in these studies, the allowable error is 10% at a significance level of 90%.

Table 7.6: Parameters

Group	KonP	KpaP	KoffP	UF	ICF	TCF LV onP	TCF LV paP	TCF LV offP	TCF onP	TCF paP	TCF offP
RT10	13.66%	37.55%	48.79%	47.99%	69.72%	61.49%	69.72%	66.85%	61.49%	36.69%	58.76%
RT20	12.57%	53.58%	33.86%	48.48%	89.58%	46.50%	40.66%	34.72%	46.50%	89.58%	35.96%
RT40	13.16%	46.32%	40.53%	68.38%	89.87%	72.98%	52.12%	51.34%	72.98%	89.87%	68.56%
RT50	13.40%	44.46%	42.14%	76.62%	93.13%				85.57%	92.36%	81.67%
RT60	30.45%	2.58%	66.97%	49.37%	100.00%	99.93%	100.00%	100.00%	99.93%	0.00%	99.93%

Note: *The maximum power of the 3 blocks in MV, Tr and G occur at the same moment, therefore TCF onP, TCF paP and TCF offP are the total coincidence factors for the three voltage levels.*

7.1.6.1 Variance

Because the parameters considered consist of quotients of random variables, the mathematical expression of the variance that must be applied in these cases is as follows:

$$Var(\hat{R}_k) = \frac{1}{\left(\sum_e N_e \times \bar{x}_e\right)^2} \sum_{e=1}^{2} \frac{N_e^2 (N_e - n_e)}{N_e \times n_e} \times \frac{\sum_{i=1}^{n_e} (y_i - \hat{R}_k \times x_i)^2}{n_e - 1}$$

where:

- VAR(R_k): Estimator of the Variance of the estimator of the sample mean of the parameter corresponding to group *k*
- $\bar{x}_e$: Sample mean of the variable that applies in the denominator of the simple mean of the parameters analyzed of the stratum *e* of the group *k*
- N_e: Population size of the stratum *e* of the group *k*
- n_e: Simple size assigned to the stratum *e* of the group *k*
- x_i: Observed variable of the client *i* that applies in the numerator of the estimator of the sample mean
- $\hat{R}_k$: Estimator of the sample mean of the parameter *R* of the group *k*
- y_i: Observed variable of client *i* that applies in the denominator of the estimator of the sample mean

In the following table are shown the estimators of variance of the sample means of those groups subjected to sampling.

Table 7.7: Variance Estimators

Group	KonP	KpaP	UF	TCF LV onP	TCF LV paP	TCF LV offP	TCF onP	TCF paP	TCF offP
RT20	0.00001	0.00009	0.00013	0.00051	0.00042	0.00033	0.00051	0.00017	0.00035
RT40	0.00000	0.00002	0.00009	0.00020	0.00021	0.00022	0.00020	0.00007	0.00023

7.1.6.2 Estimation Error

The mathematical formula applied on the calculation of the estimation error of each one of the parameters of each group subjected to sampling is as follows:

The generic formula is:

$$Relative\ Error = z \times \frac{\sqrt{Var(\hat{R}_k)}}{\hat{R}_k}$$

where:

- $\hat{R}_k$: estimator of the sample mean of the parameter R of the group k
- $\sqrt{Var(\hat{R}_k)}$: Estimator of the standard deviation of the sample mean of the parameter R of the group k
- z : 1.645 for a confidence level of 90%

The estimation errors reached are as follows:

Table 7.8: Estimation Errors

Group	KonP	KpaP	UF	TCF LV onP	TCF LV paP	TCF LV offP	TCF onP	TCF paP	TCF offP
RT20	3.27%	2.90%	3.90%	7.97%	8.30%	8.63%	7.97%	2.38%	8.61%
RT40	1.83%	1.69%	2.23%	3.17%	4.56%	4.78%	3.17%	1.58%	3.66%

As it can be observed, all the parameters have been estimated with an estimation error below the allowable one (10%).

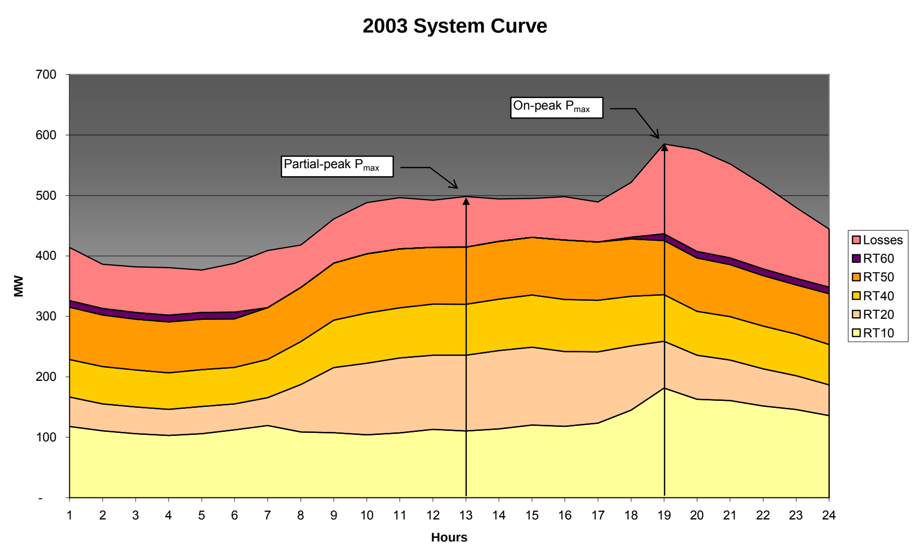
7.1.7 JPS System Curve Comparative Analysis

The following analysis of the JPS System Curve between 2003 and 2008 was performed to facilitate the decision-making process regarding the tariff design for the next period (2009 – 2013).

7.1.7.1 2003 Load Characterization Study

The information received relating to the 2003 Load Characterization Study, facilitated an examination of the profile of the system curve on a weekday (November 12th, 2003), and the contribution to the On-Peak and Partial-Peak of each category..

Figure 7.14: 2003 System Load Curve



Notes:

- The maximum power demand for On-Peak hours took place at 7:00 p.m.
- The maximum power demand for Partial-Peak hours took place at 12:30 p.m.

The Partial-Peak maximum demand was 15% lower than the On-Peak one and the average difference between these two in 2003 was around 11%.

The category contribution to the maximum demand by block was as follows (without losses):

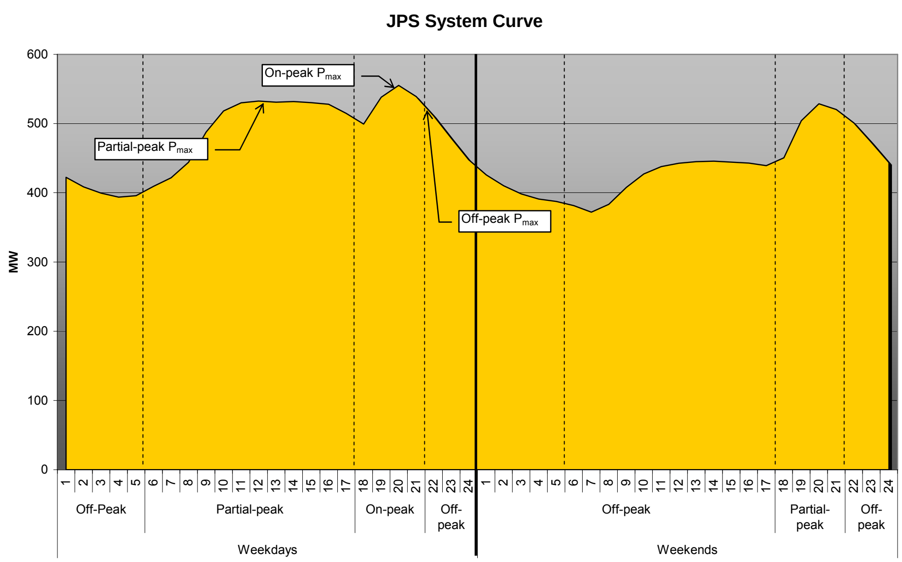
Table 7.9: Maximum Demand Contribution by Block

	Max Demand Contribution	
Rates	Partial Peak	On Peak
RT10	27%	42%
RT20	30%	18%
RT40	22%	19%
RT50	21%	19%
RT60	0%	3%

7.1.7.2 2008 Load Characterization Study

JPS Total System curve profile and its composition are as follows:

Figure 7.15: 2008 System Load Curve



Notes:

- The maximum power demand for On-Peak hours takes place at 8:00 p.m. on Weekdays.
- The maximum power demand for Partial-Peak hours takes place at 12:00 p.m. on Weekdays.

The curve corresponds to the 2008 average curve. That is to say, it is not the curve of the Peak Day. The difference between the On-peak maximum demand and the Partial-peak maximum demand is 4%. It is important to note that during 2008 the On-peak maximum demand was 614.7 MW and the Partial-peak maximum demand was 621.7 MW.

In considering the maximum demand for Partial-Peak hours, it was observed that:

- During 2008 in 39 of 53 weeks (74%) the maximum demand for Partial-Peak hours occurred on Weekdays (day peak).
- In the rest of weeks (26%) where the partial peak maximum demand occurred during weekends (evening peak) it can be seen that there is an average difference of 4.6% between the day peak and the evening peak.

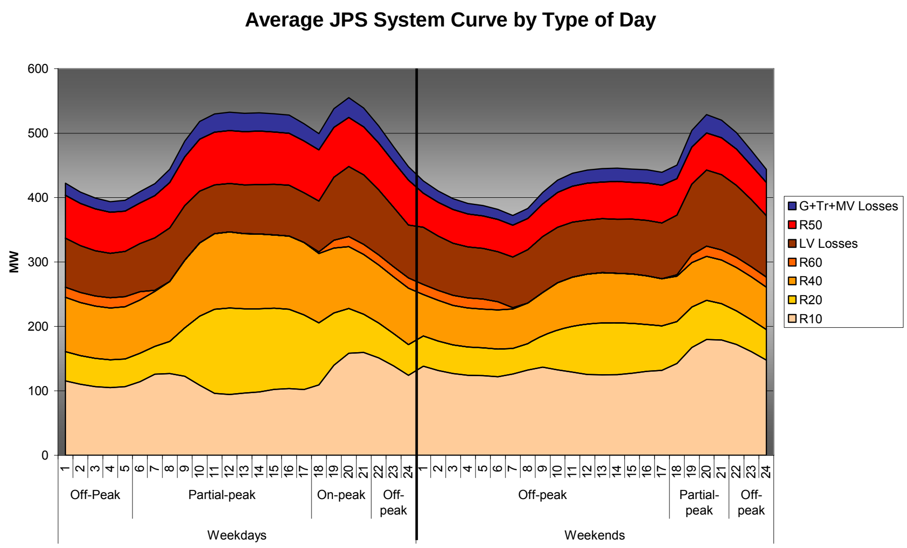
The above stated comments demonstrate that one can compare the 2003 results with 2008, although there is only a weekday curve for 2003.

The category contribution to the maximum demand by block is as follows (without losses):

Table 7.10: Maximum Demand by Block

	Max Demand Contribution	
Rates	Partial Peak	On Peak
RT10	22%	38%
RT20	31%	17%
RT40	28%	23%
RT50	19%	18%
RT60	0%	4%

Figure 7.16: Weekday and Weekend System Curves



Below, the profile for RT40 and RT50 customers are shown taking into account their tariff option (STD and TOU). They are expressed in relative terms due to a scale matter (TOU typical customer consumes 2-3 times a STD customer).

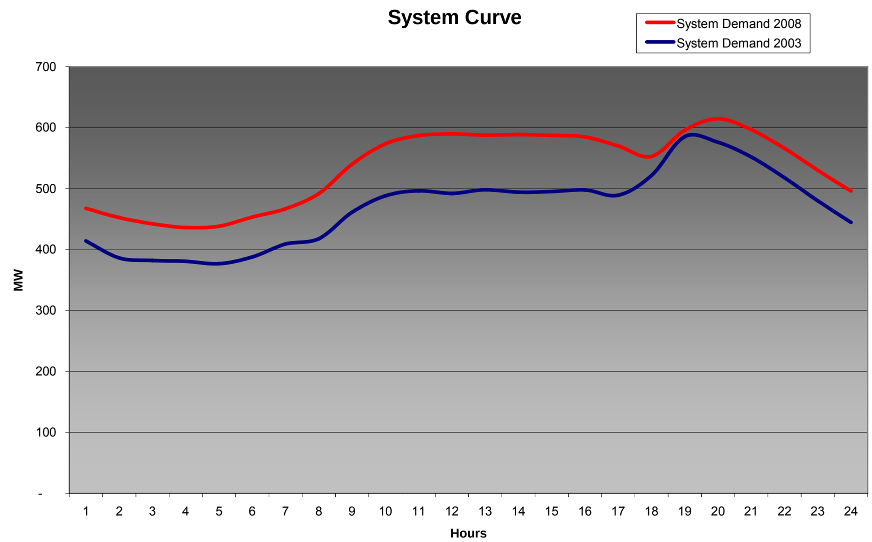
7.1.8 2003 vs. 2008 System Load Curve Analysis

System Load Curve

2003 and 2008[20] System curves are as follows:

[20] The 2008 curve was adjusted to equal in the On-Peak block the registered real maximum demand.

Figure 7.17: System Curve Comparison



Notes:

- Variation for the maximum demand within the On-peak block: (approx. 5%)
- Variation for the maximum demand within the Partial-peak block: (approx. 18%)

The demand growth has been higher within the Partial-peak block with respect to the On-peak block

7.1.8.1 Curves by Category

The curves are presented below in absolute and relative terms for each category and provide an explanation of the changes in load structure between 2003 and 2008.

The curve in MW illustrates the impact of each category to the System Curve. The curve in relative terms avoids scale issues, thereby showing the variations in the consumption behaviour of the typical consumer.

Figure 7.18: Rate 10 Load Curve Comparison

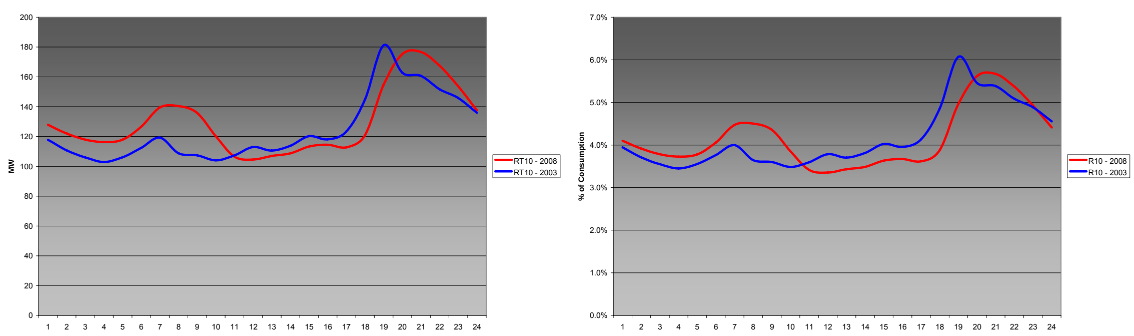
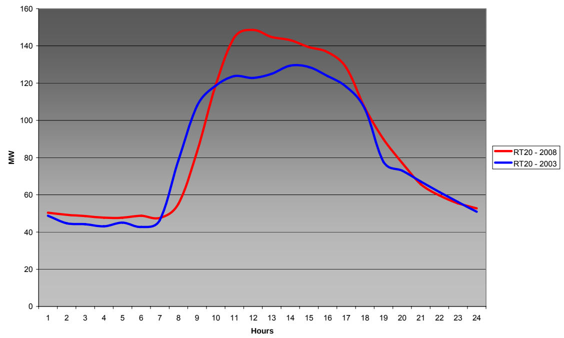
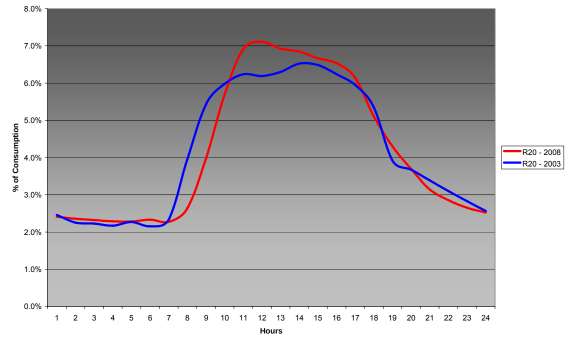


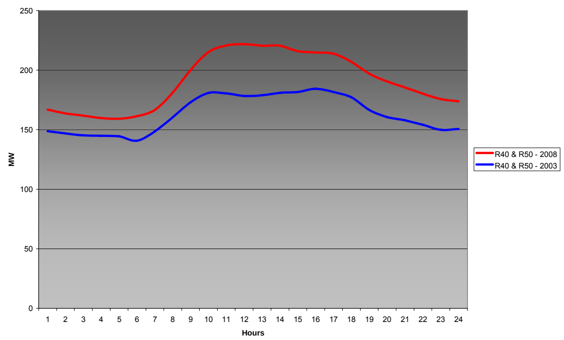
Figure 7.19: Rate 20 Load Curve Comparison

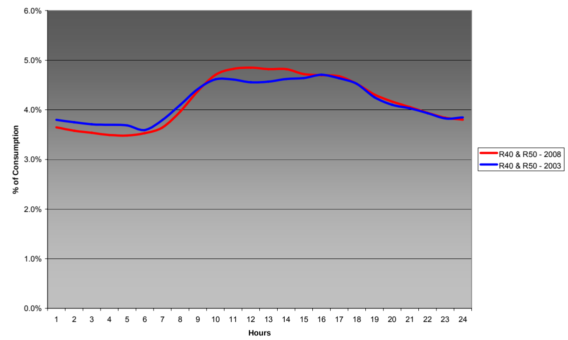




These categories are presented together to avoid making mistakes while organizing the 2003 data that considered four groups of consumers: RT40 LV, RT40 MV, RT50 LV and RT50 MV.

Figure 7.20: Rate 40 and 50 Load Curve Comparisons





The previous figures indicate that:

1. The most important category responsible for the Partial-peak maximum demand growth has been RT20, which has experienced variations in the distribution of its consumption keeping its behaviour in the Peak-period but moving consumption from the firsts hours of the Partial-peak to the middle hours of the same period, causing a more than proportional growth of the peak of this period with regard to the evening peak.
2. RT40 and RT50 have experienced a slight change in their profile between the Off-peak and the Partial-peak periods, contributing to the Partial-peak maximum demand growth. Even though the TOU profile reflects an efficient use of the grid capacity and, mainly RT40) a further analysis by customer could be carried out to state definitively if:
   a. they have really changed the consumption patterns due to a strong price signal or,
   b. they have chosen the TOU option because it is the one that better fits their consumption patterns and indirectly reduces their bills.

   It is clear that it is a combination of both phenomena and reflects that these categories evaluated as a whole (TOU + STD) have not experienced a reduction in the Peak-block period. The improvements done by the TOU have been offset by the STD. Putting this in a positive way, one can say that if the TOU option had not existed, the increase in the evening peak would have been more significant given that STD customers have increased their consumption in this period.

7.1.8.2 TOU vs. STD Billing Sensitivity

The following tables show what would be the bill (Demand Charge only) for the RT40 and RT50 typical customers. In both Rates the bill has been calculated bill for a:

- STD option customer as if he keeps in this option
- STD option customer as if he were in the TOU option
- TOU option customer as if he were in the STD option
- TOU option customer as if he keeps in this option

Table 7.11: Rate 40 Billing Analysis

RT40: TOU and STD Tariff Option Demand Billing Analysis

STD: Demands for Billing		Typical Customer kVA	Charges (JMD/kVA)	Bill (JMD)	
If it is STD	Max	87.68	914	80 140	STD
If it is TOU	On Peak	73.76	510	75 000	TOU
	Partial Peak	87.20	399		
	Off Peak	69.97	37		

TOU: Demands for Billing		kVA	Charges (JMD/kVA)	Bill (JMD)	
If it is STD	Max	203.46	914	185 961	STD
If it is TOU	On Peak	169.91	510	172 768	TOU
	Partial Peak	199.88	399		
	Off Peak	171.97	37		

In the case of RT40, the customer that has chosen the TOU option will remain with that option due to a lower bill, but the bill sensitivity done with the customers with STD option indicates that there are still potential TOU clients.

Table 7.12: Rate 50 Billing Analysis

RT50: TOU and STD Tariff Option Demand Billing Analysis

STD: Demands for Billing		Typical Customer kVA	Charges (JMD/kVA)	Bill (JMD)	
If it is STD	Max	627.18	822	515 540	STD
If it is TOU	On Peak	578.25	459	507 135	TOU
	Partial Peak	626.59	358		
	Off Peak	511.74	34		

TOU: Demands for Billing		kVA	Charges (JMD/kVA)	Bill (JMD)	
If it is STD	Max	1 310.03	822	1 076 847	STD
If it is TOU	On Peak	1 193.86	459	1 046 550	TOU
	Partial Peak	1 278.57	358		
	Off Peak	1 201.13	34		

In the RT50 STD option there are still potential TOU clients.

7.1.9 Conclusions

- Taking a look at the Current System Curve it is evident that JPS has achieved an optimal profile with a double peak very close to each other (equal in 2007 and 1% higher the day peak with respect to the evening peak). The measures adopted regarding the price signal given by the tariff have been successful and should be kept for the next tariff period. Perhaps slight changes should be done to encourage more the consumption during the off-peak period.
- Another issue to tackle is the RT20 consumption. Due to the lack of a TOU option, or other type of tariff design to induce a more efficient use of the grid, actions in the field of efficient use of energy must be carried out, such as:

– Lighting: Lamps Replacement
– Work on the isolation of rooms in small industrial and commercial buildings so as to make a better use of cooling.
– Encourage the replacement of old and inefficient equipment (Refrigerators, Air conditioners)

Most of these recommendations as well as others are already on JPS' web site, but perhaps other actions should be taken to get a better behaviour not only in RT10 but also RT20.

The other thing that can be done is to review the 25 kVA demand as the limit between RT20 and RT40. In other countries, medium demand customers are the ones whose demands are over 10 kVA. In the case of JPS, RT20 presents the following characteristics according to the curve and billing files processed during the Load Characterization Campaign Study:

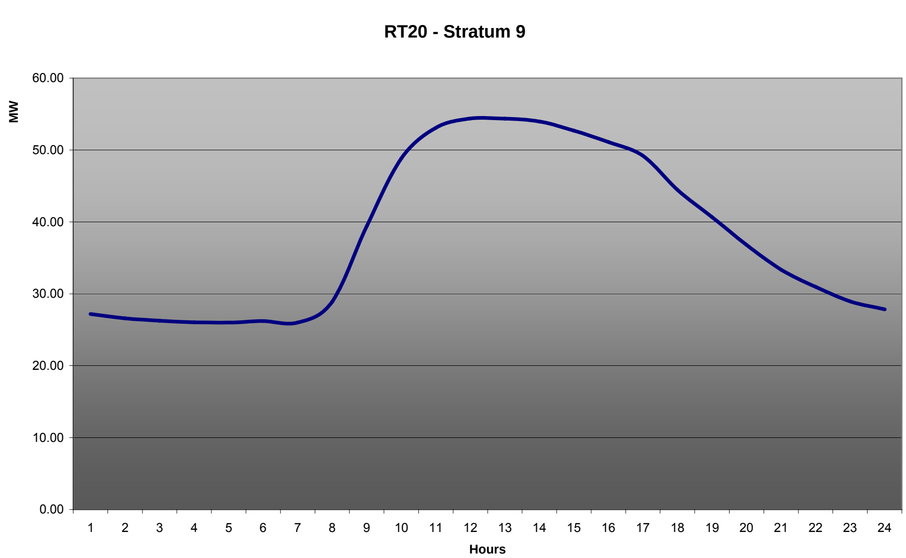
Table 7.13: Rate 20 Customer Stratum

			2 008					
Rate	Stratum	Range	Average Customers	%	kWh	%	Load Factor	Average Maximum Demand (kW/Customer)
RT20	1	0 - 100 kWh/mes	18 562	30%	8 015 290	1%	26%	0.19
RT20	2	100 - 500 kWh/mes	24 360	40%	66 121 328	10%	46%	0.68
RT20	3	500 - 1000 kWh/mes	7 152	12%	57 198 724	9%	42%	2.16
RT20	4	1000 - 1500 kWh/mes	3 184	5%	43 660 308	7%	41%	3.80
RT20	5	1500 - 2000 kWh/mes	1 963	3%	38 256 759	6%	41%	5.46
RT20	6	2000 - 2500 kWh/mes	1 233	2%	30 962 252	5%	46%	6.17
RT20	7	2500 - 3000 kWh/mes	840	1%	25 821 072	4%	49%	7.15
RT20	8	3000 - 4500 kWh/mes	1 566	3%	64 098 960	10%	51%	9.24
RT20	9	> 4500 kWh/mes	2 583	4%	304 130 704	48%	56%	23.90
Total			61 444	100%	638 265 397	100%		

It has been highlighted that that stratum labelled as 9 represents 48% of RT20 energy consumption and the average maximum demand of these customers is over 10 kW (around 24 kW).

The curve profile of this stratum in weekdays is:

Figure 7.21: Rate 20 Stratum



It would be interesting to lower the limit of 25 kVA to 10 kVA and re-classify all the RT20 – Stratum 9 customers (approximately 2,500) as RT40 customers. This way they will be able to choose the TOU option that will contribute to improve the System curve profile, considering that this option encourages the consumption during the off-peak block.

- At the present time, the fuel charge is uniform for all STD customers. TOU customers pay the uniform fuel rate multiplied by a different factor per hour block. In the Load Characterization Study the following parameters were calculated by category among others:
  - % of On-peak energy consumption
  - % of Partial-peak energy consumption
  - % of Off-peak energy consumption

These parameters will be useful for stating a weighted fuel charge per category taking into consideration the responsibility that each category has in the total energy consumption by block. For TOU option customers, the unitary cost per kWh in each block should be a pass-through charge (prior to the heat rate and losses adjustment).

7.2 Non-Fuel Tariff Rates

This section aims at determining the set of tariffs that will allow JPS to obtain the Revenue Requirement presented in **Section 5.3**. Different approaches were carried out looking for a set of tariffs that balanced the interests of both the customer and the Company:

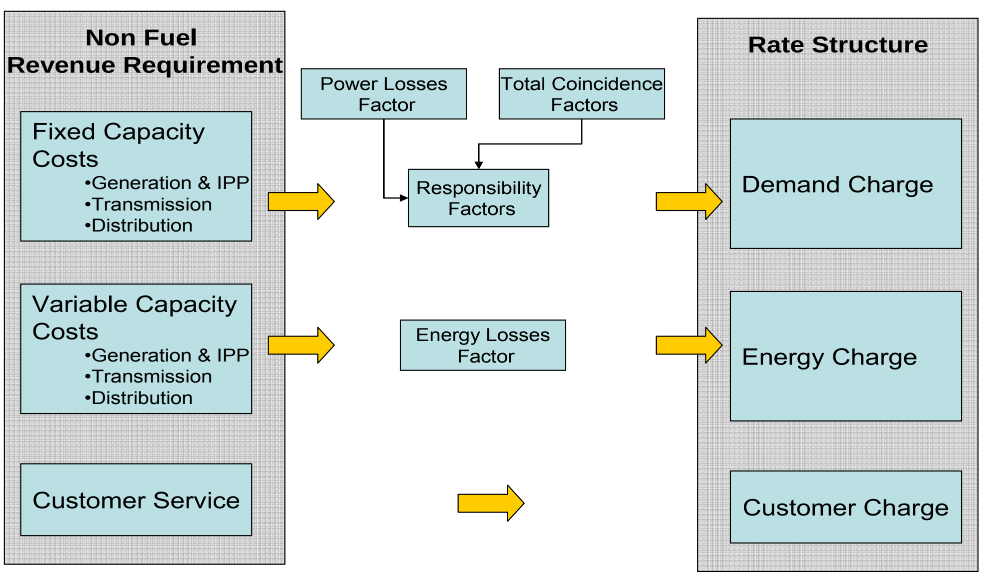
- Customer perspective: simple, fair, equitable and affordable rates; and
- Company perspective: cost reflective rates which when applied to the billing determinants will yield revenues equal to the Non-Fuel revenue requirement.

From the different approaches carried out to allocate costs by category, the Average Cost approach is presented below as a starting point and the Two Part Tariff approach, which is the final basis of the present proposal.

The fundamental idea is to follow the principle of cost causality from the cost of service study. The "cost causer pays" rule says that costs should be assigned to customers so that the party that causes a cost to be incurred will pay for those costs. Failure to reflect cost causation in the tariff structure would result in cross-subsidies, whereby some customers would subsidize other customers. Perpetuating cross-subsidies undermines both competition and efficiency goals.

The **Figure 7.22** below summarises the linkage between the Revenue Requirement and the Tariff Design.

Figure 7.22: Distribution of Revenue Requirement over Rate Structure



The Non-Fuel Costs from Administration were distributed between the other activities (Generation, Transmission, Distribution and Commercial), considering the direct OPEX and Capital Cost of each activity. For this reason they are not presented in the figure above.

The cost allocation by activity was extracted from the accounting systems. The OPEX could be broken down into:

1. Generation
2. Transmission
3. Distribution (Medium Voltage and Low Voltage)
4. Customer Services
5. Finances
6. General and Administration

Distribution costs breakdown by voltage level was done based on the network length of each voltage level.

The asset base and all that has to do with it (Gross asset base, Accumulated Depreciation, Depreciation expenses and Net asset base) could be broken down by activity too:

1. Generation (Steam production, Hydraulic production, Other production)
2. Transmission (High Voltage)
3. Distribution (Medium Voltage, Low Voltage and Customer Service)
4. General Property

The Distribution asset base breakdown by voltage level was done based on the network length of each voltage level. **Table 7.14** presents the breakdown mentioned by component of the Test Year Revenue Requirement.

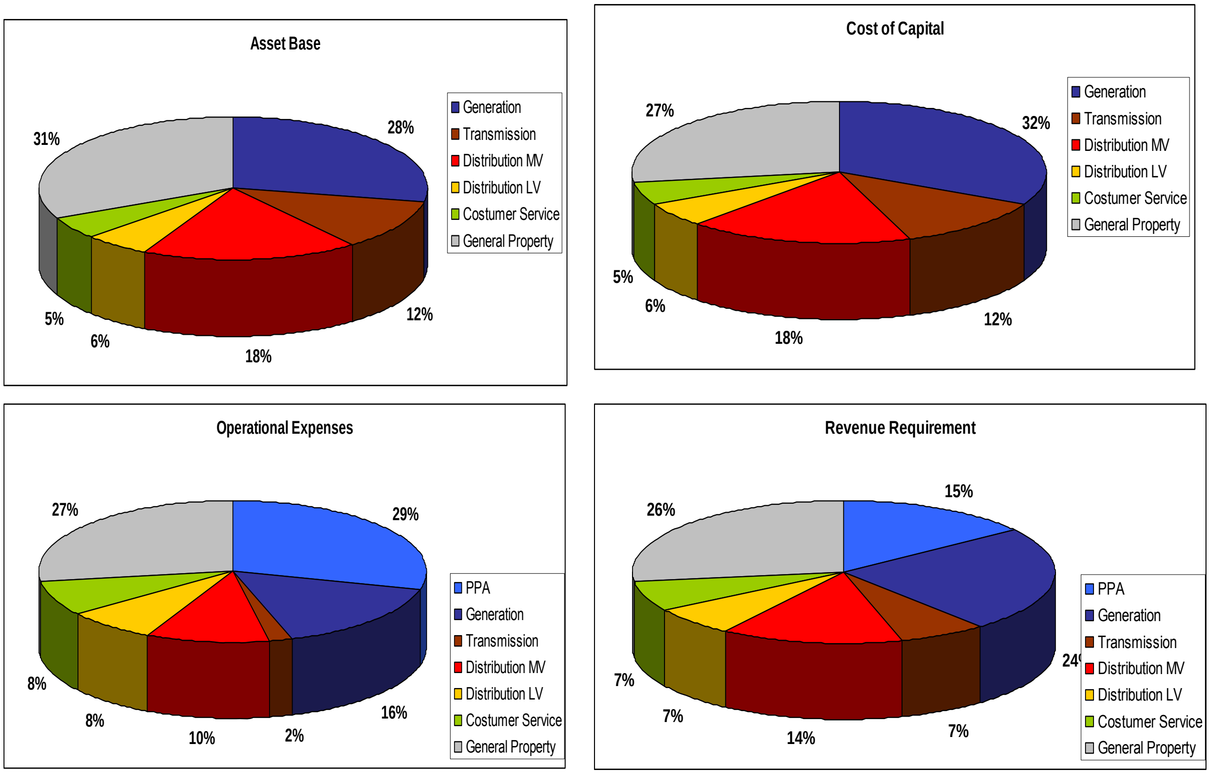
Table 7.14: Revenue requirement by Activity

			Cost of Capital				
Activity	Unit	Asset Base	Depreciation	Opportunity Cost of Capital	Total	Opex & Others	Revenue Requirement
PPA	J$'000					5,661,990	5,661,990
Generation	J$'000	19,776,153	2,143,527	3,856,518	6,000,044	3,030,712	9,030,756
Transmission	J$'000	8,119,703	613,991	1,583,411	2,197,402	390,614	2,588,016
Distribution MV	J$'000	12,642,081	766,286	2,465,313	3,231,599	2,001,800	5,233,399
Distribution LV	J$'000	3,992,236	241,985	778,520	1,020,505	1,461,572	2,482,077
Costumer Service	J$'000	3,581,102	299,286	698,345	997,631	1,559,123	2,556,754
General Property	J$'000	22,263,682	631,766	4,341,607	4,973,373	5,244,569	10,217,942
Total	**J$'000**	**70,374,955**	**4,696,840**	**13,723,715**	**18,420,555**	**13,688,389**	**37,770,934**

Note that:

1. Asset Base:
    a. Is the total net asset base including cost free assets; and
    b. General Property includes Net current assets, CWIP and other noncurrent assets.
2. Opportunity Cost of Capital
    a. Cost free assets were deducted proportionally in all the activities; and
    b. The net asset base without cost free assets was multiplied by the pre-tax WACC.
3. OPEX & Others
    a. PPA expenses are included; and
    b. General Property includes:
        i. Net finance costs.
        ii. Other income.
        iii. Self-insurance fund contributions.
        iv. Gross up for taxes on SIF.
        v. Caribbean Cement revenues.

Figure 7.23: Cost by Activity



For the tariff design, as explained below, the Non-fuel Revenue Requirement is broken down by the nature of the costs. Fixed capacity costs are linked to the maximum demand that each voltage level has in the different time blocks. Variable costs are linked to energy consumption and commercial costs depend mainly on the number of customers. The unitary value of these components of the revenue requirement multiplied by the correspondent responsibility factors of each category allows the calculation of charges.

In some cases the ideal proposal must be modified due to metering constraints, e.g. Residential customer meters do not measure demand, therefore fixed capacity costs have to be recovered through the energy and customer charges (i.e. residential customers do not have a demand charge).

7.2.1 Rates with Average Costs Approach

The following section presents the results of average tariffs for the current customer categories, considering the allocation of the costs of providing the service through the application of the responsibility factors obtained from the load characterization campaign. This calculation allows the comparison between the rate in force per category and the average cost that each of them should pay according to their cost of service responsibility. These rates, which are meant to recover the costs of providing the service, do not take into account socio-economic factors that finally constrain the actual set of tariffs that are implemented. Also, this cost allocation method focuses on costs but fails to consider if the demand, composed by different customer types will be able, and willing to consume and pay for the electricity service at the average cost. Based on these aspects, in the next section the Two Part Tariff approach is carried out aiming to deal with socio-economic factors and demand side considerations and, at the same time, allowing the Company to meet its full revenue requirements.

7.2.1.1 Variable Non-Fuel Costs

The variable non-fuel costs (basically Generation variable non-fuel costs) are distributed between the different categories of users, based on the consumption function that each category demands, adding the energy losses originated in the network from the connection level up to the Generation level.

$$E_{GEN} = \sum_k E_k \times LossF_{Conn\_level\,k}^{Gen}$$

where:

E_{GEN}: Generated energy
E_k: Consumed energy by category ***k***

$LossF_{Conn\_level\,k}^{Gen}$: Accumulated energy losses factor from the connection level of category ***k*** to the Generation level.

Therefore, the variable non-fuel Generation cost from which a certain category ***k*** is responsible is:

$$CostG_k = CostG \times \frac{E_k \times LossF_{Conn\_level\,k}^{Gen}}{E_{GEN}}$$

where:

$CostG_k$: Generation Cost assigned to the category ***k***

$CostG$: Total variable cost of Generation

7.2.1.2 Network Capacity Costs

In the case of capacity costs, the Company must design its network in order to meet the maximum demand that is caused in each network level by the customers who are connected downstream in that level. Therefore it is logical to think about a cost allocation criterion by each voltage level based on the contribution that each category has to the maximum power demand that takes place in that level.

Given a voltage level ***J***, the maximum demand is obtained from the variable energy and power sold, measured to the customers, the total coincidence factors obtained through the load characterization campaign study and the addition of the power losses.

$$\hat{P}^J = \sum_{k=1}^{n} \frac{E_k}{8760 \times LF_k} \times RF_k^J + \sum_{k=n+1}^{K} \left(\sum_{i \in k} \hat{P}_i \right) \times RF_k^J$$

where:

$\hat{P}^J$ = Maximum power at voltage level ***J***.

k: Category, where ***k=1, ...,n*** corresponds to the categories that only have energy measurement, whereas ***k=n+1, ..., K*** corresponds to the categories that have power measurement.

RF_K^J= Responsibility Factor of category ***k*** with voltage level ***J***. Equal to the product between the TCF_K^J and the total accumulated power losses factor from category ***k*** voltage level of connection up to voltage level ***J***.

E_K = Annual energy sold to category ***k****'s* customers

8,760 = Hours/Year

LF_k = Load Factor of the category ***k***.

$\hat{P}_i$ = Individual maximum registered power demand of the costumer ***i*** that belongs to the category ***k*** and has demand measurement.

The responsibility factors contribute to determine the participation that each category has at $\hat{P}^J$, and in this way allows the distribution of the costs linked to level ***J***.

From above, it can be determined that the contribution to the maximum demand of voltage level ***J*** of a category ***K*** is:

– If it is a category where customers have power measurement:

$$P_k^{Coin\,J} = \left(\sum_{i=1}^{N} \hat{P}_i\right) \times TCF_k^j \times AFP_{Connection\,Level}^J$$

– If it is a category where costumers only have energy measurement:

$$P_K^{Coin\,J} = \frac{\sum_{i=1}^{N} E_i}{T \times LF_k} \times TCF_k^j \times AFP_{Connection\,Level}^J$$

where:

$P_k^{Coin\,J}$: Power of category ***k*** coincidental with the maximum demand of the level ***J***.

$\boldsymbol{TCF_K^J}$: is defined as category k total coincidence factor with the maximum power of voltage level J. From the maximum power measured in a category k customer, this factor allows us to know the contribution to the maximum power of voltage level J.

$\boldsymbol{AFP^J_{Connection\,Level}}$: Accumulated factor of power losses from the connection level of category *K* to level *J*

T: Time

Then, the cost of level ***J***, assigned to the category ***k*** results:

$$Cost_k^J = Cost^J \times \frac{P_k^{Coin\,J}}{\hat{P}^J}$$

where:

Cost^J: Total capacity cost of the voltage level ***J***.

$\hat{P}^J$: Maximum power of level ***J***.

In the case of JPS, the consumption (energy and maximum demand) is measured by hour block (On-Peak, Partial-Peak and Off-Peak) for customers that apply to be in RT40 and RT50 where the Time-of-Use option is available. Due to this fact, the allocation cost mechanism involved the assignment of a percentage of the total costs calculated for each voltage level to each of the three time blocks. The portion of these costs, which each category is responsible for, was calculated considering the power demand of each category coincidental with the maximum demand calculated per voltage level and per block.

7.2.1.3 Commercial Costs

The Commercial Costs were separated into three groups:

- Residential Services
- General and Streetlight Services
- Power Services

The principle followed, by which, the customers have been separated into these groups, has the objective of assigning greater costs by customer to those groups whose size indicate to the Company a greater effort to satisfy their needs, or more personalized attention that at the end implies greater costs per customer.

Based on the above, a weighed percentage matrix was constructed in order to allocate total commercial costs.

7.2.1.4 Average Cost Approach

The **Table 7.15** below presents the revenue requirement by category according to the average cost approach.

Table 7.15: Revenue Requirement by Customer Category

Rate Category	Non Fuel Rev. Requirement J$'000
R10	14,039,881
R20	6,571,769
R60	886,244
R40 STD	8,643,223
R40 TOU	2,544,241
R50 STD	3,540,900
R50 TOU	1,544,677
Total JPS	**37,770,934**

To be able to compare the revenue requirement calculated by category according to the average cost approach with the revenue that JPS would obtain by multiplying the adjusted actual rate schedule to the Test Year determinants, the following data is presented in **Table 7.16.**

Table 7.16: Test Year Billing Determinants

				Billed Demand kVA			
Rate Category	Description	Customers	Energy (kWh)	STD	On-Peak	Partial-Peak	Off-Peak
R10	Residential: First 100 kWh	204,069	119,493,289				
R10	Residencial: Over 100 kWh	323,565	382,017,313				
R10	Residencial: Over 100 kWh		530,671,247				
R20	General	61,243	486,186,458				
R60	Streetlight	349	69,373,073				
R40	Power LV (STD)	1,466	642,349,989	205,381			
R40	Power LV (TOU)	417	281,631,809		47,046	60,375	55,216
R50	Power MV (STD)	94	360,169,129	84,094			
R50	Power MV (TOU)	27	136,097,694		29,929	43,018	44,584
Total JPS		**591,230**	**3,007,990,000**	**289,474**	**76,975**	**103,392**	**99,800**

Table 7.17: The Adjusted Actual rates at base FX rate of $85:

Rate Category	Description	Customer Charge JMD/Month	Energy Charge JMD/kWh	Demand Charge JMD/kVA STD	Demand Charge JMD/kVA On-Peak	Demand Charge JMD/kVA Partial-Peak	Demand Charge JMD/kVA Off-Peak
R10	Residential: First 100 kWh	102.00	6.54				
R10	Residencial: Over 100 kWh	102.00	11.42				
R20	General	234.00	10.15				
R60	Streetlight	850.00	12.03				
R60	Traffic Signals	850.00	12.03				
R40	Power LV	3,245.00	2.78	1,033.00	577.00	451.00	42.00
R50	Power MV	3,245.00	2.51	929.00	519.00	405.00	38.00

The non-fuel revenue result using the test year billing determinants and the actual tariffs currently in force is shown in **Table 7.18** below:

Table7.18: Test Year Non-fuel Revenues at Base Exchange rate of $85

Rate Category	Non Fuel Revenue J$'000
R10	9,986,470
R20	5,107,249
R60	838,187
R40 STD	4,386,780
R40 TOU	1,478,646
R50 STD	1,846,607
R50 TOU	759,005
Total JPS	**24,402,944**

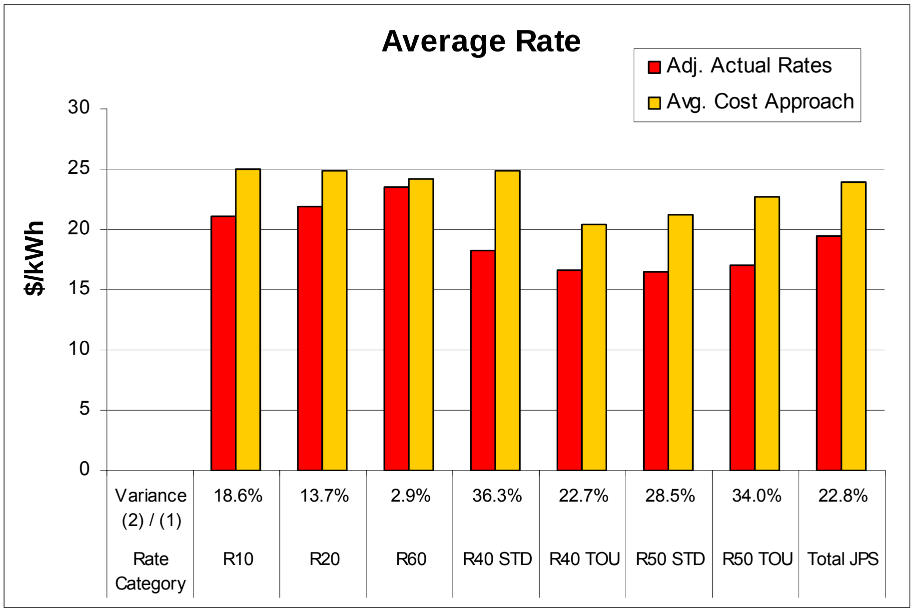
For comparison purposes, if one assumes a fuel charge of $11.404 /kWh (fuel charge for January 2009) and TOU option fuel charges are calculated with the actual premium factors (On-Peak: 1.302, Partial-Peak: 1.044 and Off-Peak: 0.869) the variation in the average tariff by category is as follows:

Table 7.19: Average Tariff by Category

Rate Category	Variance (2) / (1)	Adj. Actual Average Tariff $ / kWh (1)	Average Revenue Requirement $ / kWh (2)
R10	18.6%	21.08	25.01
R20	13.7%	21.91	24.92
R60	2.9%	23.49	24.18
R40 STD	36.3%	18.23	24.86
R40 TOU	22.7%	16.65	20.43
R50 STD	28.5%	16.53	21.24
R50 TOU	34.0%	16.97	22.75
Total JPS	**22.8%**	**19.52**	**23.96**

Using the average cost approach the following rate increase would be required by customer category.

Table 7.20: Tariff increase using Average Cost



In the following section, an alternative to the average cost tariff design is developed aiming at improving the tariff design through an allocation cost criteria based on aspects that has to do with the market JPS is serving, such as:

- Economic and social environment
- Non technical losses recovery
- Willingness to pay by category or by tiers within the categories
- Risk of losing Large customers that by the time being absorb part of the cost of service

7.2.2 Proposed Tariff Redesign

According to the marginalist theory[21,22,23,24], in the presence of cost sub-additivity, strictly marginalist tariffs produce lower revenues than required to sustain the utility company. The difference between the Revenue Requirements and the Revenue that would be obtained if prices were set equal to marginal costs is known as the Revenue Gap. Consequently, the tariff design must ensure the Revenue Gap is met.

Ramsey[25] developed an optimal deviation criterion of marginal costs that minimizes social welfare loss and the tariffs that result from applying the said criterion are known as Ramsey tariffs[26]. Ramsey's criterion (or inverse elasticity rule) is based on obtaining the missing revenue of those groups of consumers whose consumption is less dependent on the price (low demand

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[21] Electricity Economics Regulation and Deregulation, Geoffrey Rothwell and Tomás Gómez, IEEE Series

[22] Regulatory Reform Economic Analysis and British Experience, Mark Armstrong, Simon Cowan and John Vickers, MIT press.

[23] Power System Economics, Designing Markets for Electricity, Steven Staff, IEEE Series.

[24] Ronald H. Coase - The Marginal Cost Controversy - Economica, New Series, Vol. 13, No. 51. (Aug., 1946), pp. 169-182.

[25] Frank Ramsey - "A Contribution to the Theory of Taxation", Economic Journal, 37, March 1927

[26] William Baumol - "Optimal Departures from Marginal Cost Pricing", W. Baumol y D. Bradford, The American Economic Review, Vol. 60 No. 3, June 1970

elasticity – price). However, this method may lead to tariffs which are very inequitable, in the sense that often times it is the categories of the population with lower income that present the most inelastic demands. In addition, the method requires the estimation of the price elasticity of each customer class, which is not simple.

An alternative method to the Ramsey tariffs is the so-called equi-proportional mark-up method (EPMU). Under this method, the revenue gap is obtained by adjusting all the different tariff categories proportionally to the revenue obtained through the marginal costs.

Both Ramsey tariffs and EPMU tariffs consider deviations from the marginal costs and inevitably generate welfare loss.

A superior alternative is the Two-part Tariff[27] approach, with distributive considerations[28], where the variable charge is established equal to the long-run marginal cost and the revenue gap, to meet the utility's total costs, is recovered through a fixed charge, known as network access charge (NAC). Under this regime, there are no social welfare losses, and a "First Best" situation is maintained.

For achieving this type of structure one begins by calculating the long-run marginal costs for each activity and voltage level and multiplies them by the responsibility factors of each category of user. Then the revenue gap has to be recovered through a network access charge (NAC).

The long-run marginal cost of each voltage level is calculated by applying the Average Incremental Cost formula to the Total Cost variations due to the demand growth. The formula for the Long-Run Incremental Cost of j level is presented below:

$$LRAIC^{j} = \frac{\sum_{t=1}^{T} \frac{\Delta TC_t^j}{(1+CCR)^t}}{\sum_{t=1}^{T} \frac{\Delta D_t^j}{(1+CCR)^t}}$$

where,

ΔTC_t^j = total cost increase of voltage level "j" due to the demand growth.

ΔD_t^j = demand increase of voltage level "j".

CCR = the CCR discount rate is the regulated rate of return and the period T corresponds to the following tariff period 2009 - 2014.

The proposed tariff structure has tariff charges derived from marginal costs, to which a fixed monthly charge per customer is added, the NAC. This mechanism ensures that the different types of users pay according to their willingness to pay. This way the lower income sectors will pay a lower rate because they have a lower NAC. Further analysis done per customer category can determine that instead of recovering the NAC through a fixed charge per customer, part of it may be recovered through another type of charge (energy or demand charge). This happens for example when the number of tiers within a category is insufficient to group adequately a wide range of heterogeneous customers (Heterogeneity due to size of the customers, level of energy consumption and power demand, etc).

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[27] Stephen J Brown & David S. Sibley - The Theory of public utility pricing - Cambridge University Press – 1986 - Chapter 4 – Non uniform pricing I

[28] Martín Feldstein - Distributional Equity and the Optimal Structure of Public Prices - The American Economic Review, Vol. 62, No. 1/2. (1972), pp. 32-36

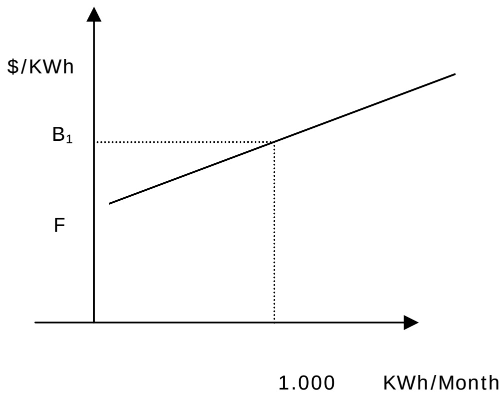
Additionally, the Two Part Tariff design becomes a useful structure that will help JPS and the Government to tackle the non-technical losses issue and ensures JPS revenue equal to the revenue requirement while mitigating the customers' loss of welfare.

7.2.2.1 Optimal Two Part Tariff Theory

In this methodology, there is a fixed charge regardless of the level of consumption as a right to access the service and a variable charge for each unit consumed. In this way, the bill paid by the consumer, B, can be expressed as follows:

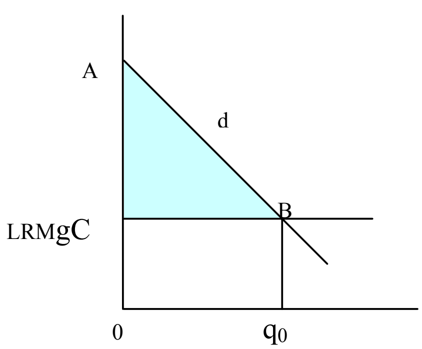
$$B = F + p \cdot q$$

Figure 7.24: Two Part Tariff Bill Structure



The choice of the fixed charge and the variable charge per unit deserves special attention because they affect the welfare of consumers and the company providing the service. An optimal two part tariff consists of setting a variable charge for each unit sold equal to the long-run marginal cost and a NAC which constitutes a fixed monthly charge regardless of the level of consumption to cover the portion of costs that is not possible to recover through the variable charge. For this NAC to be viable, it must not exceed the consumer surplus (CS), otherwise the customer would choose not to connect to the network and the utility would lose this client, with the risk that the customer becomes an illegal user consumer. This would increase the level of non-technical losses.

Figure 7.25: Consumer Surplus

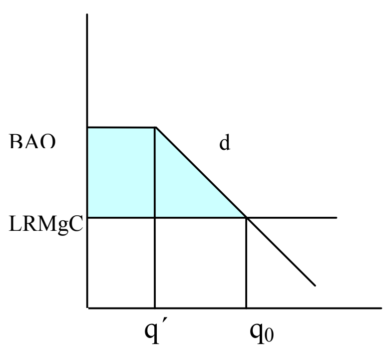


In **Figure 7.25** above, it can be observed that for quantities below q_0, the individual is willing to pay prices above the long-run marginal cost, as the demand curve is above that price. The shaded area indicates the net CS considering the amount he actually pays for the q_0 units. Indeed, the area ***0-A-B-q₀*** represents the maximum amount that the consumer is willing to pay for q_0 units, while the ***0-LRMgc-B-q0*** rectangle represents the amount actually paid, since each unit is charged the same price LRMgC. The shaded area is the CS.

As stated previously, it is important to note that the NAC cannot exceed the CS, in which case the consumer would have a negative net surplus. In other words the amount that is required for consumption is higher than his willingness to pay, making it more advantageous for the individual not to buy any units. In this case the welfare loss is equal to the CS. Thus, it is important to have at least a minimum estimate of the CS which is the upper limit of the NAC.

In the case of electricity supply, the consumer's demand is closely related to the cost of the Best Alternative Option (BAO). Indeed, electricity will be demanded only if its price is equal or less than the BAO, provided that this opportunity is an acceptable substitute. For example, the Company cannot charge a price higher than the cost of self-generation. Consequently, demand for electricity is as shown in the figure below. As it can be observed, the demand ***d*** matches the BAO up to ***q'*** units and then becomes decreasing.

Figure 7.26: Consumer Surplus in Electricity



7.2.2.2 NAC Introduction

As mentioned above, the NAC must not exceed the CS of each consumer to make sure that none of them make the decision to disconnect from the network. Moreover, the sum of the NAC charged to all users should be equal to the revenue gap.

Considering that different users have different CS, if the Company intends to charge a uniform NAC that is the same for all customers, it should be lower than the lowest CS for all consumers. This would substantially limit the value of the NAC since some categories of users (especially low-income) have a CS that is almost zero.

For this reason the customers universe is divided into categories of users (***k***) and within these in sub-categories (***sk***), or ranges of consumption. For each range of consumption the lower value of CS is estimated becoming the upper limit of NAC ***sk*** to apply only to this sub-category (***sk***).

Not all users have the same willingness to pay for electric service, i.e. not all of them have the same demand curve. Rather, it depends in the case of residential users on the size of the household, the stock of appliances and the socio-economic status. Regarding the latter, the level of total household income is a crucial determinant of the willingness to pay. The reality indicates that the poorest families must spend a higher proportion of their income to pay for the electric bill than families with higher incomes. For this reason, it is not possible to divide the revenue gap between the total numbers of customers, but the customer base should be analysed separately in different categories and sub-categories, so the willingness to pay of each subcategory (***sk***) can be taken into account. In addition, it must be considered that each subcategory might have different substitutes to electricity (i.e. different avoided cost options).

To illustrate this, think that self-generation could be a reasonable substitute of network electricity for families with medium or high income, while kerosene lamps, candles and LPG or kerosene refrigerators could be reasonable substitutes in the case of low income families.

7.2.2.3 NAC Calculation

According to what was explained above, the surplus in each category is determined by the costs of the best alternative option, the marginal cost and the demand curve.

The best alternative option (BAO) is based on the analysis of each group of customers. This provides information that helps analyse the profile of each consumer type.

In the case of Residential Service, the consumption ranges analysed were:

- 1st Tier: 0 – 100 kWh/month
- 2nd Tier: 100 – 500 kWh/month
- 3rd Tier: over 500 kWh/month

In the case of General Service, the consumption ranges analysed were:

- 1st Tier: 0 – 100 kWh/month
- 2nd Tier: 100 – 1000 kWh/month
- 3rd Tier: 1000 – 2000 kWh/month
- 4th Tier: over 2000 kWh/month

For Power Service categories, the groups of customers analysed were:

- RT40: STD option
- RT40: TOU option
- RT50: STD option
- RT50: TOU option

Given the experience in other studies, the range 0 - 100 kWh/month comprises mostly users with very low income who use electricity for lighting and food refrigeration. Therefore, this range has as BAO to electricity:

- Lighting: Kerosene or propane gas lamp
- Refrigeration: Refrigerator fuelled with propane gas or kerosene

Regarding the other consumption groups of consumers the selection of the BAO took into consideration the following determinants:

- Average energy consumption
- Load factor
- Reserve factor recommended by manufacturers of self - generators (The maximum power must be multiplied by 1.4 to get the kVA that at least should have the unit)

In the case of small demand groups (< 12 kVA) choosing the most economical generator that meets their electricity demand mainly considers:

- Cost of capital
  - Generator
  - Charger
  - Batteries

– Inverter

- Maintenance cost of the generator
- Cost of fuel consumption

In the case of medium and large customers that require equipment over 12 kVA, some considerations must be made to determine the BAO. The self-generator required for these levels of consumption are groups of continuous operation. The cost of capital and OPEX of each group is based on:

- Price of the generator
- Cost required for installation
- Minor overhauls
- Major Overhauls
- Costs linked to the backup equipment
  - Price of alternative generator unit
  - Spare parts in stock

Doing this for all tariff categories, variable and fixed costs of BAO were calculated, as shown below.

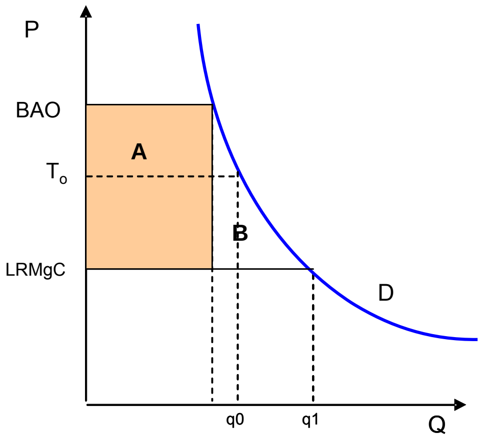
Table 7.21:Costs of Best Alternative Option by Customer Category

Group	Stratum	Description of the Best Alternative	Fixed cost $/year	Fixed cost $/month	Variable cost $/MWh	BAO Avg Costs $/MWh
R10_1	0 - 100 kWh/month	Coleman 5132 +Fridge	12,870	1,073	16,741	39,032
R10_2	100 - 500 kWh/month	Coleman Pulse 1750	56,261	4,688	23,662	47,324
R10_3	> 500 kWh/month	Toyama T6500T	229,223	19,102	19,639	39,278
R20_1	0 - 100 kWh/month	Coleman 5132 +Fridge	12,870	1,073	16,741	46,175
R20_2	100 - 1000 kWh/month	Toyama KGE 3000 TC	66,423	5,535	16,763	33,526
R20_3	1000 - 2000 kWh/month	Campbell Hausfeld 10000	418,192	34,849	25,949	51,899
R20_4	> 2000 kWh/month	GELEC 20kVA	2,053,299	171,108	43,412	86,824
RT40 (STD)		Cummins C150 D5 4	9,414,232	784,519	20,791	41,581
RT40 (TOU)		Cummins C150 D5 4	12,841,732	1,070,144	18,849	37,697
RT50 (STD)		Cummins DFHC	85,071,357	7,089,280	19,192	38,385
RT50 (TOU)		Cummins DFLE	126,948,219	10,579,018	19,673	39,347
RT60		SEI G-65 JD	5,660,744	471,729	23,046	46,092

The other information needed to complete the calculation of consumer surplus is the long-run marginal cost determination. This cost represents the cost of energy and power purchases (generation) plus the marginal costs (cost of capital + OPEX) linked to expansion of the network investments. In the case of small customers the surplus is calculated as follows:

A Cobb Douglas demand function is supposed, then $q = k \times P^{\varepsilon}$, where ***q*** is the energy consumption, ***k*** is a constant, ***P*** the average tariff and ε the demand elasticity.

Figure 7.27: Small Customer's Consumer Surplus



The Surplus is the sum of areas A and B. In formula is:

$$CS_{i \in k} = \frac{T_o^{-\varepsilon} \times q0_k}{\varepsilon + 1} \times \left(VBAO_k^{\wedge(\varepsilon+1)} - LRMgC_k^{\wedge(\varepsilon+1)} \right) + FBAO_k - LRMgCC_k$$

where:

$CS_{i \in k}$: is the customer i surplus that belongs to ***k*** category ($/Customer/month).

T_0: Actual average tariff $/kWh.

ε : demand elasticity

$q0_k$: Average consumption of a typical ***k*** category customer (kWh/month).

$VBAO_k$: is the variable cost of the BAO ($/kWh).

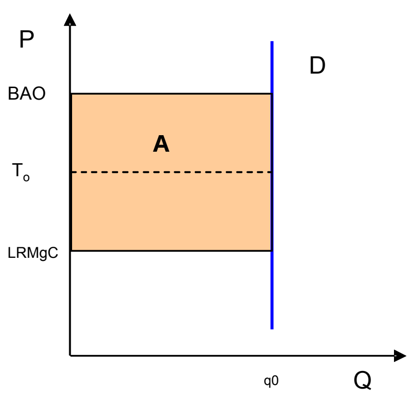
$LRMgC_k$: is the variable long run marginal cost ($/kWh).

$FBAO_k$: is the fixed cost of the BAO ($/customer/month).

$LRMgCC_k$: is the commercial long run marginal cost ($/customer/month).

For Medium and Large Customers an inelastic demand is supposed.

Figure 7.28: Medium and Larger Customer's Consumer Surpluses



In formula:

$$CS_{i\in k} = \left(VBAO_{k} - LRMgC_k\right)\times q0_k + \frac{\left(FBAO_k - LRMgCP_k\right)\times P\max_k\right)}{Customers} - LRMgCC_k$$

where:

$CS_{i\in k}$: is the customer i surplus that belongs to ***k*** category ($/Customer/month).

$q0_k$: Average consumption of a typical ***k*** category customer (kWh/month).

$VBAO_k$: is the variable cost of the BAO ($/kWh).

$LRMgC_k$: is the variable long run marginal cost linked to energy ($/kWh).

$FBAO_k$: is the fixed cost of the BAO ($/kW/month).

$LRMgCP_k$: is the capacity long run marginal cost ($/kW/month).

Customers: number of ***k*** category customers

$LRMgCC_k$: is the commercial long run marginal cost ($/customer/month).

$Pmax_k$: Sum of the maximum demand of ***k*** category customer (kW/month)

The surplus of each category is the result of multiplying the individual surplus by the number of users in each category. By adding up the surpluses of all categories, the total surplus of the market is obtained.

As indicated above, the NAC must be equal to the deficit generated by the difference between the revenue requirement and the income derived from the application of the long-run marginal costs.

From the known revenue gap and the total surplus of the market, a factor called ***alpha*** is calculated indicating the percentage of the total surplus of consumers who should be transferred to the Company so that it is sustainable over time, recovering its long-run average costs.

Table 7.22 summarizes:

- Non-fuel revenue requirement
- Revenues at marginal costs
- Revenue Gap (Deficit)
- Total estimated market surplus
- Alpha
- Total NAC (equal Revenue Gap)

Table 7.22: Alpha Calculation

	Income (J$'000)	
	Revenue Requirement	**Marginal Costs**
Total	37,770,934	15,219,266
Deficit		22,551,669
Total Surplus		98,778,093
Alfa		**22.83%**
NAC		22,551,669
Difference (Deficit - NAC)		0

Table 7.23: Revenue Requirement to be recovered through NAC by category

Rates	Description	NAC (JMD 000)
R10_1	0 - 100 kWh/month	319,268
R10_2	100 - 500 kWh/month	6,079,806
R10_3	> 500 kWh/month	2,281,590
R20_1	0 - 100 kWh/month	110,244
R20_2	100 - 1000 kWh/month	1,333,249
R20_3	1000 - 3000 kWh/month	935,826
R20_4	> 2000 kWh/month	2,854,146
RT40 (STD)		3,815,442
RT40 (TOU)		1,537,586
RT50 (STD)		1,823,087
RT50 (TOU)		711,377
RT60	Streetlight	750,048
Total		**22,551,669**

In order to reach the establishment of a simple rate schedule, which in turn takes into account the willingness to pay for each category and intending to be fair with the customers within each category, the NAC is proposed to be expressed as follows:

- Residential Service (RT10)
  - NAC_1 for the range 0 - 100 kWh/month expressed in $/Customer/Month
  - NAC_2 for the range 100 - 500 kWh/month expressed in $/Customer/Month
  - NAC_3 for consumption over 500 kWh/month expressed in $/Customer/Month

One customer charge will appear in the customer bill and it will be the sum of the Marginal Commercial Cost Charge and the NAC.

- General Service (RT20)
  - NAC_1 for the range 0 - 100 kWh/month expressed in $/Customer/Month
  - NAC_2 for the range 100 - 1000 kWh/month expressed in $/Customer/Month
  - NAC_3 for the range 1000 - 2000 kWh/month expressed in $/Customer/Month
  - NAC_4 for consumption over 2000 kWh/month expressed in $/Customer/Month

One customer charge will appear in the customer bill and it will be the sum of the Marginal Commercial Cost Charge and the NAC.

- Power Service (RT 40 and RT50)
  - NAC_RT40 STD expressed in $/ kWh
  - NAC_RT40 TOU expressed in $/ kWh
  - NAC_RT50 STD expressed in $/ kWh
  - NAC_RT50 TOU expressed in $/ kWh

These categories are comprised of users with a very wide range of energy and demand consumption. Due to the fact that the surplus in these categories was calculated through the analysis of the average customer an implementation of the NAC as a fixed charge per customer is inapplicable mostly due to those customers whose consumption is far below the average of the category. For this reason the second best solution would be to state a charge expressed in terms of the contracted power ($/kVA/month), but this measure has the following consequences:

1. Introduces a new charge that depends on contracted powers
2. The actual energy charge will become almost zero because most of the marginal costs are already allocated to the demand charges and customer charges

In an attempt to introduce the minimum amount of changes to the actual tariff structure for these categories the portion of the NAC that cannot remain as fixed charge is energized to become part of the energy charge ($/kWh) and just a small portion goes to the demand charge to equalize charges between RT40 and RT50 and between the Standard and TOU options.

7.2.3 Non-Fuel Charges per Category

In this section charges to recover Non-Fuel Costs per category are presented:

7.2.3.1 Residential Customers - RT10

Tariff designs based on the Two part tariff approach generally consider that four (4) or more tiers are optimal, enabling a better organization of the customers, taking advantage of their different willingness to pay for the service and at the same time minimizing billing shocks for customers when they move from one tier to another. However, for the next 5 years, JPS will propose 3 tiers of consumption from the point of view that the tariff charges for tier 2 and tier 3 will be the same values for customer and energy charges.

- RT10 – 1st Tier (Consumption levels between 0 – 100 kWh/month)
  - Customer charge: the customer charge is applicable whether or not there is any consumption. It covers the customer service marginal costs.
  - Energy charge: This charge is paid for every kWh of consumption and it covers capacity marginal cost and a portion of non-fuel costs that are part of the gap between marginal cost of service and average cost of service. The latter is the cost that needs to be recovered for the business to be sustainable.
- RT10 – 2nd Tier (Consumption levels between 100 – 500 kWh/month)
  - Customer charge: the customer charge is applicable whether or not there is any consumption. This charge is different from the one paid by the 1st tier. It covers the customer service marginal costs and a portion of non-fuel costs that are part of the gap between marginal cost of service and average cost of service.
  - Energy charge 1: This charge is paid for the first 100 kWh and is equal to the one paid by the 1st tier.
  - Energy charge 2: This charge is paid for every kWh of consumption over 100 kWh and it covers the capacity marginal cost and a portion of the non-fuel costs that are part of the gap between the marginal and average cost of service.
- RT10 – 3rd Tier (Consumptions over 500 kWh/month): charges are identical to the 2nd tier.

7.2.3.2 Small Commercial Customers - RT20

Four tiers in this category were established, introducing 4 different fixed charges and 2 energy charges.

- RT20 – 1st Tier (Consumption levels between 0 – 100 kWh/month)
  - Customer charge: the customer charge is applicable whether or not there is any consumption. It covers the customer service marginal costs.
  - Energy charge: This charge is paid for every kWh of consumption and it covers capacity marginal cost and a portion of non-fuel costs that are part of the gap between marginal cost and average cost of service. The latter is the cost that needs to be recovered for the business to be sustainable.

- RT20 – 2nd Tier (Consumption levels between 100 – 1,000 kWh/month)
  - Customer charge: the customer charge is applicable whether or not there is any consumption. This charge is different than the one paid by the 1st tier. It covers the customer service marginal costs and a portion of non-fuel costs that are part of the gap between marginal cost and average cost of service.
  - Energy charge 1: This charge is paid for the first 100 kWh and is equal to the one paid by the 1st tier.
  - Energy charge 2: This charge is paid for every kWh of consumption over 100 kWh and it covers capacity marginal cost and a portion of non-fuel costs that are part of the gap between marginal cost and average cost of service.
- RT20 – 3rd Tier (Consumption levels between 1,000 – 2,000kWh/month)
  - Customer charge: the customer charge is applicable whether or not there is any consumption. This charge is different from the 1st or 2nd tiers. It covers the customer service marginal costs and a portion of non-fuel costs that are part of the gap between marginal cost and average cost of service.
  - Energy charge 1: identical to the 2nd tier.
  - Energy charge 2: identical to the 2nd tier.
- RT20 – 4th Tier (Consumption levels over 2,000kWh/month)
  - Customer charge: the customer charge is applicable whether or not there is any consumption. This charge is different from the ones paid by the previous tiers. It covers the customer service marginal costs and a portion of non-fuel costs that are part of the gap between marginal cost and average cost of service.
  - Energy charge 1: identical to the 2nd tier.
  - Energy charge 2: identical to the 2nd tier.

7.2.3.3 Street Lights and Traffic Lights - RT60

The Street lighting category remains with the actual tariff structure which has:

- Customer charge: the customer charge is applicable whether or not there is any consumption. It covers the customer service marginal costs and a portion of non-fuel costs that are part of the gap between marginal cost and average cost of service.
- Energy charge: This charge is paid for every kWh of consumption and it covers capacity marginal cost and a portion of non-fuel costs that are part of the revenue gap.

7.2.3.4 Large Commercial Customers who do not own Transformer - RT40

The Power Service Low Voltage category keeps the actual tariff structure.

- Customer charge: the customer charge is applicable whether or not there is any consumption and irrespective of the level of consumption. It covers the customer service marginal costs and a portion of non-fuel costs that are part of the gap between marginal cost and average cost of service.
- Energy charge: This charge is paid for every kWh of consumption and it covers capacity marginal cost and a portion of non-fuel costs that are part of the revenue gap.
- Demand charge
  - Standard Option:
    1. One demand charge applicable on each kVA billing demand
    2. Billing demand: The kilovolt-ampere (kVA) Billing Demand for each month shall be the maximum demand for that month, or 80% of the maximum demand during the five-month period immediately preceding the month for which the bill is rendered, whichever is higher but not less than 25 kilovolt-amperes

- TOU Option:
  1. One demand charge applies on each kVA billing demand per hour block.
  2. On-Peak Period Billing Demand: the billing demand in this period shall be the maximum demand for the On-Peak hours of that month. The minimum 25 kilovolt amperes (kVA) does not apply.
  3. Partial-Peak Period Billing Demand: the billing demand in this period shall be the maximum demand for the on-peak and partial-peak hours of that month, or 80% of the maximum demand for the on-peak and partial-peak hours during the five-month period immediately preceding the month for which the bill is rendered, whichever is higher but not less than 25 kilovolt-amperes.
  4. Off-Peak Period Billing Demand: The billing demand in this period shall be the maximum demand for that month (regardless of the time of use period it was registered in), or 80% of the maximum demand during the five -month period immediately preceding the month for which the bill is rendered, whichever is higher but not less than 25 kilovolt-amperes kVA).

7.2.3.5 Large Commercial Customers who own transformer - RT50

The Power Service Medium Voltage category keeps the actual tariff structure.

- Customer charge: the customer charge is applicable whether or not there is any consumption and irrespective of the level of consumption. It covers the customer service marginal costs and a portion of non-fuel costs that are part of the gap between marginal cost and average cost of service.
- Energy charge: This charge is paid for every kWh of consumption and it covers capacity marginal cost and a portion of non-fuel costs that are part of the revenue gap.
- Demand charge
  - Standard Option:
    1. One demand charge applicable on each kVA billing demand
    2. Billing demand: The kilovolt-ampere (kVA) Billing Demand for each month shall be the maximum demand for that month, or 80% of the maximum demand during the five-month period immediately preceding the month for which the bill is rendered, whichever is higher but not less than 25 kilovolt-amperes
  - TOU Option:
    1. One demand charge applies on each kVA billing demand per hour block.
    2. On-Peak Period Billing Demand: the billing demand in this period shall be the maximum demand for the On-Peak hours of that month. The minimum 25 kilovolt amperes (kVA) does not apply.
    3. Partial-Peak Period Billing Demand: the billing demand in this period shall be the maximum demand for the on-peak and partial-peak hours of that month, or 80% of the maximum demand for the on-peak and partial-peak hours during the five-month period immediately preceding the month for which the bill is rendered, whichever is higher but not less than 25 kilovolt-amperes
    4. Off-Peak Period Billing Demand: The billing demand in this period shall be the maximum demand for that month (regardless of the time of use period it was registered in), or 80% of the maximum demand during the five -month period immediately preceding the month for which the bill is rendered, whichever is higher but not less than 25 kilovolt-amperes kVA).

7.2.4 Proposed Non-Fuel Rates

According to the proposed tariff design, the Non-Fuel Rate Schedule results:

Table 7.24: Non-Fuel Rate Schedule Breakdown

				Demand Charge $/kVA			Network Access Charge		
		Customer Charge $/Month	Energy Charge $/kWh	STD and On-Peak	Partial-Peak	Off-Peak	$/ Month	$/ kWh	$/ kVA/Month
R10_1	0 - 100 kWh/month	109.88	5.17				80.12	1.03	
R10_2	100 - 500 kWh/month	109.88	5.17				365.12	12.48	
R10_3	> 500 kWh/month	109.88	5.17				365.12	12.48	
R20_1	0 - 100 kWh/month	109.88	5.01				365.12	3.38	
R20_2	100 - 1000 kWh/month	109.88	5.01				845.12	9.79	
R20_3	1000 - 3000 kWh/month	109.88	5.01				2,275.12	9.79	
R20_4	> 2000 kWh/month	109.88	5.01				4,665.12	9.79	
RT40 (STD)		109.88	0.06	1,321.06			10,846.16	5.17	123.85
RT40 (TOU)		109.88	0.06	813.52	641.60	61.33	10,846.16	5.17	38.61
RT50 (STD)		109.88	0.06	1,315.24			10,846.16	4.88	54.20
RT50 (TOU)		109.88	0.06	779.90	520.38	42.75	10,846.16	4.88	85.67
RT60	Streetlight	109.88	6.66				8,954.73	10.27	

Putting the NAC with the correspondent charge the following is obtained:

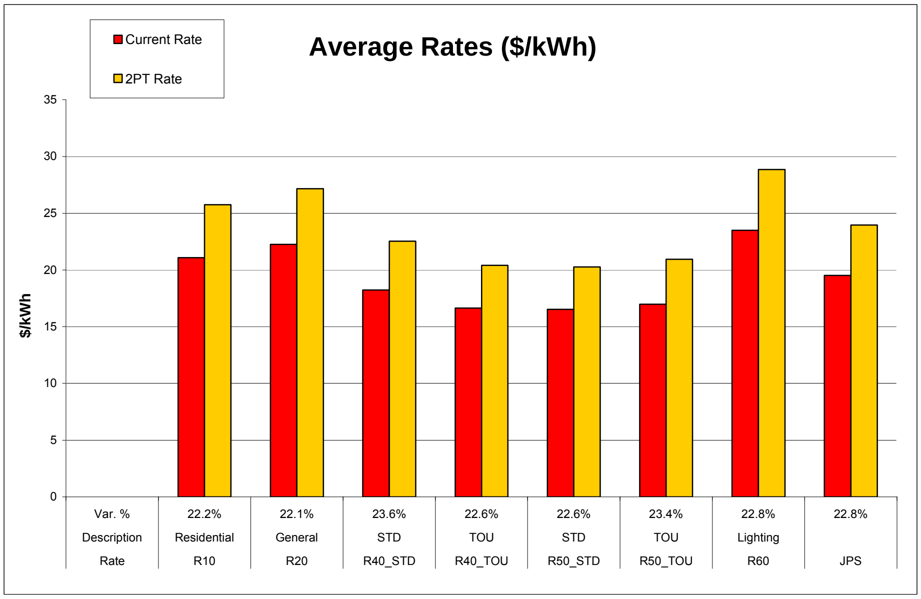
Table 7.25: Non-Fuel Final Rate Schedule

				Demand Charge $/kVA		
Rates	**Description**	Customer Charge $/Month	Energy Charge $/kWh	STD and On-Peak	Partial-Peak	Off-Peak
R10_1	0 - 100 kWh/month	190.00	6.20			
R10_2	100 - 500 kWh/month	475.00	17.65			
R10_3	> 500 kWh/month	475.00	17.65			
R20_1	0 - 100 kWh/month	475.00	8.38			
R20_2	100 - 1000 kWh/month	955.00	14.80			
R20_3	1000 - 3000 kWh/month	2,385.00	14.80			
R20_4	> 2000 kWh/month	4,775.00	14.80			
RT40 (STD)		10,956.03	5.23	1,444.91		
RT40 (TOU)		10,956.03	5.23	813.52	680.21	61.33
RT50 (STD)		10,956.03	4.94	1,369.44		
RT50 (TOU)		10,956.03	4.94	779.90	606.05	42.75
RT60	Streetlight	9,064.61	16.93			

7.2.5 Histogram of Impact

The rates proposed applied to the Test Year determinants yield the average tariff per category that is presented in **Table 7.26**. A comparison with the actual rates in force is also shown.

Table 7.26: Average Tariff by Customer Category



Although the tariff increase is very similar between the categories, the two part tariff design approach carried out allowed the Company to distribute the increase within each category, taking into account the socio-economic conditions of the users where one assumed a high correlation between family income and electricity consumption. The following sections present the results by range of consumption which demonstrates that costumers will pay above their marginal cost - there are no subsidized consumers - and that no customer will pay above their best alternative opportunity, which would drive them away from JPS. The latter is very healthy for everybody because the Company has the ability to retain the customers within the system which redounds to the benefit of all customers.

7.2.5.1 Residential Customer

Table 7.27 shows RT10 proposed charges.

Table 7.27: Rate 10 Charges

Description	Customer Charge $/Month		Energy Charge $/kWh		Fuel Charge	
	Current	**2PT**	**Current**	**2PT**	**Current**	**2PT**
First 100 kWh	102.00	190.00	6.54	6.20	11.40	11.40
100 - 500 kWh	102.00	475.00	11.42	17.65	11.40	11.40
Over 500 kWh	102.00	475.00	11.42	17.65	11.40	11.40

As can be observed there are two columns per charge. Adjusted actual charges are in the first column, and Two-part tariff approach rates are in the second one.

Table 7.28 presents the billing impacts for typical customers in each tier.

Table 7.28: Bill Impact on Rate 10 Typical Customers

Description	Average consumption kWh/month	Monthly Bill $/Month		Impact on Consumers $/Month	%
		Current	**2PT**	**2PT/Current**	**2PT/Current**
First 100 kWh	55	1,089	1,158	69	6.4%
100 - 500 kWh	200	4,179	5,140	962	23.0%
Over 500 kWh	1,000	22,438	28,382	5,943	26.5%

As can be observed, while the Residential category has on average an increase of 21.7%, the first tier that includes mainly families with low income will receive an average increase of 6.4%. The number of residential customers that have this minimum increase is about 200,000 customers representing 40% of the residential category.

Customers whose consumption is within the second tier will see an average increase of 23.0%, a value which is below the average increase required by the Company.

Finally, customers with consumption over 500 kWh / month are those with the highest rate increase within this category, although the vast majority, if their consumption is looked at it can be inferred that they belong to the population with highest income within the island.

Table 7.29 summarizes the residential energy sales and customer structure for the Test Year.

Table 7.29: Rate 10 Customer Structure

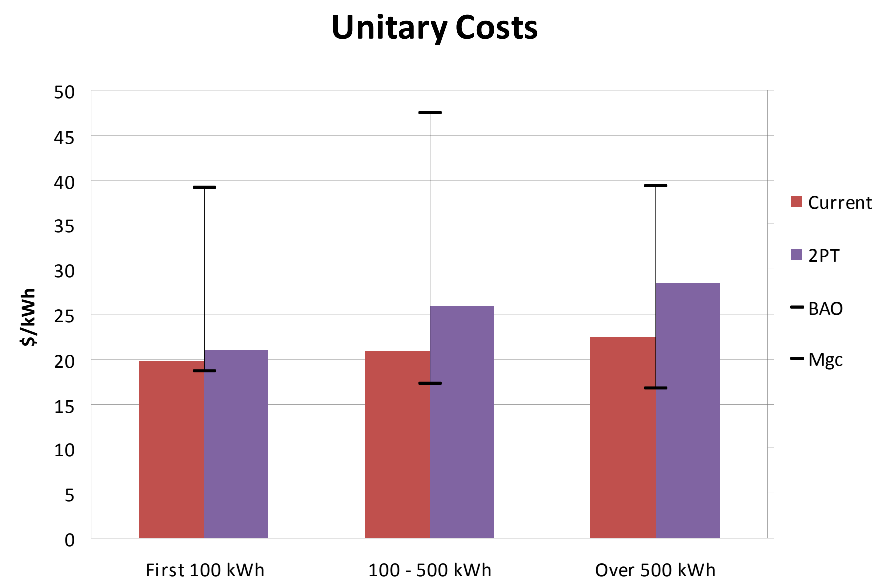
Rates	Description	Customers	% / Category	Energy Sales MWh	% / Category
R10_1	0 - 100 kWh/month	204,069	39%	119,493	12%
R10_2	100 - 500 kWh/month	306,530	58%	717,073	69%
R10_3	> 500 kWh/month	17,035	3%	195,616	19%
		527,634	**100%**	**1,032,182**	**100%**

Finally, the **Figure 7.29** below shows important data which not only has to do with the histogram of impact but to validate the tariff design. The graph shows the following data for typical customers per tier of consumption:

- Current average rate
- Proposed average rate
- Its marginal cost
- Cost of his best alternative opportunity.

The latter two data sets represent the limits within which the tariff should be determined. As previously indicated, if the price is below marginal cost that customer is being subsidized while if the rate is above the cost of the best alternative opportunity there is a risk that the customer will disconnect from the network, to the detriment of all other customers who would have to bear a higher cost for energy.

Figure 7.29: Unitary Costs by Consumption Levels



7.2.6 Small Commercial Customer

Table 7.30 shows the proposed RT20 charges.

Table 7.30: Rate 20 Charges

Description	Customer Charge $/Month		Energy Charge $/kWh		Fuel Charge	
	Current	**2PT**	**Current**	**2PT**	**Current**	**2PT**
First 100 kWh	234.00	475.00	10.15	8.38	11.40	11.40
100 - 1000 kWh	234.00	955.00	10.15	14.80	11.40	11.40
1000 - 2000 kWh	234.00	2,385.00	10.15	14.80	11.40	11.40
Over 2000 kWh	234.00	4,775.00	10.15	14.80	11.40	11.40

As can be observed there are two columns per charge. Adjusted actual charges are in the first column, and Two-part tariff rates are in the second.

Table 7.31 presents the billing impacts for typical customers in each tier.

Table 7.31: Bill Impact on Rate 20 Typical Customers

Description	Average consumption kWh/month	Monthly Bill $/Month		Impact on Consumers $/Month	Impact on Consumers %
		Current	**2PT**	**2PT/Current**	**2PT/Current**
First 100 kWh	75	1,851	1,959	108	5.9%
100 - 1000 kWh	400	8,856	10,793	1,937	21.9%
1000 - 2000 kWh	1,400	30,411	38,423	8,012	26.3%
Over 2000 kWh	3,500	75,677	95,832	20,155	26.6%

As can be observed, while the General Service category has on average an increase of 23.4%, the first tier that includes mainly small commercial users will receive in the case of the typical consumer an increase of 5.9%. The number of customers that will benefit with an increase below the average increase of this category is about 19,000 customers, representing 30% of the category.

Customers whose consumption is within the second tier will see an average increase of 20.9% that is close to the average increase for this category.

Finally, customers with consumption over 1,000 kWh / month (Tier 3 and 4) are those who experience the highest increase within this category.

Table 7.32 summarizes the general service energy sales and customers structure for the Test Year.

Table 7.32: Rate 20 Customer Structure

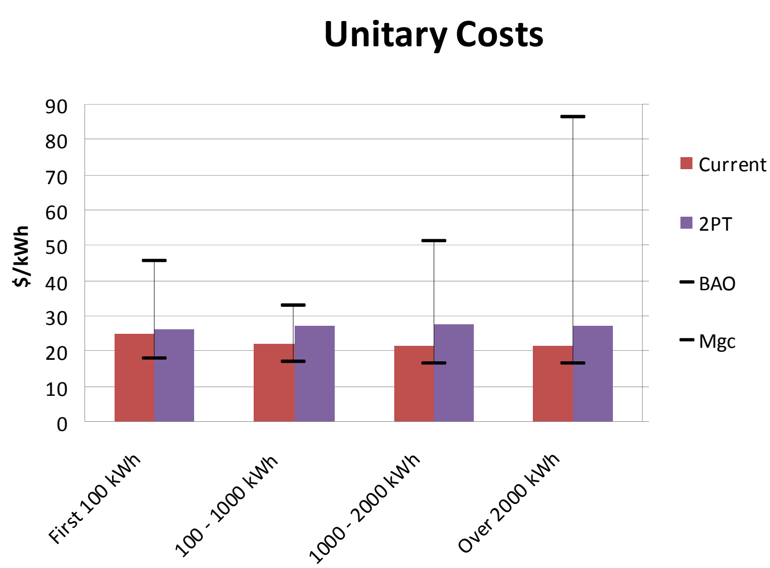
Rates	Description	Customers	% / Category	Energy Sales MWh	% / Category
R20_1	0 - 100 kWh/month	18,738	31%	8,335	2%
R20_2	100 - 1000 kWh/month	31,813	52%	128,238	26%
R20_3	1000 - 3000 kWh/month	5,196	8%	85,184	18%
R20_4	> 2000 kWh/month	5,496	9%	264,429	54%
		61,243	**100%**	**486,186**	**100%**

Figure 7.30 below shows important data which not only has to do with the histogram of impact but to validate the tariff design. The graph shows the following data for typical customers per tier of consumption:

- Current average rate
- Proposed average rate
- Its marginal cost
- Cost of his best alternative opportunity.

The latter two data sets represent the limits within which the tariff should be determined. As previously indicated, if the price is below marginal cost that customer is being subsidized while if the rate is above the cost of the best alternative opportunity there is a risk that the customer will disconnect from the network, to the detriment of all other customers who would have to bear a higher cost for energy.

Figure 7.30: Unitary Costs by Rate 20 Consumption Levels



7.2.7 Large Industrial Customer Non-Fuel Tariff

Table 7.33 shows the Power Service's charges for large commercial customers.

Table 7.33: Rate 40 & 50 Charges

Description	Customer Charge $/Month		Energy Charge $/kWh		STD and On-Peak Demand Charge $/kVA		STD and On-Peak Fuel Charge $/kWh	
	Current	Proposal	Current	Proposal	Current	Proposal	Current	Proposal
RT40 (STD)	3,245	10,956	2.78	5.23	1,033	1,445	11.40	11.40
RT40 (TOU)	3,245	10,956	2.78	5.23	577	814	14.85	14.85
RT50 (STD)	3,245	10,956	2.51	4.94	929	1,369	11.40	11.40
RT50 (TOU)	3,245	10,956	2.51	4.94	519	780	14.85	14.85

Description	Partial-Peak Demand Charge $/kVA		Partial-Peak Fuel Charge $/kWh		Off-Peak Demand Charge $/kVA		Off-Peak Fuel Charge $/kWh	
	Current	Proposal	Current	Proposal	Current	Proposal	Current	Proposal
RT40 (STD)								
RT40 (TOU)	451	680	11.91	11.91	42	61	9.91	9.91
RT50 (STD)								
RT50 (TOU)	405	606	11.91	11.91	38	43	9.91	9.91

As can be observed there are two columns per charge. Adjusted actual charges are in the first column, and the proposed rates are in the second one.

Table 7.34 presents the billing impacts for typical customers for each category and option.

Table 7.34: Bill Impact on Rate 40 & 50 Customers

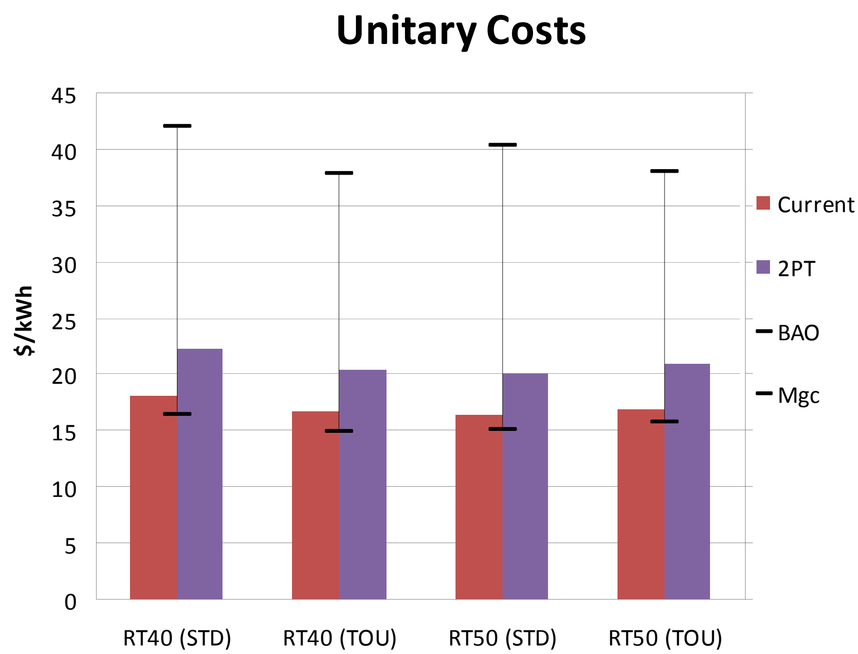
	Average consumption kWh/month	Demand (kVA) STD and On-Peak	Demand (kVA) Partial-Peak	Demand (kVA) Off-Peak	Energy (kWh) STD and On-Peak	Energy (kWh) Partial-Peak	Energy (kWh) Off-Peak	Monthly Bill 000 $/Month Current	Monthly Bill 000 $/Month Proposal	Impact on Consumers J$'000 /Month	Impact on Consumers %
RT40 (STD)	36,520	134						660	812	153	23.1%
RT40 (TOU)	56,315	113	145	132	6,964	24,742	24,610	938	1,146	208	22.2%
RT50 (STD)	318,748	852						5,231	6,387	1,156	22.1%
RT50 (TOU)	414,869	1,095	1,574	1,631	51,300	182,272	181,297	7,042	8,666	1,623	23.1%

In the Figure below is shown important data which not only has to do with the histogram of impact, but to validate the tariff design. The graph shows for typical customers per category and option the following data:

- Current average rate
- Proposed average rate
- Its marginal cost
- Cost of his best alternative opportunity.

The latter two data sets represent the limits within which the tariff should be determined. As previously indicated, if the price is below marginal cost that customer is being subsidized while if the rate is above the cost of the best alternative opportunity there is a risk that the customer will disconnect from the network, to the detriment of all other customers who would have to bear a higher cost for energy.

Figure 7.31: Unitary Costs by Rate 40 & 50 Consumption Levels



Customers in these categories represent less than 0.5% of the total customer base but account for 45% of all energy consumed. For this reason it is very important for the Company to set charges that encourage the Rate 40 and 50 customers to stay on the system., This is the reason why the increases for these two rate categories are similar to the average increase being sought by the Company, despite the existence of a greater willingness to pay by this group, given the cost of the best alternative opportunity that exists for this group, as demonstrated by Figure 7.31..

8 Fuel Tariff Rate Calculation

According to Section 3(D) of Schedule 3 of the Licence:

> ***"the Licensee shall apply the Fuel Rate Adjustment Mechanism that is in force on the date of this Licence. The Fuel Cost Mechanism that is in force on the date of this Licence is described in Exhibit 2."***

The provisions of Exhibit 2 are that the total applicable energy cost for a given billing period shall include:

> ***"The cost of fuel per kilo-watt hour (net of efficiencies) shall be calculated each month on the basis of the total fuel computed to have been consumed by the Licensee and Independent Power Producers (IPPs) in the production of electricity as well as the Licensee's generating heat rate as determined by the Office at the adjustment date and the IPPs generation heat rate as per contract with the IPPs and systems losses as determined by the Office at the adjustment date of total net generation (the Licensee and IPPs)"***

The Licence is however, silent on exactly how the fuel rate is to be calculated. JPS has written several papers to the OUR between 2004 – 2008, alerting the OUR to a concern about the calculation of the fuel rate and the possible risk of under-recovery or over-recovery of fuel costs. That is to say, since the fuel cost net of efficiency adjustments (or the applicable fuel cost) must be recovered through a per kWh rate, JPS was concerned that it could over- or under-recover the applicable fuel cost through the billing process, since the per kWh fuel rate derived for a particular month might not actually recover the applicable fuel cost due to a variation in the actual billed energy sales in the subsequent month. The OUR agreed to the introduction of a volumetric adjustment mechanism (VAM) in 2005, that resolved a major part of the concern. However, JPS is still concerned about the TOU discount/premium that is applied to the fuel rate for applicable TOU customers and the fact that this too may lead to the under- or over-recovery of fuel costs, as mentioned earlier in **Section 2.4.4** and quantified in **Table 2.11**.

Additionally, JPS is fundamentally concerned about the impact that fuel prices and IPP availability/reliability have on system dispatch and overall fuel cost and by extension the system heat rate and the resultant determination of recoverable fuel cost. For the 2004 – 2009 period the heat rate target was set under the assumption of the IPPs achieving 90% availability and 4% EFOR. It is extremely important to note that since all IPP costs and performance refunds (i.e. liquidated damages) are included in the fuel rate calculation, when the IPPs performance is below expectation, JPS is effectively penalised by the resulting deterioration in the system heat rate. This is obviously of great concern to JPS given that the:

(i) the IPP performance is entirely outside of JPS' control;
(ii) IPPs make up a significant proportion of total fuel costs and will increase their proportion in the future; and
(iii)the current fuel cost penalty also applies to the IPP fuel cost.

This section puts forward JPS' proposals for the calculation of the fuel rate for the price cap period 2009 – 2014, which includes proposals for the efficiency targets (heat rate and system losses); a proposed adjustment to the heat rate target to appropriately neutralize any fuel price and/or IPP impact on the system heat rate; a proposed modification to the calculation of the fuel rate to include the actual weights (or distribution) of the TOU billing; and an overall maximum monthly penalty/reward amount to limit the re or loss on the recovery of fuel costs.

8.1 Heat Rate Target

The objective of setting the heat rate target for the generation system is to assure customers of fair and reasonable fuel rates by providing an incentive for:

- Improvement of the relative efficiency of converting chemical energy to electrical energy; and
- the economic dispatch of all available generation units.

JPS believes that the following principles should be applied in setting any heat rate target:

- The target should hold JPS accountable for only the factors which are under its direct control;
- The target should adequately and realistically reflect the available and future (within the rate-cap period) generating fleet's capabilities and legitimate constraints;
- JPS should be provided with an adequate medium-term planning horizon with predictable targets, which is particularly important in the context of the price cap regime; and
- The target change interval should permit JPS the opportunity to harvest gains due to the capital and effort invested in meeting and exceeding the agreed target.

The system heat rate performance over the five-year price cap period will depend on several factors affecting the economic dispatch which include the:

(i) growth in system demand
(ii) the addition of new generating units and the installed reserve margin (OUR);
(iii) heat rate improvements made to existing generating units (JPS);
(iv) availability and reliability of JPS generators (JPS);
(v) availability and reliability of IPP generators (IPPs);
(vi) absolute and relative fuel prices for JPS and the IPPs and the impact on economic dispatch;
(vii) spinning reserve policy (JPS & OUR); and
(viii) network constraints and contingencies (JPS).

While all of the above factors influence the resultant system hear rate, JPS has sole direct control over only a few.

8.1.1 Impact of JPS Operations on Economic Dispatch and Heat Rate

The economic dispatch of units refers to running only the most "cost efficient" units to meet instantaneous demand, that is, those units that have the lowest variable operating costs. The optimization of variable cost through economic dispatch is determined using computer simulation programmes that determine the level of output required from each generator. Other factors affecting economic dispatch include the following:

8.1.1.1 Generating Plant Availability and Reliability

Ensuring that generating units are reliable and available when needed is critical to achieving the optimal economic dispatch and heat rate efficiency. Reduced reliability of more cost efficient generators will result in less efficient generators compensating for their shortfall and hence result in a variation in economic dispatch, system heat rate and system fuel cost;

8.1.1.2 Network Constraints

For reasons of system security, security-constrained economic dispatch is sometimes necessary under contingency situations, to serve the demand and maintain power quality within acceptable limits.

8.1.1.3 Spinning Reserve

This is used to provide some level of supply security for the power system by allowing for spare capacity on the operating units at any instant. This spare capacity allows some units online to respond, near instantaneously, to offset any shortfall in online available capacity or small increases in demand. Gas turbines (GTs) and diesel generators have the capability to increase load significantly over short durations. In contrast, steam turbines take longer due to thermodynamic considerations. Run-of-the-river hydros operate at a megawatt (MW) output consistent with the available stream flow.

The heat rate of most units is best at close to maximum loading and worsens as the output is reduced. There is no singular approach to determining the level of spinning reserve to carry on the system. Some utilities run their system with spinning reserves equal to the largest generator on the system. In JPS' case, given the mix of generating units on the system, carrying reserves equivalent to the largest unit (presently 120MW) would increase or worsen the system heat rate as this involves a greater continuous utilisation of GTs in normal operating modes. The cost of fuel for these units would significantly increase the overall fuel bill. In practical terms also, it is not possible to carry enough reserves on JPS' system to completely mitigate the loss of load for the loss of the largest unit, given the design characteristics of existing plants.

The present strategy involves carrying spinning reserve, which can protect the system from the trip of the smaller units (up to 30MW). With the loss of an online generating unit larger than 30MWs, a shed-and-restore strategy is employed. For this strategy, the spinning reserve takes up a portion of the load lost while offline quick-start GTs constitute "operating reserves", which are started within a few minutes after under-frequency load shedding, to restore customer supply.

The heat rate and the "***Q***" factor are therefore inter-related. Running JPS' system with greater spinning reserve would somewhat improve "Q", but would also hurt heat rate performance and fuel costs. Studies mandated by the OUR are presently being conducted by JPS to inform a possible revision of the Spinning Reserve Policy to achieve an optimum cost-reliability balance. It is therefore crucial to ensure that the targets set for the heat rate and ***Q***-factor are compatible so that maximum value redounds to the consumer.

8.1.1.4 Improvements to Existing Units

Changes to existing units to improve heat rate can be classified as either operating improvements or design improvements. JPS has invested significantly in the existing generating units over the past five years to effect such operating improvements. Generally, the heat rate performance of the existing fleet of units represents the best levels that will be achievable over the next five years. Greater levels of efficiency may be achieved with some design improvements or through fuel diversification but would require significant capital investment.

The current heat rate forecast model for 2009-14 contemplates certain expected capacity gains at the Bogue Combined Cycle Plant, as highlighted in the Strategic Outlook in **Section 3**, but does not contemplate any other heat rate improvements. The conversion of Bogue to CNG has not been factored into the heat rate calculation. This is due to the uncertainty surrounding the schedule for the project given the current financing climate. Upon commissioning, JPS would agree to revise the heat rate target at the most appropriate annual tariff reset during the 2009 – 14 period.

8.1.2 Impact of New Generation on Economic Dispatch and Heat Rate

Since August 2007, the determination of the Least Cost Generation Expansion Plan and the required size and timing of new capacity addition is determined by the OUR. Further, the process of acquisition of new capacity is also under the control of the OUR.

The introduction of new generation units to the system during the 2009 – 2014 rate cap period is expected to positively impact the heat rate, though this will depend on the size of such units, their heat rate, the expected capacity factor and the timing of implementation. The effect of any one new unit on the system heat rate can be determined by modelling the new unit in the system's economic dispatch model reconciled with the expected growth in sales and demand during the period. The system heat rate will progressively get worse over time as existing base-load plants age and their heat rate degrade and as system demand is increased and more inefficient gas turbine units are used to meet normal load for longer periods.

JPS' economic dispatch model assumes that only renewables and intermediate capacity will be added during the next five years, in the form of wind, hydro and medium speed diesels and is detailed in **Annex F**.

8.1.3 Impact of Fuel Price on Economic Dispatch and Heat Rate

The variable cost of each generator is directly related to the price of fuel burned in the unit. Likewise, the relative delivered price of fuel at each plant will influence the merit order ranking of the generating units and hence the dispatch output. It is important to note that the change in fuel prices for the two main fuel sources can be disproportionate.

When fuel prices are high generally, generating units with good heat rates will have a higher merit order ranking than units with a worse heat rate, subject to their respective variable operating and maintenance (O&M) costs. Good heat rate units will therefore deliver a substantial share of the energy required, all other factors being normal. The system heat rate will therefore be good while the system fuel cost will be high.

Conversely, when fuel prices are low, the system fuel cost will be lower and the difference in the fuel component of merit order cost for good and bad heat rate units will be smaller. The merit order ranking of generators will be influenced a lot more by the value of the variable O&M than was the case in a high fuel price environment. The share of energy from units with relatively poor heat rates will also be greater and hence system heat rate will deteriorate.

In either high or low fuel price scenarios, the differential price between JPS units and IPPs will influence the system heat rate. While the global trend in fuel prices has been shown to be in the same direction, historically the price of fuel to JPS and IPPs differs due to difference in the quality of the fuels and the markets to which the fuels are indexed. This price differential has an impact on the merit order ranking and the relative dispatch levels of the generating units and hence the system heat rate

8.1.4 Impact of IPP Performance on Economic Dispatch and Heat Rate

The availability and reliability of IPPs has a direct impact on the overall system heat rate. Under the existing PPAs, the large IPPs provide either a guaranteed heat rate point or a curve. Given the type of generators (slow and medium speed diesels) used by the IPPs in general, their generating unit heat rates are among the best in the system. Since they provide over 25% on average of the required energy demand, their performance directly influences the resultant system heat rate.

The expected performance of IPPs is defined in their respective PPAs. Each IPP is allowed planned and forced outage hours and by extension is required to perform with an forecast level of availability and reliability. To the extent that the required IPP performance is not realised, more expensive and less fuel-efficient (worse heat rate) units have to provide for this energy shortfall. This negatively impacts the expected system heat rate.

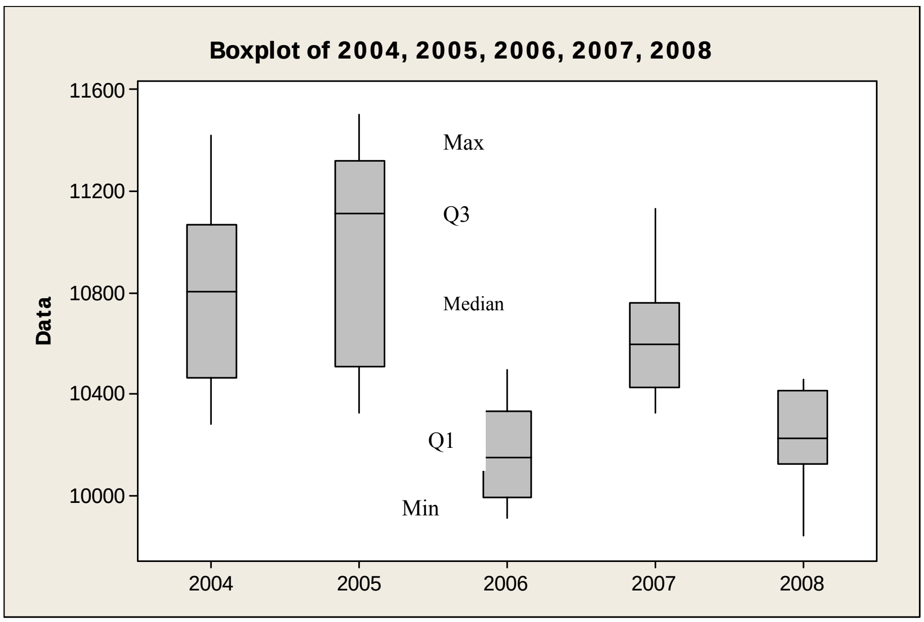
8.1.5 Analysis of System Heat Rate Performance

The historical monthly average system heat rate performance shown in **Table 8.1** indicates a general trend of heat rate improvement over the tariff review period 2004 –2008.

Table 8.1: Descriptive Statistics - Heat Rate Performance (2004 – 2008)

Year	N	Mean	St Dev	Min	Q1	Median	Q3	Max	Range
2004	12	10,832	366	10,282	10,463	10,804	11,069	11,419	1,137
2005	12	10,985	417	10,323	10,511	11,114	11,316	11,500	1,176
2006	12	10,174	191	9,914	9,993	10,153	10,333	10,498	584
2007	12	10,627	239	10,324	10,425	10,595	10,761	11,130	806
2008	12	10,215	213	9,841	10,128	10,226	10,412	10,461	620

Figure 8.1: Heat Rate Box Plot for 2004 – 2008

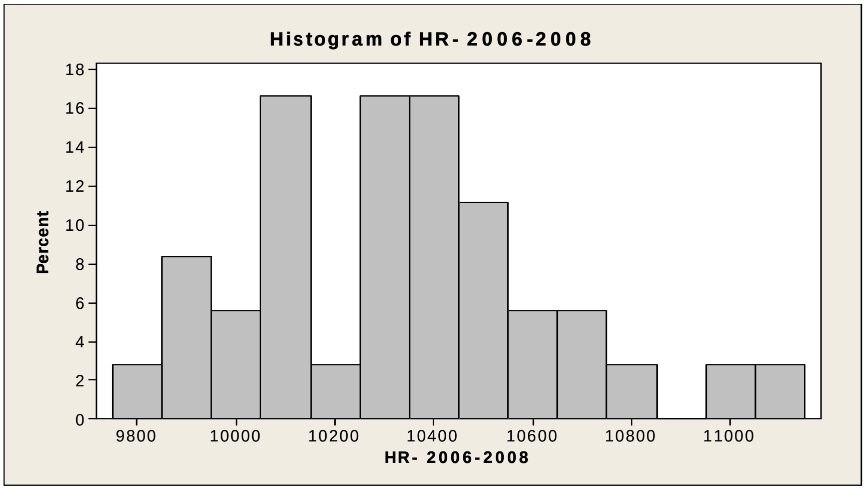


Both the average heat rate and the range (max – min) of heat rate variation has shown overall improvement comparing 2008's performance to 2004. While there is a visible stepped change in the system heat rate in 2006 with the inclusion of the new 50 MW JEP plant, the trend has shown fluctuations over the last three years. It is important to note that this variation is a normal feature of the economic dispatch given that base load units must be routinely taken off-line from time to time for maintenance and there is a normal level of forced outage that would also be expected. This is the main reason why an availability factor of 80% is assumed for the JPS fleet and 90% for the IPP fleet.

Table 8.2: Heat Rate Performance (2006 – 2008)

Year	N	Mean	St Dev	Min	Q1	Median	Q3	Max	Range
2006 – 8	36	10,339	295	9,841	10,128	10,334	10,511	11,130	1,289

Figure 8.2: Heat Rate Performance for 2006 – 2008



While the mean heat rate over the three-year period was 10,339 kJ/kWh, the standard deviation of 295kJ/kWh statistically indicates that 68% of the monthly average heat rate values ranged between 10,044kJ/kWh and 10,634kJ/kWh (one standard deviation). This is a 590kJ/kWh spread influenced by any or all of the factors affecting heat rate performance mentioned above.

8.1.6 Proposal for Heat Rate Target

The mechanism used to calculate the pass-through Fuel Cost on a monthly basis under the current tariff operates according to the following formula:

$$\text{Pass thru Fuel Cost} = \text{Fuel Cost Actual} * \frac{\text{Heat Rate Target}}{\text{Heat Rate Actual}} * \frac{(1 - \text{Losses Actual})}{(1 - \text{Losses Target})}$$

The heat rate target should continue to be based on the total generating units throughout the system (both JPS and IPPs), since fuel optimisation through economic dispatch seeks to optimize overall system variable cost.. A heat rate forecast for the 2009 – 2014 rate cap period is provided in **Annex F.** This is similar to the approach used in setting the 2004 – 2008 heat rate target where average performance was considered indicative of future performance subject to the addition of new capacity or the retirement of existing ones. In this analysis, the effect of some of the heat rate influencing factors are not properly accounted for since average performance does not exactly mimic the cumulative effect of the actual monthly heat rate penalty/reward system. That is to say, average heat rate performance for a year does not fully capture the effect that a wide range of monthly heat rate values would have on a monthly penalty/reward calculation, especially given the monthly variation in fuel prices and foreign exchange rates throughout a given year. In this regard, it is JPS' view that the heat rate target must consider the impact that the likely changes to the influencing factors, which are outside of JPS' control, would have on the actual monthly heat rate value.

JPS cannot influence the availability or reliability of the IPPs and should not be exposed to any additional penalties (fuel and heat rate) as a result of any failure to perform. JPS faces increased performance risk to the IPPs as their plants age over time and as they expand their generating capacity as a percentage of the system installed capacity. A failure to achieve the target level of availability and reliability by the IPPs has the largest negative effect on the system heat rate, all other factors remaining constant. Since the performance guarantees (e.g. liquidated damages) that the IPPs provide for under performance is effectively refunded to the customer through the IPP fuel surcharge/adjustment, it is JPS that suffers the penalty when the system heat rate worsens because of the poor performance of IPPs.

Over the years, the OUR has set a heat rate target that requires continuous improvement by JPS, which is ultimately to the benefit of the customers. The system wide target (to include IPPs) was set at 11,900 kJ/kWh in 2002, then revised downwards to 11,600 kJ/kWh in 2003 and then to 11,200 kJ/kWh in 2004. This represents a required 6.25% improvement in the use of fuel over the period, which is significant by any standard. Further review of the historical statistics will show that JPS has only been able to consistently better the current heat rate target of 11,200kJ/kWh subsequent to the addition of the JEP 50MW in 2006. Despite this however, the system heat rate performance since 2006 has shown wide variation as highlighted before. This has been so in the face of the relative stagnation in demand growth over the period, the stable heat rate performance of individual JPS units and the consistent availability and improving reliability of JPS' combined fleet of generators. It is the wide variations in fuel prices and IPP availability and reliability that have been the significant influencing factors on dispatch and the resultant variation in system heat rate over this period.

To confirm these effects, JPS has performed dispatch evaluations to assess the effect that changing fuel prices and IPP availability would have on the system heat rate for 2008. The result of this analysis, shown in **Annex G**, confirms that from a baseline average performance of 10,215 kJ/kWh (80% JPS and 90% IPP availability and 2008 average fuel prices respectively), the variation in system heat rate due to IPP availability varying to the min and max values for 2008 had up to a 455 kJ/kWh negative effect and 80kJ/kWh positive effect on the system heat rate.

Over this range of variability of IPP availability, if the fuel prices are simultaneously varied over the range (min – average – max) of fuel prices experienced in 2008, combined they increase the system heat rate variation from a negative impact of 635kJ/kWh to a positive effect of 128 kJ/kWh. The impact of variations in IPP availability and fuel prices will have more adverse effects on the system heat rate if the other heat rate affecting variables aforementioned are simultaneously varied negatively.

Based on the planned mix of generating units, including IPPs, their projected availability and dispatch, and the foregoing discussion of heat rate affecting variables and the possible variation in heat rate performance for reasons beyond JPS' control, JPS proposes a two stepped reduction (improvement) to the heat rate target for the rate cap period 2009 – 2014, as noted below:

- An initial 3.1% reduction to 10,850 kJ/kWh for the period July 2009 – June 2010;
- A further 1.4% reduction to 10,700 kJ/kWh for the period July 2010 – June 2014 (contingent on the 60 MW JEP Expansion)[29].

This represents a 4.5% reduction in the heat rate target as of July 2010. The second step reduction is primarily the result of the anticipated 60MW generation expansion that is expected to be completed in August 2010.

JPS agrees with the current established approach to set and publish the heat rate target for the price cap period in a similar manner to the "Q" factor , "X" factor and system losses targets

[29] The second step 150 kJ/kWh reduction in the heat rate target would be implemented only if the JEP 50 MW expansion was expected with certainty by August 2010. If not, it would be implemented in the month after the JEP 50 MW expansion is commissioned, or on a prorated basis for each 10 MW of capacity that is commissioned. So, if 30 MW were commissioned the target would be reduced by 30/50ths of 150 kJ/kWh or by 90 kJ/kWh.

should all be established in advance for the price cap period. Together these will provide the utility with the correct set of incentives to improve its operational efficiencies and service quality performance consistent with the main objectives of a price cap regime.

However, JPS would agree to the revision of the heat rate target if any major fuel diversification projects (i.e. CNG or Petcoke) are commissioned into service during the price cap period.

It is important to note that each 100 kJ/kWh reduction in the heat rate target will result in fuel savings to customers of approximately US$3.5M per annum at today's fuel prices (US$4.5M p.a. at 2008 fuel prices). Therefore, the proposed 500 kJ/kWh reduction in the heat rate target from 11,200 kJ/kWh to 10,700 kJ/kWh will reduce the cost of fuel for customers by approximately US$17.5M per annum.

8.2 System Losses Target

8.2.1 Loss Reduction Initiatives

The Company has detailed its initiatives over the 2004 – 8 review period in **Section 2.5.2** and **Section 9** which includes review of these results in **Table 2.13**, which shows that JPS recovered losses amounting to approximately $750M in 2008, being 49.3 GWh, or 1.2% of net generation. While losses have risen from 19.3% in 2004 to 22.9% by 2008, this amount would have been significantly higher had it not been for the intervention by JPS. In summary, the quantum of losses has been increasing but at a reduced rate (**Figure 2.6**), and in fact the quantum of losses has remained flat over the last three years despite the significant increase in fuel prices. This is the direct empirical evidence of the success of JPS' loss reduction initiatives, as losses in absolute terms have historically grown by an average rate of 5% p.a. during the decade of the 1990s.

It should be noted that a detailed explanation of the numerous loss reduction initiatives undertaken over the past two years has been provided in the next section (**Section 9 - System Losses**). This reveals a clear strategy for dealing with losses relating to large commercial customers, who account for 50% of energy sales, through the use of AMI as well as the strategies for addressing the challenges with residential and small commercial customers.

Included in **Section 3** "Outlook", are the details of the planned initiatives which identify the Company's main loss reduction initiatives for the price cap period (2009 – 14). These initiatives and the attendant costs are highlighted below:

a. Improvement in the Company's loss measuring capabilities with the completion of the Energy balance project (US$7M project).
b. Technical loss reduction Initiatives:
   - VAR management (US$1M project)
   - Primary upgrade (US$5M project)
   - Transformer replacement (US$2M per annum)
c. Non-technical loss Reduction:
   - AMI metering (US$5M project)
   - Customer audits (US$2M per annum)
   - Theft resistant Network programmes and smart meters (US$6M per annum)
d. Administrative controls and improvements (US1M per annum)

In total, JPS plans to spend US$28.3M in CAPEX and US$16.6M in O&M during the price cap period to reduce technical, non-technical losses and administrative losses.

Finally, JPS has made recommendations for changes to the regulatory and legislative frameworks to increase the effectiveness of penalties and sanctions associated with electricity theft (see **Section 9** for details). The current laws and regulations have not proven to be an effective deterrent to persons stealing electricity, or to crime in general in Jamaica. The theft of electricity is a crime and a socioeconomic problem of Jamaica. It will require a concerted effort by all stakeholders - JPS, the GOJ, the police force and citizens to arrest this growing problem of crime.

8.2.2 Benchmarking System Losses Performance

JPS is unaware of the economic basis for the determination of the current system losses target of 15.8%. That target was increased from 13.5% to 15.8% during the first rate determination conducted by the OUR in 2000 at a time when system losses had averaged 17% consistently for the previous decade or more[30] thus implying a stretch target of 1.2%. In the 2004 rate determination, the OUR turned down JPS' request to increase the losses target further opting to leave the target unchanged. However, economic conditions have deteriorated significantly since 2001. In 2001, the foreign exchange rate was $44:1, the average fuel and non-fuel tariffs were US6¢ and 8¢/kWh respectively, resulting in a total tariff of 14¢. Today, the foreign exchange rate is closer to $90:1, the average fuel tariff is US13¢/kWh and the non-fuel tariff is likely to be 12¢/kWh, making a total tariff of 25¢/kWh, while at the same time, losses have averaged 23% for the last three years. This unfortunately means that the cost of our product has increased four-fold for our customers in J$ terms which undoubtedly would have some impact on non-technical losses.

Against this background, JPS hired a group of external consultants to conduct an economic analysis of non-technical losses to determine the drivers and variables contributing to these commercial losses. The study is included at **Annex L.** The study revealed that there are in fact three significant independent variables which can be used to predict non-technical losses, namely: (i) the level of poverty in a country; (ii) the average residential customer electricity bill per GDP capita; and (iii) the level of violence in a country. Violence is measured by murder per capita and is a reflection on both the propensity to commit a crime and the effectiveness of the judicial system in a country. **Table 8.3** shows the coefficient estimate and the t-statistic for the mentioned variables that were used in a model that achieved a coefficient of determination (R^2) of 0.855 for a sample of 63 utility companies. This suggests that 85.5% of the variability of the non-technical losses of the companies in the study was explained by the three variables used in the model, which is statistically significant.

Table 8.3: Independent Variables for Non-Technical Losses

Variable	(Coefficient estimate)	(t-statistics)
Poverty	0.9078868	4.51
Electricity bill/GDP pc	0.5256652	2.94
Violence	0.342431	4.35

Using this model one can estimate what non-technical losses should have been for the period 2001 to 2008 and compare JPS' actual performance against this theoretical benchmark. This is shown in **Table 8.4**.

8.2.3 Proposals for System Losses Target

JPS expects to reduce system losses from 22.9% to 18.3% over the rate cap period primarily as a result of the loss reduction initiatives summarised in the previous section. This represents almost a 1% point reduction per annum for the next five years as a result of a combined CAPEX and O&M spend of approximately US$45M. JPS sincerely believes this to be the most optimistic forecast given the current socioeconomic environment and outlook. The Company is nevertheless acutely aware of the OUR's profound concern that JPS be given the correct signals to continuously commit adequate resources and exercise best effort to combat losses. In recognition of the need to demonstrate a continued commitment to reduce losses and share the cost burden with customers, JPS is proposing the imposition of a 2% stretch target. **Table 8.4** outlines the proposed schedule of loss reduction fixed for the rate cap period.

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[30] Per page 7 of the Application for Tariff Review 2000 Rate Determination.

Table 8.4: Proposed System Losses Target

	Actual	Forecast					
	Dec-08	Jun-09	Jun-10	Jun-11	Jun-12	Jun-13	Jun-14
Projected System losses	22.9%	22.5%	21.5%	20.5%	19.7%	18.9%	18.3%
Stretch target		2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Proposed Losses Target		**20.5%**	**19.5%**	**18.5%**	**17.7%**	**16.9%**	**16.3%**

Table 8.5: Analysis of the Losses Spectrum

	Actual	Forecast					
	Dec-08	Jun-09	Jun-10	Jun-11	Jun-12	Jun-13	Jun-14
Non-technical losses	13.0%	12.9%	12.2%	11.4%	10.8%	10.2%	9.8%
Technical losses	9.9%	9.6%	9.3%	9.1%	8.9%	8.7%	8.5%
Total losses	**22.9%**	**22.5%**	**21.5%**	**20.5%**	**19.7%**	**18.9%**	**18.3%**

Please note that a 2% stretch target implies an annual fuel penalty for JPS of approximately US$9M per annum at today's fuel prices, or US$14M at the average fuel price for 2008. A more punitive approach would be excessive and ultimately self defeating as it would effectively destroy the financial health of the Company and with it the capacity to combat losses.

It is important to note that JPS will be spending approximately US$9M per annum to reduce losses, which the Company believes is the optimal spend given the benefit to be achieved for customers and the need to deter non-technical losses in particular from growing. However, given the capital intensive nature of technical losses, various third party studies have concluded that 8.5% is the optimal level for a system the size and configuration of JPS'. The cost of reducing technical losses beyond this level will exceed the benefit to be gained (i.e. the savings in fuel cost). In relation to non-technical losses, where the average spend will be US$7M per annum, this will unfortunately only yield an annual fuel savings of approximately US$3M[31] at today's fuel prices. This net difference of US$4M per annum represents the cost of deterring losses (i.e. to ensure the situation does not deteriorate further). There is no reason to conclude that by spending more money that faster results would be obtained, given the physical resource constraints and the socioeconomic nature of this problem. The problem of losses parallels the current crime epidemic in Jamaica and there is no basis to conclude that simply devoting more resources can bring about dramatic improvement in either. It is no more feasible to conclude that simply funnelling more money to the Police will result in dramatic improvement in the incidence of crime than it is for. There is much cultural and legislative changes which will be required to resolve the current epidemic of crime in Jamaica.

To this end, JPS has proposed certain changes regarding the treatment of non-technical losses once identified, namely to impose penalties in an effort to deter the illegal abstraction of electricity. It is not possible for the Company to go out overnight with the police force and arrest the estimated 100,000 illegal users of electricity across the island of Jamaica. Indeed, a recent preliminary survey by the Ministry of Housing has found that 675,000 persons (or 25% of the population) are living in informal (or squatter) settlements[32]. JPS is committed to working with the GOJ and its affiliate organizations (such as REP and NWC) to encourage the development of

[31] The benefit is the reduction in fuel costs charged to customers and at today's fuel prices, each 1% point reduction in system loss below the target results in an annual total savings of US$4.5M for customers. As it relates to non-technical losses specifically, we forecast that the average reduction for the next five years will be 0.6% points per annum, which translates into an annual savings of US$2.75M.

[32] Per report by Dr. Horace Change, Minister of Housing, extract from the Financial Gleaner on February 13, 2009.

proper housing infrastructure for such persons, to mitigate the need for the illegal access of water and light by these inhabitants. It is recognized that the NWC has an even more uphill battle in their fight against unaccountable water (losses) which now stands at over 50%. JPS intends to again form a partnership with NWC in an effort to see what synergies may be gained from joint efforts to reduce non-technical losses.

8.3 Adjustment of Fuel Charge due to TOU Discount

This represents the adjustment discussed in **Section 2.4.4** to take into consideration the impact of the TOU adjustments on the standard fuel rate. The deficiency noted in the calculation of the standard fuel rate and the volumetric adjustment mechanism (VAM) can be fixed by ensuring both properly contemplate the sales distribution used to derive the fuel rate for any given month to the actual billed sales distribution in the subsequent month. The important point is that all sales are not billed at the standard fuel rate.

The proposed modification would be done by applying the weights of the respective sale categories to the sales reported for these categories. These are then summed to get the weighted sales before dividing the total applicable fuel cost by the weighted average of sales to derive the fuel rate. Thus the new formula to calculate the fuel rate to be applied to standard customers would read:

$$S_S = \frac{F * W_S}{\sum_i w_I N_I}$$

Where S is the system rate for standard category, F is the fuel cost, W is the weight for standard category and $\sum_i w_i N_i$ is weighted reported sales.

This will ensure that the standard rate is properly adjusted for the discount/premium charged to TOU customers and that the full cost of the applicable fuel amount is properly recovered through the energy sales in the subsequent month in conjunction with the use of the VAM. As demonstrated in previous correspondences, failure to account for this could lead JPS to under-recover or over-recover the applicable fuel cost.

8.4 Determining the Maximum Fuel Penalty/Reward

Given that fuel is generally meant to be a pass-through, subject to two main efficiency measures, summarized below are the significant exposures that the Company faces in the recovery of its fuel costs in many instances for reasons that are beyond its control. These include:

- variation in monthly fuel prices and the foreign exchange rate which can significantly amplify the amount of the actual fuel penalty/reward;
- socioeconomic conditions affecting non-technical losses (see **Section 8.2.2**);
- inherent monthly variation in heat rate due to the need to service base-load units; and
- exposure to IPPs (see **Section 8.1** for further details)

All of the above risks are amplified when it is considered that the price cap period will be set for the next five years and there could be significant deterioration in any of the abovementioned variables that are beyond the control of JPS that could result in the significant under-recovery of fuel costs for JPS. As mentioned previously in **Section 2.5.2**, and shown in **Table 2.6**, JPS actually experienced a net fuel penalty of $977 million in 2005 and $1.1 billion in 2007. However, given the actual fuel prices experienced in 2008 and the current foreign exchange rate, these losses could have amounted to $3 billion in 2008. The Company believes the risk of this recurring to be significant given the current aggressive assumptions about reducing system losses over the rate cap period and the significant age of our Old Harbour Plant (almost 40 years old) as well as the need to retire this plant. By the OUR's forecast these units are not scheduled to be retired before 2014.

To summarize the impact of the variation in the key efficiency measures mentioned previously, JPS assumes a 5% reduction in system losses over the rate cap period (2009 – 14), where, at today's prices, each 1% reduction in system losses results in an annual savings to the customer of US$4.5 million. Similarly, JPS assumes a 500 kJ/kWh reduction in the heat rate performance by 2010, where again, at today's fuel prices, each 100 kJ/kWh reduction results in annual savings of US$3.5 million. These numbers could be amplified by 30% using the 2008 average fuel prices and by 70% using the peak fuel price during 2008. This is of significant concern to JPS of course, given the relatively low fuel prices today and the uncertainty pertaining to fuel prices and the foreign exchange rate over the next five years. As a result, if JPS was only able to reduce system losses to 20% per annum for example, it would potentially experience a maximum annual penalty of US$17 million in 2014, as shown in **Table 8.6**, and experience potential cumulative penalties in excess of US$50 million.

Table 8.6: Scenario of Actual Losses of 20%

	2010	2011	2012	2013	2014
Actual system losses	20.0%	20.0%	20.0%	20.0%	20.0%
Proposed system losses target	19.5%	18.5%	17.7%	16.9%	16.3%
Excess over target	0.5%	1.5%	2.3%	3.1%	3.7%
Penalty at today's fuel prices - US$M	1.8	5.3	8.1	10.9	13.0
Penalty at today 2008 average prices - US$M	2.3	6.9	10.5	14.2	16.9

Similarly, if JPS were to experience a catastrophic failure on any one of its base-load units (being plants that are in excess of 30 years of age) resulting in the loss of 60 MW of capacity, which had to be replaced with less efficient units, it would then experience a 300 kJ/kWh deterioration in its heat rate performance. The same impact could occur if any of the IPPs lost 40 MW of their generating supply due to a catastrophic failure. Again, given the savings of US$3.5 million per annum per 100 kJ/kWh, this could possibly lead to the under recovery of fuel costs by JPS by as much as US$10.5 million per annum at today's prices, or 30% more using the average fuel price during 2008. Again, there would be much uncertainty as to what amount this could grow to financially over the next five years given the relatively low fuel prices today.

It is also true that there could be similar upside to JPS if it were able to reduce system losses at a much faster rate than projected (though this is highly unlikely), or there could be upside on the heat rate if the IPPs achieve availability of more than 90%.

JPS does not seek to derive any of its core profits from the recovery of fuel costs (i.e. the fuel rate), nor does it wish to be exposed to substantial risk on the recovery of fuel costs, especially given the significant amount of variables that are outside of the control of the Company. It is the Company's proposal therefore that a maximum limit be imposed on the fuel penalty/reward.. The proposal is that the annual penalty or reward should not exceed more than 15% of the target non-fuel profit used in the revenue requirement determination in **Section 5.3**. This is to ensure that the Company does not make any excessive profits on the recovery of fuel costs nor does it face any excessive penalties, while still being incentivised by the fuel recovery efficiency measures. Given, that the target non-fuel profit is $7.1 billion per **Table 5.21** at a base exchange rate of 85:1, then the target annual profit for the Company would be US$84 million and the maximum annual penalty or reward should be restricted to US$12 million using the 15% criteria. Therefore, the maximum monthly penalty/reward in relation to the recovery of fuel costs be capped to US$1 million per month. That is to say, the applicable fuel cost to be recovered from customers would be subject to the adjustment of the two efficiency measures of heat rate and system losses but subject to a maximum monthly penalty or reward of US$1 million.

9 System Losses

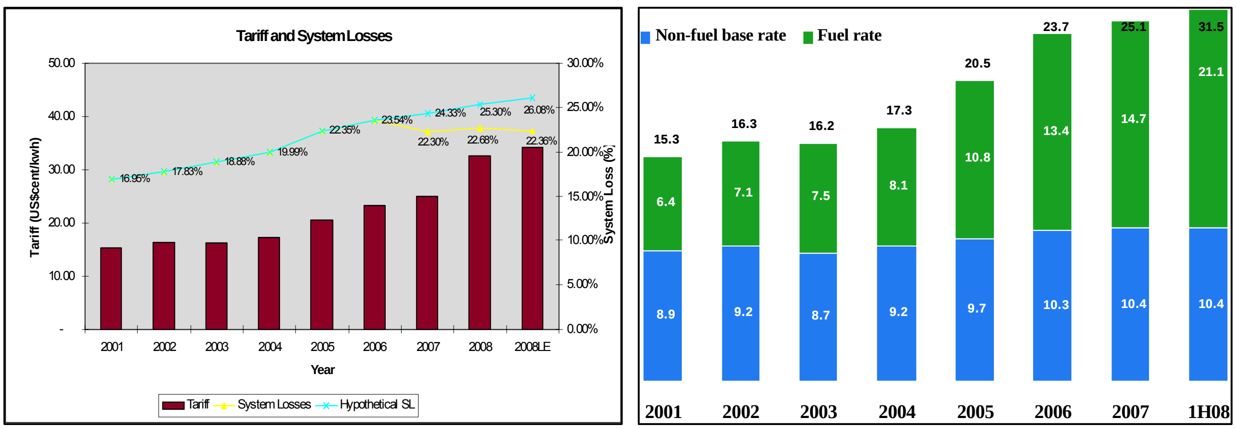
9.1 Introduction

The objective of this section is to provide the OUR with a summary of the system loss initiatives the Company has undertaken during the review period, as well as the challenges that JPS faces in managing the system losses and to put forth certain proposals as it relates persons found illegally abstracting electricity.

9.1.1 The JPS Losses Situation – vs. - Challenges

The graphs below show that there is a strong correlation between system losses and energy prices.

Figure 9.1: System Losses and Energy Prices Comparison



However, at the same time it was easily detectable that other than spending more resources dedicated in trying the best to control the losses, JPS did not have many options as the total price trend for the end users was controlled primarily by the fuel component of the energy price and by the billing exchange rate. It was also proved that had JPS not dedicated so many of its efforts to combating losses the system losses figure could have been much higher than what it is today. In fact, if one compares JPS with the energy utilities of other socio-economically similar countries, it will be shown that JPS' system losses, is less than many other utilities, this because of the Company's continuous efforts to reduce losses including using new technologies to combat losses.

Figure 9.2: Technical Losses Spectrum

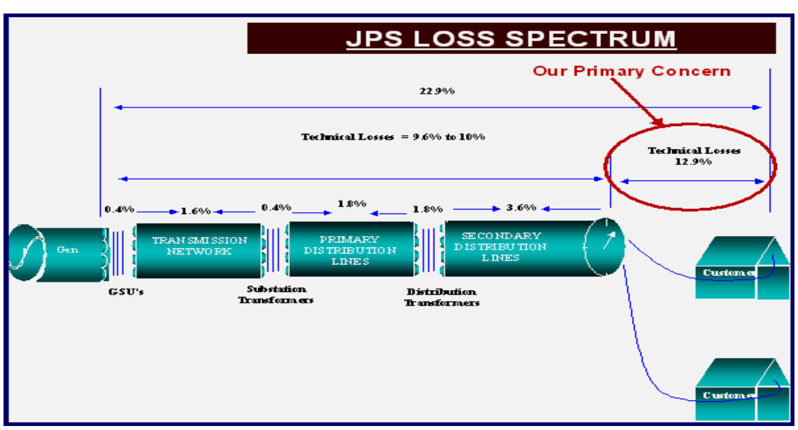


Figure 9.2 shows that at the end of 2008 the total JPS system loss stands at 22.9% out of which the technical losses are within the range of 9.6% to 10% while the Non Technical losses are 12.9%.

When a comparison is done between JPS' Technical losses and the losses of other utilities with similar network size and structure, there were both better and worse than JPS existing in countries of similar socioeconomic background. This motivates the Company to be much better and JPS continues steadfastly in its endeavours to reduce Technical losses, as explained below.

When a comparison is done with JPS' Non Technical losses to other utilities, though it is discovered that the Company is much better than many of the utilities that exist in countries with similar socioeconomic conditions, JPS commits a vast amount of its business resources to reducing losses. System losses jeopardize the viability of the business especially given that the existing regulated fuel tariff recognizes only 15.8% of the total system losses, which leaves JPS absorbing all the losses above this threshold.

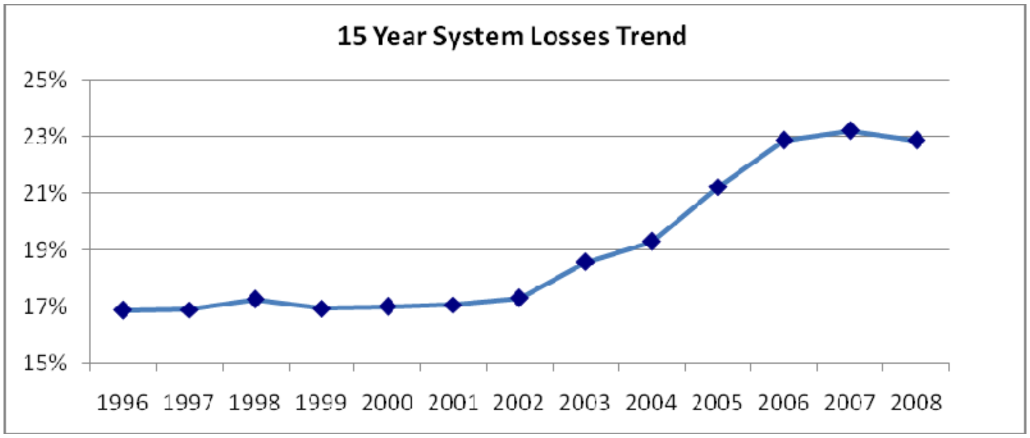
In many other countries, the percentage of system losses recognition by the energy tariff is dependant to the socioeconomic structure of the country. A vivid example is the Caribbean country the Dominican Republic, which is in some instances, has broadly similar socioeconomic conditions when compared to Jamaica. One difference is that in the Dominican Republic, the country's energy sector is unbundled and there exist several Generation companies (both Government and Private owned), one Transmission company (Government owned) and three Distribution companies (both Government and Private owned). The Distribution companies have system losses of 33% and higher. Though the loss figure sounds very high, it was agreed that to reduce losses substantially under the present socioeconomic structure of the country, the companies would require extremely high investment during next ten years but possibly with very little tangible return. As this could cause an unbalance in the country's economy through over investment in a particular sector, the Government and the Regulatory Commission decided to recognize the Distribution Companies' system losses through a direct Subsidy to the Distribution companies along with implementation of stringent Laws to restrain illegal abstraction of electrical energy from the distribution network. The Distribution companies nevertheless remained with the responsibility to continuously try and reduce system losses.

Similarly, in Brazil, where there are more than four (400) million inhabitants, they have sixty-three (63) distribution utilities in over fifty (50) main municipalities. The level of non-technical losses varies significantly across these utilities, primarily dependant on the socioeconomic conditions of each municipality. Accordingly, the regulator in Brazil has turned to looking at the socioeconomic conditions in each territory as a means to deciding what level of system losses should be recovered through the tariffs.

9.1.2 Overview of Loss Reduction Activities – Years 2004 – 2008

By way of background, the chart below illustrates the Company's System Losses Trend:

Figure 9.3: JPS 15 year System Losses Trend



As is evident from the above graph, while there has been a noticeable increase in system losses since the last tariff review, through the several initiatives implemented by the Company, there has been a slight reduction or levelling off of system losses in the last two years. Set out below is a summary of the activities the Company has undertaken since 2004.

9.1.2.1 Years 2004-2005

For the years 2004 to 2005, the Company narrowed its focus primarily on locating and removing illegal connections and prosecuting offenders. Accordingly, there was transfer of Revenue Protection Division (RPD) and Large Account Audit groups to the Security and Asset Protection Department with a continuation of the main focus of 2003 which was to police and remove illegal connections. The removal of illegal connections in informal settlements and similar communities was intensified during this period whilst at the same time encouraging these persons to become legitimate customers. A secondary focus during this period was the commencement of annual audits of major customers and, where considered necessary, small customer meter audits were conducted.

By the end of 2004, through the efforts of the RPD, 307 persons were arrested and charged with theft of electricity and a total of 29,864 illegal connections were removed across the Island. RPD activities were also aimed at legitimate customers who may have tampered with meters or carried out some form of meter bypass. In the fourth of quarter of 2004, JPS and the NWC formed a joint but brief alliance to address illegal connections that affected both Companies. For the year ending 2005, almost 400 persons had been arrested and charged with the theft of electricity.

9.1.2.2 Year 2006

In 2006 a comprehensive review of the program over the past 5 years was done from which recommendations were made and implemented in an aggressive manner to curtail the spiralling increase in energy losses and ultimately to reduce it. The focus was further intensified among the large accounts, which was also extended beyond the rate 40 and 50 customers to rate 20 customers. In summary the main activities are outlined below:

Activities

Loss Reduction Management Unit: The establishment of an Energy Loss Reduction Management Unit led by a General Manager with direct support from two (2) energy loss analysts. The main purpose of this unit is the prioritization of energy loss reduction programs, to monitor and track programs.

- Meter Specialist: Recruitment of a Meter Specialist to support the Meter Operations Department in completing the revenue class metering of Substations;
- Revenue Protection Department (RPD): Increase of the workforce of the Revenue Protection Department by 18;
- Large Account Audit Unit: Increase of the workforce of the Large Account Audit unit from 6 to 12 and implement the Large Account Audit Program:
  - A total of over 4,000 field investigations and audits were completed among Commercial & Industrial customer meter facilities to identify meter anomalies contributing to energy losses. Approximately 10% percent of these accounts were found with irregularities ranging from defective meters to meter tempering, direct connection and meter bypass. The average incremental increase in sales per irregularity was estimated 4,000 kWh per month or a total of 16,000 MWh was recovered.
- Implementation of Amnesty Program
  - This program allowed individuals to regularize their illegitimate status with the Company. Features of the program included – no criminal charges, no back billing and no increase in deposit and/or payment plan for arrears. Local upcoming artiste Noddy Virtue was engaged by the Company to record a song aimed at discouraging the theft of electricity – "Live Right Pay Fi Yu Light" A total of 7,171 customers and electricity users applications were received and logged.
  - Approximately 4,000 applicants from garrison communities were received.
- Public Involvement
  - JPS launched an aggressive advertisement campaign, which focused primarily on the business sector through print and radio ads warning against theft of electricity.
- Targeted Feeder Energy Loss Reduction Program
  - A total of 106 feeder profiles were developed detailing technical and non-technical energy loss characteristic for each feeder. This was geared towards prioritizing loss reduction solutions on feeders with the highest level of energy loss by measuring and tracking energy loss at the feeder level.
  - Customer to Feeder Mapping Project
    - A major part of the targeted feeder program was the GPS mapping and tagging of 570,000 customers to their respective feeders and line sections.
  - Duhaney Substation 410 Pilot Target Feeder Energy Loss Reduction
    - The Duhaney Substation 410 Feeder was selected as a pilot to demonstrate the loss reduction effort required on a feeder basis prioritized around feeders with the highest level of energy loss. The energy loss was successfully reduced from 28% to 17% of the energy delivered to the feeder. 70% of the energy recovered was due to meter anomalies.

Third Party Support Engaged:

- KEMA T&D International Consultant
  - Engaged to assess and validate JPS 2006 Technical & Non-Technical Loss Reduction Programs:
    - Recommendations included:
      - Revenue Assurance Process to effectively reduce losses on a sustained basis;
      - Revenue Intelligence System to increase the strike rate; and
      - Development of the Advanced Metering Infrastructure as part of the revenue assurance process and intelligence system.

- Plexus Research Inc.
  - Contracted to conduct a business case assessment for the entire customer base. This did not prove economical with an investment of US$80 million and payback in the order of 6 years. In light of the first assessment this led to a further business case assessment of commercial and industrial customers, which showed favourable returns on investment with a payback of 5 years and an investment of US$6 million. This created the impetus for the AMI project which was launched in late 2007.
- Alliance Data Services Inc. (ADSI)
  - Banner CIS consultant contracted to validate the billing system and revenue assurance process.
- A local security firm was contracted to perform audits and investigation of JPS meter reading process, field investigation and the disconnection and reconnection operation of delinquent customers.

Funding of Loss Reduction Effort

The renewed drive to curtail energy loss was supported with additional funds in 2006 beyond the budgetary approval with further capital investment of US$2.5M and O&M US$1.4M

9.1.2.3 Year 2007

In 2007 the leadership of the Company decided to build on the lessons learnt in prior years and took the decision to mobilize the entire workforce in the fight against energy losses by decentralizing the management of losses. This resulted in linemen, engineers, field service technicians, technician engineers, and parish managers being fully engaged and sensitized of the loss reduction program. Attacking system losses therefore became a routine part of JPS operations. Additionally, loss reduction initiatives were widened from being focused on raids and removal of illegal lines to more analytical and technology based solutions, together with in depth reviews of internal systems and controls as well as public education. By the end of May in 2007, there had been 138 arrests, 13,000 account audits, removal of over 7,000 throw ups and a recovery of 9 GWh or JA$100.5 million in retroactive billing. In particular, October 2007 saw the roll out of the new loss reduction advertising campaign "HOW COME?"

9.2 Loss Reduction Activities 2009 - 2014

9.2.1 Technical Losses

- In 2008 JPS replaced the entire 138 KV substation circuit breakers with new ones as the system old circuit breakers were contributing to energy losses.
- In 2008 JPS also installed/rehabilitated 73.2 MVAR of capacitor banks in its circuits to improve the power factor and voltage of the circuits by reducing the reactive demand of the circuits. The project of installation of switched capacitor banks is ongoing and the target is to achieve a system power factor of 0.98. Below is the status of the system power factor improvement project up to January 2009 and project plan for the rest of 2009.

Table 9.1: Project Status Capacitor Bank Installation

	Achievement to date		
	MVAR Installed	Units Installed / Rehabilitated	% Complete
Region Metro			
St. Catherine	12.9	21.5	63%
KSAS	4.8	8	36%
Subtotal	**17.7**	**29.5**	**53%**
Region East			
KSAN	6.6	11	92%
Portland	1.2	2	29%
St. Thomas	2.4	4	100%
Subtotal	**10.2**	**17**	**74%**
Region West			
Hanover	1.5	2.5	36%
Westmoreland	4.8	8	133%
St. James	1.5	2.5	17%
Subtotal	**7.8**	**13**	**46%**
Region South			
Clarendon	5.7	9.5	56%
St. Elizabeth	1.2	2	50%
Manchester	11.1	18.5	142%
Subtotal	**18**	**30**	**88%**
Region North			
St. Ann	10.2	17	106%
St. Mary	4.8	8	100%
Trelawny	4.5	7.5	125%
Subtotal	**19.5**	**32.5**	**108%**
TOTAL:	**73.2**	**122**	**71%**

Feeder PF Status	**Feeder Status At Dec. 08**	**Feeder Status Jan. 09**
% of feeder/ transformer metering points / 95% p.f.	0.473	0.5
% of feeder/ transformer metering points / 98% p.f.	0.182	0.2

This Capacitor Bank Project has improved the system voltage and stability. In prior years at summer time, because of the increase in partial peak demand and subsequent drop in voltage the Company would have to shed certain feeders to maintain the system balance. However, in 2008 the problem was avoided completely because of an improvement in voltage level and system stability caused by all capacitor banks in circuit.

Table 9.2: Project Plan Capacitor Bank Installation 2009

	Existing Inventory			Additional Banks For 0.98 P.F. (Based On January 2009 Data)				
	Fixed	Switched	Total	Switched		Fixed		
District	Mvars	Mvars	Mvars	# of Banks	Mvars	# of Banks	Mvars	Overall Mvars
KSAN	26.7	14.1	40.8	2	1.2	0	0	42
Portland	2.4	0	2.4	5	3	0	0	5.4
St. Thomas	8.4	0.6	9	2	1.2	1	0.6	10.8
KSAS	38.1	24.9	63	8	4.8	0	0	67.8
St. Catherine	18.4	6.7	25.1	15	9	3	1.8	35.9
Trelawny	6	0	6	3	1.8	0	0	7.8
St. Ann	20.4	0	20.4	5	3	0	0	23.4
St. Mary	5.4	0	5.4	2	1.2	0	0	6.6
Clarendon	11.4	0	11.4	13	7.8	1	0.6	19.8
Manchester	6.6	9.6	16.2	6	3.6	0	0	19.8
St. Elizabeth	3	0.6	3.6	0	0	0	0	3.6
Westmoreland	4.8	3.6	8.4	6	3.6	0	0	12
Hanover	2.1	1.8	3.9	5	3	0	0	6.9
St. James	10.8	12	22.8	8	4.8	0	0	27.6
Totals	**164.5**	**73.9**	**238.4**	**80**	**48**	**5**	**3**	**289.4**

9.2.2 Non-Technical Losses

Non-Technical Losses are caused by the illegal abstraction of energy both by JPS customers as well as users of energy who do not have any formal business relation with JPS. During our Loss reduction activities it was observed that the illegal abstraction of energy exists amongst all the different classes of customers/users and it is spread island wide.

9.2.2.1 Large Account and RPD Audits

The Company's investigations into losses have been classified into two different groups:

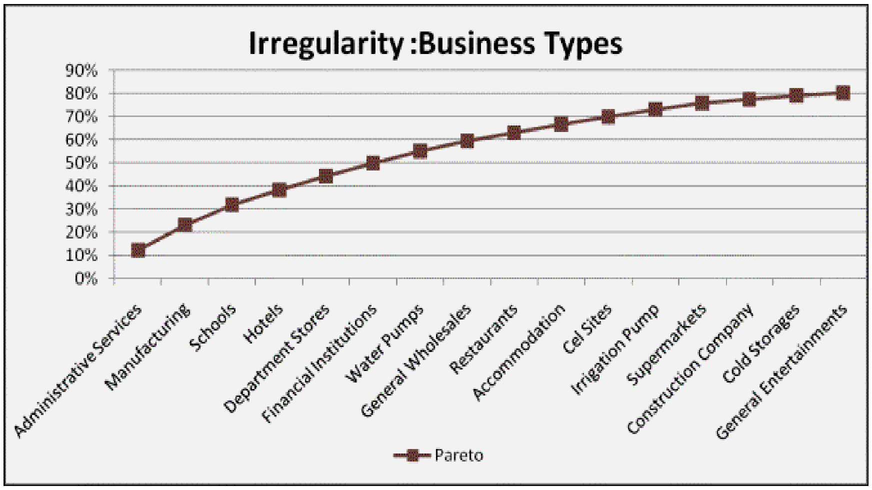
i. Large Account Audits;
ii. Revenue Protection Activities, which deals with the audit of small and large commercial accounts that do not belong to the group of large accounts.

In JPS, all customer accounts that consume more than 3,000 kWh of energy per month are considered as "Large Accounts". JPS has approximately 7,100 large accounts. It was the Company's usual practice to audit these large accounts against any possible threat of diversion of energy by different means but under today's context, when these large accounts represent more than 50% of JPS' billing, the audit activity requires a high use of knowledge, efficiency and technology. Accordingly, while the trend of energy theft increased rapidly in all rate classes, JPS placed greatest emphasis on large account audits. In 2008, Advanced Metering Infrastructure (AMI) for our Large Accounts was implemented and today there are approximately 1,900 large accounts metered with AMI Metering. These meters are communicable and from a central control facility can be continuously monitored for instantaneous customer demand, consumption, supply outage and third party intervention into the metering system at pre-designed intervals of 15 minutes. These also meters also assist the Company's TOU customers in controlling their demand and consumption during On-Peak and Partial-Peak hours. Surprisingly, in 2008, 85 (or 5%) of the Company's large accounts were identified as being involved in diversion of energy by tampering with their meters or the associated CTs. In fulfilment of the Company's Loss

Reduction programme, 2008 saw all the Company's large accounts being audited at least once and the audits revealed illegal diversion of energy in 9% of these customers.

The Company has become much more focused in its efforts, particularly in applying intelligence in auditing of these large accounts. **Table 9.3** is a comparison of the results achieved during the last three years of the large account audits. The results clearly show the benefits of increased efforts in the reduction of Non-Technical Losses as well as the fact that abstraction of energy is adopted by a variety of JPS' customers, as shown in **Figure 9.4**. By the end of 2009, the Company plans to measure the consumption of 5,000 large accounts through AMI metering.

Figure 9.4: Identity of Chief Offenders



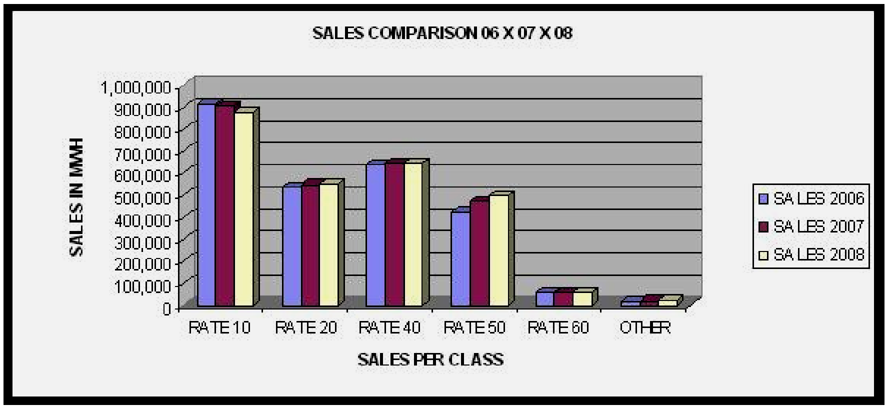
The revenue protection activity which basically deals with the audit of all small and large commercial accounts outside the group of large accounts, also came across the same nature of findings where of 7,775 accounts audited in 2008, it was discovered that approximately 900 of those accounts were involved in illegal diversion of energy. **Table 9.3** shows the amount of energy recovered in 2006, 2007 and 2008 by auditing our Large Accounts and discovering illegal abstraction of energy.

Table 9.3: System Losses Program Achievements

	2006	2007	2008
Large account audits	4,450	7,345	8,610
RPD audits	8,548	8,570	7,775
Removal of throw-ups	6,861	18,929	42,425
Strike rate	25%	17%	11.4%
Energy recovered/back-billed (kWh)	18,905	48,919	49,265
Revenues recovered (J$ Millions)	$200	$494	$750
Loss reduction contribution to Losses	0.21%	1.2%	1.22%

When analyzed energy sales, it is observed that there has been a decline residential sales over the last three years despite an increase in the customer base while there has been marginal growth in all other areas, as shown in the **Figure 9.5**.

Figure 9.5: Sales Comparison



It is evident from the results yielded from our commercial and industrial customer audits that concerted effort is now required for residential customers. However, given that there are approximately 525,000 residential customers, the approach will have to be modified given that the resources necessary to cover such a large group could make such a project unfeasible. The installation of AMI meters would cost in excess of US$80 million for this entire group and would take approximately 10 years to complete. However, given the urgent need to address losses within group of customers, the Company has decided to address the energy losses in this group in different ways.

9.2.2.2 Audit of Zero (0) Consumption Customers

Firstly, it was observed that a large number of residential customers were being billed for zero consumption for consecutive months. This could be possible due to a mechanical defect in the meters, or due to no load condition in the customers' premises, or due to customers bypassing their meters. As none of these possibilities could be rejected, the Company first took steps to verify if there had been any problem with our electromechanical meters.

Surprisingly, the Company identified approximately 68,000 "Hansen" electromechanical meters out of which approximately 3,300 were found to have stopped working due to a typical mechanical failure. Customers that were being measured by these defective meters had zero consumption for some period of time in their billing history. As these customers had nothing to do with this problem caused by the meters, the Company decided to replace the 3,300 Nansen meters by the new Elster make electromechanical meters without back-billing the unregistered consumptions for the past months. The Company further decided to remove 1,965 inactive (not in use) meters from the network. The replacement of all defective Nansen meters was recently completed.

Table 9.4: Project Progress Report

	Project Progress				Project Result		
Parish	Total Accounts	As at Jan 7, 2009	As at Jan 22, 2009	As at Feb 6, 2009	KWh Oct 2008	KWh Nov 2008	KWh Dec 2008
Black River	353	79.30%	84.10%	92.07%	20	2740	11575
Falmouth	269	92.60%	96.30%	96.28%		1443	1242
KSA North	405	71.10%	72.10%	75.50%		9298	16474
KSA South	405	6.90%	31.90%	74.57%		3908	5578
Lucea	217	76.50%	97.20%	97.24%	87	2080	3004
Mandeville	260	96.90%	96.90%	97.31%		5762	17574
May Pen	356	84.30%	89.60%	89.89%	370	3679	11794
Montego Bay	805	37.40%	58.80%	69.19%		9004	32948
Morant Bay	104	86.50%	86.50%	86.54%	1311	2564	3128
Port Antonio	153	75.20%	88.20%	92.16%		1378	2645
Port Maria	177	74.60%	77.40%	83.62%		3312	3108
Sav-la-Mar	667	65.20%	75.70%	92.35%		5084	9413
Spanish Town	533	50.70%	68.30%	78.84%	28	11849	13524
St. Anns Bay	561	40.60%	49.00%	69.34%		8052	10084
Grand Total	**5265**	**59.60%**	**71.00%**	**82.37%**	**1816**	**70153**	**142091**

JPS had numerous other residential customers with zero (0) consumption for consecutive months whose consumption were not measured by Nansen meters. It was therefore decided to dedicate the Company's resources towards intense auditing of these residential accounts. Up to January 2009, 396 of such residential customers were audited and 19% were discovered with illegal diversion of energy. **Table 9.5** below shows the findings in the last quarter.

Table 9.5 Project Report of Rate 10 Account Audit

Findings	Total
Found With Illegal Connection	106
Found with Installer Seal Missing, No visible tampering	36
Found Disconnected	49
Found With Energy, Meter Not Advancing	4
Found With Installer Seal Broken	12
Found With Installer Intact, No Visible Tampering	256
Found With Different Meter	3
Found With Miss Placed Pointer	1
Found Un-occupied (Meter & Service Wire Removed)	18
Found with Barrel Lock, No Visible Tampering	4
Found with Test Seal Broken	3
Premises Un-accessible (Threat To Life & Property)	51
Meter Found With Open Potential Link	2
Inverted Meter	1
Defective Meter	11
Wrong Meter (120v Meter to be Change to 220v Meter)	7
TOTAL	564

9.2.2.3 Removal of Inactive Account Service Equipments

At JPS, the practice had been to leave the meter and the service wire intact at the customer's premises after the customer terminated his service. This was done under the assumption that a new customer would typically apply for service in short order and it would therefore be a waste of resources to remove equipment and material upon termination only to have to return in short order with a new crew to re-install the service equipment/material in order to provide supply to the new customer at the same location.

Unfortunately, this practice did not bode well for JPS, as several such inactive account locations where users have illegally reconnected their electricity supply without applying for service from JPS have been observed. As mentioned earlier, the Company decided to remove the service wire and meters for all inactive accounts (non registered consumer) along with replacement of the defective Nansen meters. While doing so the Company came across various unauthorized users who complained of being disconnected in the process of removing the service wires. As these were not legal customers, they had to either come to JPS to request a new connection and become a regular customer or remain without energy. These cases were also referred to the RPD for further follow up.

Figure 9.6: Meter Centre and Residential AMI PROJECT

It is well known that all across Jamaica the tendency of stealing energy has increased with time. This illegal abstraction of energy not only takes place through meter tampering or diversion of energy by JPS customers but also by throw ups used by unauthorized energy users. These illegal abstractions result in large amount of system losses to JPS.

Like other countries JPS has learnt that: (i) the more the meter is left within the reach of the customer, the greater the possibility of meter tampering; and (ii) the more exposed the secondary network, the greater the possibility of energy being stolen.

9.2.2.4 Meter Centres

Thus arrived the concept of the meter centre. The meter centres are installed on the pole, which can accommodate 6 single-phase meters (currently JPS is installing 4 in compliance with the GEI orientation).

Figure 9.7: JPS Meter Centre for Residential Customers

These meter centres are fed from the transformer by concentric neutral cable and output goes directly to the customer's premises through concentric neutral cable as well. Thus the meters do not remain within absolute accessibility of the customer. The concentric neutral cable having the conductor cores in concentric form is theft proof and any intent of breaching the cable insulation to get the supply phase core causes a local flash over. The continuation of secondary circuit within poles is done through multiplex insulated cables. Above are some photos of meter centres installed at loss prone areas, which has so far given a reasonable result based on the limitation this type of construction. Below is the project programme for the installation of meter centres during 2009.

Table 9.6: Planned Installation of Meter Centres during 2009

Parish	Recovery MWh//Mth	No> Transf. /Mth	MWh/Mth Recovery	Total No. Conv. Trans.	Total No. Metered Trans.	Total Cust.	No. Meter Centres
Clarendon	16.00	4	160.00	40	60	800	200
Hanover	12.00	3	120.00	30	45	600	150
KSAN	20.00	5	200.00	50	75	1000	250
KSAS	20.00	5	200.00	50	75	1000	250
Manchester	12.00	3	120.00	30	45	600	150
Portland	12.00	3	120.00	30	45	600	150
St. Ann	16.00	4	160.00	40	60	800	200
St. Catherine	20.00	5	200.00	50	75	1000	250
St. Elizabeth	12.00	3	120.00	30	45	600	150
St. James	20.00	5	200.00	50	75	1000	250
St. Mary	8.00	2	80.00	20	30	400	100
St. Thomas	12.00	3	120.00	30	45	600	150
Trelawny	12.00	3	120.00	30	45	600	150
Westmoreland	8.00	2	80.00	20	30	400	100
TOTAL	200	50	2000	500	750	10000	2500

9.2.2.5 Residential AMI Metering

In loss prone areas, though the Company has begun implementing meter centres and concentric neutral cables to reduce the possibility of energy theft, the Company has still observed several instances where customers and the users have deliberately attempted to violate the shield and tamper proof system to steal energy. The following pictures show the way the network has been tampered with.

Figure 9.8: Evidence of Network Tampering

The success of the AMI metering project with the large accounts and at the same time the limited cases of violations of meter centres by end users, has motivated the Company to consider rolling out of the same type of project for residential customers, especially in loss prone areas. The system works slightly differently for residential customers, where up to 24 single-phase shunt electronic meters with remote disconnect/reconnect switches installed inside a meter cabinet. This cabinet with optional tamper proof locking arrangement is installed on the utility pole at a high altitude out of the reach of customers. The customers' meter readings and consumption are transmitted via radio frequency (RF) or power line carrier (PLC) to a display unit installed inside the each customer's premises. The communication to these meters is done through micro controlled units via communication modems such as PSTN, GPRS, RF or PLC. This system also gives the facility for 2 way automatic communications for remote meter interrogation and for disconnection/reconnection.

Figure 9.9: The Shunt Electronic Meter cabinet with digital display unit

Many other countries of similar socioeconomic structure have already implemented this residential AMI metering system to help address their system losses. The pictures below show the implementation methodology and the accomplished project of a Latin American Country. At this stage JPS is awaiting the Bureau of Standard's approval of the metering system and also approval of the Regulator for introduction of these residential AMI meters. The pilot project is scheduled to commence in March 2009 and the Company plans to implement 10,000 residential customer AMI meters in 2009.

Figure 9.10: Typical Residential AMI Metering Layout

9.2.2.6 Meter Sealing

During regular meter inspections recently, many meters where the customers had tampered with the meter seal were discovered. There were even instances where it was observed that newly installed meter seals were tampered within 7 days of installation. The methods used for seal tampering has reached to such an extent that other than close physical checking it is very difficult to detect the seal tampering. Additionally, there have been many instances where it has been observed that the meter seals are found intact and yet the meters have been tampered with. The difference of the energy load tested in and out of the meters was the only way to detect the tampering. The seals currently used by JPS are available in the market and hence replacement of a seal is not very difficult for a customer who is inclined to tamper with their meter.

It was therefore decided to bring in a new type of Tamper Evident Holographic Seal in our system. These seals cannot be copied and once violated are easily detectable. These seals are being made with specific codification for different class of consumers and each of these seals will have a unique number. The Company plans to start using these Holographic Seals as of April 2009.

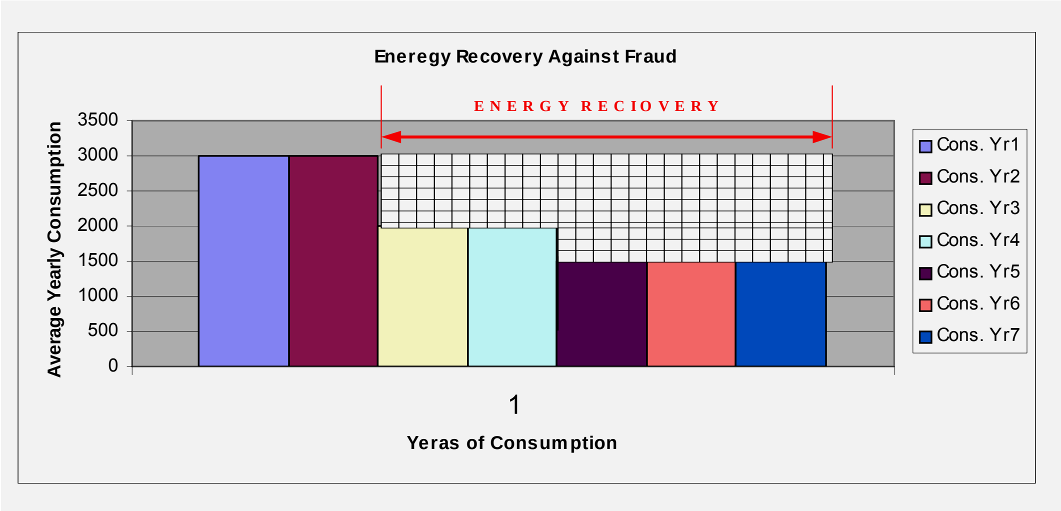
9.3 JPS Proposals for OUR Consideration

1. **Introduction of penalty payment provision for JPS customers (with average monthly consumption greater than 200 kWh) found illegally abstracting electricity.**

This is a widely practiced concept in several countries around the world for the prevention of energy losses caused by fraudulent customer activities. In Jamaica there is no penalty provision in the electricity regulation. It should be noted that this proposal does not focus on the ordinary residential customer, as the average monthly consumption of residential customers is 164 kWh. Therefore it is hoped that such a penalty will restrain the illicit activity amongst the higher income group of persons in the country, the small commercial establishments and the industrial customers.

The graph below (**Figure 9.11**) is an example of the methodology used by JPS today in the recovery of lost energy due to customer activities.

Figure 9.11: Energy Recovery Methodology



When an illegal abstraction of electricity is detected, the load of the customer/user is measured and calculated to derive the energy consumption that should have been used based on the actual current load found. The difference between this calculated consumption and the consumption shown by the tampered installation results in an energy loss determination. Depending on the facts of the particular finding, JPS can seek restitution of the amount of electricity supplied but not paid for from the customer/user for a maximum of six (6) years. JPS then assesses the customer for the consumption difference where the consumption of the customer had been less than the billed consumption. In all other cases, the billing may be for a lesser period and would be calculated from the time when the customer's consumption fell notably due to the illegal abstraction of electricity. In the graph above the white checkered area represents the energy that is recovered. However, in this entire process, there is no penalty assessed against the customer for this activity, rather the customer pays for the same amount of energy that he was supposed to pay for during the period assessed. This provides an indirect incentive to the customer/user to steal electricity, since effectively the customer/user benefits from an interest free loan from JPS. Additionally, when these customers/users are identified, the usual process is to arrange repayment over a period of approximately six (6) month thus achieving a second benefit for their wrong doing.

JPS acknowledges that the law dictates that the illegal abstraction of electricity is a criminal act. Regrettably, however, the court system does not currently provide a practical or an expedient avenue for the Company to pursue civil action against the thousands of individuals engaged in the illegal abstraction of electricity, some of whom live in poor rural areas or urban communities. And even the criminal prosecution of such individuals, which is an action to be undertaken by the state, would require significant resources and time by the Company and its staff to pursue because of the inherent nature of these court proceedings. However, this is a matter that the Company plans to continue lobbying the relevant authorities about to ensure the law is effective in discouraging this criminal act. The Company looks forwards to the new Electricity Act in the hope that it will provide some help in this regard, as this legislation is long overdue.

However, as it relates to the illegal abstraction of electricity by JPS customers/users with consumption above 200 kWh per month, JPS requests the imposition of a penalty clause for the diversion of electricity to deter customers/users from such activity by way of a 30% surcharge of the amount assessed to be stolen from the Company.

Half of this surcharge could be remitted to the OUR, or any other organization recommended by OUR, which in turn can be utilized for increased monitoring of losses, for infrastructure development, or for house-wiring projects in poor communities. Earlier in this paper, the increased number of energy stealing activities during the past years was highlighted. This has demanded an increase in the Company's administrative tasks as well. Accordingly, JPS would use the other half of the surcharge to contribute towards the loss reduction activities.

It is important to note that the present situation has become so chronic, that JPS would have to direct a significant amount of resources island-wide to manage the loss situation. JPS is not proposing to include an infinite amount of expenses in the revenue requirement to be paid by good paying customers. In this regard, the surcharge would provide an additional incentive to JPS to commit additional resources at this problem with the full knowledge that additional revenues gained would help fund the initiative itself. In at least one other Caribbean island (the Dominican Republic), there is the provision of a 20% surcharge for energy theft that is paid directly to the utility.

The Company therefore proposes the introduction of a penalty charge clause for customers/users (whose consumption is higher than 200 kWh per month) found illegally abstracting electricity by way of a 30% surcharge. Half of this surcharge should be paid to the Company and half should be paid to the OUR or their designate.

2. Introduction of foreign currency and interest expense charges to JPS customers caught stealing energy.

The methodology described above, used for the recovery of illegally abstracted energy has two shortcomings. The retroactive energy recovery charge considers the actual fuel and non-fuel tariff billed during the previous periods but gives no consideration to the current exchange rate (at the time when the diversion is identified) and to the opportunity cost of capital to the Company. As you are aware, the fuel tariff is billed at the prevailing exchange rate each month in recognition that the fuel is purchased entirely (100%) in U.S. dollars (US$). Similarly, the non-fuel tariff is adjusted by 76% of the movement in the US$ in recognition that 76% of all non-fuel costs are incurred in US$.

Accordingly, any retroactive billing to a customer/user that ignores what the current foreign exchange rate is at the time when the diversion is detected, effectively exposes the Company to the foreign exchange risk during the entire period of the diversion. So, for example, if a customer/user diverted electricity for all of 2008, when the average exchange rate was $73:1, and the diversion was not detected until March 2009, when the current exchange rate was $90:1, then JPS should be able to back bill the customer/user at the prevailing fuel and non-fuel tariffs for 2008 but appropriately adjusted to the current exchange rate of $90:1. This principal is consistent with the foreign currency adjustment mechanism currently applied to customer bills.

Secondly, JPS should be able to charge the customer/user for its opportunity cost of capital, given that non-payment by the customer/user must have had a negative impact on JPS' working capital. That opportunity cost of capital could be agreed to be the Company's cost of debt (rounded to 11.5% for simplicity), which, if applied to a back billing which has been adjusted for the movement in the US$, represents the correct method to calculate the opportunity cost of capital for the Company.

The Company therefore proposes the introduction of an interest charge in respect of energy identified as diverted by customers/users and a foreign exchange adjustment to reflect the

difference between the foreign exchange rate at the time of the original billing(s) and the current rate at the time when the diversion is detected/quantified.

3. Introduction of demand management using reclosers for high loss areas.

In the context of third world countries, there are examples of several energy utilities across the world where demand management is a tool to reduce losses. It is a well-known fact that within the JPS service areas, in many Inner Cities, there are many more users of energy than legitimate customers, consequently rendering these areas as high losses areas. It is impossible for JPS to reduce losses in these areas without assistance from the political directorate and consistent support from the police force. Despite the Company's best efforts to improve community relations, due to the highly volatile nature of many of these high loss areas, the Company's employees only have limited access to these communities which limits the Company's ability to perform routine operations such line inspections and meter readings, let alone to focus on disconnection/reconnection activities and loss reduction activities. In fact much of the loss reduction activities are conducted under police escort, where such support can be obtained. Especially at night, it becomes virtually impossible to get into such inner city communities.

The JPS system peak, partial and off-peak demand hours naturally coincide with the peak, partial and off-peak demand hours of these areas. Due to the unauthorized use of energy, these areas cause high non-technical losses to the system and the losses trend gets higher during the peak and off peak hours. Now during the peak demand hours JPS often needs to run the costlier gas turbine units (GTs) to meet the demand. The additional cost of these units is borne by all JPS customers. If JPS is permitted to manage the demand by the shedding of power to these high loss prone areas during the peak hours, it will give JPS the flexibility of controlling the system demand so as to minimize the use GTs. This will in turn reduce the cost of fuel charged to legitimate JPS customers.

The negative side of such demand management flexibility is that those few JPS customers who reside within these high loss communities will not be able to enjoy electricity during the peak demand hours. However, this would be for the collective benefit of most legitimate customers, as less than 2% of legitimate customers reside in those high loss areas that are volatile communities. To minimize their inconvenience the Company could limit the demand management to only two hours during the evening peak (say 6pm to 8pm) and to three hours during the day peak (say 11am to 2pm). It is estimated that by applying this strategy to the 2008 system demand that the Company would have reduced the total fuel bill (and thus the customer charge) by approximately 4% or $2 billion dollars. This would have translated into significant savings for customers as a whole and reduced the demand on foreign exchange for the Country as well.

In reality, to some extent the same thing (loss of supply) may happen to these few legitimate customers within the inner cities during the evening peak demand hours, as in most cases the Company's employees do not get access to these areas even to attend to their single supply failure calls and the customers have to wait until the next day to be attended to. But, at the same time, all the unauthorized energy users, who may have even caused the supply interruption, continue to enjoy electricity. The flexibility of load shedding to these limited areas could be done remotely by operable on line reclosers. The Dominican Republic currently uses these reclosers for demand management. Initially, that country did not have the legal provision of shedding of power but subsequently the law was changed to facilitate the demand management for the reasons cited above.

JPS has 12 such online reclosers installed in feeders that control some of these loss prone inner cities, but they are rarely used and used only when an under frequency condition arises. Below is the list of these installed JPS online reclosers.

Table 9.7: Areas Identified for Recloser Installation

#	Location	Parish	Feeder
1	Seaview	KSAS	D&G 310
2	Jones Town	KSAS	Greenwich Rd 310
3	Torrington Park	KSAS	Greenwich Rd 310
4	Harbour Heights	KSAS	Cane River 410
5	Rose Heights – Montego Bay	St. James	Queen Drive 710
6	Retirement – Montego Bay	St. James	Bogue 310
7	Canterbury – Montego Bay	St. James	Queens Drive 810
8	Central Village	St. Catherine	Twickenham 210
9	Maxfield Park	KSAS	Hunts Bay 810
10	August Town	KSAN	Hope 510
11	New Haven	KSAN	Duhaney 310
12	Arnett Gardens – Trench Town	KSAS	Hunts Bay 810

The Company therefore proposes the consideration of a demand management programme for high losses areas and welcomes a fulsome discussion on the matter. Demand management would be limited to a maximum of two hours during the evening peak (say 6pm to 8pm) and three hours during the day peak (say 11am to 2pm). Alternatively, it could be implemented as a day peak strategy in the first instance

10 Reconnection Fee[33]

10.1 Introduction

JPS charges a disconnection/reconnection fee to customers requesting reconnection after having been disconnected for non-payment of past due bills. Reconnection is effected only after full payment of all outstanding amounts. The precedent set in previous determinations by the OUR is that the fee charged by JPS be sufficient to recover the actual costs of disconnecting and reconnecting customers plus a ten percent service charge. In the 2004 rate case, the reconnection fee approved by the OUR was $1,441. Although JPS had the opportunity to seek an increase in this fee annually, JPS chose not to do so at the time.

In the intervening four years, cost inflation has resulted in the need to increase the cost of disconnection/reconnection activities. Inflation (as per the approved Annual Tariff Adjustment Applications) during the four-year period since June 2004 has been approximately 70%.

As such, JPS is now seeking an adjustment of the reconnection fee so as to enable full cost recovery as set out by the OUR.

10.2 Methodology

The total cost of disconnecting and reconnecting a customer who had been disconnected for non-payment of outstanding amounts is a summation of the operations and maintenance costs incurred to disconnect and reconnect the account, the administrative expenses incurred by the collections staff of JPS who manage the process and external audit fees. The fee is calculated by dividing the total actual annual cost of reconnections for a specified base year by the number of reconnections during that period to obtain a disconnection/reconnection cost per unit to which a ten percent service fee is added.

10.3 Operations and Maintenance Costs

JPS outsources its disconnection/reconnection activities to third party contractors. Consequently the operating and maintenance costs associated with the disconnection/reconnection (or discon/recon) process mainly consist of third party contractor costs. These costs vary based on the type of discon/recon activity. The contractor rates have been held constant since 2004 but given inflationary over the period these rates have been revised upwards by 40%. This was done through a tender process and the new rates became effective on February 1, 2009. The Company has agreed with the contractors that these rates will be adjusted each year going forward based on local inflation so as to avoid the need for any large increases in future.

The monthly contractor costs incurred during the period July 2007 to June 2008 are shown in **Table 10.1** below:

[33] It should be noted that section 16 of the Electric Lighting Act empowers the Company not only to disconnect a customer for non-payment of bill but also to assess against the customer any expenses incurred in removing the supply.

Table 10.1: Third Party Cost of Discon/Recon Activity

Contractor Costs	Amount ($)
July-07	13,625,861
August-07	14,247,101
September-07	4,796,185
October-07	7,161,148
November-07	12,233,806
December-07	11,483,586
January-08	10,837,028
February-08	13,819,900
March-08	13,607,783
April-06	12,746,359
May-08	15,090,877
June-08	14,265,260
Total 2007/2008	143,914,894

Applying the negotiated increase in contractor rates of 40%, the result is an estimated O&M cost of $205,800,000 before the application of GCT

Additionally, in 2008, JPS introduced audit activities on customers who have been disconnected but who may not have come in to request reconnection. Approximately 20% of our disconnected customers fall into this category. JPS does not believe that all these customers are without service, but rather that they have found other means of reconnecting themselves or stealing electricity. Hence, the decision to introduce audit activity on disconnected accounts. These audits entail visiting and checking each of the disconnected premises and taking the appropriate action, (e.g. complete removal of service wire if the customer has reconnected them self and not paid the bill). The audits are being carried out by third party contractors and, based on the service level agreement, will cost $700 per audit, approximately half the cost of the discon/recon service.

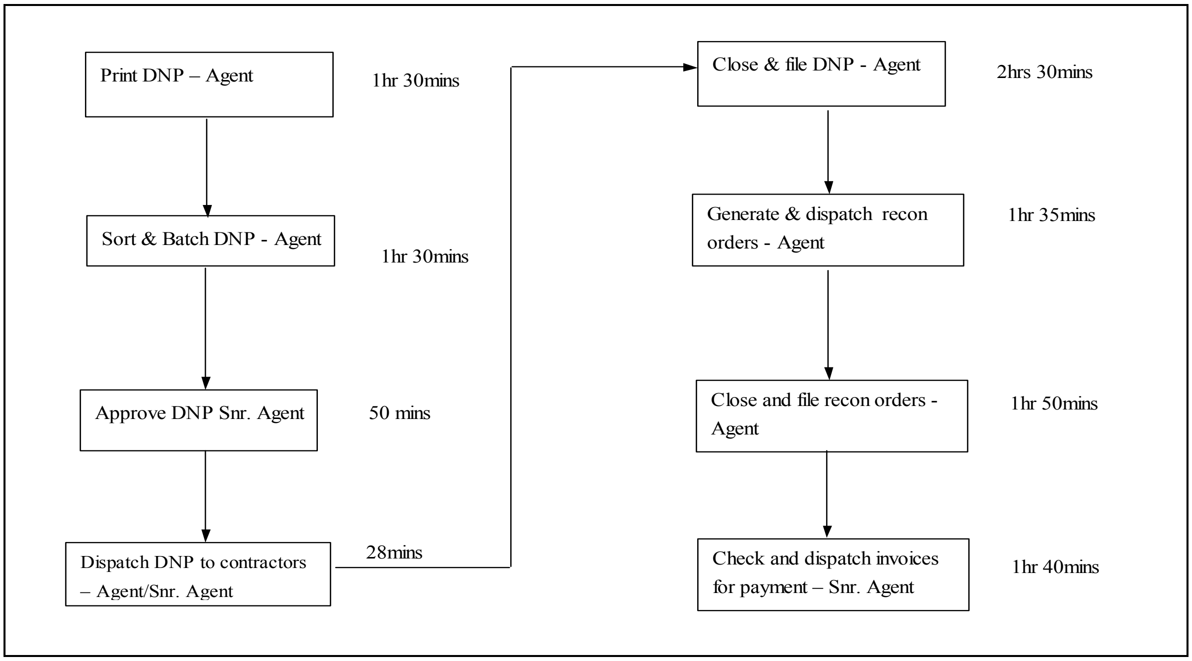
Based on the number of reconnections in 2007/8 (147,243), which represents 80% of the number of disconnections, there are approximately 37,000 customers that do not come back for reconnection each year. Accordingly, it is estimated that approximately 3,100 audits need to be done monthly, at a cost of $700 per audit, resulting in an additional annual cost of $26 million plus GCT. As a result of these audits, the Company anticipates increasing reconnections by 30,000 customers per year (or about 80% of the customers who are actually audited).

10.4 Administrative Costs

The Collections department of JPS administers all of the activities associated with the discon/recon process. This department is currently decentralized, with each parish office having a discon/recon team. A calculation of the annual administrative cost incurred during the reconnection process was derived from information acquired from the collections teams located in the parishes.

There are two types of staff involved in the discon/recon process: a collections agent and a senior collection agent. The workflow of the activities carried out by each staff is indicated **Figure 10.1** below.

Figure 10.1: Discon/recon Activity Workflow at JPS



The collections team that deals with the discon/recon activities consists of 49 individuals: 37 collections agents and 12 senior collections agents. Discon/recon activities conducted by the staff take approximately 4 hours and 1.5 hours daily for each collection agent and senior collection agent, respectively.

The total administrative costs are calculated in the **Table 10.2**, based on the known 2007 salaries and benefits (as per the relevant union agreements), applicable employer taxes (9% for NHT, HEART and Education Taxes), the stated number of employees involved in the process and the amount of time spent by each worker.

Table 10.2: Details of Administrative Cost

Employee Type	Salary	Benefits	Employer Taxes	Total Cost per employee	Hourly Rate	Number of employees	Avg time spent per day	Total Annual Cost
Collections Agents	1,190,205	287,667	126,046	1,603,918	$771.11	37	4.0	$29,672,478
Senior Collections Agent	2,376,479	504,165	245,356	3,126,000	$1,502.88	12	1.5	$7,033,500
								$36,705,978

This annual cost of $36.7 million will have to be adjusted once the 2008 salaries have been finalized, which are currently subject to negotiation with the unions. However, for the purposes of completing the total cost estimate for 2008, it will be assumed that there will be an increase in the total employee cost of 16.87% (based on the inflation for 2008). The total administrative cost estimate for 2008 is therefore $42,900,000.

10.5 Audit Fees

Audit fees are costs incurred by JPS for an independent review of the stated reconnection costs. This is estimated to be J$1,000,000.

10.6 Service Charge

JPS requests that the service charge be increased from 10% to 15% in recognition of the significant increase in the JPS' trade receivables (i.e. working capital) during the period as a result of the significant increase in world oil prices. Despite maintaining the collection period constant over the past 5 years, trade receivables have grown by 85% in absolute terms from $4.6 billion as at December 31, 2004 to $8.5 billion as at December 31, 2008. At the same time, reconnection costs (on which the administrative fee is based) have only grown by 20%. Accordingly, in recognition of our opportunity cost of capital on trade receivables (specifically arrears) associated with late paying customers, the Company's believe it appropriate to increase the administrative fee from 10% to 15%. This is considered appropriate since all customers who are disconnected are necessarily late in the payment of their bills.

10.7 Reconnection Fee Calculation

The discon/recon fee is calculated in the **Table 10.3** based on all of the information previously provided: (i) the number of reconnections in 2007/8; (ii) the expected improvement in the number of reconnections as a result of special audits; (iii) the estimated contractor cost for normal activities; (iv) the cost of conducting special audits; (v) the estimated JPS employee cost; (vi) the estimated audit fee; and (vii) an additional 15% administrative fee. The result of this calculation is shown below:

Table 10.3: Calculation of Discon/Recon Fee

	Description	Costs
i	Number of reconnections for 2007/8	147,243
ii	Expected increase in the number of reconnections	30,000
	Total number of reconnections	177,243
iii	Estimated Contractor Cost for normal discon/recon activity	205,800,000
	GCT on discon/recon activity @ 16.5%	33,957,000
iv	Estimated contractor cost for audit of non-reconnected accounts	26,000,000
	GCT on audit of non-reconnected accounts @ 16.5%	4,290,000
v	Administrative Cost for 2008	42,900,000
vi	Audit Fees	1,000,000
	Total Cost	313,947,000
	Per Unit discon/recon cost for 2008	1,771
vii	Plus 15% Service Charge	266
	Final per unit cost for discon/recon	**2,037**

Accordingly, the Company requests that the OUR approve the increase of the discon/recon fee to $2,037, which represents an increase of approximately 7% per annum since 2004, as the current fee of $1,441 has not been revised since that date. This amount also compares favourably with the current charge by the National Water Commission for similar activities, which currently stands at $2,200.

11 Guaranteed and Overall Standards

The OUR regulates the quality of supply and services provided by JPS by setting guaranteed and overall standards of performance in accordance with the Licence. These standards are set to ensure JPS delivers a reasonable quality of service.

Guaranteed standards are mandatory baseline standards prescribed by the OUR regulating the quality of service experienced by individual customers. Breaches of any of these standards trigger the opportunity for an affected customer to claim compensation in accordance with a schedule of penalties established by the OUR.

Overall standards are service quality targets prescribed for the public electricity system for services that have a potential impact on all or large groups of customers. Overall Standards do not provide a guarantee of compliance with the standard for individual customers. Breaches of these standards do not attract compensatory payments to individual customers but can affect JPS' quality of earnings through penalties and therefore provides an incentive for maintaining and improving service quality.

Condition 17 of the Licence provides for Guaranteed Standards to be reviewed between Tariff Reviews and Overall Standards at tariff reviews. However both sets of standards were revised at the 2004 Rate Case and it is now accepted that the practice will be to review both standards at the five (5) year tariff review.

11.1 Guaranteed Standards

Over the last four years JPS has achieved a high level of compliance with the Guaranteed Standards benchmark targets. This achievement is within the context of the challenges posed by the expanding customer base and the need to contain cost while improving the quality of service. Of the 12 standards average compliance has exceeded 90% on nine (9) during the review period. Since 2001 when the standards were first promulgated the overall trend has shown a distinct steady improvement in compliance (see Appendix L). Despite the overall positive trend the Company is aware that there are opportunities and room for improvement in compliance in some standards and has therefore recommitted resources to achieve this over the next tariff period.

To this end JPS, as of February 2009, has begun deployment of a company-wide Customer Contact System that will provide the capability to report compliance with ***GS 05 – Complaints/queries - time to acknowledge inquiry, after receipt***. With regards to ***GS 10 – Billing Adjustments***, JPS is committed to improving the performance in this area. In 2008, the Company implemented Phase 1 of the Billing Adjustment Application project aimed at automating the process of completing billing adjustments and improving the efficiency with which these are completed. Phase 2 will be implemented in 2009. This will result in more service orders for billing adjustments completed more efficiently/quickly. In 2007/2008 the Company spent a significant portion of our resources dealing with backlogs in this area. With these substantially complete, it is expected that continued improvement in the Company's performance will be seen.

11.1.1 Proposals for Modification

In general, JPS believes the GS targets to be of the appropriate type and level for providing a reasonable quality of service to customers while allowing JPS to be cost efficient in the provision of those services that are important to customers. With the exception of the modifications noted below, JPS is proposing that the current set of standards be maintained through the 2009 – 14 tariff period. The continued expansion of the customer base and the need to meet productivity gain targets will provide a natural stretch factor for JPS to continue to maintain current high levels of compliance.

The following modifications are recommended:

GS02 - Complex Connections

Despite a trend of improving compliance, JPS continues to face a major challenge in meeting the target performance levels under this standard. Many of the challenges relate to the general difficulty of mobilizing construction projects in Jamaica. Hurdles include the timely receipt or confirmation of permits, rights of way, easements or other critical prerequisites from third parties. Attempts at improving the efficiency of compliance include the outsourcing of some construction with modest success. The Company continues to re-engineer work processes, which have contributed to a moderate improvement in performance over the past 18 months. However, there is unlikely to be any further dramatic gains to be had from this initiative. The Company therefore proposes that the performance target for this Standard be revised marginally to:

GS 2(a) Estimates within 15 days; connections within 35 working days after payment
(b) Estimates within 15 days; connections within 45 working days after payment

This modification would provide customers with a more realistic indication of the lead time required to complete these connections based on known constraints

GS05 – Complaints / Queries

There is currently no company-wide system to log, monitor and report on customer complaints/queries. JPS has therefore not being in a position to report its actual compliance performance with this standard. Deployment of a new Contact Management System began in February 2009 and will be completed by second quarter of 2009. When completed, the system will provide the capability to report on queries/complaints, received via different media - call in, fax, letter, email or office visits - and JPS' response time against the standards performance target. In light of this JPS proposes no change to the current standard.

GS10 - Billing Adjustments

Billing adjustments are usually done subsequent to the discovery of incorrect registration of consumption either due to an error of commission or omission or meter failure. While the replacement of a malfunctioning meter can be done fairly quickly, an adjustment of the customer account requires detailed analysis and investigation into the consumption pattern to establish an accurate basis for the adjustment. Establishing the consumption levels takes up to 1 billing period as the subsequent meter reading following the meter change is required. This renders compliance with the standard very daunting. JPS therefore propose a modification to the standard to read:

"Billing Adjustments: Timeliness of adjustment to customer's account - where necessary, customer must be billed for adjustment within 2 billing periods after conclusion of investigation of billing error.

GS06 – Reconnection after payment of overdue amounts

Despite the latitude granted by the standard, JPS subsequent to the 2004 Rate Review adopted a non- discriminatory policy in relation to the reconnection of customers after disconnection for outstanding balances. The Company adopted the more aggressive 24-hour standard for both urban and rural customers and has operated on that standard, with a high level of compliance (see **Annex E**) over the 2004-2009 tariff period. It is proposed that this standard be formally revised to establish a single target of 24-hours to reconnect customers after notification to the Company of payment of overdue amounts.

GS08 – Estimates should be based on last three actual readings

A one-time modification of the billing system was effected in 2006 to fulfil the requirement of this standard that estimated consumption be calculated based on the customer's last three actual readings (new account exempt). This methodology is now hard coded into the estimation routine of the CIS and therefore does not require ongoing compliance monitoring. It is therefore proposed that this standard be converted to an Overall Standard for continuing enforcement, or continue in force by way of a directive.

GS11 – Timeliness of repairs of streetlights

GS11 measures the same performance target as Overall Standard OS11, is redundant and should be removed.

11.1.2 Compensation for Breaches of Guaranteed Standards

JPS has established an excellent compliance rate (see **Annex E**) in compensating customers who make claims for breaches of the Guaranteed Standards. In fact, JPS is the only local utility that has proactively and consistently encouraged customer to claim when breaches are identified. Over the past three years the Company has spent **$5.5M** to promote the standards through radio and print advertisement and promotional materials such as book markers, posters, bill inserts and brochures. The Company is disappointed that despite its best efforts customer claims for the period 2005 to 2008 totalled $851,402.

In spite of these results, JPS is committed to dedicating resources in the 2009 – 14 tariff period to continue to encourage customer response in this area. JPS believes this effort is important to spur and foster at the national level, consumer pro-activism in promoting and protecting their interest.

The current compensation rates are reasonable and it is proposed that they remain unchanged.

11.2 Overall Standards

The current schedule for the overall standards was set at the 2004-2009 tariff review.

JPS has attained the benchmark targets for OS02 (a), OS07 (a), OS09 and OS10 for the 2004-2008 period and marginally below benchmark for OS01 and OS08.

JPS' performance relative to standards OS03-OS04 is fulsomely dealt with under the Performance-based Rate Making Mechanism (PBRM) section of this filing. Performance relative to OS05 – system losses – will also be addressed in the relevant section of the submission.

The Customer Contact System currently being implemented will provide the capability to report on performance relative to standard OS 11, *Effectiveness of call centre representatives (percentage of complaints resolved at first point of contact)*. JPS requests a moratorium of six (6) months subsequent on the determination of this rate filing to ensure full functionality of the measurement and reporting functions of this system.

11.2.1 Proposals for Modification

OS2 (a) & OS2(b)

Similar to GSO6, JPS adopted a non-discriminatory policy in respect of OS2 (a) and (b) and configured our operations to comply with the more aggressive 48 hour restoration standard for all our customers. It is therefore proposed that this standard be united at 48 hours.

OS7 (b)

In December 2005 the OUR/JPS and the Bureau of Standards Jamaica concluded a Protocol, “Electricity Meter Testing in Jamaica”. The Protocol includes provision for the sample testing of meter lots and groups. It is proposed that the benchmark target for testing be linked to the targets established in the protocol.

Subject to the proposed modifications noted above the current set of Overall standards is considered suitable and adequate to provide a reasonable quality of service to customers.

MAIFI

JPS proposes that Momentary Average Interruption Duration Index (MAIFI) be included as an Overall Standard

Annex A: Acronyms and Abbreviations

ABNF = Non-fuel base rate

ADC = Average Dependable Capacity

ADO = Automotive diesel Oil

AMI = Advanced metering infrastructure

BAO = Best alternative option

CAPEX = Capital Expenditure

CAPM = Capital Asset Pricing Model

CIS = Customer Information System

CML = Customer Minutes Lost

CPI = consumer price index

CRP = Country Risk Premium

CS = Consumer surplus

CT = Current transformer

CWIP = Construction work in progress

DCF = Discounted Cash Flow

DEA = Data Envelope Analysis

EFLOP = Equivalent Full Load Provision

EMS = Environmental Management System

EPMU = Equi-proportional mark-up method

GDP = Gross Domestic Product

GOJ = Government of Jamaica

HFO = Heavy fuel oil IPP = Independent Power Purchase

IVR = Interactive voice response

IDT = Industrial Dispute Tribunal

J$ = Jamaican dollar

KVA = kilovolt-ampere

LCEP = Least Cost Expansion plan

MAIFI = Momentary average interruption frequency index

MFP = Multifactor productivity

MVA = Mega volt amperes

MW = Megawatts

MWh = Megawatt-hours

NAC = Network access charge

NWC = National Water Commission

O & M = Operations and maintenance

OCB = Oil circuit breakers

OPEX = Operating expenditure

PEG = Pacific Economics Group, LLC

PPA = Power Purchase Agreements

PBRM = Performance based rate-making mechanism

PRBO = Post retirement benefit obligation

PT = Potential transformer

RDC = Required Dependable Capacity

REP = Rural Electrification Programme Limited

ROE = Return on Equity

ROI = Return on Investment

RPD = Revenue Protection Department

SAIDI = System average interruption duration index

SAIFI = System average interruption frequency index

SCADA = Supervisory Control and Data Acquisition

SFA = Stochastic frontier analysis

SIF = Self-insurance Fund

TFP = Total Factor Productivity

TOU = Time of Use

VAM = Volumetric adjustment mechanism

WACC = Weighted Average Cost of Capital

Annex B: Cost of Capital Study

1. INTRODUCTION AND SUMMARY

Jamaica Public Service Company (JPS) is subject to a price cap plan, which adjusts its tariffs according to a "CPI-X," performance based ratemaking mechanism (PBRM). The terms of JPS' initial PBRM were established in 2004, and JPS will be subject to a formal regulatory review in 2009. This review will establish both new initial tariffs and an updated PBRM formula. An important component of JPS' cost of service, which the initial rates will be designed to recover, is the Company's cost of equity.

Pacific Economics Group LLC (PEG) was retained by JPS to advise on several issues that will be critical during the 2009 rate review. For the PBRM, PEG was asked to recommend an appropriate value for the X factor and any appropriate changes to the Q factor. We were also asked to recommend an appropriate value for JPS' cost of equity. This report presents PEG's analysis of and recommendations for the cost of equity; our research on the PBRM will be presented later in October 2008.

In its 2004 rate determination, the Office of Utilities Regulation (OUR) established a real, allowed return on equity (ROE) for JPS of 14.85%. This allowed ROE had two components. The first was a real cost of equity determined through the capital asset pricing model (CAPM), equal to 9.535%. The second was a country risk premium (CRP) to reflect the differential risks of investing in Jamaica, equal to 5.315%.

There have been a number of truly historic developments in financial markets since the initial 2004 determination. The world is currently in the midst of its worst financial crisis in decades. This crisis is far from over, and it is not clear how it will play out. Nevertheless, financial markets will certainly be characterized by greater uncertainties, and probably increased capital demands, than in the recent past. We believe these factors point to a higher required cost of equity for JPS.

In developing our allowed ROE recommendation, PEG adhered closely to the framework that the OUR used in its last determination. We based our recommendation entirely on the CAPM. In most instances, we also relied on the same data sources that were previously used to select values for the parameters of the CAPM formula.

PEG has updated our October 2008 analysis to reflect the most recent economic data. Our updated analysis leads to a recommended real, ROE for JPS of 21.6%. This recommendation is, in turn, founded on recommended values for the risk-free rate of return of 0.32%; an equity beta of 0.95; a market risk premium of 11.66%; and a country risk premium of 10.23%. All of these values are broadly consistent with the OUR's findings in 2004, but in sum they support an increase in JPS' cost of equity. We believe this adjustment in JPS' allowed ROE is reasonable given the most recently available data and ongoing developments and uncertainties in the world's capital markets.

This report is organized as follows. The next section discusses the regulatory and economic context that supports PEG's approach for estimating JPS' cost of equity. Section 3 details our specific recommendations for the parameters of the CAPM formula. Section 4 presents brief concluding remarks.

2. REGULATORY AND ECONOMIC CONTEXT

2.1 CAPM Fundamentals

In its 2004 determination, the Office of Utilities Regulation (OUR) relied entirely on the capital asset pricing model (CAPM) for determining the cost of equity for Jamaica Public Service. We have accordingly used the CAPM as the basis for updating JPS' cost of equity. This section will briefly review the underlying rationale for the CAPM and the parameters needed to implement the CAPM formula.

The CAPM is concerned with how investors allocate portfolios and the risk premiums they demand. A risk that is particular to a single asset (or, at best, a small group of assets) is known as an unsystematic risk. In contrast, a systematic risk is one that is common to all assets. Systematic risks are sometimes also referred to as market risks.

The risk of the entire portfolio, rather than to any particular security, is ultimately what matters to investors. Investors will rationally diversify the assets they hold in their portfolios to minimize their overall risk. This diversification process will continue until unsystematic risk is, essentially, eliminated. The risk that remains is therefore the systematic risk. This is also referred to as non-diversifiable risk since it is the risk to investors that cannot be eliminated through portfolio diversification.

The fundamental conclusion of the CAPM is that, in equilibrium, the risk premium on an asset is determined by its *contribution* to the (systematic) risk of the overall portfolio. The contribution of a specific asset to the overall portfolio risk is captured in the "beta" coefficient. The beta of any particular asset measures how much systematic risk is associated with that asset relative to the average asset in the portfolio. By definition, the overall portfolio must have a beta equal to one. Assets with a beta that are less than one will therefore be less risky, on average, than the portfolio. These assets will accordingly command lower risk premiums than the overall portfolio. Conversely, assets with a beta greater than one are more risky than the portfolio on average and will command relatively greater risk premiums.

The derivation of the CAPM rests on certain assumptions. The main assumptions are that the market is comprised of many investors that optimize the mean-variance trade-off in their portfolios. These portfolios include publicly-traded stocks and bonds. All investors are also assumed to use the same information on return means and variances for individual assets as well as the covariance of returns across assets.

Given these assumptions, the optimum portfolio in the CAPM is derived. The main implications of CAPM are that all investors hold an identical market portfolio; this portfolio contains all publicly-traded assets; and any asset's contribution to portfolio risk is captured in a single parameter, the beta. In the classic CAPM formulation, this beta is defined to be the covariance between that asset's return and the market return, divided by the variance of the market return.

These points can be made more concrete by considering some of the mathematics underlying investors' behaviour, especially as they pertain to the equilibrium value of an asset's beta. This derivation assumes that investors care about both the mean and variance of portfolio return. We also assume that there is a risk free asset. Since investors require a premium to hold risky assets, the return on the risk free asset must be lower than that for all other, risky assets. Returns for the overall market portfolio and for any individual asset can therefore be expressed as premia over the risk-free rate.

Let R_m, R_f and R_a denote the portfolio rate of return, the risk-free rate of return and the return on any arbitrary asset *a*. We can construct a metric that captures both the return (expressed as a premium over the risk-free rate) and variance of the market portfolio through the ratio below

$$(R_m - R_f)/\text{var}(R_m) \qquad [1]$$

Let the weight on asset *a* in the overall market portfolio be equal to W_a ($W_a < 1$). The contribution of asset *a* to the portfolio's return (over the risk free rate) is then given by

$$W_a (R_a - R_f) \qquad [2]$$

We can measure the contribution of any given asset *a* to the variance in portfolio returns by the covariance between that asset's returns and the portfolio return, multiplied by the weight of that asset in a portfolio. This product is given by

$$W_a \text{cov}(R_a, R_m) \qquad [3]$$

Dividing equation [2] by equation [3] we have

$$(R_a - R_f)/\text{cov}(R_a, R_m) \qquad [4]$$

In a portfolio context, equation [4] is a measure of the reward-risk ratio for asset *a*. The reason is that the denominator of this expression reflects the contribution of this asset to the variance in overall portfolio returns. Investors ultimately care about the variance of returns for the entire portfolio, so this expression measures how asset *a* contributes to both the portfolio's returns and risks.

In equilibrium, all investments must offer the same reward-risk ratio. If this was not the case, investors would reallocate funds towards any asset with a higher ratio of rewards to risks. This would raise the price paid for that asset which, for a given discounted stream of expected cash flows, would reduce that asset's return. This price adjustment process would continue until there were no incentives to reallocate the portfolio, or until the reward-risk ratio for all assets was equalized. Since the equilibrium reward-risk ratios for all assets in the portfolio are the same, the reward-risk ratio for the entire portfolio must also be equal to this value. This implies that the values in equations [1] and [4] are the same. Equating these values and rearranging, we have

$$R_a = R_f + [\text{cov}(R_a, R_m)/\text{var}(R_m)](R_m - R) \qquad [5]$$

This is the familiar CAPM formula. Here the return for asset *a* is equal to the risk-free rate plus a value of beta multiplied by the market premium over the risk free rate. Beta (β) is equal to the covariance between the return on asset *a* and the portfolio return, divided by the variance of the portfolio return. This beta is multiplied by the term $R_m - R_f$, which is sometimes referred to as the market risk premium (MRP). Given this formula, it is straightforward to see that beta for the entire market portfolio must be equal to one. Treating the market portfolio as a composite asset and substituting into equation [5] yields the following

$$\begin{aligned} B_m &= \text{cov}(R_m, R_m)/\ \text{var}(R_m) \\ &= \text{var}(R_m)/\ \text{var}(R_m) \qquad [6] \\ &= 1 \end{aligned}$$

Thus in the basic CAPM, the portfolio beta is one by definition. If an asset has a beta value greater than one, it makes a more than proportional contribution to overall portfolio (systematic) risk. Similarly, an asset with a beta value less than one makes a less than proportional contribution to systematic risk. This intuition behind beta values stem directly from the CAPM model and the fact that beta is calculated as the ratio of covariance between asset and market returns, divided by the variance of market returns.

Since it was first introduced, the CAPM has spawned a voluminous empirical literature. Many researchers have found support for CAPM in actual asset markets. Other papers find that CAPM is either inadequate or incomplete as an explanation for relative returns. Much of this latter work has found that factors other than those suggested by CAPM – particularly the size of the firm - also have a significant impact on asset returns. Many of these papers have noted that the classic CAPM tends to under-predict required returns for smaller firms.

In practice, estimating the CAPM parameters is typically done using data from large, well-developed financial markets, such as those in the United States. When an estimated CAPM formula is applied in a country like Jamaica, it is also necessary for the formula to include a country risk premium (CRP). This premium would reflect the greater, systematic risk level that prevails in Jamaica compared with the US. When this country risk premium is added, the relevant CAPM formula becomes

$$R_a = R_f + \beta_a (R_m - R_f) + CRP \qquad [7]$$

Implementing the CAPM in Jamaica therefore requires estimates of the risk free rate of return, the equity beta, the MRP and the CRP. The next section will discuss the values that were proposed for these parameters, and the final cost of equity which was approved, in the previous rate determination for JPS.

2.2 Previous OUR Decision

In its previous determination, the OUR relied entirely on the CAPM for setting JPS' allowed cost of equity. The decision stated that "(t)he OUR is of the view that the CAPM offers the best method of estimating the cost of equity. CAPM is most widely used to estimate firms' cost of capital, notwithstanding the fact there is considerable evidence of shortcomings in the CAPM. It must be emphasized however that its clear theoretical foundations and simplicity contribute to its continuing popularity."[34] To be consistent with the OUR's stated preference for the CAPM, PEG has updated the estimate of JPS' cost of equity using a CAPM analysis.

The OUR developed its own estimates for the main empirical parameters of the CAPM formula. In the OUR research, the real risk free rate of return was equal to 2.27%. This value was equal to the value of the latest US 10 year Treasury bond rate (on April 26, 2004) of 4.77% minus an expected rate of US inflation of 2.5%.[35]

The OUR estimated the asset beta to be 0.45. This value was based on a weighted average of industry betas that were published in a 1996 World Bank working paper.[36] This paper reported betas for electric (and other) utilities that varied depending on the type of regulatory regime to which they were subject. The paper estimated that electric utility betas under high-powered (*i.e.* CPI-X price cap) regimes averaged 0.57, while the betas under intermediate-powered and low-powered (*i.e.* rate of return) regimes averaged 0.41and 0.30, respectively.[37] The OUR reasoned that the tariff regime for JPS fell between a high-powered and intermediate-powered regime, since JPS will operate under a price cap plan that nevertheless allows for a "considerable amount

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[34] OUR determination, p. 46.

[35] OUR, *op cit*, p. 40.

[36] Alexander, I., C. Mayer, and H. Weeds (1996), "Regulatory Structure and Risk and Infrastructure Firms," World Bank Policy Research Working Paper #1698.

[37] Alexander *et al*, p. 29.

of pass through in the tariff structure."[38] The OUR therefore determined the final beta by applying 75% and 25% weights to the betas for intermediate- and high-powered regimes reported in the World Bank study. This led to a final asset beta of 0.45 (*i.e.* .75*.41 + .25*.57 = .45).[39] The OUR also projected that JPS would have a 48% gearing ratio under the next price cap plan. Its estimated asset beta of 0.45 was therefore consistent with an equity beta of 0.87 (*i.e.* 0.45/(1-.48) = 0.87).

The OUR estimated the market risk premium based on the difference between the yields for a basket of asset yields and the risk free interest rate. Because the 10 year US Treasury bond was used to measure the risk free rate, the OUR concluded that market yields must also be calculated using a basket of US share prices. OUR used the S&P 500 index to measure US market share yields and determined that the projected growth in the S&P 500 was most likely to represent a forward-looking MRP. This MRP value was estimated to be 8.20%.

Finally, the CRP was estimated using the difference between yields on US dollar denominated bonds issued by the US Treasury and the Government of Jamaica (GOJ). Specifically, the CRP was estimated as the difference between the GOJ, 10-year, US dollar indexed bond minus the 10-year US Treasury bond on April 21, 2004. This value was estimated to be 4.43%.

In summary, the OUR estimated the following values for the CAPM parameters and the overall cost of equity for JPS:

Risk free rate	2.27%
Asset beta	0.45
Gearing	48%
Equity beta	0.87
Real market risk premium	8.20%
CAPM risk premium cost of equity	9.37%
Country risk premium	4.43%
Real cost of equity	13.80%

JPS took a somewhat different approach, estimating its cost of equity using both CAPM and discounted cash flow analyses and adjusting the results for differences in financial risk, size of company, and regulatory risks. Based on this analysis, JPS estimated a cost of equity of equal to 12.2% in nominal terms or 9.7% in real terms (*i.e.* the nominal cost of equity minus expected US inflation of 2.5%).

JPS' proposed country risk premium was equal to 6.77%. This was equal to the difference estimated returns on GOJ, US dollar indexed bonds minus US Treasury bonds using January 9, 2004 data. The GOJ yields were actually estimated using a regression that JPS developed and which regressed actual GOJ yields on maturity dates. This regression was then used to estimate a yield for a notional, 10-year GOJ indexed bond since, at the time of the filing, no GOJ bonds had a maturity date exactly equal to 10 years.[40] Given these estimates, JPS estimated that its real cost of equity was equal to 16.46% (*i.e.* 9.70% + 6.76% = 16.46%).

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[38] OUR, *op cit*, p. 47.

[39] OUR, *op cit*, p. 47.

[40] JPS filing, p. 51.

The differences between the JPS and OUR estimates were primarily attributable to differences in the estimated CRP. The OUR determined that the appropriate CRP fell within a range of values. In its final decision, the OUR chose the midpoint between the values proposed by JPS and itself for the real cost of equity. This value was 9.535% (*i.e.* (9.37%+9.7%)/2 = 9.535%). The OUR selected a value for the CRP of 5.315%, which was somewhat closer to its estimate of 4.43% than JPS' estimate of 6.77%. The final, allowed value for JPS' real cost of equity was therefore equal to 14.85%.

2.3 Macroeconomic and Financial Conditions

PEG was asked to provide updated recommendations for the CAPM parameters and an overall cost of equity for JPS. Our recommendations have overwhelmingly followed the framework and approach that the OUR used in the previous rate determination, using updated information. Before turning to our analysis of these conditions, however, it will be valuable to provide an overview of current financial market conditions and their likely implications for capital costs in the next few years.

Clearly, this is a turbulent time for the financial marketplace. The past several months have seen the bankruptcy or near collapse of venerable financial institutions like Lehman Brothers, Bear Stearns, and the American Insurance Group. Large, rapidly growing commercial banks such as Wachovia and Washington Mutual have essentially disappeared. The government-sponsored entities (GSEs) colloquially referred to as Fannie Mae and Freddie Mac are also near insolvency. The impetus for these problems is that a significant share of US mortgages extended to "subprime," or low income, borrowers are non-performing. However, for a number of inter-related reasons, the impact of these troubled assets is not confined to the firms that made the mortgage loans. For example, a large share of these mortgages have been purchased by Fannie Mae and Freddie Mac and "securitized," or repackaged as "mortgage backed securities" which are then sold to investors throughout the world. Wall Street investment banks have extended the ownership of these mortgage-backed assets through their underwriting activities and, more indirectly, by developing complex "derivative" products which are designed to offset or mitigate the assets' risks. Some of these derivatives have effectively served as insurance which has, in turn, imposed losses on the firms issuing derivatives when the underlying assets became imperilled. For these and related reasons, the impact of the bad mortgage debt has been spread widely among financial firms. The consequence is that the world is currently experiencing its worst financial crisis in at least 20 years (since the troubles with the US savings and loan industry) and perhaps since the Great Depression.

To respond to the rapidly deteriorating situation, the US federal government recently passed an emergency bailout package. This legislation will give the Treasury wide latitude to purchase and hold non-performing mortgage and mortgage-backed assets. These assets will later be re-sold to investors as the financial marketplace stabilizes. The Treasury's purchases will financed through new borrowing. While the cost of the bailout package has been estimated to be $700 billion, no one really knows what will be ultimately required, since so much depends on developments in US mortgage markets and housing prices which are simply unknowable at the present time.

It is highly likely, however, is that the financial crisis will lead to substantial increases in the demand for capital. Much of this increased demand will come directly from the increased borrowing authority of the US Treasury. Additional demands will come from financial institutions, since many surviving institutions remain thinly capitalized and need to bolster their equity as a buffer against further risks. One factor that could dampen the demand for credit could be a US economic recession, but even this may have little net impact on credit demands since the resulting decline in government tax revenues (due to declining economic activity) will increase the fiscal deficit and thereby further increase Treasury's credit demands.

There is also little chance that the US Federal Reserve will "monetize" additional Treasury borrowing by expanding the money supply. The Fed appears to believe that it has a limited ability to manoeuvre because of ongoing concerns with inflation. Many of these worries stem from the large increases in worldwide oil prices. However, the Fed has also been concerned that the "core" rate of US inflation (*i.e.* the change in consumer prices excluding prices for energy and food products) has shown signs of acceleration. Any substantial increase in credit demands is therefore unlikely to be matched by increases in the US money supply, and this combination is likely to put upward pressure on US interest rates.

For different reasons, the electric utility industry is also likely to experience greater demands for capital. Capital demands have been driven by factors including aging infrastructure, the need for increased capacity (in generation, transmission and distribution), demands for enhanced reliability and power quality, and investments related to improving environmental quality and mitigating climate change. If investment and capital demands continue to increase, they will put upward pressure on utility rates. These upward pressures will exacerbate the cost increases associated with higher prices for generation fuel, which is most utilities' largest single operating cost.

Upward cost pressures increase the industry's risks for a number of reasons. First, in many regulatory regimes, there is typically a significant regulatory lag between when costs are incurred and rates are adjusted. Even if full cost recovery is eventually granted for new investments, investors remain at risk during the period of regulatory review, and these periods will become longer and more frequent in an era when costs are increasing.[41] At the same time, regulators may be more reluctant to allow full cost recovery during bad economic times, since doing so can lead to large utility price increases when customer finances are already negatively impacted by general economic conditions. Many utilities are also at risk for the costs of their generation fuel expenses even if they have "automatic" fuel adjustment clauses. For example, Fitch has written

> ***"volatile and rising energy commodity prices represent a challenge to investor-owned electric utility companies. Many state regulatory commissions have approved procedures allowing utilities in their jurisdiction to adjust tariffs periodically to reflect the actual cost of fuel and purchased power. However, the plans in place for individual companies vary significantly in their timing and effectiveness. Also, the implementation of rate adjustments is still subject to regulatory and political risk, particularly in a period of rising energy costs…A utility's ability to weather a period of high and rising commodity costs is influenced by many factors, including the state's market structure, rules regarding power procurement and the utility's obligation to serve customers' energy needs, the utility's resource mix relative to its load requirement, access to adequate liquidity and the state's regulatory/political environment."***[42]
>
> ***Also upward demands for credit for electricity sector***

For these and related reasons, the electric utility industry has already seen an increase in its riskiness vis-à-vis other sectors. A report commissioned by the Edison Electric Institute (EEI), the trade association for US investor-owned electric utilities, reports that the average beta for

[41] For example, companies must typically show that utility assets are currently "used and useful" before they can receive rate relief for the costs of those assets. The costs of "used and useful" assets have clearly already been incurred before rates will be adjusted.

[42] FitchRatings, "US Electric Utilities: Credit Implications of Commodity Cost Recovery, February 13, 2006.

electric utilities increased from 0.55 in 2000 to 0.87 in 2005.[43] It would not be surprising if beta has further increased since 2005, given the greater risks and uncertainties for electric utilities since that time.

In Jamaica, country risks since the previous rate determination may have been contained by generally lower inflation (until recently) and a stabilized fiscal deficit (as a percent of Jamaican GDP). However, it is not clear whether this progress can be sustained. The outlook for the Jamaican economy is clouded by the global economic situation and its reliance on imported oil. A worldwide economic slowdown is certain to reduce revenues for the country's tourist industry, and continued high energy prices will further dampen domestic economic activity. The latter can negatively impact JPS even with a full pass-through of fuel prices into tariffs. Higher fuel costs and electricity prices can lead to declining sales, greater defaults on customer bills, and stronger incentives for customers to engage in energy theft. All of these developments would harm JPS finances and increase its risks.

A number of other factors may have also increased the country risk in Jamaica since 2004. One is the increased occurrence of natural disasters, such as Hurricanes Ivan and Dean and tropical storms Denis, Emily, Wilma and Gustav. These natural disasters have a significant impact on Jamaica's entire economy. Jamaica has also experienced inflation rates of 17% and approximately 20% in 2007 and 2008, respectively, largely because of rising world oil and commodity prices. The impact of the world credit squeeze can also be expected to have a significant, harmful impact on Jamaica, which relies heavily on foreign debt to finance its budget and continues to have a very high debt to GDP ratio. All these developments are just beginning to manifest themselves and will raise the riskiness of investing in the country.

In sum, PEG believes that conditions are likely to signal upward pressures on interest rates and greater risks for the electric utility industry. These factors would tend to increase the costs of equity for all electric utilities, including JPS.

3. Recommended Cost of Equity for JPS

We turn now to an analysis of, and recommendations for, the individual components of the CAPM formula. We begin with a recommendation for the rate of inflation, which is necessary since the previous OUR determination expressed the allowed ROE in real, inflation-adjusted terms. We then turn to recommendations for the risk free rate of return, the equity beta, the market risk premium, and the country risk premium. Finally, we summarize our recommended value for JPS' overall, real cost of equity.

3.1 Inflation

In the previous OUR determination, projected inflation was determined to be 2.5%. PEG recommends that this updated value be set at 2.3%. This is equal to the difference between average, daily yields on 10-year US Treasury bonds and the inflation-indexed, 10-year Treasury bonds from the period between January 2, 2003 and October 1, 2008 (the last observed value at the time of this report). The inflation-indexed Treasury bond represents a real interest rate, so the difference between this yield and the nominal 10 Year Treasury yield reflects investors' expectations for inflation over the term of the bond. Our 2.3% recommendation for inflation therefore reflects a forward-looking, market-based value for this parameter.

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[43] Brattle Group, "Why Are Electricity Prices Increasing? An Industry-Wide Perspective," June 2006, p. 83.

3.2 Real Risk-Free Rate of Return

In the previous determination, the real, risk-free rate of return was somewhat higher than the OUR's originally proposed value of 2.27%.[44] In its 2009 update, PEG has relied on very recent Treasury rates as the basis for the risk-free rate of return. The yield of the 10 year US Treasury on January 22, 2009 was 2.62%. With an inflation rate of 2.3%, this is consistent with a real, risk-free rate of return of 0.32%.

3.3 Equity Beta

A critical component of the CAPM is the beta. Our recommendation for this parameter did not utilize the World Bank report which the OUR relied on in its previous determination. The main reason is that this report was written in 1996 and is now quite stale. The previously-referenced EEI report also indicates that betas have been increasing for electric utilities, and a study from a dozen years ago would not reflect this trend.

PEG's recommended beta for JPS was based on the average equity beta for a carefully selected group of peer US utilities. This differs from the approach of the previous OUR determination but, as stated above, we believe that approach is no longer relevant since it relies on data from more than twelve years ago. The peer group approach is also well accepted for estimating allowed ROE in regulatory proceedings and consistent with statements in the previous determination about appropriate methodologies for estimating beta. For example, the OUR wrote that "…companies in the same industry do have some characteristics in common and a careful contrasting may allow a conclusion to be drawn about a range of (beta) values. The primary objective should be to find companies in the US and worldwide that are truly comparable to JPS."[45]

PEG's approach to this "primary objective" was the following. We began with the sample of electric utility companies that are listed in ValueLine, a respected source of financial information. ValueLine reports betas for 56 electric utility companies.[46] Table One presents data on the distribution of beta coefficients for these companies. It can be seen that most companies have measured betas between 0.8 and 0.95. The average beta for the ValueLine electric utility sample was 0.87, which is equal to the beta that the OUR estimated for JPS in its previous determination.

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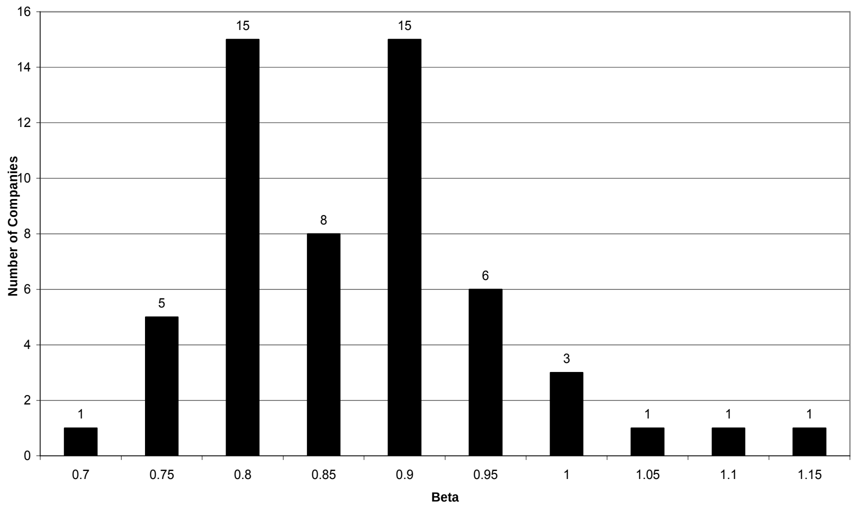
[44] This 2.27% value was consistent with the OUR's proposed real cost of equity, before the CRP, of 9.37%. The final, approved real cost of equity was equal to 9.535%. If all components of the CAPM formula are adjusted proportionately, this would be consistent with a risk-free rate of return of 2.30% (*i.e.* 2.27%*(9.535/9.37)=2.3%).

[45] OUR, p. 49.

[46] PEG communicated directly with ValueLine on the precise methods that they used to compute betas for specific companies. Those communications revealed that ValueLine's reported betas were equity betas and not asset betas. These same reported values for asset betas would lead to substantially higher estimates for the cost of equity.

Table One

Distribution of Value Line Betas for Electric Utilities



We then pared the ValueLine sample down to focus on companies that were most comparable to JPS. We used three main criteria as the basis for judging comparability. The first was company size, as measured by number of customers served, MWh delivered and total capitalization. The economic literature has found that company size can have an important influence on whether or not the CAPM appropriately measures a company's beta, so in keeping with this literature we wanted to restrict our sample to firms that, like JPS, were relatively small.

We also included only electric utilities that had bundled power (*i.e.* generation, transmission and distribution) operations. This is important since structural changes in the US marketplace have led some utilities to divest their generation or transmission services. Our peer group was selected to include utilities that provided the same range of services as JPS.

Third, we focused only on firms that had relatively small gas distribution operations. This can be relevant because the beta for gas utility services may be different than that for electric utilities. Most of the utilities in our sample did not distribute natural gas at all (like JPS).

PEG's selected peer group of eight US electric utilities is presented in Table Two. In addition to each utility's beta, this table also presents information on the total customers served, MWh distributed, total capitalization, the S&P credit rating, gearing ratio, and ValueLine safety rank. We believe these data show that our selected peer utilities are broadly similar to JPS.

It can also be seen that the average beta for this peer group is 0.95. This is somewhat greater than the average beta of 0.87 for the ValueLine sample, but this is not surprising since these utilities are much smaller than the average US utility. This beta coefficient is also higher than the equity beta of 0.87 which was chosen by the OUR in the previous determination. However, we believe it is appropriate to revise beta upward when updating JPS' cost of equity, for two primary reasons. The first is that the previous determination did not explicitly account for the small firm effect, which is known to generally increase measured beta. The second is that electric utility betas have been trending upward over time, and the OUR data sources did not account for this

Table Two

US Peer Group Companies for Jamaica Public Service

Company[1]	Customers	MWh	Capitalization (Million US$)	S&P Credit Rating	Gearing Ratio	Value Line Safety Rank	Beta
Minnesota Power	153,749	13,551,795	1,284	BBB+	0.43	2	0.90
Black Hills Power	103,158	4,141,419	1,248	BBB-	0.45	3	0.90
Central Vermont Public Service Corporation	156,610	2,297,944	250	BB+	0.49	3	1.10
Central Louisiana Electric Company	265,556	9,035,874	1,526	BBB	0.50	3	1.00
El Paso Electric Company	345,956	8,932,342	956	BBB	0.55	2	0.95
Empire District Electric Company	164,011	4,704,140	728	BBB-	0.54	3	0.85
Madison Gas & Electric	136,659	3,353,490	776	AA-	0.46	3	0.95
Otter Tail Power	127,053	3,990,854	1,225	BBB+	0.49	2	0.95
Peer Group Average	**181,594**	**6,250,982**	**999**	**BBB**	**0.49**	**2.63**	**0.95**
Jamaica Public Service	**581,828**	**4,078,776**	**768**	**NA**	**0.48**	**NA**	**0.95**

[1] The names given are those of the primary electric company subsidiary. The parents' names are ALLETE, Inc., Black Hills Corporation, Central Vermont Public Service Corporation, CLECO Corporation, El Paso Electric Company, Empire District Electric Company, MGE Energy, and Otter Tail Corporation, respectively.

development. PEG's approach rectifies each of these concerns since we use 2008 ValueLine data and focus only on relatively small electric utilities. We therefore recommend that, for an updated CAPM formula, the beta be set equal to 0.95.

It may also be instructive to compare the asset beta implicit in our recommendation to the OUR's previously determined asset beta. ValueLine does not report asset betas directly, but these can be computed by using information on the gearing ratios for each of the companies in our peer group. Table Two shows that the average gearing ratio for the peer group is 0.49. If each company's gearing ratio is weighted by its share of overall peer group capitalization, this gearing ratio is essentially the same (*i.e.* equal to 0.485). With a gearing ratio of 0.49, our recommended equity beta of 0.95 corresponds to an asset beta of 0.48 (*i.e.* 0.95 * (1 – 0.49) = 0.48). This asset beta is only slightly larger than the 0.45 value that was previously approved by the OUR.

3.4 Market Risk Premium

In the previous determination, the OUR used a forward-looking projection of the market risk premium (MRP). The projection for this parameter was set at 8.2% and was equal to the forecast growth in the S&P 500 index. To be consistent with this approach, PEG has also used a forward-looking projection of a broad market index to determine the MRP. ValueLine forecasts that the Dow Jones index will reach 20,425 in five years (2013). At the time of this report, the Dow closed at just under 10,000. The ValueLine forecast is therefore consistent with an nominal growth rate of 14.28% per annum (*i.e.* ln(20.425/10,000)/5 = .1428). Given our recommended values of a 0.32% real risk premium and a 2.3% rate of inflation, this is consistent with a market risk premium of 11.66% (*i.e.* 14.28% -0.32 2% - 2.3% = 11.66%). PEG therefore recommends that the MRP be set at 11.66%.

3.5 Country Risk Premium

In the previous determination, the country risk premium (CRP) was calculated as the difference between yields on US dollar-denominated bonds by the Government of Jamaica (GOJ) and the US Treasury. JPS measured the latter using 10 year Treasury bond yields. Since there were no outstanding US dollar-denominated GOJ bonds with a maturity date of 10 years, JPS estimated the equivalent of a 10 year GOJ yield through a statistical exercise. The Company regressed GOJ yields on the (natural log) of their maturity dates and obtained an estimate of the impact of maturity dates on yields. A maturity date of 10 years was then substituted into this regression to generate a predicted value for the yield of a 10 year GOJ bond.

PEG also looked at the difference between GOJ and Treasury yields as the basis for calculating the CRP. In our 2009 update, we used the yields for each bond on January 22, 2009, which was the last available date at the time this report was written. The 10 year US Treasury yield on January 22, 2009 was 2.62%. On the same day, the GOJ yield on the bond maturing in 2019 (*i.e.* 10 years from 2009) was equal to 12.85%. The difference between these yields was 10.23%. This numerical analysis therefore indicates that the CRP between Jamaica and the US should be 10.23%, which is greater than the 5.315% approved in the previous determination. For the reasons discussed, we believe the greater riskiness of the financial marketplace makes it reasonable to conclude that the CRP for Jamaica has increased.

3.6 Estimated Cost of Equity

PEG recommends the following values for the parameters of the CAPM formula:

Real, risk free rate of return	0.32%
Equity beta	0.95
Market risk premium	11.66%
Real cost of equity before CRP	11.40%
Country risk premium	10.23%
Total real cost of equity	21.63%

PEG therefore recommends a real cost of equity for JPS equal to 21.63%, or 21.6% or simplicity. Compared with the return approved in 2004, we believe this increase is warranted given the framework outlined in the previous determination, the most recently available evidence, and the current conditions in the financial marketplace which almost certainly signal a riskier environment with strong demands for capital.

4. Conclusion

PEG was asked by JPS to estimate the company's cost of equity, which will be used to set tariffs to be in effect from 2009 through 2014. PEG believes the best estimate of JPS' real cost of equity over this period is 21.6%. This recommendation is based on the framework that the OUR established in its 2004 rate determination, but it has been updated to take account of the most recently available information in 2009.

It should also be noted that PEG's recommendations on each of the CAPM parameters are broadly similar to the OUR's previous findings. Our recommended cost of equity is greater than the previously-approved 14.85% rate for three reasons. One is that PEG is recommending a higher beta. We believe this is warranted since our recommendation accounts for the small company effect and reflects much more recent equity market conditions for electric utilities. PEG also recommends a higher MRP than the value approved in 2004. This is reasonable, in part because world equity markets have under-performed for years, and the recent stock market declines mean that investors are starting from a low “base” value. It is not unusual for stocks to register very large gains during their initial recovery, and we believe it is very likely that equity markets will recover during the five years of the PBRM since earnings and balance sheets for most corporations (other than financial firms) have generally remained healthy. Third, PEG is recommending a higher CRP. This is warranted in light of current financial market conditions. The world is currently in the midst of its worst financial crisis in decades. The uncertainties in financial markets are likely to increase the risks and costs of raising equity, particularly for relatively small countries like Jamaica.

Annex C: Audited Financial Statements

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Annex D: Sales Forecasts - 2009-2013

EXECUTIVE SUMMARY

Electricity is a primary input for almost all aspects of economic activity in Jamaica and thus constitutes a commodity of great importance. Shortages and disruptions in electricity supply impact adversely on the country's economic and social development. To cater to the growing energy demand, it is imperative to develop adequate generation, transmission and distribution facilities, in a timely and cost effective manner. This Sales Forecast document, seeks to project the energy demand that will be required by the Jamaican economy from the Jamaica Public Service's (JPS') electricity grid for the period January 2009 through December 2013. This section details the latest 5-year demand forecast developed by the Jamaica Public Service (JPS or the Company) and the underlying methodology. The projections build on previous in-house demand forecasts, including those developed in February 2004 for the 2004 Rate Case submission.

Over the five-year period, demand and net generation are projected to change at a compounded annual growth rate of 0.8% and -0.6% respectively.

INTRODUCTION

Since 2000, there have been three regulatory changes in the national electricity industry, which has had a significant impact on JPS' approach to business. Firstly, the regulatory framework was strengthened through an amendment to the Office of Utilities Regulation (OUR) Act in 2000. Secondly, the introduction of an All-Island Electricity Licence in 2001; and thirdly, in 2004 the opening of the energy generation sector to competition. Together these legal instruments have provided the OUR with a framework for balancing the concerns of customers with the objectives of the utility company. Another significant change in the national electricity industry occurred in 2001 when the company was privatized. This privatization saw the Government of Jamaica selling 80% of its shareholding to Mirant Incorporated. On August 9, 2007, Mirant Corporation sold its shareholding to Marubeni Caribbean Power Holdings Limited, a wholly owned subsidiary of Marubeni Corporation of Japan (Marubeni).

These developments facilitated the following:

- An increase in consumers' expectations with respect to the quality of service,
- A reduction in the debilitating constraints on capital investment, and
- A clarification on the level of returns that investors can anticipate from their investment.

It is therefore in this context, that the exercise of forecasting demand assumes enormous importance.

The demand forecast, which serves as the catalyst to the Company's investment in the medium and long-term, must therefore reflect a fair degree of accuracy if over-investment or under-investment is to be avoided. Over-investment leads to superfluous capacity, which consumers pay for by way of higher electricity tariffs. On the other hand, under-investment causes inadequacy of supply, which inevitably results in system instability and blackouts that retard economic development and impair the quality of life experienced.

SUMMARY

The projection of JPS' demand and energy requirements was developed for the period January 2009 through December 2013. Demand and net generation are projected to change at a cumulative average growth rate of 0.8% and –0.6% respectively.

Energy Demand

Energy demand growth over the next five years is projected to occur in two distinct phases. In the first phase, 2009-2010, energy growth is expected to be negative, reflecting the overall outlook for the Jamaican economy. Energy growth is forecasted to be negative 0.8% in 2009 and negative 0.9% in 2010. This negative expected growth rate is attributable to two main variables. Firstly, economic growth as measured by GDP is expected to be negative in 2009, at the onset of a recession, and nil in 2010. This is based on the deteriorating economic climate that is being experienced worldwide, coupled with the current financial crises that are expected to intensify and spill over directly and indirectly into the real economies of developing countries, including Jamaica. The second variable is that of real disposable income. Real disposable income will be eroded as the economy moves deeper into recession, as low consumer demand will give rise to a cycle of job losses. This has already been evidenced from the last quarter of 2008, which have seen a spike in the national unemployment rate. However, the negative growth rate in energy generation will be dampened especially in 2009, as the economy rebounds from the record high fuel prices experienced in the first half of 2008. The average electricity prices will also affect electricity demand, especially with respect to residential consumers. Residential customers' impact will be double fold as it impacts their direct electricity bills as well as disposable income, as costs to commercial electricity consumers are typically passed along through commodity prices. In 2009, electricity prices are expected to decline by approximately 17%, primarily due to the fall in oil prices, although the devaluation of the J$ has the potential to negate this expected reduction. The reduction in prices should increase residential customer demand as average consumption increases due to reduced electricity bills. Residential consumption is highly responsive to the cost of electricity. Also, residential consumers have been noted to have a lag between changes in their disposable income and the time it takes to align consumption with income.

The second phase will encompass 2011 – 2013. This phase will be characterized by a positive growth trend for energy demand; growth in energy sales is expected to range between 1.2% and 2.4%. The cumulative average growth rate for the three years will be 2.0%. Growth will be driven by the turnaround in the economy, as subsequent to 2010, the growth rate of GDP is expected to be positive as the economy becomes revitalized. This positive growth trend will increase the demand for electricity across all sectors. In 2010 and 2011, incremental increases are expected in electricity prices, which will slow the recovery in sales growth over the period as emphasis is placed on conservation, self-sustenance and the need to align businesses with the economic cycle and outlook. During 2011 and 2013, energy sales will be driven by the commercial and industrial sectors as the economy recovers from recession. Growth will also be realised from the Residential group during this period, as disposable income increases as upward pressure is placed on the demand for labour, as a result of increasing productive activities, and increases in the growth level of housing stock as the construction industry becomes revitalized.

Table 1 summarizes the base demand and energy requirement forecast. The projected demand is based on separate estimates of energy sales for each rate class. Unlike previous forecasts for which Residential customers drove growth in energy, the current forecast projects energy growth to be driven by Streetlight and Municipalities (Rate 60), Power Service – Low Voltage (Rate 40) and Other Sales categories. Growth in the above mentioned categories should be fuelled by economic growth between 2011 and 2013, following the projected economic decline in 2009, with the civic responsibility of the Government of Jamaica to maintaining the infrastructural needs of the country, fuelling growth in the Rate 60's. Growth in economic activity will result in an increase in the average consumption and number of customers in the commercial, industrial and public sector of the country. However, growth in the two aforementioned rate classes is expected to overshadow that of other rate classes. Both rate classes will experience moderate increases in their percentage of aggregate sales over the period.

The cumulative annual growth rate for the Residential (Rate 10), General Services (Rate 20) and Power Services – Large Voltage (Rate 50) categories are expected to be relatively flat over the five-year period as seen in Table 1. Energy growth in these categories reflects the general decline and subsequent revitalization of the economy throughout the period.

Table 1: Projected Demand and Energy Requirements by Class of Service

Projected Demand and Energy Requirements by Class of Service									
Year	Residential (R10) (MWh)	Gen Service (R20) (MWh)	Power Service LV (R40) (MWh)	Power Service HV (R50) (MWh)	Street Light (R60) (MWh)	Other (MWh)	Total Sales (MWh)	Losses (MWh)	Net Generation (GWh)
2009	1,041,764	642,742	752,234	571,941	70,433	25,003	3,104,117	824,499	3,928,616
2010	1,031,999	639,909	749,788	555,216	73,379	25,132	3,075,424	773,549	3,848,973
2011	1,035,746	643,462	771,383	557,570	77,341	28,012	3,113,513	744,708	3,858,221
2012	1,041,275	650,814	808,088	574,596	81,562	32,864	3,189,199	728,808	3,918,007
2013	1,043,027	658,092	844,700	590,843	86,086	38,556	3,261,304	730,599	3,991,903
CAGR	**0.2%**	**0.2%**	**2.1%**	**0.0%**	**4.4%**	**6.9%**	**0.8%**	**-6.0%**	**-0.6%**

Losses

It is assumed that JPS will reduce its overall system losses to 18.3% by 2013 from the 22.9% level experienced in 2008. For the purpose of this forecast, reduction in losses is assumed to impact the net generation requirement and not sales. Also, the impact of non-technical losses is assumed to be negligible.

Net Generation

Between 2009 and 2010, net generation is expected to decrease by 4.7% and 2.0% respectively. The majority of the reduction in net generation in 2009 is as a result of anticipated significant improvements in system losses. Reduction in energy demand will account for the remaining decrease in net generation in 2009 and 2010. During 2011 and 2013, net generation is projected to increase each year to support the growth in electricity demand. The cumulative average growth rate over this period is projected at 1.2%.

The rate of growth is projected to be approximately 1.4% less than that of energy demand growth over the five-year period, due to modest but sustained annual improvement in system losses.

Number of Customers

The number of customers is expected to grow at a cumulative average growth rate of 1.4% over the next five-years. This represents a reduction of over one percentage point compared to previous forecasts. This growth will be fuelled by the continuation of various factors, including:

i. Annual forecasted population growth of 0.40%;
ii. Increased housing units completed; and
iii. Positive GDP growth between 2011 and 2013.

Table 2 below reflects the projected number of active customers for the period 2009 to 2013.

Table 2: Projected Number of Active Customers

Projected Number of Active Customers							
Year	Residential (R10)	Gen Service (R20)	Power Service LV (R40)	Power Service HV (R50)	Street Light (R60)	Other	Total
2009	528,282	61,275	1,555	122	201	3	591,439
2010	534,453	62,359	1,575	122	205	3	598,717
2011	541,779	63,794	1,612	125	209	3	607,522
2012	550,209	65,431	1,660	131	214	3	617,648
2013	558,755	67,111	1,709	136	218	3	627,933
CAGR	1.3%	2.1%	1.9%	1.7%	2.0%	0.0%	1.4%

General

Table 3: Summary of Key Variables for Historic and Projected period

Summary of Actual and Projected Key Economic Variables							
	Real GDP	Population	Real Disposable Income	Real Electricity Prices	Energy Sales	Active Customers	Average Consumption
1989 - 2008	1.62%	0.71%	1.94%	0.73%	4.51%	3.77%	0.71%
1994 - 2008	0.90%	0.67%	2.07%	0.88%	3.78%	3.53%	0.25%
1999 - 2008	1.21%	0.50%	1.45%	6.05%	2.50%	2.82%	-0.32%
2004 - 2008	1.10%	0.44%	0.54%	7.38%	0.86%	2.55%	-1.65%
2009	-1.00%	0.40%	-1.39%	-17.65%	-0.82%	0.90%	-1.71%
2010	0.00%	0.40%	-0.40%	2.02%	-0.92%	1.23%	-2.13%
2011	1.00%	0.40%	0.60%	2.16%	1.24%	1.47%	-0.23%
2012	1.50%	0.40%	1.10%	-4.22%	2.43%	1.67%	0.75%
2013	1.50%	0.40%	1.10%	-3.06%	2.26%	1.67%	0.59%
CAGR	0.60%	0.40%	0.19%	-4.44%	0.83%	1.39%	-0.55%

The five-year projected average Energy Sales growth rate of 0.8% per annum reflects the historical trend of a slowdown in the growth rate of energy sales. In addition, this growth rate also highlights the expected economic cycle projected for the period, moving from one of recession in 2009 – 2010, to one of economic recovery starting in 2011. Economic growth as measured by GDP, is projected at negative 1.0% in 2009 and nil in 2010. GDP is expected to increase by 1.0% in 2011 and 1.5% in 2012 and 2013. This will have a direct impact on real disposable income, and energy sales by means of an increase in average consumption per customer. The outturn over the last three years has been affected by several factors including significant adverse weather conditions (very active hurricane seasons), a volatile oil market characterized by high oil prices, and most recently high levels of instability in the financial markets. This forecast makes no provision for the recurrence of a similar impact.

Electricity Sales for the twenty-year period 1989-2008 experienced cumulative average growth of 4.5% per annum (See Table 3). This reflects significant differences to the 0.86% average annual growth for the five-year period 2004-2008 when the economy experienced a slowdown in economic activity and a flurry of hurricane and economic shocks. A defined tariff mechanism was introduced in 2001, which included annual inflation adjustments, monthly foreign exchange adjustments, fuel pass-through and a Rate determination in 2004. This tariff mechanism, along with continual devaluation of the Jamaican dollar and significant increases in the price of oil especially that experienced in 2008 combined to increase real electricity prices by an average annual rate of 7.4% over the past five years.

Real electricity price is projected to experience a negative cumulative average growth rate of 4.1% over the projected period, 2009 – 2013. This will be driven by a projected significant reduction in oil prices over the peak experienced in 2008, the introduction of two renewable projects in 2010 and the conversion of the Bogue facility to CNG in 2011.

METHODOLOGY

General

There are three main approaches to demand forecasting: Trend Analysis, Econometric modelling and the End-use technique. The main difference between the first two approaches and the End-use technique is that they rely heavily on historical data. On the other hand, the End-use approach emphasizes the current conditions. In deriving the demand forecast a combination of the Econometric modelling and Trend Analysis was employed.

Econometric modelling was the dominant technique used because:

1. Unlike the End-use technique, which requires considerable field research and primary data collection, the information used in this technique is easily available.
2. When compared to the End-use technique, data gathering is relatively inexpensive.

Econometric modelling techniques were adopted to estimate the Number of Customers and the Average Consumption per Customer. This method attempts to define electricity consumption as a function of two variables, namely: changes in the number of customers and the level of usage per customer.

Essentially, the econometric approach to electricity consumption forecasting seeks to explain the underlying determinants of electricity consumption through the application of economic theory using statistical and mathematical measurement techniques. The model seeks to determine economic and other factors that influence the demand for electricity. Such factors should include price, income and basic economic growth indicators.

Once a theoretically sound model is developed for each customer class, equations are developed and solved using a mathematical procedure known as regression analysis[47]. Different models are developed for each customer class according to its respective usage pattern. The regression procedures are used to quantify the strength and effects of the relationships of the theoretical specification of the models.

Where the growth rate of any class is deemed to have an arithmetic progression, a Simple Trend Analysis is used. This was done for the Other Sales rate category.

Major Explanatory Variables for Models

Residential Energy Sales (Rate 10)

Residential energy sales forecast is a product of the projections from:

i. The model used to estimate the average annual consumption from residential customers; and
ii. The model used to project the average annual number of residential customers.

The primary determinants used in developing the average number of customers are population growth projections and the growth in the number of completed housing units.

The residential demand model is developed from the theory that the consumer examines his income and the prices of the goods being considered for purchase. He chooses that basket of

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[47] **Regression analysis** is a collective name for techniques for the modeling and analysis of numerical data consisting of values of a dependent variable (also called response variable or measurement) and of one or more independent variables (also known as explanatory variables or predictors). The dependent variable in the **regression equation** is modeled as a function of the independent variables, corresponding parameters ("constants"), and an *error term*.

goods which fits within the limits of his budget and which yields him the greatest satisfaction. For the residential class model, it is reasonable to assume that household electricity demand should depend on household income and the price of electricity.

The variables we have found to be important in explaining residential electricity demand are:

i. Real Per Capita Disposable Income;
ii. Real Average Price of Electricity;

For the purpose of this forecast, we took the residential sales revenue and divide it by the total residential consumption for the period. The average price of electricity so obtained is then divided by the Consumer Price Index (Inflation Rate) to obtain the real average price of electricity.

The dependent variable for the residential average use model is the annual megawatt – hour (MWh) consumed per active residential customer. It is obtained by taking the ratio of total yearly residential electricity consumption to the mean annual number of active residential consumers. The dependent variable data have been carefully screened and crosschecked in order to eliminate faulty observations.

General Service Class (R20)

The General Service categories are non-residential customers with demand less than 25 kilovolt-amperes (kVA). This category is primarily made up of Small Commercial and Industrial businesses. In Jamaica, the Commercial/Industrial sector is very heterogeneous. It includes office buildings, banks, hotels, restaurants, bars, snack counters, movie theatres, barbershops and many other service sector establishments. In addition it covers general stores, gasoline stations, pharmacies and other commercial enterprises, both wholesale and retail. Many non-profit and government institutions are also served under the commercial class, such as churches, hospitals, schools and embassies.

The diversity of the commercial class has made it difficult to be very precise about what should be the nature and form of the explanatory variables, that is, the variables that explained the aggregate demand for electricity.

The primary determinants used in developing the average number of customers for the general service category are real GDP growth and population growth projections.

The variables that are postulated to explain the General Service demand for electricity are:

i. Real average price of electricity for Rate 20 customers
ii. Population Growth
iii. Gross Domestic Product on real prices
iv. Real Gross Domestic Product for the previous year
v. Weather conditions (i.e. Hurricanes)

The dependent variable for the model is the annual megawatt hours (MWh) consumed per Small Industrial/Commercial Customer. It is obtained by taking the ratio of total yearly Rate 20 electricity consumption to the mean annual number of active Rate 20 consumers.

Power Service Sales (Rate 40 & 50)

Power Service customers are non-residential customers with demand of 25 kilovolt-amperes (kVA) or more. These are primarily medium and large commercial and industrial customers. Customers are classified as Rate 40 or 50 depending on the voltage level that the service is provided. Rate 50 customers are provided with service at the primary voltage level.

Historic analyses have been affected by the reclassification of customers between these two classes. Separate models were developed for each Rate class.

The primary determinants used in developing the average number of customers for the power service category are real GDP growth and the passage of time.

Rate 40:

The Power Service low voltage energy consumption is taken to depend on:

i. Real average price of electricity for Rate 40 customers
ii. Gross Domestic Product on real prices

Rate 50:

The Power Service high voltage energy consumption is taken to depend on:

i. Real average price of electricity for Rate 50 customers
ii. Gross Domestic Product on real prices
iii. Real Gross Domestic Product for the previous year

The dependent variable for these models is proposed as the annual megawatt hours (MWh) consumed per Large Industrial/Commercial Customer. It is obtained by taking the ratio of total yearly Large Industrial/Commercial electricity consumption to the mean number of Large Industrial/Commercial consumers.

Street Lighting and Municipalities (Rate 60)

Rate 60 sales growth projections were derived based on expectations for economic growth, and the outlook for the Government's fiscal policies. In addition, the trend in the growth of this rate class is has been fairly constant and according to the authorities, the trend is not expected to change significantly over the forecast period.

The main variables, used for the Rate 60 sales forecasts were:

i. Real average price of electricity for Rate 60 customers
ii. Gross Domestic Product on real prices
iii. Real Gross Domestic Product for the previous year

Other Sales Category

The other sales category reflects power interchange sales between JPS and a few major Bauxite plants across the Island.

Based on an analysis of this category, a Simple Trend Analysis was deemed best in forecasting future consumption, as there were no clear explanatory variables identified in the determination of consumption needs for this category.

Determination of Variables

Real Average Electricity Price

The real average price of electricity model was calculated by dividing the average sales revenue by the average energy sales for the respective rate classes. The prices were then deflated with the historical and projected consumer price index to convert them to "real" prices.

The projection of average electricity prices was a reiterative and detailed process. Electricity prices over the 5-year period must take into account several variables. These include:

i. Fuel prices;
ii. Effects of changes in the mix and capacity of the generation fleet; and
iii. The projected changes in non-fuel tariff arising from Rate Determination every 5 years as well as CPI, Q and X factor adjustments. Rate Determination outcomes were projected through a reiterative procedure for 2009 and 2014.

Fuel price projections were developed through a pricing model, which used the latest short-term fuel oil curves for the West Texas Intermediary as projected by the Energy Information Administration (EIA)[48]. From the fuel price model, base prices were extrapolated for the No. 2 and No. 6 Fuel Oil based on a regression of historical values. These base prices were then adjusted to include additional costs for insurance, taxes and transportation to deliver to the numerous plants. The long-term forecast assumes the average price for West Texas Intermediate (WTI) oil to be $63.50/barrel in 2009. Between 2010 and 2013, the WTI price per barrel of oil is expected to decline by an average 4% per annum. WTI is expected to average $65/barrel over the five-year planning horizon

As outlined in below, the assumption includes the introduction of two small renewable generation plants between 2010 and 2011, the conversion of the existing Bogue generating facility from Fuel Oil to Compressed Natural Gas (CNG) in 2011. CNG price projections were developed. The estimate for the renewable prices included a margin for the recovery of investment and a reasonable return on the construction and operation of each facility.

Changes in Generation Capacity and Mix

This relates to the development of annual rates for fuel and IPP charges. In addition to the price of fuel, which is a major driver, two other important variables were considered in developing fuel and IPP rates. These are additional generating capacity and the Company's annual maintenance plan, both of which are used to determine generation dispatch projections. This generation dispatch provides annual fuel cost projections that were adjusted for system losses and heat rate projections to determine average fuel charges customers would experience over the period 2009 –13.

Non-Fuel Tariff

The non-fuel tariff was determined using the Company's financial model. The model generated values for annual non-fuel rates by taking into account estimates for rate-base, capital structure and the weighted average cost of capital and revenue requirements for the Rate-Case test years. Projections were also made for annual CPI adjustment as well as Q and X factor adjustments.

Real Gross Domestic Product

Real GDP was used as the primary indicator of economic activity and was also used as an explanatory variable in the General Service rate class, Power Service rate class and Streetlight models. Data on nominal GDP was obtained from the Statistical Institute of Jamaica (STATIN). Historical GDP data covering the period 1980 – 2007 was used in the regression analysis. See Table 3 for historical GDP growth rates. Real GDP is projected to grow at a cumulative average growth rate of 0.6% over the next five years.

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[48] The latest short-term fuel curve used was based on that issued by the Energy Information Administration on the 14th. November 2008, for the period through 31st. December 2009. (See http://www.eia.doe.gov/oiaf/forecasting.html)

Real Disposable Income Per Capita

Real disposable income per capita was used as an indicator of customer purchasing power and was utilized as an explanatory variable in the residential average use model for the determination of residential electricity demand. The variable was calculated as the quotient of real disposable income for the population. Historic data on nominal disposable income was obtained from STATIN.

Real per capita disposable income is expected to grow at a cumulative average growth rate of 0.2% over the next 5 years, this growth rate includes the effects of erosion to disposable income expected in 2009 and 2010 from the effects of the recession, associated job losses and the curtailment of wage increases. Real disposable income in 2009 and 2010 are projected to decrease at a rate of 1.4% and 0.4% respectively.

As reflected in Table 3, the slowdown in real disposable income over the previous years was as a result of wage increases lagging that of inflation, especially in the years of double digit inflation.

Population Growth

Population data for the period 1980 – 2007 was obtained from STATIN. Cumulative average population growth rate over the last five years was 0.4%. Population growth rate was used as an explanatory variable in the Residential Rate class model.

The projected population growth rate for the five-year period is 0.4% per annum.

Inflation

Like the other variables, inflation as measured through movement in the CPI for the period 1980 – 2008 was obtained from STATIN.

Over the last 28 years, the economy has experienced several inflation cycles. During the period 1997 – 2002, Jamaica experienced single digit inflation rates ranging from 6.1% to 9.2%. During 2003 – 2005 and 2007 – 2008 inflation rates were in double digits, from a low of 12.9% to a high of 16.8%. During 2006, the inflation rate was 5.8%, that is the lowest level of inflation since 1981. The high level of inflation being experienced from 2007 onwards is part of a new cycle of double-digit inflation rates, however the forecast is for this to be curbed at the end of the 2009 calendar year. The model assumes an inflation rate of 12% for 2009, which reflects the continued downward trend being experienced since the last quarter of 2008. This outlook is also consistent with the outlook from the Bank of Jamaica, which predicts inflation to range between 12.5% and 13.5% for the 2009 fiscal year[49]. Inflation is projected to gradually decline to 7.0% by 2013 (see Table 6). The basis for the projection is outlined in the Macro Economic Outlook section below.

Result and Conclusion

In each of the regressions estimated, most of the coefficients (elasticities) were correctly signed, reasonable in magnitude and significant at the 5% confidence level. Also, the disaggregation of the energy demand into different classes instead of using only time series data on energy demand not only increased the number of observations but also covered a much wider range of variation.

Given our limited ranges and time period (between 13 and 30 observations/year) the demand studies can be said to be of a reasonable high quality.

[49] Obtained from the Bank of Jamaica's Quarterly Press Briefing by the Hon. Derick Latibeaudiere, Governor, Bank of Jamaica on the 18 February 2009.

Specification and Diagnostic Test

Specification tests on variables selection, functional forms and the possibility of correlation among the explanatory variables were done. The results are that some weak forms of serial correlation and heteroskedasticity may be present but neither appears to pose serious problems. As a result, the regression estimates and associated conclusions remain valid.

Forecasts Model Specification

Two models were developed for each rate class, except Other Sales category:

i. The first model forecasts sales per customer; and
ii. The second model forecasts the number of customers.

This separation allows the Company to distinguish between overall sales growth that is driven by population growth or electrification (which produce changes in the number of customers) and sales growth that is driven by technological change or increases in income (which produce changes in usage per customer). For the Other Sales category, sales are forecast directly.

Sales per Customer Models

Table 4 below summarizes the sales per customer models (except for the sales model for Other Sales). The variables that are reflected include the estimated coefficients, t-statistic and the critical t-statistic for each variable at the 5% confidence level, and the R-squared and adjusted R-squared values for the models, along with the time frame used for each model. In each case, the natural log of sales per customer is used as the dependent variable.

Table 4: Sales per Customer Regression by Rate Class[50]

Sales per Customer Models					
Explanatory Variable	**Rate 10**	**Rate 20**	**Rate 40**	**Rate 50**	**Rate 60**
ln (real price)	-0.343 -(4.3027)	-0.015 -(0.2166)	-0.192 -(0.8803)	-0.253 (2.2250)	0.080 (0.2109)
ln (real disposable income)	0.426 (7.8961)	--	--	--	--
ln (population)	--	3.371 (2.3139)	--	--	--
ln (real GDP)	--	5.830 (2.8203)	2.179 (3.9418)	4.292 (2.5806)	-0.901 -(0.2877)
ln (real GDP) * time period	--	-0.003 -(2.7237)	--	-0.001 -(3.0146)	0.001 (0.7083)
Hurricane	--	0.036 (1.1271)	--	--	--
Constant	-0.074 -(0.4419)	-29.824 -(2.4852)	-20.717 -(3.0720)	-7.555 -(0.8915)	-0.339 -(0.0186)
R-squared Adjusted R-squared	**0.857** **0.846**	**0.441** **0.308**	**0.652** **0.557**	**0.691** **0.640**	**0.672** **0.563**
Critical t-statistic	(2.3910)	(2.4138)	(2.5600)	(2.5600)	(2.6850)
Timeframe used	**1982-2008**	**1982-2008**	**1994-2008**	**1993-2008**	**1996-2008**

The variables are defined as follows:

i. **ln (real price)**: Nominal prices are calculated as class revenue divided by class sales. They are converted to real prices using CPI data. That is, Real price = Nominal price / CPI. This variable controls for the effect of changes in tariff rates on usage. Customers are expected to use less electricity as prices rise.
ii. **ln (real disposable income)**: Data on nominal national disposable income was obtained and converted to real disposable income using CPI data. Real disposable income is

[50] T-statistics are shown in parenthesis. Rate 10, 20, 40, 50 and 60 dependent variable is the natural log of sales per customer.

assumed to grow at the same rate as real GDP in the forecast period. This variable controls for the effect of increases in income on residential sales per customer, as customers are expected to use more electricity as income rises.

iii. **ln (population)**: This represents the growth rate experienced during the year.

iv. **ln (real GDP)**: Data on nominal GDP were obtained from STATIN. This was converted to real GDP using CPI data. This variable controls for the effect of economic conditions on commercial and industrial energy use, and usage per customer is expected to increase as GDP increases.

v. **ln (real GDP) * time trend**: This variable is an interaction between the GDP and time trend variables. It captures the fact that economic growth has had a different effect on usage over time. The negative estimated coefficients for the Rate 20 and 50 models indicate that the effect of changes in GDP on changes in usage per customer has declined over time.

vi. **Hurricane**: This is equal to 1 in the years in which the country experienced a hurricane(s) and zero in all other years. It reflects the changes in sales per customer that occurred because of the impact of the Hurricane(s).

Number of Customer Models

Table 5 below summarizes the number of customer models, including the variables that are included, the estimated coefficients, t-statistics and the critical t-statistic for each variable at the 5% confidence level, and the R-squared and adjusted R-squared values for the models, along with the time frame used for each model. In each case, the natural log of the number of customers is used as the dependent variable.

Table 5: Number of Customer Regressions by Rate Class[51]

Number of Customers per Rate Model					
Explanatory Variable	**Rate 10**	**Rate 20**	**Rate 40**	**Rate 50**	**Rate 60**
ln (Real GDP)	--	0.5257 (2.1975)	1.1422 (1.7405)	2.8415 (6.5517)	--
Time	--	--	0.0122 (1.8312)	--	0.0197 (6.6604)
Housing Completed	0.1053 (4.6390)	--	--	--	--
ln (population)	--	4.3891 (7.9925)	--	--	--
ln (Customer/Population)	0.9288 (12.9398)	--	--	--	--
Constant	7.0447 (52.4618)	(30.1684) -(16.5136)	(31.2676) -(4.8222)	(30.5875) -(5.7116)	(34.1386) -(5.7766)
R-squared Adjusted R-squared	**0.994** **0.993**	**0.974** **0.970**	**0.884** **0.866**	**0.754** **0.735**	**0.801** **0.778**
Critical t-statistic	(2.3910)	(2.3910)	(2.5600)	(2.5096)	(2.5931)
Timeframe used	**1982-2008**	**1982-2008**	**1994-2008**	**1993-2008**	**1996-2008**

The variables are defined as follows:

i. **ln (real GDP)**: Data on nominal GDP were obtained from STATIN. This was converted to real GDP using CPI data. This variable controls for the effect of economic conditions on commercial and industrial energy use, and usage per customer is expected to increase as GDP increases.

[51] T-statistics are shown in parenthesis. In all cases, the dependent variable is the natural log of the number of customers.

ii. **Time**: This variable reflects changes that occur over time that are not captured by the other included variables. The coefficient is interpreted as the annual percentage change in the dependent variable, controlling for the other included variables.
iii. **Housing Completed**: This relates to the incremental increases in housing each year. This is used to determine the increases in customer as a result of increased housing lots.
iv. **ln (population):** This variable is an interaction between population and the time trend variable. It captures the fact that population growth has had a different effect on customer growth over time.
v. **ln (customer/population)**: This represents the rate at which growth in the population is converted to customers.

The timeframes used for each model were selected by examining the data for each class and taking into account restrictions due to data availability. In all cases, we use actual and the latest estimated data through 2008 so that the results reflect the most recent conditions.

Creation of the Forecasts

The sections above describe the regression models that estimate the historical relationships between sales per customer (or the number of customers) and a range of explanatory variables. This section describes how those models were used to create forecasts of sales and the number of customers.

Table 6: Actual & Projected Macro Economic Variables 2004-2013

Macro Economic Variables					
Year	Real GDP Growth	Population Growth	Houses Completed	Foreign Exchange Rate	Inflation
2004	0.97%	0.51%	5,832	61.63	13.73%
2005	1.43%	0.47%	4,186	64.58	12.88%
2006	2.46%	0.48%	2,725	67.15	5.76%
2007	1.15%	0.32%	2,226	70.62	16.80%
2008	-0.50%	0.40%	1,500	80.47	16.80%
2009	-1.00%	0.40%	1,000	92.54	12.00%
2010	0.00%	0.40%	1,500	97.97	9.04%
2011	1.00%	0.40%	1,750	102.56	7.82%
2012	1.50%	0.40%	2,000	106.94	7.40%
2013	1.50%	0.40%	2,000	111.09	7.00%

- Actual **Real GDP Growth** was obtained from STATIN for the period 2004 to 2007, the growth rate for 2008 represents the latest estimate and those for 2009 to 2013 represents growth rates forecasted based on economic projections and past trends.
- Actual **Population Growth** was obtained from STATIN for the period 2004 to 2007, the growth rate for 2008 represents and estimate. Growth for the period 2009 to 2013 is based on recent trends, which is assumed to continue into 2009 and remain constant thereafter.
- Actual **Number of Houses Completed** was obtained from the Bank of Jamaica for the period 2004 to 2007, for the period 2008 to 2013, estimates and forecasts were made based on current and expected fall off in economic activity and current levels of default on housing loans and fall out in the construction sector.
- The **Foreign Exchange Rate** reflects the average selling rate of the United States dollar on the last trading day of the year. Actual rates were obtained from the bank of Jamaica for the period 2004 to 2008. Rates for the period 2009 to 2013 were projected based on Purchase Power Parity assumptions.
- **Inflation** was calculated based on movement in the Jamaican CPI each year, actual data was obtained from STATIN for the period 2004 to 2008. 2009 to 2013 are based on economic projections as discussed further in this document.

First, forecast values of real electricity price growth, real GDP growth (which is also applied to real disposable income), population growth, and inflation are applied to the model. Based on the macroeconomic outlook discussed in Section 4, JPS' forecasts for the 5-year period are as shown in Table 6.

The predicted values of the dependent variable were then calculated for the historical and forecast periods, from which the annual forecast percentage changes in the dependent variable were calculated. Recall that for all rate classes, separate forecasts are generated for sales per customer and the number of customers. These are combined (i.e., multiplied) to form the sales forecast for each rate class. Forecasted growth rates for sales and the number of customers are as shown in Table 7 and Table 8.

MACROECONOMIC OUTLOOK

JPS' business operations are affected to a great extent by the macro-economic conditions of Jamaica. Over the past five years and in particular in 2008, several factors contributed to making the year a challenging one. These factors include:

i. Excessive fuel price increases;
ii. Double digit Inflation;
iii. Continued devaluation of the Jamaican dollar;
iv. Effect of Hurricane Ivan (2004), Hurricane Dean (2007) and Tropical Storm Gustav (2008); and
v. Global financial crises as a result of a decline in the US Sub-prime sector in 2008

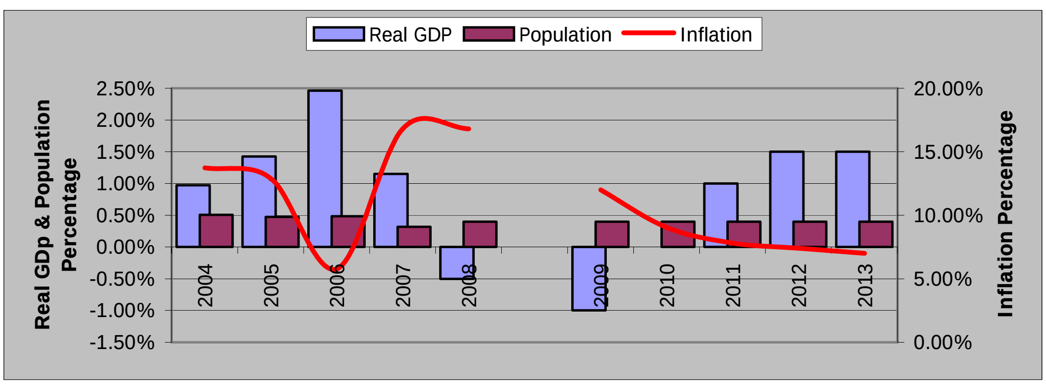
These factors impact on all stakeholders in the electricity industry including customers and investors. As such, the expected direction of the local economy, over the next 5 years, is of great significance.

Looking Ahead: 2009 – 2013

The economic outlook for the period 2009 – 2013 is one of the most important determinants of the energy demand and net energy requirement projections.

Figure 1 and Table 6 shows the forecasts of these factors over the 5-year period.

Figure 1: Historic and Projected Macro Economic Variables



Inflation

The period 2003 – 2005 has recorded double-digit inflation, which was driven by several key factors. In 2003, the combination of a 20% depreciation of the Jamaican Dollar and the tax package of the 2003 – 2004 fiscal year resulted in inflation of 14.1%. In 2004, the pass-through effect of the significant currency depreciation of 2003 and Hurricane Ivan contributed to inflation of 13.7% in 2004. Sharp increases in the price of oil and the effect of an active hurricane season resulted in 2005 being another double-digit inflation year (12.9%).

In 2006, the Jamaican economy experienced its lowest level of inflation of 5.8% since 1981. However, the economy returned to a state of double-digit inflation in 2007, which continued throughout 2008.

The outlook is for the inflation rate to decrease in the 2009 calendar year on the backdrop of high interest rates, an economic slowdown and other anti-inflationary stimulus in the economy. Inflation for 2009 is projected at 12.0%. The economy is projected to return to single digit inflation by 2010. This is based on the policies being implemented by the Government and The Bank of Jamaica to curb inflationary pressures in the economy. These policies are mainly based on monetary policy issues, evidenced by the issuing of high yield government bonds and the increase of bank reserve requirements in an attempt to reduce the money supply in the economy. During the last quarter of 2008, these measures along with falling world oil prices have had a significant effect of curbing the high rate of inflation that was prevalent in the first three quarters of the year.

It must, however, be noted that the Government will be faced with significant challenges in its quest to maintain a stable level of inflation. The largest economic challenge facing the Government is the size of the public sector debt. The Public Debt/GDP ratio has consistently being over 100% over the last ten years. This is compounded by the fact that the Jamaican economy is heavily taxed. This will be further exacerbated by the need to improve investment opportunities and growth in a country on the verge of a recession.

Another factor contributing to the likelihood of single-digit inflation is the effect of global economic recessions in Jamaica’s main trading partners, most notably the United States and the United Kingdom. This should have a two-fold effect on the economy. Firstly, substantial remittances from these nations will be reduced resulting in significant decline in individual disposable income, and thus its multiplicative effect on prices. Secondly, with the advent of higher local interest rates, assuming the central government’s ability to maintain an attractive exchange rate, the Jamaican economy will be more attractive to foreign investors thus increasing financial capital flows into the island.

The medium term outlook is for inflation to remain in single digit with slight annual reductions annually to 7.0% by 2013. The Company developed the projections for inflation for the period 2009 to 2013 independently. However, these projections were strongly influenced by forecasts presented by The Bank of Jamaica (BOJ) and The International Monetary Fund (IMF) in their Annual Country Outlook.

Exchange Rate

Exchange rate forecasts were generated between the Jamaican currency and that of the United States of America.

The default assumption in exchange rate forecasting, in the absence of exogenous shocks or balance-of-payments corrections, is that the real exchange rate will be maintained. That would require a nominal depreciation equal to the differential between the inflation rates in the two currencies. This was obtained through the use of purchasing power parity.

Jamaican inflation is expected to remain significantly above US inflation over the planning period and consequently a continual depreciation of the Jamaican Dollar is forecasted. The projection is for a cumulative average depreciation of 6.7% per annum. This compares to the 5.5% annual depreciation experienced between 2004 and 2008 and the 6% devaluation of the Jamaican Dollar in the first month of 2009.

United States inflation is projected to average 3.1% throughout the five-year period 2009 to 2013, and was obtained from our Parent Company’s Planning Team.

GDP Growth

GDP growth has been constrained by a crowding out of the private sector, labour market rigidity, high security costs, and external shocks. All of these factors are still present in the Jamaican economy and therefore limits the prospect of rapid economic growth. With the downturn and current recessions being experienced with our main trading partners (the U.S.A. and U.K.), global financial instability, fall out in the productive sector and anticipated high levels of unemployment (in excess of 10%), we anticipate a decline in GDP for 2009. We have projected a 1% decline in GDP for 2009.

On the other hand, with the anticipated ease in the negative global crises and planned investment in infrastructure, tourism, education and reduced electricity prices, we expect to see some recovery and growth in the subsequent years, commencing in 2011. The forecast is therefore for modest GDP growth of 1.0% in 2011 and 1.5% in 2012 and 2013. The economy is expected to be flat in 2010 as the businesses in the economy realigns themselves from the recessionary effects that would have been carried over from 2009, thus no growth is projected for 2010.

The latest estimate for GDP growth for 2008 by the PIOJ was approximately negative 0.5%. This is reflected in our analysis.

Population Growth

The Jamaican population has been increasing at a decreasing rate over the last twenty years as presented in Table 6. The outlook for 2009 – 2013 is for the population to reflect the same level of cumulative average growth that has been experienced throughout the last 5-years.

Housing Units Completed

The number of housing units completed has been declining on an annual basis between 2004 and 2007; this declining rate is expected to continue into 2008. Housing units completed should be a function of economic activity and especially the construction sector in an economy. With the projected recession, and the ongoing decline in the construction sector, the number of housing units to be completed is expected to decline in 2009 by at least 30%. This is also predicated on the backdrop of significant levels of default on residential loans from both private and public institutions in the last quarter of 2008 and into 2009. Housing units are expected to increase come 2010, as the economy tries to return to some level of normalcy. This growth is expected to continue into the future, and should be fuelled by increasing economic activity and growth in real disposable income.

Projections for GDP, Population and Housing Units Completed are based on Company projections and are independent of any other institution or planning authority.

ANALYSIS OF RESULTS

Projected Average Consumption and Consumption Growth Rates

Table 7: Projected Average Consumption per Rate Class and Growth Rates between 2009 and 2013

Projected Average Consumption by Rate Class and Growth Rates							
Year	Residential (R10) (MWh)	Gen Service (R20) (MWh)	Power Service LV (R40) (MWh)	Power Service HV (R50) (MWh)	Street Light (R60) (MWh)	Other (MWh)	Total Sales (MWh)
2009	1.97	10.49	483.60	4,688.24	349.68	8,334.23	5.25
	0.1%	-2.4%	-1.1%	-0.4%	-0.4%	-9.4%	-1.7%
2010	1.93	10.26	476.20	4,551.14	357.21	8,377.41	5.14
	-2.1%	-2.2%	-1.5%	-2.9%	2.2%	0.5%	-2.1%
2011	1.91	10.09	478.52	4,444.04	369.17	9,337.25	5.12
	-1.0%	-1.7%	0.5%	-2.4%	3.3%	11.5%	-0.2%
2012	1.89	9.95	486.87	4,391.49	381.74	10,954.55	5.16
	-1.0%	-1.4%	1.7%	-1.2%	3.4%	17.3%	0.8%
2013	1.87	9.81	494.30	4,329.98	395.07	12,851.94	5.19
	-1.4%	-1.4%	1.5%	-1.4%	3.5%	17.3%	0.6%
CAGR	**-1.1%**	**-1.8%**	**0.2%**	**-1.7%**	**2.4%**	**6.9%**	**-0.6%**

The following are the major highlights of the sales projection in respect to the average consumption pattern of the respective rate classes:

i. The average residential consumption (Rate 10) has fallen by 9.9% between 2004 and 2008. This consumption trend is expected to continue, as householders aim to maximise their disposable income in the presence of increasing prices and an erosion of one's disposable income. Also, residential consumers and the government have been actively pursuing energy self-generation and energy conservation, especially in light of the high oil prices experienced in 2008. This increased focus on self-generation and energy conservationism will reduce the consumption needed from the grid. During the forecasted period, a further 5.3% reduction in the average consumption per residential customer is anticipated.

   The 0.1% percentage increase in average consumption in 2009 is directly in response to reduction in real electricity prices of over 17% to that experienced in 2008.

ii. The cumulative average growth rate of average consumption for the Rate 20 class is expected to be negative 1.8%. During 2008, the average Rate 20 consumer consumed 11 MWh. This is expected to decline to 9.8 MWh by 2013, a reduction of 10.9%. This is against the backdrop that in 2004, the annual consumption was 11.8 MWh. This also reflects the customers, in this case Rate 20 customers' continued drive towards energy conservation in light of tighter competitive markets, increased costs of production, and lower profit margins.

   As noted in 2009 and 2010, Rate 20 customers are expected to adjust consumption the most, which is in direct response to a slowdown in the economy. 2009 is characterised by negative growth, while 2010 reflects no growth as measured by GDP.

iii. Rate 40, which represents the Power Service – Low Voltage category has seen two distinct phases in average consumption since 2004. In 2004, the average consumption for this category was 472.8 MWh, this increased at an average 3.5% over the next two years to 506.6 MWh in 2006 in response to development in the economy. However, subsequent to 2006, the average consumption has mimicked other rate classes and has seen yearly reduction to average 488.8 MWh in 2008. This reduction in average consumption is expected to continue throughout 2011 as this rate class respond to the negative forces of the economy, most notably GDP growth. Average consumption by 2011 is projected at 478.5 MWh per annum.

   In response to economic activity, as seen in 2012, the average consumption is expected to reverse and thus have a positive growth trend increasing at an average 1.6% per annum to average 494.3 MWh by 2013. The cumulative average growth rate for Rate 40 over the period is 0.2%.

iv. Rate 50 is comprised of two distinct consumption groups: Customers who constitute the majority of the Large Voltage – Power Service, and the Caribbean Cement Company (CCC).

The average consumption for the Large Voltage customers has been volatile since 2004, averaging 4,065.7 MWh per annum throughout the five-year period to 2008. In 2008, the average consumption was 3,986.1 MWh per annum. The average consumption over the next five years is expected to see a reduction in usage, as the industrial companies consolidate their consumption from the grid while at the same instance focus on means of self-sustenance. Large Voltage customers are expected to experience a cumulative average growth rate of negative 1.7% over the period, with average consumption per customer being 3,665.3 MWh per annum by 2013.

Caribbean Cement's average consumption is highly responsive to changes in GDP and especially in response to the construction sector of the economy. Between 2004 and 2006, sales to the CCC was in excess of 100,000 MWh/annum, however over the past two years, the Company has seen a fall off in sales, with sales averaging 93,000 MWh/annum during this period. This is in response to two variables; in 2007 the CCC experienced difficulties within its operations that resulted in a downsizing of output capacity. Subsequently, after rectifying operational inefficiencies the CCC increased its productive capacity by adding a new Kiln facility. However, this has not resulted in increased sales for the Company, as the CCC has made tremendous strides towards self-sustenance and energy conservation. This trend is expected to continue, and we expect the demand from the CCC to move also in tandem with the projected GDP path over the next five years. We project sales to the CCC to average approximately 94,000 MWh/annum over the projected period.

The results provided in Table 7 above reflect the average consumption of the Rate 50 energy class, inclusive of Caribbean Cement Company's consumption.

v. Rate 60 consumption growth, which is comprised of Street Lighting activities is expected to be relatively constant throughout the forecasting period. The cumulative average growth rate is projected at 2.4%. This growth rate is based on the efforts of the JPS and the Municipalities to increase the maintenance of street lighting across the island, especially in residential communities and commercial centres.

Since 2004, the average consumption has increased by 10.2% to average 351.3 MWh per annum. Over the next five years, average consumption is projected to grow at a cumulative rate of 2.4% to average 395.1 MWh per annum by 2013.

vi. The other category, which is comprised mainly of energy sales to Alcoa and Windalco, is expected to experience the highest level of growth throughout the period; this is projected at 6.9% per annum. Since 2004, this class has experienced a 62.8% growth, with average consumption increasing from 5,652 MWh/annum to 9,203 MWh/annum in 2008. The bauxite industry is driven by economic growth globally, as the demand for aluminium is influenced by market activities, especially in construction. With the current economic decline, the average consumption from this sector is expected to falloff in 2009 and remains relatively low in 2010 as international economies recover from their respective recessions. With increased production levels globally come 2011, and upward pressure on aluminium prices from increased demand, the local bauxite sector is expected to increase operations and so energy demand growth from the grid is expected to be positive, averaging in excess of 10% each period.

Projected Number of Customers and Customer Growth Rates

Table 8: Projected Number of Customers and Growth Rates between 2009 and 2013

Projected Number of Active Customers and Growth Rates							
Year	Residential (R10)	Gen Service (R20)	Power Service LV (R40)	Power Service HV (R50)	Street Light (R60)	Other	Total
2009	528,282	61,275	1,555	122	201	3	591,439
	0.9%	1.2%	0.1%	-2.8%	2.0%	0.0%	0.9%
2010	534,453	62,359	1,575	122	205	3	598,717
	1.2%	1.8%	1.2%	0.0%	2.0%	0.0%	1.2%
2011	541,779	63,794	1,612	125	209	3	607,522
	1.4%	2.3%	2.4%	2.8%	2.0%	0.0%	1.5%
2012	550,209	65,431	1,660	131	214	3	617,648
	1.6%	2.6%	3.0%	4.3%	2.0%	0.0%	1.7%
2013	558,755	67,111	1,709	136	218	3	627,933
	1.6%	2.6%	3.0%	4.3%	2.0%	0.0%	1.7%
CAGR	1.3%	2.1%	1.9%	1.7%	2.0%	0.0%	1.4%

During the period 2004 – 2008, approximately 47,500 customers were added to the system, resulting in an 8.8% growth over the period. The Rate 50 and Rate 20 categories with growth rates of 5.4% and 2.1% experienced the highest level of growth respectively during 2004 – 2008. Previously, the Rate 10 - residential customers experienced the highest growth rates. However, with high levels of electrification throughout the island and a slowdown in residential construction, residential growth has declined, and was 1.7% during this period. Though, on an aggregate level residential customer increase accounted for over 85% of overall customer growth, increasing by approximately 41,000 customers.

For the forecasting period 2009 – 2013, the cumulative average growth rate for customers to the grid is projected at 1.4%. Rate 20 is expected to reflect the highest level of customer growth at an annual average rate of 2.1%, adding an estimated 6,500 customers to the grid. However, residential customers (Rate 10) are expected to account for the majority of new customers to the grid. Residential customers are expected to account for 35,000 (84%) of aggregate new customers to the grid, growing at a cumulative average rate of 1.3% over the five-year period.

Growth in customers, especially Rate 20 during 2009 and 2010 is accounted for by the knowledge that when faced with challenges, such as lay-offs and a poor economic climate, persons with an entrepreneurial outlook seek to start up their own businesses and see closure of existing businesses as the last resort and will attempt to seek out profitable opportunities through continued and increasing business ventures. Thus, instead of a fall-off in customers, the economy should see an increase in actual business ventures throughout, especially with regards to the Rate 20 category. Customer growth in the Power Service categories is expected to be influenced primarily and move in tandem with movement in GDP. As such these rate classes will see a slowdown in customer growth in 2009 and 2010, and between 2011 and 2013 increased growth that coincide with projected higher levels of economic activity. Customer growth should be driven by increased hotel development and industrial growth.

Residential customer growth is positively correlated to the population size and the number of completed housing units. Both of which are expected to increase throughout the planning period.

Energy Demand Forecast

Table 9: Projected Annual Demand growth by Class of Service 2009-13

Forecasted sales growth rates 2009-2013							
Year	Residential R10 (MWh)	Gen Service R20 (MWh)	Power Service LV - R40 (MWh)	Power Service HV - R50 (MWh)	Streetlight R60 (MWh)	Other (MWh)	Total Sales (MWh)
2009	0.93%	-1.18%	-0.99%	-3.15%	1.53%	-9.44%	-0.82%
2010	-0.94%	-0.44%	-0.33%	-2.92%	4.18%	0.52%	-0.92%
2011	0.36%	0.56%	2.88%	0.42%	5.40%	11.46%	1.24%
2012	0.53%	1.14%	4.76%	3.05%	5.46%	17.32%	2.43%
2013	0.17%	1.12%	4.53%	2.83%	5.55%	17.32%	2.26%
CAGR	**0.21%**	**0.24%**	**2.17%**	**0.05%**	**4.42%**	**7.44%**	**0.84%**

The basic growth rate for energy demand forecast and energy sales for the different sectors are shown in Table 9 above. Aggregate sales are projected to experience a cumulative average growth rate of 0.8% over the five-year period, 2009 - 2013.

The highest growth rates will be experienced in the Other Sales and Street lighting categories, which will average 7.4% and 4.4% respectively. These growth rates will be driven primarily by growth in the last three years of the forecast, which will be driven by an increase in the average consumption per customer, in response to the anticipated economic upturn between 2011 and 2013. The remaining rate classes except for Rate 40 will average less than a one percentage cumulative growth rate over the same five years, due mainly in response to the falloff in electricity consumption in 2009 and 2010, and the subsequent reductions in average consumption throughout the period. Cumulative average growth rates for these rate classes will range from 0.1% to 0.2%. Rate 40 should experience a cumulative average growth rate of 2.2% over the five-year period.

Table 10 below, highlights the projected composition of aggregate sales over the planning horizon.

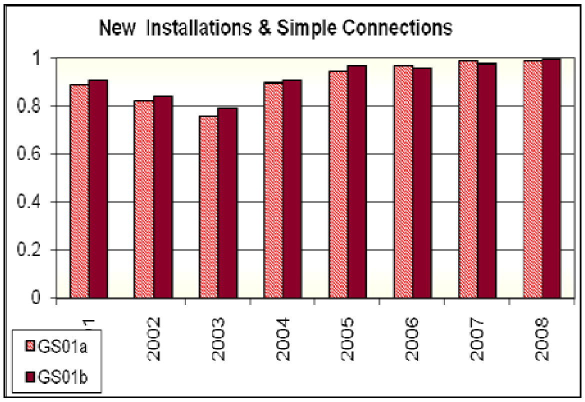
Energy sales is still expected to be dominated by Residential sales over the period, however there is will be a slight erosion of its overall contribution, as householders consume less energy on average than in the past. Contribution from the remaining rate classes are projected to remain relatively stable with maximum variation in contribution to overall sales from any one rate class being 0.4%, this is expected to occur from Street lighting (Rate 60).

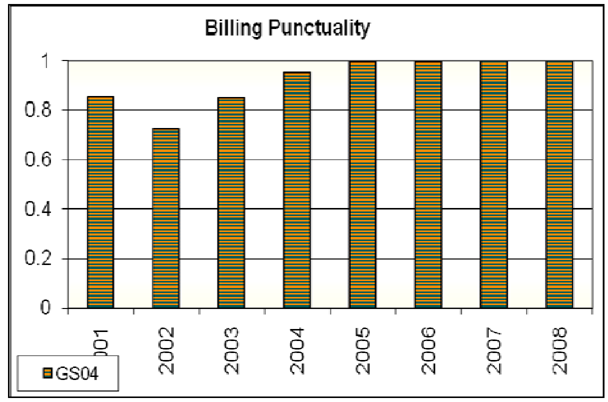
Table 10: Projected Distribution of Energy Sales (2009-2013)

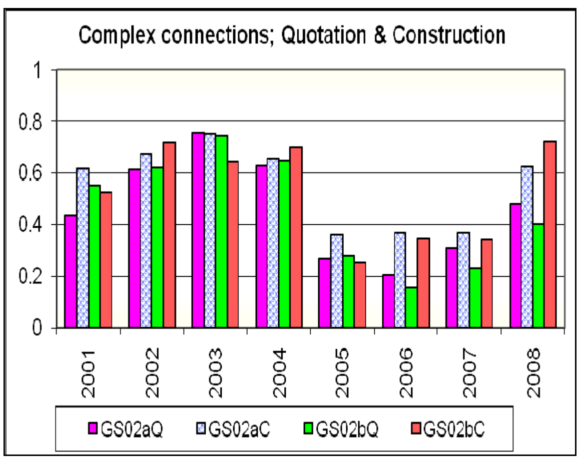
Projected Distribution of Demand by Class of Service							
Year	Residential (R10) (MWh)	Gen Service (R20) (MWh)	Power Service LV (R40) (MWh)	Power Service HV (R50) (MWh)	Street Light (R60) (MWh)	Other (MWh)	Total Sales (MWh)
2009	33.56%	20.71%	24.23%	18.43%	2.27%	0.81%	100.00%
2010	33.56%	20.81%	24.38%	18.05%	2.39%	0.82%	100.00%
2011	33.27%	20.67%	24.78%	17.91%	2.48%	0.90%	100.00%
2012	32.65%	20.41%	25.34%	18.02%	2.56%	1.03%	100.00%
2013	31.98%	20.18%	25.90%	18.12%	2.64%	1.18%	100.00%

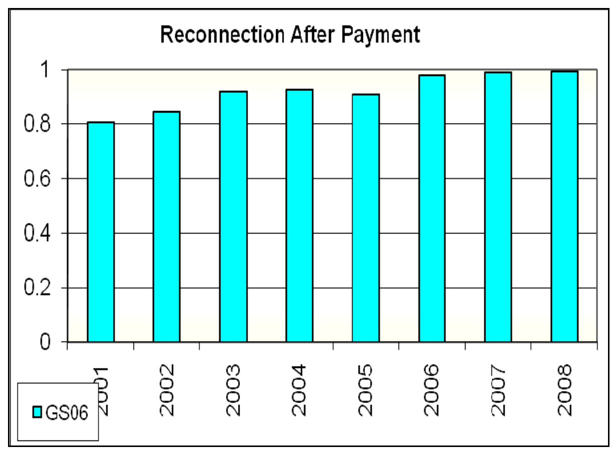
Annex E: Service Quality Performance Indicators

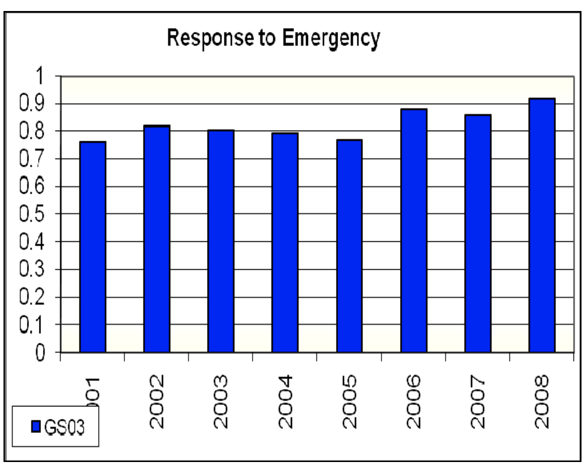
Guaranteed Standards

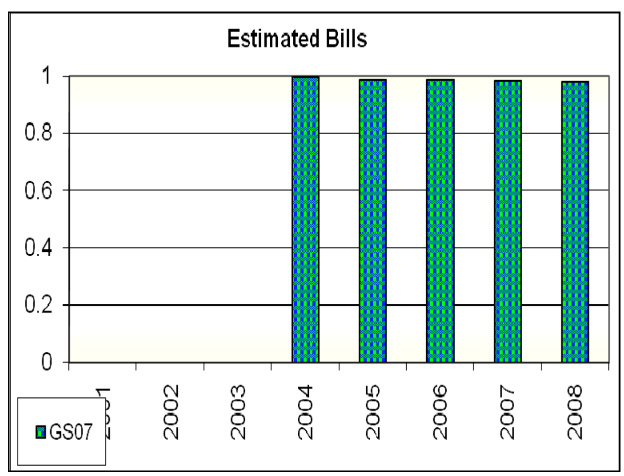


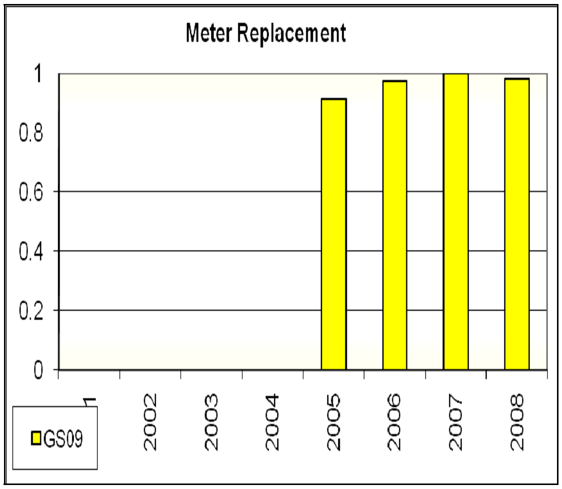


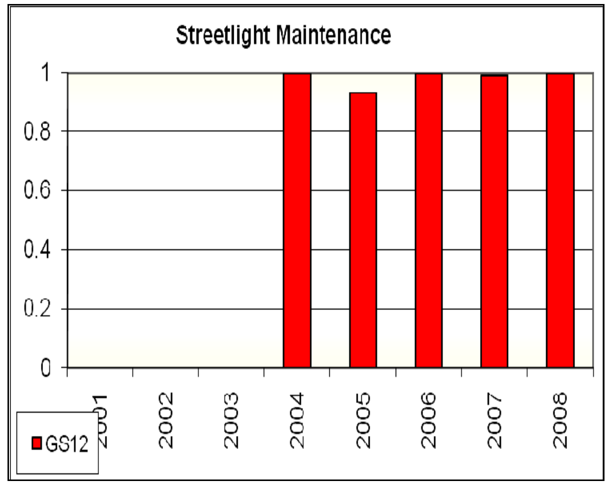


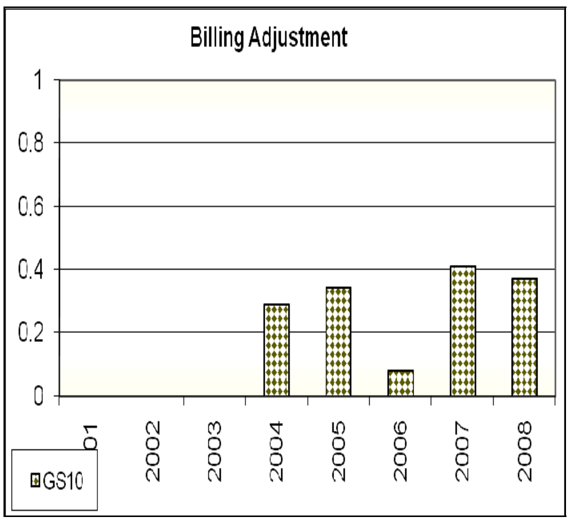







Meter Replacement
1
0.8
0.6
0.4
0.2
0
2002
2003
2004
2005
2006
2007
2008
GS09


Streetlight Maintenance
1
0.8
0.6
0.4
0.2
0
2002
2003
2004
2005
2006
2007
2008
GS12


Billing Adjustment
1
0.8
0.6
0.4
0.2
0
2002
2003
2004
2005
2006
2007
2008
GS10

Overall Standards

Code	Description	Regulatory Standard	Target 2009	2005	2006	2007	2008
OS01	Percentage (%) of planned outages for which at least forty-eight (48) hours advance notice is provided.	100%	100%	92.99%	87.17%	46.17%	-
OS02	Percentage of line faults repaired within a specified period of the fault being reported: Urban - 48 hours	100%	100%	95.73%	99.85%	98.93%	99.30%
OS02	Percentage of line faults repaired within a specified period of the fault being reported: Rural - 96 hours	100%	100%				
OS03	SAIFI (Transmission)						
OS03	SAIFI (Distribution)						
OS04	SAIDI (Transmission)						
OS04	SAIDI (Distribution)						
OS04A	CAIDI (Transmission)						
OS04A	CAIDI (Distribution)						
OS05	Total system losses	15.80%	15.8%	21.74%	23.26%	21.89%	24.47%
OS06	Percentage of meters read within time specified in the company's billing cycle (currently monthly for non domestic customers and bi-monthly for domestic customers)	99%	99%				93%
OS07	Percentage of other rates 40 and 50 customer’s meters tested for accuracy annually.	50%	50%	20.02%	0.26%	0.54%	95%
OS07	Percentage of other rate categories of customer meters tested for accuracy annually	15%	15%				
OS08	Billing punctuality: 98% of all bills to be delivered within a specified time after meter is read.	5 WD	98%	87.06%	81.44%	87.35%	74.30%
OS09	Percentage of customer’s supplies to be restored within 24 hours of forced outages in both Rural and urban areas	98%	98%	59.32%	99.67%	99.74%	99.69%
OS10	Percentage of calls answered within 15 seconds	90%	90%	84.85%	85.94%	86.11%	84.85%
OS11	Percentage of complaints resolved at first point of contact	TBC	TBD				
OS12	Percentage of all street lighting complaints resolved within 14 days	99%	99%				

Note:

- Performance relative to OS03 and OS04 standards are dealt with in Section 6.3 – Q-Factor

Annex F: Heat Rate Performance Modelling

JPS Heat Rate

Plant	Unit	2004 %	2005 %	2006 %	2007 %	2008 %	Average %	2009 %	2010 %	2011 %	2012 %	2013 %	2014 %
Rockfort	1	9,233	9,516	9,590	10,187	9,303	9,566	9,566	9,566	9,566	9,566	9,566	9,566
	2	9,585	9,888	10,055	10,189	9,540	9,851	9,540	9,851	9,540	9,851	9,540	9,851
	Subtotal	**9,289**	**9,614**	**9,619**	**10,189**	**9,429**	**9,628**	**9,552**	**9,726**	**9,552**	**9,726**	**9,552**	**9,726**
Hunt's Bay	B6	12,748	12,995	13,131	12,609	12,654	12,828	12,828	12,828	12,828	12,828	12,828	12,828
	GT #4							0	0	0	0	0	0
	GT #5	16,847	16,508	16,845	16,279	16,399	16,576	16,576	16,576	16,576	16,576	16,576	16,576
	GT #10	14,873	14,639	14,814	14,592	14,320	14,648	14,648	14,648	14,648	14,648	14,648	14,648
	Subtotal	**13,489**	**13,604**	**14,020**	**13,305**	**13,174**	**13,518**	**13,501**	**13,227**	**13,111**	**13,094**	**13,096**	**13,107**
Old Harbour	OH #1	15,635	15,913	16,379	16,075	16,050	16,010	16,200	16,200	16,200	16,200	16,200	16,200
	OH #2	14,403	14,023	15,006	15,481	14,076	14,598	14,598	14,598	14,658	14,658	14,658	14,698
	OH #3	12,547	12,622	12,829	13,266	13,133	12,879	12,879	12,879	12,929	12,929	12,929	12,979
	OH #4	12,660	12,485	12,501	13,071	12,732	12,690	12,690	12,690	12,720	12,720	12,720	12,770
	Subtotal	**13,450**	**13,487**	**13,615**	**14,232**	**13,497**	**13,656**	**13,580**	**13,479**	**13,462**	**13,462**	**13,480**	**13,623**
Bogue	GT #3	18,262	16,767	17,241	17,694	18,591	17,711	17,711	17,711	17,711	17,711	17,711	17,711
	GT #6	17,745	17,445	17,295	17,473	17,392	17,470	17,470	17,470	17,470	17,470	17,470	17,470
	GT #7	17,520	17,420	17,294	17,716	17,355	17,461	17,461	17,461	17,461	17,461	17,461	17,461
	GT #8	17,258	17,494	17,283	17,538	17,888	17,492	17,492	17,492	17,492	17,492	17,492	17,492
	GT #9	16,192	16,232	15,003	16,167	15,845	15,888	15,888	15,888	15,888	15,888	15,888	15,888
	GT #11	11,577	11,721	13,184	12,337	12,118	12,188	12,188	12,188	12,188	12,188	12,188	12,188
	GT # 12	13,198	13,255	13,479	13,490	13,298	13,344	13,344	13,344	13,344	13,344	13,344	13,344
	GT # 13	13,241	12,969	13,279	13,665	13,797	13,390	13,390	13,390	13,390	13,390	13,390	13,390
	Combined Cycle	9,161	9,025	9,126	9,249	9,171	9,146	9,146	9,146	9,146	9,146	9,146	9,146
Subtotal		**10,907**	**12,169**	**10,011**	**10,340**	**9,956**	**10,677**	**10,539**	**10,470**	**10,574**	**10,480**	**10,480**	**10,534**
JPSCo's Heat Rate		**11,752**	**12,138**	**11,338**	**11,900**	**11,257**	**11,677**	**11,581**	**11,363**	**11,209**	**11,209**	**11,257**	**11,440**

Total System Heat Rate

	2004	2005	2006	2007	2008	Average	2009	2010	2011	2012	2013	2014
	%	%	%	%	%	%	%	%	%	%	%	%
JPSCo's Heat Rate	11,752	12,138	11,338	11,900	11,257	11,677	11,581	11,363	11,209	11,209	11,257	11,440
JEP	8,355	8,355	8,189	8,166	8,166	8,246	8,246	8,246	8,246	8,246	8,246	8,246
JEP-50			8,189	8,166	8,166	8,166	8173	8173	8173	8173	8173	8173
JPPC	8,074	8,066	8,009	8,061	8,048	8,052	8,052	8,052	8,052	8,052	8,052	8,052
Jamalco	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500
Jamaica Broilers												
Wigton												
Munro												
Renewable Projects												
Brigde Capacity 3 - 60MW Diesel									8,500	8,500	8,500	8,500
Total IPP Heat Rate	**8,211**	**8,268**	**8,152**	**8,161**	**8,136**	8,186	**8,171**	**8,171**	**8,167**	**8,168**	**8,169**	**8,169**
System Heat Rate kJ/kWh	**10,805**	**10,985**	**10,175**	**10,627**	**10,214**	10,561	**10,380**	**10,209**	**10,073**	**10,073**	**10,120**	**10,280**

JPS' System Historical and Projected MCR (MW)

Unit		2004 MCR (MW)	2005 MCR (MW)	2006 MCR (MW)	2007 MCR (MW)	2008 MCR (MW)	Avg MCRMW	2009 MCR (MW)	2010 MCR (MW)	2011 MCR (MW)	2012 MCR (MW)	2013 MCR (MW)	2014 MCR (MW)
Rockfort	1	18.00	18.00	18.00	18.00	18.00	18.00	18.00	18.00	18.00	18.00	18.00	**18.00**
	2	18.00	18.00	18.00	18.00	18.00	18.00	20.00	20.00	20.00	20.00	20.00	20.00
	Subtotal	**36.00**	**36.00**	**36.00**	**36.00**	**36.00**	**36.00**	**38.00**	**38.00**	**38.00**	**38.00**	**38.00**	**38.00**
Hunt's Bay	B6	68.50	68.50	68.50	68.50	68.50	68.50	68.50	68.50	68.50	68.50	68.50	68.50
	GT #4												
	GT #5	21.50	21.50	21.50	21.50	21.50	21.50	21.50	21.50	21.50	21.50	21.50	21.50
	GT #10	32.50	32.50	32.50	32.50	32.50	32.50	32.50	32.50	32.50	32.50	32.50	32.50
	Subtotal	**122.50**	**122.50**	**122.50**	**122.50**	**122.50**	**122.50**	**122.50**	**122.50**	**122.50**	**122.50**	**122.50**	**122.50**
Old Harbour	OH #1	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
	OH #2	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00
	OH #3	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00	65.00
	OH #4	68.50	68.50	68.50	68.50	68.50	68.50	68.50	68.50	68.50	68.50	68.50	68.50
	Subtotal	**223.50**	**223.50**	**223.50**	**223.50**	**223.50**	**223.50**	**223.50**	**223.50**	**223.50**	**223.50**	**223.50**	**223.50**
Bogue	GT #3	21.50	21.50	21.50	21.50	21.50	21.50	21.50	21.50	21.50	21.50	21.50	21.50
	GT #6	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00
	GT #7	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00
	GT #8	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00	14.00
	GT #9	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
	GT #11	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
	GT #12	38.00	38.00	38.00	38.00	38.00	38.00	38.00	42.00	42.00	42.00	42.00	42.00
	GT #13	38.00	38.00	38.00	38.00	38.00	38.00	38.00	42.00	42.00	42.00	42.00	42.00
	CCGT	38.00	38.00	38.00	38.00	38.00	38.00	38.00	40.00	40.00	40.00	40.00	40.00
	Bridge Capacity - 1												
	Bridge Capacity - 2												
	New Petcoke Plant												100
	Subtotal	**217.50**	**217.50**	**217.50**	**217.50**	**217.50**	**217.50**	**217.50**	**227.50**	**227.50**	**227.50**	**227.50**	**327.50**

Unit	2004 MCR (MW)	2005 MCR (MW)	2006 MCR (MW)	2007 MCR (MW)	2008 MCR (MW)	Avg MCRMW	2009 MCR (MW)	2010 MCR (MW)	2011 MCR (MW)	2012 MCR (MW)	2013 MCR (MW)	2014 MCR (MW)
Subtotal	**21.59**	**21.59**	**21.59**	**21.59**	**21.59**	**21.59**	**21.59**	**22.39**	**22.39**	**22.39**	**22.39**	**22.39**
JPSCo's Total	**621.09**	**621.09**	**621.09**	**621.09**	**621.09**	**621.09**	**623.09**	**633.89**	**633.89**	**633.89**	**633.89**	**733.89**
JEP	74.16	74.16	74.16	74.16	74.16	74.16	74.16	74.16	74.16	74.16	74.16	74.16
JEP-50			50.20	50.20	50.20	50.20	50.20	50.20	50.20	50.20	50.20	50.20
JPPC	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00	60.00
Jamalco	11.00	11.00	11.00	11.00	11.00	11.00	2.00	2.00	2.00	2.00	2.00	2.00
Jamaica Broilers	0.00	0.00	0.00	0.00	0.00	-	0.00	0.00	0.00	0.00	0.00	0.00
Wigton												
Munro												
Renewable Projects									6.40	6.40	6.40	6.40
Brigde Capacity 3 - 60MW Diesel									60.00	60.00	60.00	60.00
Import Sub Total	145.16	145.16	195.36	195.36	195.36	175.28	186.36	186.36	252.76	252.76	252.76	252.76
Total	766.25	766.25	816.45	816.45	816.45	796.37	809.45	820.25	886.65	886.65	886.65	986.65
Peak Demand (MW)	604.8	616.0	625.7	629.4	621.7	619.52	626.3	628.9	634.4	640.5	646.5	647.6
Reserve Margin (%)	26.7%	24.4%	30.5%	29.7%	31.3%	28.5%	29.2%	30.4%	39.8%	38.4%	37.1%	52.4%
Peak Growth Rate (%)	2.7%	1.9%	1.6%	0.6%	-1.2%	0.3%	0.7%	0.4%	0.9%	1.0%	0.9%	0.2%

JPS' System Historical and Projected Capacity Factor (%)

Plant	Unit	2004 %	2005 %	2006 %	2007 %	2008 %	Average %	2009 %	2010 %	2011 %	2012 %	2013 %	2014 %
	1	82%	64%	76%	17%	77%	63%	63%	63%	63%	63%	63%	63%
Rockfort	2	70%	76%	71%	70%	75%	72%	72%	72%	72%	72%	72%	72%
	Subtotal	**76%**	**70%**	**74%**	**44%**	**76%**	**68%**	**68%**	**68%**	**68%**	**68%**	**68%**	**68%**
	B6	60%	63%	36%	65%	67%	58%	58%	58%	51%	55%	56%	56%
	GT #4												
Hunt's Bay	GT #5	17%	23%	22%	26%	15%	20%	20%	15%	7%	7%	7%	7%
	GT #10	40%	36%	35%	35%	36%	36%	36%	11%	10%	10%	10%	11%
	Subtotal	**47%**	**49%**	**33%**	**50%**	**49%**	**46%**	**46%**	**38%**	**32%**	**35%**	**35%**	**36%**
	OH #1	63%	55%	34%	42%	24%	43%	39%	24%	20%	20%	20%	33%
	OH #2	39%	70%	52%	67%	51%	56%	51%	51%	40%	40%	45%	51%
Old Harbour	OH #3	64%	70%	60%	55%	60%	62%	55%	55%	45%	45%	50%	55%
	OH #4	67%	48%	67%	62%	65%	62%	60%	60%	58%	58%	58%	60%
	Subtotal	**58%**	**61%**	**56%**	**58%**	**54%**	**57%**	**53%**	**51%**	**44%**	**44%**	**47%**	**52%**
	GT #3	15%	19%	7%	18%	11%	14%	14%	8%	7%	7%	7%	8%
	GT #6	5%	11%	10%	11%	10%	9%	6%	6%	6%	6%	6%	6%
	GT #7	12%	15%	16%	12%	7%	12%	7%	7%	6%	6%	6%	6%
	GT #8	9%	12%	11%	10%	6%	9%	6%	6%	6%	6%	6%	6%
	GT #9	10%	17%	15%	17%	11%	14%	10%	10%	7%	7%	7%	9%
Bogue	GT #11	36%	58%	4%	9%	27%	27%	15%	7%	7%	7%	7%	9%
	GT #12	67%	68%	79%	73%	81%	74%	71%	71%	65%	66%	66%	66%
	GT #13	72%	64%	78%	71%	76%	72%	71%	71%	65%	66%	66%	66%
	CCGT	45%	22%	70%	67%	75%	56%	52%	52%	45%	47%	47%	47%
	Subtotal	**39%**	**38%**	**45%**	**43%**	**46%**	**42%**	**39%**	**39%**	**35%**	**36%**	**36%**	**25%**

Plant	Unit	2004	2005	2006	2007	2008	Average	2009	2010	2011	2012	2013	2014
		%	**%**	**%**	**%**	**%**	**%**	**%**	**%**	**%**	**%**	**%**	**%**
Subtotal		**71%**	**80%**	**90%**	**85%**	**84%**	**82%**	**82%**	**82%**	**82%**	**82%**	**82%**	**82%**
JPSCo's		51%	52%	50%	51%	53%	**48%**	49%	46%	41%	42%	43%	39%
JEP		66%	79%	71%	67%	60%	69%	69%	69%	60%	62%	63%	63%
JEP-50				73%	74%	76%	74%	70%	70%	60%	62%	63%	63%
JPPC		85%	85%	88%	83%	87%	86%	86%	86%	86%	86%	86%	86%
Jamalco			33%	30%	24%	15%	20%	85%	85%	85%	85%	85%	85%
Jamaica Broilers													
Wigton													
Munro													
Renewable Projects										30%	30%	30%	30%
Brigde Capacity 3 - 60MW Diesel										70%	70%	70%	65%
IPP		**71%**	**82%**	**78%**	**74%**	**73%**	**76%**	**78%**	**78%**	**70%**	**71%**	**72%**	**70%**
System		**55%**	**57%**	**56%**	**57%**	**57%**	**57%**	**55%**	**53%**	**50%**	**50%**	**51%**	**47%**

JPS' System Historical and Projected Unit Energy (MWh)

Plant	Unit	2004	2005	2006	2007	2008	Avg	2009	2010	2011	2012	2013	2014
		MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	**MWh**
Rockfort	1	129,635	101,063	119,749	27,434	122,095	99,995	99,995	99,995	99,995	99,995	99,995	99,995
	2	110,184	119,387	112,273	111,081	118,609	114,307	127,008	127,008	127,008	127,008	127,008	127,008
	Subtotal	239,819	220,451	232,022	138,515	240,704	214,302	227,003	227,003	227,003	227,003	227,003	227,003
Hunt's Bay	B6	361,821	378,644	217,947	390,592	399,988	349,798	348,035	348,035	307,634	330,033	336,803	336,803
	GT #4				-		-	-	-	-	-	-	-
	GT #5	32,263	42,853	40,907	48,461	27,693	38,435	37,668	28,251	13,184	13,184	13,288	13,184
	GT #10	115,005	102,204	98,443	99,578	101,138	103,274	103,274	31,317	27,093	27,093	28,470	31,317
	Subtotal	509,089	523,701	357,298	538,632	528,819	491,508	488,977	407,603	347,911	370,310	378,562	381,304
Old Harbour	OH #1	164,547	143,260	89,104	109,958	64,204	114,215	101,825	63,416	52,560	52,560	52,560	85,748
	OH #2	205,707	370,220	272,581	349,980	265,825	292,863	268,056	268,056	210,240	210,240	236,520	268,056
	OH #3	366,176	396,324	339,170	314,948	343,254	351,974	313,170	313,170	256,230	256,230	284,700	313,170
	OH #4	400,185	285,936	399,368	374,161	387,059	369,342	360,036	360,036	348,035	348,035	348,035	360,036
	Subtotal	1,129,842	1,189,268	1,093,908	1,142,112	1,052,679	1,128,393	1,043,087	1,004,678	867,065	867,065	921,815	1,027,010
Bogue	GT #3	28,885	35,039	14,109	33,529	19,889	26,290	26,290	15,848	13,184	13,184	13,184	15,067
	GT #6	5,681	13,114	12,380	14,023	12,513	11,542	7,358	7,358	7,358	7,358	7,358	7,358
	GT #7	14,681	18,924	19,048	14,636	8,160	15,090	8,585	8,585	7,358	7,358	7,358	7,358
	GT #8	11,143	14,772	13,139	11,834	7,271	11,632	7,358	7,358	7,358	7,358	7,358	7,358
	GT #9	17,240	29,998	26,133	30,297	19,652	24,664	17,520	17,520	12,264	12,264	12,264	15,768
	GT #11	62,234	101,176	7,727	15,143	48,171	46,890	26,280	12,264	12,264	12,264	12,264	15,768
	GT #12	223,634	226,783	261,724	243,547	268,989	244,935	236,345	261,223	239,148	242,827	242,827	242,827
	GT #13	238,837	212,297	260,914	235,691	252,430	240,034	236,345	261,223	239,148	242,827	242,827	242,827
	CCGT	148,715	74,049	233,964	222,147	248,178		173,098	182,208	157,680	165,921	165,921	165,921
	Subtotal	**751,050**	**726,152**	**849,138**	**820,847**	**885,251**	**621,077**	**739,179**	**773,588**	**695,763**	**711,362**	**711,362**	**720,254**

Plant	Unit	2004	2005	2006	2007	2008	Avg	2009	2010	2011	2012	2013	2014
		MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	MWh	**MWh**
Subtotal		**134,306**	**151,310**	**169,632**	**159,821**	**158,180**	**154,650**	**154,650**	**160,380**	**160,380**	**160,380**	**160,380**	**160,380**
JPSCo's Total		**2,764,105**	**2,810,881**	**2,701,998**	**2,799,927**	**2,865,632**	**2,609,930**	**2,652,895**	**2,573,252**	**2,298,122**	**2,336,120**	**2,399,122**	**2,515,951**
JEP		427,773	513,547	460,498	437,427	391,606	446,170	446,170	446,170	389,785	402,778	409,274	409,274
JEP-50		-	-	322,090	324,571	333,833	196,099	307,826	307,826	263,851	272,646	277,044	277,044
JPPC		445,499	446,211	462,644	436,729	456,704	449,558	449,558	449,558	449,558	449,558	449,558	449,558
Jamalco			31,750	29,103	23,023	13,987	24,466	14,892	14,892	14,892	14,892	14,892	14,892
Jamaica Broilers		-	-	-	-	-	-	-	-	-	-	-	-
Wigton		32,335	49,913	55,411	51,926	49,235	47,764	47,764	47,764	47,764	47,764	47,764	47,764
Munro						3	3	3	3	3	3	3	3
Renewable Projects									-	16,819	16,819	16,819	16,819
Brigde Capacity 3 - 60MW Diesel									-	367,920	367,920	367,920	341,640
Import Sub Total		**905,607**	**1,041,421**	**1,329,747**	**1,273,677**	**1,245,367**	**1,159,164**	**1,266,214**	**1,266,214**	**1,550,593**	**1,572,380**	**1,583,274**	**1,556,994**
Total		**3,669,712**	**3,852,302**	**4,031,745**	**4,073,604**	**4,111,000**	**3,947,673**	**3,919,109**	**3,839,466**	**3,848,714**	**3,908,500**	**3,982,396**	**4,072,945**
Growth Rate (%)		**-0.8%**	**5.0%**	**4.7%**	**1.0%**	**0.9%**		**3,928,616**	**3,848,973**	**3,858,221**	**3,918,007**	**3,991,903**	**4,082,452**

Annex G: Heat Rate Sensitivity Analysis

Fuel Price Effect on Heat Rate (kJ/kWh)					
IPP Availability 90%			JPS Availability 80%		
			JPS		
			Minimum	Average	Maximum
	JEP	JPPC	$5.64	$13.29	$20.15
Minimum	$9.40	$8.90	10,468	10,179	
Average	$15.41	$15.72		10,210	
Maximum	$19.99	$21.39		10,383	10,156

Effect of IPP Availability (*Average JPS Fuel Prices and Average IPP Fuel Prices*)					
			JPPC		
			Minimum	Average	Maximum
			71.80%	92.00%	99.50%
JEP Availability	Minimum	68.4%	10,665	10,557	10,520
	Average	79.3%	10,392	10,297	10,260
	Maximum	92.7%	10,255	10,167	10,130

Effect of IPP Availability (***Minimum** JPS Fuel Prices and **Minimum** IPP Fuel Prices*)					
			JPPC Availability		
			Minimum	Average	Maximum
			71.80%	92.00%	99.50%
JEP Availability	Minimum	68.4%	10,845		
	Average	79.3%			
	Maximum	92.7%			10,434

Effect of IPP Availability (***Maximum** JPS Fuel Prices and **Maximum** IPP Fuel Prices*)					
			JPPC Availability		
			Minimum	Average	Maximum
			71.80%	92.00%	99.50%
JEP Availability	Minimum	68.4%	10,619		
	Average	79.3%			
	Maximum	92.7%			10,082

Effect of IPP Availability (***Average** JPS Fuel Prices and **Minimum** IPP Fuel Prices*)					
			JPPC Availability		
			Minimum	Average	Maximum
			71.80%	92.00%	99.50%
JEP Availability	Minimum	68.4%	10,652		
	Average	79.3%			
	Maximum	92.7%			10,104

Effect of IPP Availability (***Average** JPS Fuel Prices and **Maximum** IPP Fuel Prices*)					
			JPPC Availability		
			Minimum	Average	Maximum
			71.80%	92.00%	99.50%
JEP Availability	Minimum	68.4%	10,772		
	Average	79.3%			
	Maximum	92.7%			10,333

Annex H: Depreciation Study

Introduction

The present document contains the results from the Depreciation Study following the definition of the appropriateness of the depreciation rates and testing the reasonability of the Asset Revaluation Process that JPS is currently carrying on.

Background

According to Schedule 3 (Section 2(C)) of the License, the Non-Fuel Base Rate is set based on the revenue requirement of a test year period. Further, the License stipulates that the revenue requirement shall include efficient non-fuel operating costs, depreciation expenses, taxes and a fair return on investment. Regarding the depreciation expenses, the License states that:

> ***"The depreciation component will be calculated by applying annual depreciation rates, as provided at Schedule 4, to the gross value of the individual plant asset accounts"***
>
> ***"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 net investment made by the Licensee in the 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 a…….."***

In the tariff study performed in 2004, the OUR accepted the accounting value of the fixed asset as "Rate Base" and the depreciation rates set forth in Schedule 4 were used to calculate depreciation. This is a summary of the method used in the accounting valuation of assets outlined in note 3 k of the Audited Balance Sheet 2007.

> ***"In accordance with the License, additions to property, plant & equipment and intangible assets, replacement of retirement units of plant in service, or additions to construction work-in-progress include direct labour, materials, professional fees and an appropriate charge for overheads, reduced by non-refundable contributions received from customers, where applicable. Specialized plant and equipment are revalued quarterly by management on the depreciated replacement cost basis using relevant industry indices (Handy-Whitman)[52] for equipment purchased abroad, with the foreign component of costs appropriately adjusted for movements in the Jamaica dollar and the local component of costs adjusted for movements in local inflation. Gains and losses on revaluation are initially recognized in capital reserve (see note 15) and transferred to retained earnings as realized. Land is stated at cost while buildings, general plant and machinery and other equipment are stated at cost less accumulated depreciation and impairment losses. Property, plant & equipment in the course of construction are carried at cost less recognized impairment losses. Intangible assets, comprising computer software, are stated at cost, less amortization and impairment losses".***

For this new tariff revision, JPS has requested QUANTUM this study aiming at assessing the reasonableness of the depreciation rates established in the License and the assets re-evaluation process which is currently used.

Executive Summary

Useful lives, depreciation methods, and asset valuation practices have been surveyed from Electric Utilities in 9 countries. The companies participating in the sample are located in

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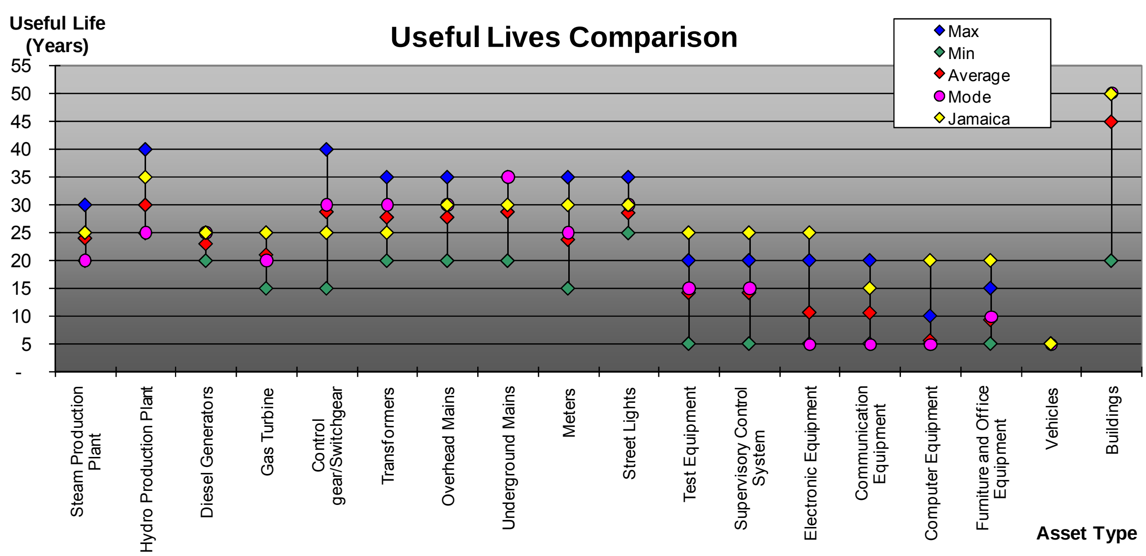
[52] **Handy Whitman, Baltimore**–This is a six-region average index for a reinforced concrete building, published by Whitman, Requardt and Associates. The index reflects materials prices for ready-mix concrete, lumber, steel bars, brick, concrete block and wages for laborers and six skilled trades. Handy-Whitman indexes also are available for electric, gas and water utilities. Published semi-annually

developing countries with the objective of comparing similar environments and homogeneous operating conditions.

The summary of the stats compared with Jamaica are the following:

Activity	Asset	Jamaica	Average	Mode	Max	Min	Jamaica - Sample Mode
Generation	Steam Production Plant	25	24	20	30	20	5
Generation	Hydro Production Plant	35	30	25	40	25	10
Generation	Diesel Generators	25	23	25	25	20	-
Generation	Gas Turbine	25	21	20	25	15	5
Transmission	Control gear/Switchgear	25	29	30	40	15	-5
Transmission	Transformers	25	28	30	35	20	-5
Distribution	Overhead Mains	30	28	30	35	20	-
Distribution	Underground Mains	30	29	35	35	20	-5
Distribution	Meters	30	24	25	35	15	5
Distribution	Street Lights	30	29	30	35	25	-
Distribution	Test Equipment	25	14	15	20	5	10
Distribution	Supervisory Control System	25	14	15	20	5	10
General Plant	Electronic Equipment	25	11	5	20	5	20
General Plant	Communication Equipment	15	11	5	20	5	10
General Plant	Computer Equipment	20	6	5	10	5	15
General Plant	Furniture and Office Equipment	20	9	10	15	5	10
General Plant	Vehicles	5	5	5	5	5	-
General Plant	Land - Leasehold	50					
General Plant	Buildings	50	45	50	50	20	-

Graphically, the above information can be presented as follows:



In general terms, Useful Lives applied in Jamaica show equal and higher values than the sample´s mode, with the exception of Control gear/Switchgear, Transformers and Underground Mains.

Many types of assets have the same useful life as the ones in the sample and special attention should be paid to those differing in 10 years or more with the sample´s mode. Quantum recommends adjusting the depreciation rates to the sample's mode presented in this study.

With respect to the Asset Base, the adjustment of historical values using the Handy Whitman Index represents the fluctuation of the capital costs involved in the different activities of an electric utility. QUANTUM considers that this methodology to evaluate the regulatory asset base applied currently by JPS provides a reasonable value.

Depreciation Methodologies

Depreciation can be defined as the measure of consumption in the useful economic life of an asset, due to the regular use, passage of time, inadequacy, obsolescence, changes in the art, etc. The depreciation of an electricity company reflects the loss in service value that cannot be restored by maintenance.

There are different methods to computing depreciation; therefore the selection of the method for regulatory matters must take into consideration a number of factors, such as:

- Efficient pricing: the regulated charges should provide a signal to the customers in relation to the scarcity of the resources used to provide network services.
- Efficient investment: the regulated charges should be those which provide the investors the incentive to invest in efficient long-lived assets that will be required to ensure the continuity and quality of service
- Efficient production: the regulatory regime should provide incentives to invest and operate in an efficient way, therefore operation, maintenance and construction should be provided at the least possible cost.
- Price stability and intergenerational equity: the regulatory depreciation should generate relatively stable charges over the long term and an equal inter temporal cost allocation between customers;
- Administrative simplicity: a regulatory depreciation should be the most simple, from the administrative point of view, as possible.
- Certainty and consistency: as possible, the approaches adopted from one regulatory period to the next, should be the same.

There are two main ways in which assets can be depreciated, the straight- line basis and the diminishing balance method, following they are briefly described:

- The straight line method of computing depreciation expenses, charges the same amount of depreciation for each year or accounting period over the service life of a plant item or a plant group. This methodology assumes that an asset's economic benefits are consumed in equal proportions over its useful life. This method is computed as shown below:
  $DeprecRate = \frac{1}{n}$, where n is the asset's useful life

This method allows the utility company to recover the capital cost of an asset in equal proportions over the assets life, reducing fluctuation of expenses from one period to the next. The asset cost is evenly spread between the present and future customer base, thus contributing to stable utility rates over time. This method is applied in most regulatory jurisdictions.

- The diminishing balance method, also known as "accelerated" depreciation, is based in the assumption that more of an asset's economic benefits are consumed in the earlier year of its useful life. This method allocates a greater part of the asset's costs in the early years of useful life, resulting in higher depreciations at the beginning of its life and lower in later years. The depreciation rate in each period is calculated upon the asset's net value, the prior year's accruals are deducted each year, obtaining a declining balance:
  $DeprecRate = 1 - \sqrt[n]{(residual\ \ value\ / \cos t)}$, where n is the asset's useful life

  This method results in the build-up of an excessive depreciation reserve, which creates a depressed net asset statement. In terms of utility rates, this method results in higher rates at the beginning of the asset life. The initial customer base bears more of an asset cost in comparison to the future customers.

Asset Base Methodologies

The asset base value is of great importance since it provides the base to calculate the return on capital. Due to the capital intensive nature of the utilities, the value of the asset base is the main contributor to the revenue requirement, therefore the tariff.

Regulatory asset base valuation methods can be classified into cost-based or value based. The *cost-based* methodologies include historic cost, indexed historic cost, replacement cost and depreciated optimized replacement cost.

The *value-based* methodologies include fair market value, net present value, deprival value and optimized deprival value. These methods have distinct advantages and disadvantages, they involve varying degrees of effort to calculate, and they offer significantly different estimates of the RAB give different incentives, differs in their pricing and investment signals. The selection of asset valuation method for use in regulatory decisions is based on the level of appropriateness for that regulated utility.

Following, the main methodologies applied to calculate the regulatory asset base are described:

<u>Cost Based</u>:

- Historic cost: This methodology values the regulatory asset base on the basis of the original cost of the asset. The historic cost is adjusted by accumulated depreciations.
    - *Advantages and Disadvantages*:
        - Is a simple method because of its administrative simplicity; is relatively inexpensive since the costs are stated in the Company's balance sheet; and its objective due to the fact that it relies on actual data.
        - It may understate asset prices in times of inflation and understate prices in times of technological change. The information may not be available or may be inadequate for assets purchased in past periods or transferred from other entities. This method is most suitable for short life assets or recently acquired assets.
- Indexed historic cost: This methodology parts from the historic cost and then the assets are adjusted by inflation as measured by consumer price index or some other industry-specific index. The accumulated depreciation is subtracted.
    - *Advantages and Disadvantages*:
        - This methodology shares most of the advantages and disadvantages of the original prices approach. By the application of indexation to reflect the effect of inflation, it does not under-estimate the values of the assets as well as their respective depreciation.
        - ***The main problem is centred in the representativeness of the index used to adjust the asset base in order to reflect the real changes in prices suffered by the assets***.
- Replacement cost: This methodology also has the name of modern equivalent asset (MEV). It values the regulatory asset base as the sum of the cost of currently replacing each asset with a similar asset, which provides the same services and capacity as the assets in existence. The estimates are adjusted by accumulated depreciation.
    - *Advantages and Disadvantages*:
        - Since the assets are evaluated at current values, it provides an incentive for efficient investment. The assets considered are those of newest technology and lowest cost to provide the service.
        - The main disadvantages involves that is a methodology in which is involved judgment and estimation, is more expensive to collect than historical cost information since it requires expert advice, it may lead to price instability if the technology and input prices are unpredictable.

- Depreciated optimized replacement cost: This methodology values the regulatory asset base with the replacement cost methodology, but considering “optimal assets”, considered as optimal those that most efficiently reproduce the capacity and service level of the existing assets. The optimization is developed to remove any inefficiency in the current asset configuration (i.e. duplication, exceeds of capacity and redundant assets). This methodology considers the depreciation of the assets.
    - *Advantages and Disadvantages*:
        - It provides an incentive for efficient investment.
        - The main disadvantages involves that is a methodology in which is involved judgment and estimation, is more expensive to collect than historical cost information since it requires expert advice, it may lead to price instability if the technology and input prices are unpredictable. The optimization process requires of expert advice to determine the optimal asset configuration.

<u>Value Based</u>:

- Fair market value: This method values the asset base as the addition of the prices that the firm would obtained by selling the assets in a competitive market. The valuation considers the next best alternative use of the asset.
    - *Advantages and Disadvantages*:
        - It uses the market to obtain the value of the current asset. The principle of next best alternative introduces the opportunity cost into the analysis.
        - The business is a very specialized one, and so are the assets, therefore there is not an active market for the assets (obtaining valuations that differ in correspondence to value given by other possible users).
        - Net present value: this method values the asset base as the addition of the discounted cash flows associated with each asset. There must be a prediction of the cash flow that the assets are expected to generate, and then discounting these amount to the present using an appropriate discount rate. If the value calculated is less than the fair market value, then this last one is used.
    - *Advantages and Disadvantages:*
        - Is complicated to define the future cash flows derived from a determined asset.
        - It generates a circularity problem, since the discount rate will determine the value of the asset base, which in turn determines the return on the regulatory asset vase.
- Deprival value: this methodology corresponds to the minimum loss the company would obtain if it was deprived from the revenues provided by each asset. If an asset must be replaced, the minimum loss corresponds to the cost of its replacement. When an asset would not be replaced, its value is determined referencing its earning capacity (recoverable amount). The recoverable amount is the present value of net cash inflows (from use or sale) attributable to the asset. In general terms, an asset would not be replaced when its recoverable amount is less than the replacement cost.

  $$DV_t = \min\{RC_t, EV_t\}$$

  Where:
  RCt = replacement cost of the asset

  $$EV_t = \max\{PV_t, NRV_t\}$$

  PVt = present value of future income streams; and
  NRVt = net realizable value, (e.g the value at which the asset can be sold)
    - *Advantages and Disadvantages*:
        - It provides information on the current value of the asset base.
        - Is sensitive to the precision and reliability of the asset allocation and cost calculation. It also generated circularity problems.

- Optimized deprival value: is a variant of the deprival method. It considers the most efficient method of providing the service if the asset is to be replaced. The formula is the same as the deprival value, except it uses the optimized replacement cost

  $$ODV_t = \min\{ORC_t, EV_t\},$$

  Where:

  ORCt = optimized replacement cost of the asset

  - *Advantages and Disadvantages*:
    - It provides information on the current value of the asset base as well as discouraging inefficient investments, since regulators will revalue inefficient assets down to their optimized replacement cost.
    - It request expert advice to develop the optimization process (higher costs and complexity). It also generated circularity problems.

Depreciation Study

Methodology

In order to assess the reasonableness of the depreciation rates established in the License, Quantum performed a benchmarking analysis of the useful life determined by the regulations of the following countries:

- Cameroon
- Brazil
- Argentina
- Bolivia
- Venezuela
- Colombia
- Dominican Republic
- El Salvador
- Guatemala

Panama and Peru were also analyzed but they were excluded from the sample due to the fact that they both use 30 years to depreciate all assets regardless of their class for regulatory matters.

The analysis has taken into consideration the typically regulated activities, Transmission and Distribution. Upon the same sample, information regarding regulatory asset base valuation has been sought in order to compare it to the methodology applied in Jamaica and to determine its reasonableness.

Depreciations

Information regarding depreciation methodologies followed by the different countries in the sample has been reviewed. A table that summarizes the information concerning the asset lives is presented below. It is a common practice to determine useful lives as multiples of 5. Therefore, in order to facilitate the analysis, the useful lives have been rounded to the closest multiple of 5. For Jamaica, the only one case of a useful live which is not a multiple of five is Vehicles, where a value of 7 is used.

Activity	Asset	Jamaica	Cameroon	Brazil	Argentina	Bolivia	Venezuela	Colombia	Dominican Republic	El Salvador	Guatemala
			Useful Life (years)								
Generation	Steam Production Plant	25	20	30	25	20	25				
Generation	Hydro Production Plant	35	30	40	25		25				
Generation	Diesel Generators	25	20	25	25	20	25				
Generation	Gas Turbine	25	15	20	25	20	25				
Transmission	Control gear/Switchgear	25	40				30	15		30	
Transmission	Transformers	25	30	20	35	30	30	25	20	30	30
Distribution	Overhead Mains	30	30	20	30	25	30	25	35	30	25
Distribution	Underground Mains	30		20	35	35	30	25	35	25	25
Distribution	Meters	30	20	25	25	30	25		35	15	15
Distribution	Street Lights	30	30		30	25	30		35	25	25
Distribution	Test Equipment	25			15	20	20	10		5	15
Distribution	Supervisory Control System	25			15	20	20	10		5	15
General Plant	Electronic Equipment	25	5		15	20	10	10	5	5	15
General Plant	Communication Equipment	15	5	5	15	15	20	10	5	5	15
General Plant	Computer Equipment	20	5	5	5	5	10	5	5	5	5
General Plant	Furniture and Office Equipment	20		10	10	15	10		5	5	10
General Plant	Vehicles	5	5	5	5	5	5		5	5	5
General Plant	Land - Leasehold	50									
General Plant	Buildings	50	50	50	50	40	50		50	20	50

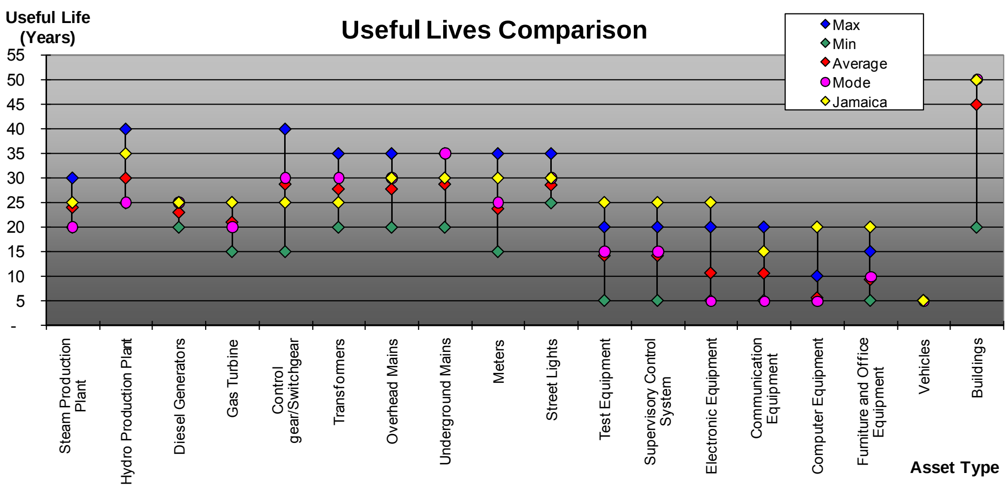
Integrating the information of the sample and the useful lives used by Jamaica, a chart that compares the asset lives of Jamaica with the sample's average, mode, maximum and minimum lives has been constructed[53].

Activity	Asset	Jamaica	Average	Mode	Max	Min	Jamaica - Sample Mode
Generation	Steam Production Plant	25	24	20	30	20	5
Generation	Hydro Production Plant	35	30	25	40	25	10
Generation	Diesel Generators	25	23	25	25	20	-
Generation	Gas Turbine	25	21	20	25	15	5
Transmission	Control gear/Switchgear	25	29	30	40	15	-5
Transmission	Transformers	25	28	30	35	20	-5
Distribution	Overhead Mains	30	28	30	35	20	-
Distribution	Underground Mains	30	29	35	35	20	-5
Distribution	Meters	30	24	25	35	15	5
Distribution	Street Lights	30	29	30	35	25	-
Distribution	Test Equipment	25	14	15	20	5	10
Distribution	Supervisory Control System	25	14	15	20	5	10
General Plant	Electronic Equipment	25	11	5	20	5	20
General Plant	Communication Equipment	15	11	5	20	5	10
General Plant	Computer Equipment	20	6	5	10	5	15
General Plant	Furniture and Office Equipment	20	9	10	15	5	10
General Plant	Vehicles	5	5	5	5	5	-
General Plant	Land - Leasehold	50					
General Plant	Buildings	50	45	50	50	20	-

Graphically, the above information can be presented as follows:

[53] Calculations involved in determining the average, mode, maximum and minimum lives do not consider Jamaica in the sample.

Activity	Asset	Jamaica	Cameroon	Brazil	Argentina	Bolivia	Venezuela	Colombia	Dominican Republic	El Salvador	Guatemala
			Useful Life (years)								
Generation	Steam Production Plant	25	20	30	25	20	25				
Generation	Hydro Production Plant	35	30	40	25		25				
Generation	Diesel Generators	25	20	25	25	20	25				
Generation	Gas Turbine	25	15	20	25	20	25				
Transmission	Control gear/Switchgear	25	40				30	15		30	
Transmission	Transformers	25	30	20	35	30	30	25	20	30	30
Distribution	Overhead Mains	30	30	20	30	25	30	25	35	30	25
Distribution	Underground Mains	30		20	35	35	30	25	35	25	25
Distribution	Meters	30	20	25	25	30	25		35	15	15
Distribution	Street Lights	30	30		30	25	30		35	25	25
Distribution	Test Equipment	25			15	20	20	10		5	15
Distribution	Supervisory Control System	25			15	20	20	10		5	15
General Plant	Electronic Equipment	25	5		15	20	10	10	5	5	15
General Plant	Communication Equipment	15	5	5	15	15	20	10	5	5	15
General Plant	Computer Equipment	20	5	5	5	5	10	5	5	5	5
General Plant	Furniture and Office Equipment	20		10	10	15	10		5	5	10
General Plant	Vehicles	5	5	5	5	5	5		5	5	5
General Plant	Land - Leasehold	50									
General Plant	Buildings	50	50	50	50	40	50		50	20	50



As it can be seen in many of the assets, the useful lives of JPS are above the modal value of the analyzed sample.

Asset Base Comparison

The following table compares the methodologies applied in each country analyzed to evaluate the regulatory asset base:

Country	Regulatory Asset Base valuation methodology
Jamaica	Indexed Historical Cost
Brazil	Optimized New Replacement Value
Argentina	Optimized New Replacement Value
Cameroon	Indexed Historical Cost
Venezuela	Indexed Historical Cost
Bolivia	Indexed Historical Cost
Dominican Republic	Optimized New Replacement Value
Guatemala	Optimized New Replacement Value

Some regulations are developing optimization methodologies for determining the Asset Base. However there is great controversy regarding the adequate technique and the relationship between the fair rate of return and the degree of risk associated to different optimization methods.

Indexed historical costs are widely used due to their transparency and simplicity in the asset determination. They provide a clear signal that incentives long term investment in capital intensive infrastructure.

Conclusions

Depreciation

From the analysis of the methodologies adopted in different countries with respect to regulatory depreciations, the conclusion is that straight line depreciation is a simple and uncomplicated method, that, captures the nature of the activity by the fact that considers the ability of the network components, that participate in the revenue generation, regardless of the age and, on the other hand, the risk of premature removal of network components (that would suggest the application of an accelerated depreciation methodology) is not of significance. The application of this methodology is recommended.

The asset's useful lives acquire vital importance for Electricity Utilities. If the useful life of the asset is too small, the depreciations will be higher, hence the investment levels and resulting asset base, will be overestimated. The contrary happens if the useful lives are set too high; this will result in a decreasing asset base.

Through the comparison of the useful lives adopted by other countries to calculate the regulatory depreciations, the lives used in Jamaica seem, in general terms, similar to the ones adopted in the countries of the sample. In some items, such as Steam Production Plant, Hydro Production Plant, Gas Turbines, Meters, Test Equipment, Supervisory Control System, Electronic Equipment, Computer Equipment, and Furniture and Office Equipment, it is observed that the useful lives used in Jamaica are superior to those used in other countries.

Regarding useful lives two recommendations can be made:

- ***In the Short term, adoption of the sample´s modal values is recommended.***
- ***In the Long Term, further analysis is recommended, comprising a statistical review of the replacements and retirements of these assets over a period of time, in order to support the usage of a shorter useful life***.

Asset Base

The asset base value is of great importance since it provides the base to calculate the return on capital. Due to the capital intensive nature of the utilities, the value of the asset base is the main contributor to the revenue requirement, therefore the tariff.

The main problem regarding the application of the indexed historic cost is choosing the correct index. The resulting asset base is usually underestimated for the long life assets and for those assets subject to technological change (software, computer devices, etc) it may over estimate the asset base.

In case the index used to express the asset base is representative and reflects the variation in the prices of the electricity assets that are part of the regulatory asset base, then the historical indexed asset base will adopt a value similar to the ODRC (optimized deprival replacement cost) methodology, with the additional benefit of these methodology that requires less resources and time to calculate it.

QUANTUM investigated the composition and usage of the Handy Whitman index. The Handy-Whitman cost index reflects the costs of different types of utility construction, including electric transmission and distribution. The cost index started in 1912, and is a widely recognized publication used by many entities in the utility industry, including regulatory bodies, operating bodies, and valuation engineering. The cost index conforms to FERC's classification and follows its categorization. Utilization of the Handy-Whitman index provides a yearly rate of increase for specific cost categories in the utility industry instead of a generic inflation rate such as the Consumer Price Index (CPI).

For example, the California Public Utilities Commission used this index to calculate the capital cost:

> ***"The proposed cost index for capital-related electric distribution costs is based on an estimate of the rental price of electric distribution utility structures, which is estimated from three data series obtained from DRI (Standard & Poor´s DRI): rental price of capital – non residential structures-public utilities); chain type price index - investment in non-residential structures - public utilities, and the Handy-Whitman electric utility construction cost index -total distribution plant, Pacific Region."***

Similar is the case of the Public Service Commission of Wisconsin which considers the adjustment of the construction investment costs through the application of the "Handy-Whitman Index of Public Utility Construction Costs, Cost Trends of Electric Utility Construction - North Central Region for Total Transmission Plant". This Commission determinates that If the referenced Handy-Whitman Index is no longer available, an equivalent successor index may be used which is generally recognized by the electric industry and acceptable to the commission.

The State of Vermont Public Service Board also admits the usage of the Handy Whitman cost index for utility construction, considering the adjustment of indirect costs by US CPI. (Since the Handy-Whitman index does not provide information on the Indirect costs).

Since this index represents the fluctuation of the capital costs involved in the different activities of an electricity utility, QUANTUM considers that the methodology to evaluate the regulatory asset base applied currently by JPS provides a reasonable value.

Annex I: X-Factor and Q-Factor Study

1. INTRODUCTION AND SUMMARY

1.1 Introduction

The non-fuel rates of Jamaica Public Service (JPS) will be subject to a performance based ratemaking mechanism (PBRM). The main features of this PBRM are detailed in the *Jamaica Gazette Extraordinary* (April 12, 2001). According to Exhibit One of this *Gazette*, the PBRM will restrict the growth in JPS' non-fuel base rates according to the following formula:

$$dPCI = dI \pm X \pm Q \pm Z \qquad [1]$$

Here, dPCI refers to the maximum allowed change in non-fuel electricity prices, dI is the annual growth in an inflation and exchange rate devaluation measure, 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 reflect changes in the quality of service provided to customers, and Z is the allowed rate of price adjustment for special cost pressures not captured by other elements of the formula.

The *Gazette* further describes how the X factor is to be calculated. It says "the X-Factor is based on the expected productivity gains of the Licensed Business (*i.e.* JPS). The X-Factor is to be set to equal the difference in the expected total factor productivity growth of the Licensed Business and the general total factor productivity growth of firms whose price index of outputs reflects the price escalation measure dI." The current dI measure applies a 24% weight to a Jamaican inflation index and a 76% weight to US inflation and corresponding changes in the US-Jamaica exchange rate. Appropriate measures of total factor productivity (TFP) growth for JPS, the Jamaican economy and the US economy are therefore critical for calibrating the terms of the PBRM. Indeed, the *Gazette* mandates that a filing supporting the application of the PBRM must include "a total factor productivity study used in determining the appropriate level of the X factor" (Schedule 3, Par. 3 (B)).

JPS has retained Pacific Economics Group, LLC ("PEG") to provide such a TFP study and to make recommendations on appropriate X and Q factors for JPS. PEG is well-positioned to undertake this research. PEG is the leading US consultant on performance-based regulation (PBR) for energy utilities and provider of energy industry productivity studies. Our personnel have testified many times on productivity and related benchmarking issues in North America. We also prepared a TFP and benchmarking study for JPS in conjunction with the initial PBRM approved for the Company in 2004. The results of our research for JPS can be briefly summarized.

1.2 Summary of Research

1.2.1 Total Factor Productivity for JPS

A total factor productivity ("TFP") index is the ratio of an output quantity index to an input quantity index. It is used to measure the efficiency with which firms convert production inputs to outputs. The growth trend of a TFP trend index is the difference between the trends in output and input quantity indexes.

We calculated the TFP trend of JPS in the provision of power generation, transmission, distribution and retailing services. Our output quantity index for JPS included trends in the number of customers served, MWh volumes delivered, and MW of peak demand. Our input quantity index summarized trends in capital and operation and maintenance (O&M) inputs JPS used to provide these outputs. All fuel and purchased power costs were excluded from costs and inputs since the PBRM applies only to non-fuel base rates, so only non-fuel inputs should be included in TFP studies used to set the terms of the PBRM.

Established methods and the best available data were used to estimate TFP trends for JPS. The sample period was 1990-2007. This represents the longest period for which we can estimate the Company's TFP, given the available data from JPS. PEG estimates that JPS' TFP in the provision of non-fuel, bundled power service grew at an average rate of 0.74% per annum over the 1990-2007 period. However, TFP grew at a more rapid rate of 1.94% over the more recent 2001-2007 period, primarily because JPS has been more effective at restraining input quantity growth in recent years.

1.2.2 Total Factor Productivity for the US and Jamaican Economies

The US government regularly measures TFP growth in the US economy. The most comprehensive such measure is the multifactor productivity (MFP) index of the US private business economy, as computed by the Bureau of Labor Statistics (BLS) of the US Department of Labor. The BLS updates this MFP measure annually. From 1990 through 2007, US non-farm, private business sector MFP grew at an average annual rate of 1.04%. The comparable growth rate over the 2001-2007 period was 1.53%.

There are no comparable, official estimates of TFP growth for the Jamaican economy. PEG developed estimates of TFP growth in Jamaica until 2002 using a standard growth accounting framework and data developed both within and outside of the country. PEG's research shows that TFP growth in Jamaica has been extremely variable. This, in turn, reflects the sharp fluctuations in the Jamaican economy over the past four decades. For example, the country experienced steady economic and TFP growth in the 1960s and early 70s, but economic performance was severely impacted by the 1970s' oil price shocks. The economy generally recovered in the 1980s, except for a recession in 1984-85, but economic and TFP growth since 1990 have been weak. Recent reports by other analysts also indicate that Jamaica's recent TFP growth has been weak, but it was not possible for PEG to estimate TFP for the country after 2002 because of the lack of available data.

These economic gyrations complicate the estimation of Jamaica's long-term TFP trends and the country's expected productivity growth during the term of the PBRM (2004-2009). Given the country's recent poor performance for TFP growth, we believe a reasonable estimate for Jamaica's TFP growth over the term of the PBRM is zero percent. This is actually greater than the TFP declines the country has recently experienced, but we do not believe it is reasonable to forecast that TFP will continue to decline indefinitely.

1.2.3 Benchmarking JPS' Non-Fuel Cost Performance

The PBRM should be calibrated on the basis of "expected" productivity growth, and future TFP growth may differ from past TFP trends. This would especially be expected if a utility has been relatively inefficient in the past. A company would then have more ability to boost TFP growth by eliminating inefficient practices. PEG evaluated JPS' non-fuel cost efficiency using econometric cost modelling. This benchmarking approach compares JPS to *average* efficiency levels in the electric power industry.

Guided by economic theory, PEG developed an econometric model in which the cost of non-fuel, bundled power services is a function of some quantifiable business conditions. The parameters of the model were estimated statistically using data on the historical costs of 41 US investor-owned US electric utilities and the business conditions they faced. The sample period used to estimate the econometric cost model was 1991 to 2006. All key parameters were plausibly signed and, in most cases, highly significant.

We used the model to predict the average non-fuel cost of bundled power services for JPS given the business conditions that it faced. The Company was found to face some challenging conditions in its efforts to contain cost. For example, JPS is not a combined gas and electric utility. JPS has very low volumes per customer served. The Company also faces high prices for capital services.

PEG compared JPS' actual non-fuel costs with those predicted by the econometric model. We found that JPS' non-fuel cost was about 28% below the value predicted by the econometric cost model over the 2003 to 2007 period. This compares with a non-fuel cost for JPS that was only .7% less than the value predicted for the 1999-2002 period. Both differences were not statistically significant; the reason is that JPS differs substantially from the average US electric utility, and these differences in business conditions tend to increase the confidence intervals around any cost prediction for the Company, thereby making it more difficult to obtain statistically significant results. Nevertheless, a comparison of JPS' benchmarking results for the 1999-2002 and 2003-2007 periods indicate that the Company has made substantial efficiency improvements in recent years. This benchmarking evidence is broadly consistent with the substantial TFP gains for the Company since 2003. The large efficiency gains that JPS has already made suggest that there is limited ability for the Company to make significant *incremental* TFP gains during the next PBRM.

1.2.4 X-Factor Implications

The X-Factor in the PBRM is to be equal to the difference in expected TFP growth for JPS and the general TFP growth of firms whose price index of outputs reflects the price escalation measure dI. PEG believes the best estimate for JPS' long-term TFP growth rate is 1.94% per annum, or the Company's average TFP growth since 2001. Since the inflation measure *dI* is based on economy-wide inflation trends in the US and Jamaica, the latter TFP growth rate is a weighted average of TFP growth trends for the US and Jamaican economies. PEG estimates that the long-run TFP growth trend of the US economy for the 2001-07 period is 1.53% and the best estimate for TFP growth for the Jamaican economy is zero. The weights specified in the PBRM for US and Jamaican inflation are 0.76 and 0.24, respectively. Overall TFP growth for firms whose output price indexes are reflected in the price escalation measure is therefore 1.16% (*i.e.* 0.76*1.53% + 0.24*0% = 1.16%). The "baseline" TFP differential based on historical TFP experience is therefore 0.78%, or 1.94% minus 1.16%.

PEG's research also shows that JPS has made substantial improvements in its non-fuel cost performance in recent years and has a limited ability to make incremental TFP gains. When setting X factors, regulators often add "stretch factors" to historical TFP differentials in the expectation that productivity growth will accelerate when companies become subject to stronger performance incentives under PBR. The average stretch factor in North American index-based PBR plans is 0.5%. Given PEG's evidence that the Company has registered substantial productivity gains in recent years, we believe the maximum stretch factor that should be approved for JPS is 0.5%. However, since there is always an element of judgment involved in selecting a stretch factor, we believe a stretch factor value between 0 and 0.5% would be reasonable for the next PBRM. When these stretch factors are added to the estimated TFP differential, this leads to an appropriate range of X factor values of between 0.78% and 1.28%. PEG has (for simplicity) rounded up this range of reasonable X factors to be between 0.8% and 1.3%, which is very similar to the range of approved X factors in many PBR plans.

1.2.5 Q-Factor Implications

PEG was also asked to analyze and make recommendations for the Q-factor that will be in effect during the next PBRM. We strongly recommend that this updated Q-Factor eliminate CAIDI as a quality indicator. Including CAIDI when SAIFI and SAIDI are part of the same service quality incentive can only lead to perverse penalties or rewards. We also believe that there are significant uncertainties regarding an appropriate benchmark for MAIFI. We accordingly recommend that MAIFI simply be monitored, rather than subject to explicit penalties or rewards, in the next PBRM. We also believe more attention should be devoted to understanding customers' willingness to pay for quality improvements, including the willingness to pay for reductions in MAIFI. More knowledge of customer preferences can help JPS make appropriate investments and ensure that any quality improvements actually improve customer welfare.

2. TFP RESEARCH FOR JPS

This section presents an overview of our work to calculate the TFP trend of JPS. The discussion is largely non-technical. Additional and more technical details of the research are provided in Appendix One.

2.1 Data

At the commencement of the project, PEG requested data on JPS operations necessary for TFP and benchmarking research. For all variables, PEG asked for as long a time series as was available. Below we list the main JPS data series provided by the Company.

Data Series	Period provided	Periodicity
1. Customer numbers, by rate class	1990-2007	Annual
2. MWh deliveries, by rate class	1990-2007	Annual
3. Gross and net MWh generation, by station	1990-2007	Annual
4. IPP purchases (MWh)	1990-2007	Annual
5. IPP costs (including capacity and fuel costs)	1990-2007	Annual
6. Peak demand and available capacity	1990-2007	Annual
7. Payroll costs (salaries and benefits)	1990-2007	Annual
8. Permanent and total employees	1983-2007	Annual
9. Total operation and maintenance costs	1990-2007	Annual
10. Operation and maintenance costs	1990-2007	Annual
11. Gross and net fixed capital stock	1990-2007	Annual
12. Total fuel and purchased power costs	1990-2007	Annual
13. Total km transmission & distribution lines	2002-2007	Annual
14. MVA transformer capacity (by substation)	2003-2007	Annual

Data was only available on most series beginning in 1990. JPS was not able to provide labour or detailed operation and maintenance (O&M) cost prior to 1998.

2.2 Indexing Details

2.2.1 Scope

Cost figures play an important role in our productivity trend research. The applicable total cost was calculated as JPS' operation and maintenance ("O&M") expenses plus the cost of electric plant ownership. Electric O&M expenses are defined as the total O&M expenses of JPS less any expenses incurred for fuel, including the fuel costs in purchased power contracts.

There were two components of JPS' capital costs. The first is the cost of capacity payments in purchased power contracts to IPPs. These capacity payments are reflected in JPS non-fuel base rates subject to the PBRM, so they should be similarly reflected in any TFP measure used to implement the PBRM.

The second component of capital cost is derived from the net book value (NBV) of JPS assets. These data were provided annually from 1990 through 2007. The Company computes NBV in each year by adding gross plant additions to the previous year's capital stock, as adjusted by depreciation and inflation. This method essentially computes a replacement cost value for JPS capital (net of depreciation).

However, in 1997 there was a significant downward adjustment in the NBV of JPS capital. This downward adjustment reflected a government policy decision not to allow JPS to recover all the costs of its past capital investment. This, in turn, was motivated by efforts to reduce the growth in bundled power prices to JPS customers.

Costs associated with this downwardly adjusted capital stock are currently reflected in JPS non-fuel base rates. We therefore refer to this adjusted NBV as the regulatory asset base. Since these regulatory assets are reflected in non-fuel base rates that will be subject to the PBRM, it is appropriate to use the regulatory capital value when computing JPS' TFP growth. It should be noted, however, that the 1997 adjustment effectively drives a wedge between the regulatory and replacement values of JPS assets. In PEG's benchmarking work, the latter value is more relevant when comparing JPS to US electric utilities. We discuss this further in Chapter Four.

2.2.2 Input Quantity Index

In constructing the input quantity index, we decomposed cost into two input categories: capital services and O&M inputs. The growth rate in the input quantity index was a weighted average of the growth rates in quantity sub indexes for capital and O&M inputs. The weights were based on the shares of these input classes in the JPS' total non-fuel cost. Because of the lack of historical data on the components of O&M spending, it was not possible to decompose O&M inputs into labour inputs and non-labour O&M inputs.

Real O&M input quantities were constructed each year by deflating nominal O&M costs by the Jamaican CPI. The study used a service price approach to capital cost measurement. Under this approach, the cost of capital is the product of a capital quantity index and the price of capital services. The quantity of capital is therefore equal to the measured capital cost described in Section 2.2.1 divided by the capital service price. This method has a solid basis in economic theory and is well established in the scholarly literature. Details of our capital cost methodology are presented in Appendix One.

2.2.3 Output Quantity Index

Growth in the output quantity index was a weighted average of growth in the number of customers served, KWh volumes delivered, and peak demand. Weights were based on the cost elasticities for each output from our econometric research. This research is described in Chapter Four.

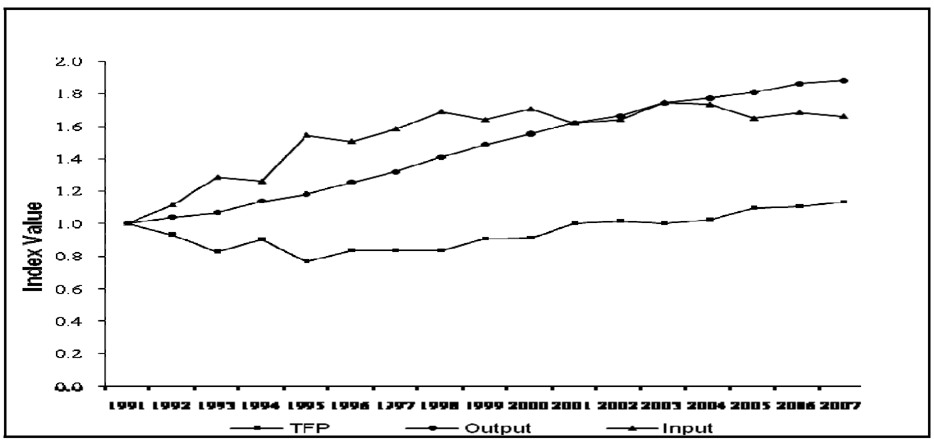
2.3 Index Results

The growth rate in the TFP index was the difference between the growth rates in JPS output and input quantity indexes. Table 1 and Figure 1 report the 1990-2007 average annual growth rates in the TFP and component output and input quantity indexes for JPS. It can be seen that the TFP trend for JPS was 0.74% per annum. Output quantity grew at an average annual rate of 3.77% over the sample period. This outpaced input quantity growth, which grew at an average rate of 3.03% per annum.

Table 1: TFP Results

Year	TFP	Output	Input
1991	1.000	1.000	1.000
1992	0.932	1.038	1.114
1993	0.828	1.065	1.286
1994	0.900	1.135	1.262
1995	0.764	1.180	1.544
1996	0.834	1.256	1.507
1997	0.834	1.318	1.581
1998	0.833	1.408	1.690
1999	0.907	1.487	1.640
2000	0.909	1.551	1.707
2001	1.001	1.622	1.620
2002	1.013	1.662	1.641
2003	0.998	1.743	1.745
2004	1.022	1.772	1.734
2005	1.096	1.808	1.649
2006	1.105	1.861	1.685
2007	1.132	1.881	1.661
Average Annual Growth Rate:			
1990 - 2007	0.74%	3.77%	3.03%
1990 - 2001	0.12%	4.62%	4.50%
2001 - 2007	1.94%	2.15%	0.21%

Figure 1: TFP Results: JPS



However, TFP, output quantity and input quantity trends have differed substantially over sample sub-periods. It can be seen that TFP grew at an average annual rate of 0.12% over the 1990-2001 period, but accelerated to 1.94% per annum over the 2001-2007 period. JPS was able to increase its TFP growth in recent years because it has contained the growth in its input quantities; input quantity grew at an average annual rate of 3.03% in the 1990-2001 period, but was almost flat (only 0.21% annual growth) between 2001 and 2007. Output growth also declined over these periods, from 4.62% annual growth between 1990 and 2001 to less than half this rate (2.15%) between 2001 and 2007. All else equal, this decline in output growth contributed to slower TFP growth, and JPS was able to boost its TFP only because it reduced its input quantity more rapidly than the decline in its output.

Table 2: Output Quantity Index

Year	Output Quantity	Number Customers	Volume (kWh)	Maximum Demand (MW)
1991	1.000	1.000	1.000	1.000
1992	1.038	1.040	1.035	1.044
1993	1.065	1.087	1.042	1.075
1994	1.135	1.141	1.126	1.160
1995	1.180	1.203	1.158	1.190
1996	1.256	1.258	1.248	1.289
1997	1.318	1.322	1.316	1.310
1998	1.408	1.382	1.430	1.421
1999	1.487	1.439	1.517	1.582
2000	1.551	1.491	1.606	1.565
2001	1.622	1.549	1.686	1.661
2002	1.662	1.589	1.728	1.685
2003	1.743	1.629	1.844	1.801
2004	1.772	1.691	1.838	1.837
2005	1.808	1.729	1.872	1.871
2006	1.861	1.801	1.912	1.901
2007	1.881	1.835	1.919	1.912
Annual Average Growth Rate:				
1990 - 2007	3.77%	3.62%	3.89%	3.87%
1990 - 2001	4.62%	4.21%	4.97%	4.74%
2001 - 2007	2.15%	2.50%	1.82%	2.19%

Table 2 displays details of the growth in the output quantity index. Over the entire 1990-2007 sample period, it can be seen that customer numbers increased at an average annual rate of 3.62%. Volumes delivered to customers increased more rapidly, at an average rate 3.89% per annum, while peak demand grew by an average of 3.87% per annum. These data show that volumes and demand per customer increased modestly over the sample period.

There are again sharp differences in the sub-periods of the sample. Between 1990 and 2001, customers grew at an average rate of 3.62% per annum, but average customer growth declined to 2.5% annually between 2001 and 2007. The declines in delivery volumes and MW demand were even more profound. Importantly, volumes and demand per customer have declined modestly since 2001, which reverses the previous trend of increasing average use per customer. With higher fuel prices and increasing emphasis on energy conservation throughout the world, the much slower growth in output quantity since 2001 is likely to be more representative of JPS' future output trends than the more rapid output quantity expansions registered between 1990 and 2001.

Table 3: Input Quantity Index

Year	Input Quantity	O&M Inputs	Capital Inputs: Total Capital	JPS Capital	IPP Capacity
1991	1.000	1.000	1.000	1.000	
1992	1.114	1.221	1.005	1.005	
1993	1.286	1.115	1.448	1.448	
1994	1.262	1.275	1.264	1.264	
1995	1.544	1.412	1.671	1.429	1.000
1996	1.507	1.313	1.685	1.206	1.976
1997	1.581	1.214	1.913	1.258	2.702
1998	1.690	1.591	1.774	1.193	2.401
1999	1.640	1.312	1.942	1.327	2.537
2000	1.707	1.376	2.011	1.333	2.800
2001	1.620	1.372	1.846	1.327	2.144
2002	1.641	1.353	1.903	1.258	2.665
2003	1.745	1.417	2.046	1.412	2.617
2004	1.734	1.361	2.077	1.526	2.274
2005	1.649	1.292	1.977	1.462	2.125
2006	1.685	1.384	1.961	1.435	2.174
2007	1.661	1.378	1.921	1.387	2.205
Average Annual Growth Rate:					
1990 - 2007	3.03%	1.91%	3.90%	1.95%	6.20%
1990 - 2001	4.50%	2.75%	5.85%	2.08%	14.00%
2001 - 2007	0.21%	0.31%	0.16%	1.70%	-3.29%

Table 3 shows details of the growth in the input quantity index. Over the entire sample period, it can be seen that O&M inputs grew at an average annual rate of 1.91%. However, O&M inputs grew at a 2.75% annual rate between 1990 and 2001, but at only a 0.31% annual rate since 2001. Similar trends are evident for capital inputs. JPS capital grew at an average annual rate of 5.85% between 1990 and 2001, but by only 0.16% per annum between 2001 and 2007.

There are sharply different trends in JPS' own capital inputs and in generation capacity purchased from IPPs. Capacity purchases from IPPs grew at a rate of over 6% per annum from 1995 to 2007 (these purchases were close to zero before 1995). JPS' own capital input increased at an average rate of 1.95% per annum over the entire 1991-2007 period. There was a large increase in capital inputs in 1993, which was the year following the installation of the #8 and #9 units at the Bogue generating station. Since that time, there has been a small decline in the real value of JPS capital inputs, as inflation in the price of JPS capital inputs has grown more rapidly than the NBV of JPS capital (expressed in J$).

3. TFP RESEARCH FOR THE US AND JAMAICAN ECONOMIES

As discussed, the X factor used in the PBRM is to be equal to the difference between expected TFP growth for JPS "and the general total factor productivity growth of firms whose price index of outputs reflects the price escalation measure *dI*." The price escalation measure depends on inflation measures for the US economy and the Jamaican economy. It is therefore necessary to obtain information on these economies' TFP trends to determine the X factor in the PBRM. We turn next to PEG's research on economy-wide TFP trends for these countries.

3.1 TFP Growth in the US Economy

The US government regularly measures TFP growth for the US economy. The most comprehensive such measure is the multifactor productivity (MFP) index of the US private business economy. This is computed by the Bureau of Labor Statistics (BLS) of the US Department of Labor. The BLS updates this MFP measure annually and also estimates MFP growth for certain sectors of the US economy.

Table 4: US MFP Trends

	Private Business
Year	US TFP[1]
1990	92.0
1991	91.4
1992	93.5
1993	93.8
1994	94.5
1995	94.5
1996	95.9
1997	96.5
1998	97.8
1999	98.8
2000	100.0
2001	100.1
2002	101.8
2003	104.3
2004	106.8
2005	108.6
2006	109.0
2007	109.7
Average Annual Growth Rate:	
1990-2007	1.04%
1990-2001	0.77%
2001-2007	1.53%

[1] Multifactor Productivity, Private non-farm business **sector**, BLS.

Table 4 presents data on BLS data for US MFP growth. These data show that, from 1990 through 2007, the MFP of the US private, non-farm business sector grew at an average annual rate of 1.04%. However, as we have seen, there are very different growth rates in TFP for JPS over this same sample period. When setting the X factor, the appropriate sample period to use for calculating JPS' TFP growth may therefore differ from the entire 1990-2007 period for which data are available. In this situation, it may also be appropriate to use a MFP growth rate for the US economy that is calculated over the same period that is used to estimate TFP for JPS. Table Four shows that US MFP growth averaged 0.77% between 1990 and 2001. In contrast, US MFP grew at an average annual rate of 1.53% between 2001 and 2007.

3.2 TFP Growth in the Jamaican Economy

Unlike the US, there are no official estimates of TFP growth for the Jamaican economy. PEG's research was also not able to identify any economy-wide TFP studies that have been done for Jamaica.[54] We therefore had to develop our own estimate of economy-wide TFP growth for Jamaica.

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[54] However, we are aware of one study that developed TFP estimates for broader economic regions that apparently included Jamaica. This TFP research appears in Nehru, Vikram and Ashok Dhareshwar, "A New Database on Physical Capital Stock: Sources, Methodology and Results," *Revista de Analisis Economico*, June 1993, 37-61. As we discuss later, Nehru and Dhareshwar develop historical capital stock data for Jamaica as well as many other countries, and this paper use these capital stock data to develop TFP estimates for economic regions. Presumably

PEG used a standard "growth accounting" framework for estimating Jamaica's TFP growth.[55] TFP growth was defined as the following

$$T\dot{F}P = \dot{Y} - \alpha\dot{K} - \beta\dot{L} \qquad [2]$$

Here, $\dot{Y}$ refers to the change in economy-wide output, $\dot{K}$ refers to the change in economy-wide capital input, and $\dot{L}$ is the change in economy-wide labour input. The α and β are the elasticities of output with respect to capital and labour input, respectively. PEG assumed that these elasticities were equal each factor's share of national income, which is common practice in economy-wide TFP studies. PEG estimated these income shares using data on National Income and Employee Compensation from the Statistical Institute of Jamaica. Income to capital was simply equal to the difference between national income and labour compensation. Using 1993-2001 data, PEG estimates that labour's average share of Jamaican income was 52% and capital's average share was 48%.[56] Therefore β was equal to 0.52 and α was equal to 0.48.

We measured output growth for Jamaica as the growth in real GDP. Labor input was measured as total employment in Jamaica by workers over age 14. Data on both variables came from the Statistical Institute of Jamaica.

Our measure of the country's capital stock came from research published by Vikram Nehru and Ashok Dhareshwar, both economists at the World Bank.[57] Nehru and Dhareshwar developed a (inflation-adjusted) capital stock series for Jamaica for the 1950 to 1990 period. The value of the capital stock was expressed in Jamaican dollars. PEG extended this capital stock series through 2002 through a perpetual inventory equation, where the real value of the country's capital additions was added in each year to the depreciated value of the previous year's capital stock. This equation is expressed below.

$$XK_t = (1 - d) \cdot XK_{t-1} + VI_t \, . \qquad [3]$$

Here, the parameter d is the depreciation rate and VI_t is the real value of Jamaica's capital additions. Nehru and Dhareshwar used a depreciation rate of 4%, and this value was also assumed in the equation above. Capital additions were measured as each year's gross fixed capital formation, as detailed in Jamaica's National Income Accounts. These data were available from the Statistical Institute of Jamaica.

Using these data and methods, PEG computed TFP growth in the Jamaican economy in each year from 1962 through 2002. Table Five presents data on TFP growth in each of these years. This table also presents annual changes in the output quantity (*i.e.* real GDP) and each of the input

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the "Latin American" region in this paper would contain Jamaica, although Nehru and Dhareshwar do not identify which countries comprise each of their regions.

[55] For example, see Nehru and Dhareshwar, *op cit*, p. 53.

[56] By way of contrast, in the US, labor typically accounts for about 70% of national income and capital accounts for about 30%. The higher labor share in the US seems reasonable, for it is widely believed that higher returns to capital are required in Jamaica vis-à-vis the US.

[57] See Nehru and Dhareshwar, *op cit*. We also investigated two alternative sources of capital stock data for Jamaica. One comes from the well-known Penn World Tables, developed by Alan Heston and Robert Summers; the other was developed by William Easterly and Ross Levine and is described in a Working Paper for the Central Bank of Chile, *It's Not Factor Accumulation: Stylized Facts and Growth Models* (Central de Chile, Documentos de Trabajo No. 164, June 2002). Like the Nehru and Dhareshwar dataset, capital stock series in each of these studies ends in 1990. We decided not to use the capital data developed in either of these reports since the details of data construction were not as explicit as in Nehru and Dhareshwar, which made it impossible to extend the capital series beyond 1990 using Jamaican data.

quantities (labour and capital). Since labour input data were only available since 1972, we assumed that labour input grew at the average annual rate over the 1972-2002 period in each year for which we had no data.

Table 5: Jamaica TFP Results

Year	TFP Growth	GDP Growth	Labor Input Growth	Capital Input Growth
1962	-0.10	1.95	0.80	3.4
1963	0.88	2.69	0.80	2.89
1964	5.90	8.23	0.80	3.99
1965	4.90	7.49	0.80	4.53
1966	1.16	3.84	0.80	4.73
1967	-0.52	2.52	0.80	5.45
1968	2.09	5.88	0.80	7.01
1969	2.65	6.30	0.80	6.72
1970	3.63	7.45	0.80	7.09
1971	1.36	4.28	0.80	5.22
1972	5.12	7.56	0.80	4.21
1973	-0.64	2.75	1.67	5.23
1974	-10.03	-6.04	4.56	3.38
1975	-3.91	-0.71	2.56	3.89
1976	-7.30	-6.47	0.24	1.46
1977	-2.79	-2.40	0.97	-0.25
1978	-0.56	0.72	2.46	0.01
1979	-0.91	-1.84	-1.62	-0.18
1980	-6.69	-5.90	2.49	-1.06
1981	0.45	2.52	4.45	-0.51
1982	1.11	1.23	0.15	0.1
1983	1.47	2.27	1.49	0.03
1984	-3.18	-0.89	4.81	-0.44
1985	-4.66	-4.73	0.35	-0.51
1986	-0.45	1.68	4.86	-0.83
1987	6.05	7.67	2.98	0.14
1988	0.11	2.16	3.08	0.95
1989	5.39	6.80	1.06	1.8
1990	4.46	6.11	1.71	1.58
1991	0.21	0.83	1.29	-0.1
1992	1.42	1.65	-0.24	0.72
1993	1.51	1.95	0.07	0.85
1994	-2.72	0.88	6.32	0.67
1995	0.96	1.03	-0.22	0.37
1996	-1.34	-1.06	-0.34	0.96
1997	-1.43	-1.74	-1.38	0.85
1998	-0.82	-0.33	0.72	0.24
1999	0.09	-0.45	-1.02	0
2000	1.05	0.67	-1.11	0.39
2001	0.97	1.71	0.63	0.85
2002	-0.45	1.02	1.57	1.35

This table reveals that Jamaica's TFP growth is quite variable from year to year. One reason is that declines in the economy's output are rarely matched by simultaneous declines in output. In addition, real output, labour input and capital input fluctuate substantially from year to year.

Table 6 summarizes Jamaica's TFP experience for different periods of the 41- year sample. It can be seen that TFP grew at a 2.2% annual rate from 1962 to 1973. This also coincides with a period of sustained, healthy growth in the Jamaican economy. But Jamaica's economic performance was severely impacted by the 1973 and 1979 oil price shocks and the high petroleum prices in the rest of the 1970s. TFP declined by an average of 4.6% per annum over the 1974-80 period, primarily because GDP declined by an average of 3.2% annually. The economy recovered in 1981-83, as GDP and TFP grew at average annual rates of 2.0% and 1.0%, respectively. A recession in 1984-85, partly due to external debt servicing issues, led TFP to decline at an average annual rate of 3.9%. The Jamaican economy then grew in the remainder of the 1980s, leading TFP to grow at a healthy 2.8% annual rate. However, Jamaica's economy has performed relatively poorly since 1990, growing by an average of only 0.5% per annum. This has, in turn, been associated with average annual TFP declines of 0.5% over the 1991-2002 period. In the last few years of our research, there are some signs of improving economic and TFP performance. For example, TFP grew at an average annual rate of 0.52% over the 2000-2002 period.

Table 6: Jamaica TFP Results – Select Periods

Description of Time Period	Year	TFP	GDP	Labour	Capital
		Avg. Annual Growth (%)	Avg. Annual Growth (%)	Avg. Annual Growth (%)	Avg. Annual Growth (%)
Steady Growth	1962-1973	2.2	5.1	0.9	5.0
Oil Shock	1974-1980	-4.6	-3.2	1.7	1.0
Recovery	1981-1983	1.0	2.0	2.0	-0.1
Debt Recession	1984-1985	-3.9	-2.8	2.6	-0.5
Recovery	1986-1990	2.8	4.8	2.7	0.5
Current Weak Growth	1991-2002	-0.5	0.5	0.5	0.6
Entire Period	**1962-2002**	**0.1**	**1.7**	**1.3**	**1.8**

These economic gyrations complicate the estimation of long-term TFP trends for the Jamaican economy. We do not believe that Jamaica's TFP decline over the 1991-2002 period (the same period for which we estimated TFP growth for JPS) is representative of the economy's long-term TFP trend. If this were the case, it would imply that Jamaica's productivity should be expected to decline more or less indefinitely. This is not consistent with most economies' experience.

It should be noted, however, that other, more recent research has also estimated weak and/or negative TFP growth for Jamaica. For example, Loayza et al estimate that TFP for the Jamaican economy declined between 2.5% and 3% per annum for the 1991-2000 period.[58] Bartlesman estimates that the country's TFP declined by 0.8% per annum over this period, which is very similar to the decline that PEG has computed.[59] Blavy estimates that TFP for Jamaica declined at an average annual rate of 1.7% between 1990 and 2000.[60] Given this evidence of weak TFP growth for the Jamaican economy, and our view that it is not reasonable to expect TFP to decline indefinitely, PEG believes that the best estimate of Jamaica's TFP growth during the term of the PBRM is zero percent.

[58] Loayza, R., P. Fajnzylber and C. Calderon (2002), "Economic Growth in Latin America: Stylized Facts, Explanations, and Forecasts," World Bank, Washington DC

[59] Bartlesman, E. (2002), "Productivity Growth in Jamaica 1991-2000: An Exploratory Analysis," World Bank background paper prepared for World Bank Report No. 26088-M, *Jamaica: The Road to Sustained Growth*, December 2003.

[60] Blavy, R. (2006), "Public Debt and Productivity: The Difficult Quest for Growth in Jamaica," IMF Working Paper WP/06/235.

4. BENCHMARKING JPS NON-FUEL COST PERFORMANCE

4.1 Introduction

Benchmarking has in recent years become a widely used tool in the assessment of utility performance. Managers look to benchmarking studies for indications of how well their companies are doing. Benchmarking also plays a growing role in regulation. Such studies can, for example, be used to assess the reasonableness of costs at the start of multiyear rate plans.

Appraisals of utility performance are often facilitated by the extensive data that utilities report to regulators and industry associations. However, accurate appraisals are still challenging. There are important differences between companies in the character of services provided, the overall scale of operations, the prices of production inputs, and other business conditions that influence their cost. Data are unavailable for many companies and do not cover all relevant business conditions where they are available.

PEG personnel have been active for several years in benchmarking research for utilities. We pioneered the use of scientific benchmarking in US regulation and have testified on our work in several proceedings. JPS commissioned PEG to measure its overall non-fuel cost efficiency. We appraised its efficiency using an econometric cost model, where JPS' performance was compared to a large sample of US vertically-integrated, investor-owned electric utilities (IOUs).

This chapter summarizes our econometric benchmarking work for JPS. Section 4.2 discusses the database used in the study cost. Section 4.3 discusses the cost measures. The basics of our econometric model are discussed in Section 4.4. The variables used in the model are described in Section 4.5. Econometric results are presented in Section 4.6. JPS data used in the model are discussed in Section 4.7. The econometric model is then used to evaluate JPS' non-fuel cost performance in Section 4.8. Additional, more technical details of the research are presented in Appendix 2.

4.2 Data

The primary source of the data used in our research was the Federal Energy Regulatory Commission (FERC) *Form 1*. This form is filed annually by all major US electric IOUs, along with certain non-utility entities that are also jurisdictional to the FERC.[61] Selected *Form 1* data have been published regularly by the US Energy Information Administration (EIA) in a series of publicly available documents that are currently entitled *Financial Statistics of Major US Investor-Owned Electric Utilities*. The data described below are from FERC Form 1 unless otherwise noted.

All major US electric IOUs which filed the FERC *Form 1* electronically in 2006 and which have reported the required data continuously since they achieved a "major" designation were considered for sample inclusion. To be included in the study utilities were required, additionally, to have plausible data and to be vertically integrated as determined by threshold levels of involvement in power generation, transmission, and distribution. Data from 41 IOUs met all of these standards. We believe that the data for these companies are the best available to perform scientific research on the non-fuel cost efficiency of IOUs in the provision of bundled power service. The included companies are listed in Table 7.

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[61] The selection criteria used in determining the major IOU classification is detailed in *Financial Statistics of Major US Investor-Owned Electric Utilities (1993)* EIA page 2.

Table 7: U.S. Power Companies in Benchmarking Sample

Alabama Power Co.	Kansas City Power & Light
Appalachian Power	Kentucky Power
Arizona Public Service Co.	Kentucky Utilities
Avista	Louisville Gas and Electric
Carolina Power & Light	Nevada Power
Central Vermont Public Service Corp.	Northern Indiana Public Service
Cleco	Northern States Power
Columbus Southern Power	Ohio Power
Consumers Energy Co.	Otter Tail Power
Dayton Power & Light	PacifiCorp.
Detroit Edison	Public Service Company of Colorado
Duke Energy	Public Service Company of Oklahoma
Empire District Electric	Puget Sound Energy
Entergy Arkansas	Sierra Pacific Power
Entergy Louisianna	South Carolina Electric & Gas
Florida Power & Light	Southwestern Electric Power
Florida Power Corp.	Southwestern Public Service Co.
Georgia Power	Tampa Electric
Green Mountain Power Corp.	Tucson Electric Power
Hawaiian Electric Co., Inc.	Virginia Electric & Power Co.
Idaho Power Co.	

4.3 Definition of Cost

4.3.1 Applicable Total Cost

Cost figures played an important role in our performance research. Bundled power service was defined to include power generation, procurement, transmission, and distribution. The total cost of service was defined to include total electric operation and maintenance expenses and the total cost of electric plant ownership.

The study used a service price approach to measure the cost of plant ownership. Under this approach, the cost of plant ownership is the product of a capital quantity index

and the price of capital services. The cost of plant ownership includes depreciation

and the opportunity cost of plant ownership. This method has a solid basis in economic theory and is well established in the scholarly literature. It also controls in a precise and standardized fashion for differences between utilities in the age of their plant. Further details of these calculations are provided in Section A.1 of the Appendix.

4.3.2 Cost Decomposition

Estimation of the cost model involved the decomposition of total cost into three major input categories: capital services, labour services, energy, and materials and miscellaneous other O&M inputs. The capital services costs are described above. The cost of labour was defined as the sum of O&M salaries and wages and pensions and other employee benefits. The cost of other O&M inputs was defined to be O&M expenses net of expenses for labour, generation fuels, and power purchases. This residual cost category included expenses for various materials, the services of contract workers, insurance, and real estate and equipment rentals.

4.4 An Overview of the Econometric Method

This section provides a substantially non-technical account of the econometric approach to benchmarking employed in this study. Additional, more technical details of the work are reported in Appendix 2.

A mathematical model called a cost function was specified. Cost functions represent the relationship between the cost of a utility and quantifiable business conditions in its service territory. Business conditions are defined as aspects of a company's operating environment that influence its activities but cannot be controlled.

Economic theory was used to guide cost model development. We posited that the actual total cost (C_i) incurred by company, *i*, in service provision is the product of minimum achievable cost (C_i^*) and an efficiency factor (*efficiency*$_i$). This assumption can be expressed logarithmically as

$$\ln C_i = \ln C_i^* + \ln efficiency_i\ .^{62} \qquad [4]$$

The term ln indicates the natural log of a variable.

According to theory, the minimum total cost of an enterprise is a function of the amount of work it performs and the prices it pays for capital and labour services and other inputs to its production process. Theory also provides some guidance regarding the nature of the relationship between these business conditions and cost. For example, cost is apt to be higher as input prices and the amount of work performed by the utility increase.

Here is a simple example of a minimum total cost function that conforms to cost theory.

$$\ln C_{i,t}^* = a_0 + a_1 \cdot \ln N_{i,t} + a_2 \cdot \ln W_{i,t} + u_{i,t}\,. \qquad [5]$$

For each firm *i* in year *t*, the variable $N_{i,t}$ is the number of customers that the company serves. It quantifies one dimension of the work that it performs. The variable $W_{i,t}$ is the wage rate that the company pays. The wage rate and delivery volume are the measured business conditions in this cost function.

The term $u_{i,t}$ is the error term of the cost function. This term reflects errors in the specification of the model, including problems in the measurement of output and other business condition variables and the exclusion from the model of relevant business conditions. It is customary to assume a specific probability distribution for the error term that is determined by additional parameters, such as mean and variance.

Combining the results of Equations [4] and [5] we obtain the following model of cost:[63]

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[62] The logarithm of the product of two variables is the sum of their individual logarithms.

[63] Here is the full logic behind this result:

$$\begin{aligned}
\ln C_{i,t} &= \ln C_{i,t}^* + \ln efficiency_i \\
&= \left(a_0 + a_1 \ln N_{i,t} + a_2 \ln W_{i,t} + u_{i,t}\right) + \ln efficiency_i \\
&= \left(a_0 + \ln efficiency^{average}\right) + a_1 \ln N_{i,t} + a_z \ln W_{i,t} \\
&\quad + \left[u_i + \left(\ln efficiency_i - \ln efficiency^{average}\right)\right] \\
&= \alpha_0 + \alpha_i \ln N_{i,t} + \alpha_2 \ln W_{i,t} + e_{i,t}
\end{aligned}$$

$$\ln C_{i,t} = \alpha_0 + \alpha_i \ln N_{i,t} + \alpha_2 \ln W_{i,t} + e_{i,t}. \qquad [6]$$

Here the *actual* (not minimum) total cost of a utility is a function of the two measured business conditions. The terms α_0, α_1, and α_2 are model parameters. Their values are assumed to be constant across companies and over some period of time. The α_0 parameter captures the efficiency factor for the average firm in the sample as well as the value of a_0 from Equation [6], the minimum total cost function. The values of α_1 and α_2 determine the effect of the two measured business conditions on cost. If the value of α_2 is positive, for instance, an increase in wage rates will raise cost.

The term $e_{i,t}$ is the error term for equation [6]. We assume that it is a random variable. It includes the error term from the minimum total cost function. It also reflects the extent to which the company's efficiency factor differs from the sample norm.

A branch of statistics called econometrics has developed procedures for estimating parameters of economic models. Cost model parameters can be estimated econometrically using historical data on the costs incurred by utilities and the business conditions that they faced. For example, a positive estimate for α_2 would reflect the fact that the cost reported by sampled companies was typically higher when higher wages were paid to employees.

Numerous statistical methods have been established in the econometrics literature for estimating parameters of economic models. In choosing among these, we have been guided by the desire to obtain the best possible model for cost benchmarking. Econometric methods are also useful in selecting business conditions for the model. Tests are available for the hypothesis that the parameter for a business condition variable equals zero. Variables were excluded from the model when such hypotheses could not be rejected.

A cost function fitted with econometric parameter estimates may be called an <u>econometric cost benchmark model</u>. We can use such a model to predict a company's cost given values for the variables that represent the business conditions that the company faced. Returning to our simple example, we might predict the (logged) cost of JPS in period *t* as follows:[64]

$$\ln \hat{C}_{JPS,t} = \hat{\alpha}_0 + \hat{\alpha}_1 \cdot \ln N_{JPS,t} + \hat{\alpha}_2 \cdot \ln W_{JPS,t}. \qquad [7]$$

Here $\hat{C}_{JPS,t}$ denotes the predicted cost of the company in period *t*, $N_{JPS,t}$ is the number of customers it served, and $W_{JPS,t}$ is the wage rate that it paid. The $\hat{\alpha}_0$, $\hat{\alpha}_1$, and $\hat{\alpha}_2$ terms are parameter estimates. Notice that in this model the cost benchmark reflects, through the estimate of parameter α_0, the *average* efficiency of the sampled utilities.

Consider, now, that if the parameter estimates are unbiased and the expected value of $u_{i,t}$ is zero, the expected value of the percentage difference between the company's actual cost and that predicted by the model is the percentage difference between the efficiency factor of JPS and that of the sample mean firm.

$$\ln\left(C_{JPS,t} \big/ \hat{C}_{JPS,t} \right) = \ln\left(efficiency_{JPS} \big/ efficiency^{average} \right). \qquad [8]$$

[64] Since this is a predicted equation using estimated parameters there is no error term.

This percentage difference is a measure of the company's cost performance.

A number like that generated by the cost benchmark model in [8] constitutes our best estimate of the company's cost given the business conditions that it faces, relative to the *average* efficiency displayed by firms in the industry. This is an example of a point prediction. An important characteristic of the econometric approach to benchmarking is that the statistical results provide information about the *precision* of such point predictions. According to econometric theory, precision is greater as the variance of the model's prediction error declines. The variance of the prediction error can be estimated using a well-established formula. The formula shows that the precision of cost model predictions is greater to the extent that:

1) The model is more successful in explaining the variation in cost in the sample
2) The size of the sample is larger
3) The number of business condition variables included in the model is smaller
4) The business conditions of sample companies are more varied
5) The business conditions of the subject company are closer to those of the typical firm in the sample

4.5 Business Condition Variables

4.5.1 Output Quantity Variables

As noted above, economic theory suggests that quantities of work performed by utilities should be included in our cost model as business condition variables. There are two output quantity variables in our model: the number of retail customers and total MWh deliveries. We expect cost to be higher for higher values of each of these workload measures.

4.5.2 Input Prices

Cost theory also suggests that the prices paid for production inputs are relevant business condition variables. In this model, we have specified input price variables for capital, labour, and other O&M inputs.[65] We expect cost to be higher as the values of each of these price variables increase.

The labour price variable used in this study was the utility's own salaries and wages per employee. The data needed to compute this variable are reported on FERC Form 1. Prices for other O&M inputs were assumed to be the same in a given year for all companies. They were escalated by the gross domestic product price index. Our approach to the computation of a price index for capital services is described in Section A.1 of the Appendix.

4.5.3 Other Business Conditions

Four additional business condition variables appear in the econometric cost model. One is the percentage of electric distribution plant in the gross value of gas and electric distribution plant. This variable was intended to capture the extent to which a company had not diversified into gas distribution. Such diversification will typically lower cost due to the ability to share inputs (e.g., personnel, computer systems, meter readers) between the two services. Higher values for this variable indicate lower levels of diversification. We would therefore expect the value of this

[65] The price for other O&M inputs does not appear in the estimated parameter tables due to the imposition of the linear homogeneity restriction predicted by economic theory.

coefficient to be positive (*i.e.* as the value of this variable goes up, there is less diversification and higher expected costs).

The second variable that was added to the cost trend model was the percentage of generation that was not hydroelectric. Hydroelectric generation is generally less expensive than other kinds of generation. We therefore expect cost to increase as the value of this variable rises.

The third variable that was added to the cost model was customers per mile of T&D line. This variable measures the geographical extensiveness of the utility's power delivery system. For a given number of customers, it is typically more expensive to deliver power as customers become more geographically dispersed and require more extensive delivery systems, or as the density of the service territory decreases. We therefore expect this coefficient to be negative.

The fourth business condition variable that was added to the cost model was a trend variable. This variable captures any trend in the cost of sampled utilities that was independent of the trends in other included business conditions. We would not be surprised to find a negative value for the trend variable parameter which reflects efficiency trends in the industry.

4.6 Econometric Results

Estimation results for the cost model are reported in Table 8. The parameter values for the three additional business conditions (other than the trend) and for the first order terms of the translogged variables are elasticities of the cost of the sample mean firm with respect to the basic variable. The first order terms are the terms that do not involve squared values of business condition variables or interactions between different variables. The table shades the results for these terms for reader convenience.

Table 8: Econometric Results for Cost Level Research

Explanatory Variable	Estimated Coefficient	T-Statistic	Explanatory Variable	Estimated Coefficient	T-Statistic
L	0.141	39.162	%E	0.325	3.379
LL	-0.009	-0.456			
LK	-0.131	-7.804	%NH	0.046	1.517
LN	0.055	4.681			
LV	-0.054	-4.905	D	-0.134	-6.186
K	0.583	142.865	Trend	-0.018	-13.780
KK	0.209	7.719			
KN	-0.040	-2.585	Constant	16.089	963.640
KV	0.058	4.234			
			System Rbar-Squared	0.940	
N	0.598	10.901			
NN	-0.903	-3.683	Sample Period:	1991-2006	
NV	0.732	3.243			
			Number of Observations	681	
V	0.441	8.648			
VV	-0.580	-2.733			

Variable Key

L = Labor Price
K = Capital Price
N = Number of Customers
V= Deliveries
%E= Percent of Plant that is Electric
%NH= Percent generation not hydro
D= Customers per total line mile

The tables also report the values for the corresponding asymptotic t ratios. These were also generated by the estimation program and were used to assess the range of possible values for parameters that are consistent with the data. A parameter estimate is deemed statistically significant if the hypothesis that the true parameter value equals zero is rejected. This statistical test requires the selection of a critical value for the asymptotic *t* ratio. In this study, we employed critical values that are appropriate for a 90% confidence level given a large sample. The critical value was 1.645.

Examining the results in Table 8, it can be seen that the cost function parameter estimates were plausible as to sign and magnitude. With regard to the first order terms of the translogged variables, cost was found to be higher as input prices and output quantities increased. At the sample mean, a 1% increase in the number of customers raised bundled power cost by 0.60%. A 1% increase in deliveries raised bundled power cost by about 0.44%.

Turning to results for the input prices, it can be seen that the elasticity of cost with respect to the price of capital services was 0.58%. This was more than four times the estimated elasticity of the price of labour. This reflects the capital intensiveness of the electric utility business.

The coefficients on the additional business condition variables were also sensible and, with the exception of the percent non-hydro variable, statistically significant.

- Cost was higher as the percentage total plant that is electric increased.
- Cost was higher for utilities with a higher share of non-hydro generation.
- Cost was lower for utilities with greater customer density *i.e.* more customers per mile of T&D line.

4.7 Business Conditions of JPS

We turn next to applying the estimated cost model to the evaluation of JPS' non-fuel cost. This application requires inserting values for each of the independent variables in the model into the fitted econometric model. This then generates a cost prediction for JPS given its own specific cost "drivers."

One important issue that must be addressed here is how JPS' non-fuel "cost" is defined. As discussed in Chapter Two, the regulatory asset value used to set current JPS rates incorporates a one-time, downward adjustment in the value of capital. This adjustment effectively drives a wedge between the regulatory and replacement costs of JPS' net assets; that is, the latter would be computed without the one-time downward adjustment. The econometric model estimated for US electric utilities essentially uses a replacement cost valuation of electric utility net assets. "Apples to apples" comparisons between JPS and the US utilities would therefore employ a replacement cost value of JPS assets, so we have evaluated JPS' non-fuel costs using replacement cost asset values.

Most of the data needed for the application were collected directly from JPS. Table 9 compares the average values of business condition variables for JPS to the US sample mean values of these variables. It can be seen that the average total cost of JPS (using the replacement cost asset value) was just over 14% of the US sample mean. Meanwhile, the number of customers served by JPS was about 61% of the US mean. JPS' cost per customer was therefore well below that of the average US utility. JPS' delivery volumes were 11% of the US sample mean. Given the relative customer number data, this shows that JPS' volumes and peak demand per customer were less than one-fifth of those of an average US electric utility. The cost and volume data also show that JPS' costs per MWh delivery are somewhat greater than the US sample average.

Table 9: Average Values of Variables in the Benchmarking Study

Variable	Units	U.S. Sample Average	JPS	JPS / Sample Mean
Total Cost	Dollars	944,554,636	134,110,652	14%
Number of Customers	Count	844,805	511,758	61%
Total Deliveries	MWh	25,114,316	2,831,785	11%
Maximum Demand	MW	5,535	567	10%
Price of Capital Services	Index Number	96.55	142.42	148%
Price of Labor Services	Dollars / Year	40,171	42,861	107%
Price of Materials	Index Number	105.09	107.84	103%
% Plant that is Electric	Percent	0.933	1.000	107%
% Generation not Hydro	Percent	0.940	0.966	103%
Customers per Total TX & Dx Miles	Customers / Mile	31.7	72.7	229%

Turning next to input prices, the table shows that JPS had labour prices somewhat greater than the US sample mean. This may appear counterintuitive, but JPS provides a great deal of benefits to its employees (*e.g.* discounted electricity rates) that are not provided by US utilities. These additional costs lead to a substantial increase in

JPS' computed labour price. JPS' capital service price was also 48% above the US sample mean. This is overwhelmingly due to the higher returns that are necessary to attract capital in Jamaica vis-à-vis the US.

Regarding the other business conditions, JPS' share of non-hydro generation was similar to that of the US mean. JPS' customers per T&D miles are greater than the US average. Note, finally, that JPS has no gas distribution customers. This has limited its opportunity to realize potential scope economies by sharing inputs with other utility services.

4.8 Econometric Benchmarking Results for JPS

Table 10 presents the results of our appraisal of JPS' non-fuel cost using the econometric model. Using the replacement cost asset value, the Company's average non-fuel cost during the 2005-2007 period was about US$169 million. This was found to be 28% below predicted non-fuel cost. However, this difference was not statistically significant. The main reason is that the business conditions for JPS differ substantially from those of the typical US utility. As previously explained, confidence intervals around a cost prediction will become wider as the data for an individual utility diverge from sample mean values for the same variables. As confidence intervals widen, it becomes more difficult to reject the hypothesis that a company is an average cost performer. In this instance we cannot reject that hypothesis, in spite of the fact that JPS' actual costs are well below the level predicted by the econometric model.

Table 10: Actual and Predicted Cost Levels for Jamaica Public Service

Period	Actual Cost	Predicted Cost	Difference
1999-2002	118,661,608	119,495,153	-0.70%
2005-2007	169,360,045	224,758,589	-28.30%

It is material, however, that JPS' cost performance has improved markedly from earlier years. This is evident from Table 10, which also presents the Company's benchmarking results using the same econometric model but applied to an earlier (1999-2002) period for JPS costs. It can be seen that the Company's actual costs were essentially equal to their predicted value in the 1999-2003 period. Our cost models therefore show that JPS has effectively improved its efficiency by an estimated 28% between the 1999-2002 and 2005-2007 period. This is consistent with the remarkable TFP gains that JPS has registered in recent years. Overall, PEG believes that our benchmarking and TFP results provide strong evidence that JPS has made substantial efficiency gains in recent years. This, in turn, implies that there is a limited ability for the Company to make significant *incremental* TFP gains during the PBRM.

5. JPS' Q FACTOR

The PBRM for JPS also includes a "Q factor," which is designed to encourage the Company to provide appropriate levels of service quality to its customers. The Q factor rewards or penalizes JPS based on the Company's measured performance on three quality indicators. These indicators are the system average interruption duration index (SAIDI), or the duration of power outages experienced by customers, on average, in a year; the system average interruption frequency index (SAIFI), or the total number of power outages experienced by customers, on average, in a year; and the customer average interruption duration index (CAIDI), or the duration of an average power outage that a customer experiences. It is well-known that, mathematically, SAIDI is equal to the product of SAIFI and CAIDI (*i.e.* SAIDI = SAIFI * CAIDI).

Rewards or penalties depend on the measured value for each quality indicator relative to an established quality benchmark. The benchmark for each quality indicator varies over the term of the PBRM. In 2006, the benchmark is equal to JPS' measured value for the indicator in 2005 – for example, the benchmark performance for SAIDI in 2006 is JPS' measured SAIDI in 2005. Benchmarks become progressively more challenging in each subsequent year. In 2007, each indicator's benchmark is equal to its 2005 value minus 2% (lower values indicate better quality performance and more challenging benchmarks); in 2008, the benchmark for each indicator is equal to its 2005 value minus 5%; and in 2009, the benchmark for each indicator is equal to its 2005 performance minus 8%.

The Q factor also sets "dead bands" around the benchmarks for the purposes of determining rewards or penalties. For each indicator in each year, if measured performance is more than 10% superior to the benchmark, JPS is awarded three quality points. If measured performance is within plus or minus 10% of the benchmark (*i.e.* within the 10% dead band), JPS is awarded zero quality points. If measured performance is inferior to the benchmark by more than 10%, JPS is awarded negative three quality points. Total quality points are then summed across the three indicators, and a Q-factor price adjustment is applied based on the Company's total quality points. The range of Q factors varies from a maximum of a 0.5% allowed price increase (for the maximum, positive quality points of +9) to a 0.5% price decrease (for the minimum positive quality points of -9).

In addition, JPS must begin collecting data on its momentary average interruption frequency index (MAIFI) performance. The OUR plans to add MAIFI to the PBRM in 2009. This is motivated by concerns about the vulnerability of critical machinery and systems to even a temporary loss of power. The OUR has also said it plans to use JPS' MAIFI performance over the 2006-2009 period as the basis for the MAIFI benchmark. However, JPS has expressed some concerns about measuring MAIFI, including uncertainties about how far downstream into the distribution system the metric should be measured and the additional resources that would be required to measure MAIFI accurately. In response, the OUR has reiterated its intention to integrate MAIFI into the Q factor and its willingness to discuss implementation strategies for realizing this objective, including a determination of how far into the distribution system is necessary for collecting information on momentary interruptions.

PEG generally supports the idea of a Q-factor, and we believe there are several commendable aspects of the Q factor mechanism for JPS. One appealing feature is that the Q factor is symmetric and allows for penalties and rewards. A second is that there is a transparent, empirical basis for the benchmarks that are established. It can sometimes also be appropriate to have "stretch goals" for benchmarks, although we have not undertaken any analysis to determine whether the stretch factors built into JPS' benchmarks are appropriate.

However, some aspects of the Q factor can be enhanced. One unambiguous improvement would be to eliminate CAIDI as an indicator. This metric is redundant when SAIFI and SAIDI are already reflected in the mechanism. It can also be demonstrated mathematically that SAIFI and SAIDI are ultimately what matter to customers; we present mathematical logic demonstrating this result in Appendix Three of this report. Therefore nothing is added by including CAIDI as an indicator when SAIFI and SAIDI are already used to measure service quality.

Even more importantly, using SAIFI, SAIDI and CAIDI to measure quality can lead to anomalous and unwarranted penalties or rewards in a service quality mechanism. A company can be penalized for poor CAIDI performance even though it has decreased both the frequency and duration of its power interruptions. Stated differently, an increase in CAIDI can occur even though both SAIFI and SAIDI have declined. This is merely the result of the mathematical relationship between SAIFI, SAIDI and CAIDI and does not reflect eroding service quality. A company should not be penalized when both the frequency and duration of its power outages decline, since these are the reliability metrics that matter to customers. However, such anomalous results can occur when CAIDI is used as a quality indicator.

This type of anomalous outcome is not just theoretical, since it has actually occurred in the operation of JPS' Q factor. In 2008, JPS' measured SAIDI exceeded the benchmark by 10% and its measured SAIFI was superior to the benchmark by 33%. If the Q factor adjustment depended only on these indicators, JPS would have been allowed to increase its prices to reflect this service quality improvement. However, because the Company improved its SAIFI by a greater percentage increase than SAIDI (*i.e.* 33% improvement in SAIFI versus 10% improvement in SAIDI), the measured value for CAIDI declined. Again, this result was simply due to the mathematical relationship between SAIFI, SAIDI and CAIDI; *any time* SAIFI improves more rapidly than SAIDI, CAIDI must fall. This does not reflect a diminution in service quality, yet under the Q factor, the change in JPS' CAIDI led to -3 quality points. This offset the +3 quality points that were earned on the SAIFI and SAIDI indicators and thus prevented JPS from being (appropriately) rewarded.

When the Q factor is updated, the CAIDI indicator should be eliminated. There is no valid reason to include all three quality indicators. Doing so can only lead to ongoing anomalous results and, potentially, inappropriate penalties or rewards. Including CAIDI can also create perverse operational incentives for JPS. For example, when the Q factor depends on CAIDI, the plan creates incentives to reduce outage times after customers have experienced interruptions. One way to achieve this goal is to increase the size of work crews. However, this response may not be optimal if it diverts resources away from activities that can prevent outages from occurring in the first place. For instance, larger service restoration crews may reduce the funds available for tree trimming, which can reduce both SAIFI and SAIDI. Adding CAIDI to the Q factor can therefore distort incentives and inadvertently lead to higher values of SAIFI and SAIDI. For all these reasons, PEG strongly recommends that CAIDI be eliminated as a quality indicator when the PBRM is updated.

PEG also has concerns about adding MAIFI as an indicator, notwithstanding the OUR's stated desire to do so. It is relatively rare to include MAIFI as an indicator in approved service quality incentive plans. PEG surveyed service quality regulation practices for all 50 US states in a 2007 report for Detroit Edison. In penalty/reward service quality plans, we found SAIFI was used as a quality indicator 18 times, SAIDI used 16 times, but MAIFI used only 3 times. One reason that MAIFI is not commonly rewarded or penalized under Q factor-type mechanisms is uncertainties regarding appropriate MAIFI measures and/or the resources that would need to be expended to measure MAIFI accurately. These are the same concerns that have been expressed by JPS, and even after several years they have not yet been resolved with the OUR. It is important for service quality in any plan to be measured in an agreed and transparent fashion; if this is not the case, penalties or rewards may be arbitrary or not reflect "real" service quality performance.

PEG is concerned about the lack of historical MAIFI data that has been carefully examined and found to be appropriate as the basis for service quality benchmarks which would, in turn, be used to reward or penalize future MAIFI performance. Until JPS and OUR have a better understanding of the MAIFI data, we believe it is premature to add MAIFI as an indicator to the Q factor. A more prudent, intermediate step would be for JPS to report MAIFI on an annual, or perhaps more than annual basis, to the OUR. The OUR could monitor MAIFI performance and ask JPS to explain, and perhaps rectify, any potential MAIFI problems that are observed. This approach has been used by many US jurisdictions, and it could help both JPS and the OUR better understand the underlying MAIFI data better. This improved understanding could provide the foundation for adding MAIFI as an indicator that is formally rewarded or penalized in the following PBRM, to take effect in 2014.

PEG also believes that any future "stretch targets" for benchmarks should be based on empirical evidence on the service quality levels that JPS customers demand and are willing to pay for. It should not simply be assumed that "more" service quality is better, since improving the quality of service requires resources. These additional resources will increase JPS costs and, ultimately, the prices paid by customers. JPS should be encouraged to increase its quality of service only if these improvements are commensurate with their customers' preferences and willingness to pay (WTP) for further quality improvements. It may therefore be valuable to undertake research on customers' WTP for quality; this information can help to determine appropriate, long-run quality benchmarks and ensure that the Q factor actually improves customer welfare by encouraging only those service quality improvements that customers actually want. Better understanding of customers' WTP can also inform decisions on whether it is appropriate to add MAIFI as an indicator; this would be the case if research indicates a high WTP for the elimination of even momentary power interruptions.

6. X-Factor and Q-Factor Implications for JPS

The X-Factor in the PBRM is to be equal to the difference in expected TFP growth for JPS and the general TFP growth of firms whose price index of outputs reflects the price escalation measure *dI*. PEG estimates that the best estimate for JPS' expected TFP growth over the term of the PBRM is 1.94%; this is equal to the Company's average TFP growth during the 2001-2007 period. The inflation measure *dI* is based on economy-wide inflation trends in the US and Jamaica, so the latter TFP growth rate is a weighted average of TFP growth trends for the US and Jamaican economies. The weights specified in the PBRM are 0.76 and 0.24, respectively. Over the same 2001-2007 period used to estimate JPS' TFP growth, the TFP growth trend of the US economy was 1.53%. PEG believes the most reasonable estimate of TFP growth for the Jamaican economy over the term of the next PBRM is 0%. The "general TFP growth of firms whose price index of outputs reflects the price escalation measure *dI*" is therefore 1.16% (*i.e.* 0.6*1.53% + 0.4*0% = 1.16%). The baseline TFP differential based on historical TFP experience is therefore (1.94% - 1.16%), or 0.78%.

Because the PBRM is to be based on JPS' "expected" TFP growth, however, it may be desirable to add a "stretch factor" to the Company's historical TFP trend. Stretch factors are motivated by the notion that, since PBR plans create stronger incentives compared with cost of service regulation, companies that switch from cost of service to performance-based regulation are likely to experience an increase in TFP growth compared with historical norms.[66] In principle, the incremental gains in TFP should be related to the utility's efficiency at the outset of the PBR plan. Less efficient utilities will have more "fat" to cut and therefore greater ability to boost TFP. It is therefore reasonable to expect greater TFP acceleration under PBR for less efficient utilities.

This principle has also been recognized in the OUR's previous determination, which approved a stretch factor for JPS, and the 2002 Tariff Study produced for the OUR. That study noted that "if JPS is efficient, then its calculated TFP will be the same as that for the efficient comparator companies and the X value can be set equal to forecast TFP growth without an additional convergence element (between JPS and the most efficient utilities on the performance frontier)."[67] This report therefore considers a stretch factor of zero could be appropriate for JPS if it is deemed to be an efficient performer.

It should also be remembered that in competitive markets, firms with superior performance earn above average returns. This is true even in the long run.[68] This implies that it is not reasonable to impose "frontier" performance standards on all firms in the industry since this does not allow returns to be commensurate with performance. If regulation is to emulate the operation and outcomes of a competitive market, companies must always have "room" to outperform the benchmark that is reflected in the prices they face. This enables the firm to be appropriately rewarded for superior performance. If the industry's best-observed practice is imposed on all firms, any firm that fails to achieve this standard will earn below average returns. This would be true even for superior performers that nevertheless fall short of the industry's best performance. This outcome is clearly contrary to having returns be commensurate with performance and thus is not consistent with effective regulation.

PEG's econometric benchmarking research shows that, over the 2005-2007 period, JPS has non-fuel, bundled power costs that are 28% lower than what would be expected for an average US utility operating under the same conditions. While we cannot reject the hypothesis that JPS is an average cost performer, there is little doubt that the Company has made sizeable efficiency gains in the last five years. For example, our econometric model shows that JPS' non-fuel costs were essentially equal to their predicted value over the 1999-2002 period. This implies that JPS has made efficiency gains of approximately 28% in the last five years. This evidence from our benchmarking model is broadly consistent with our TFP research, which also indicates that JPS has made substantial TFP gains in recent years.

PEG's work implies that the appropriate stretch factor for JPS should be no more than an average stretch factor in other approved North American PBR plans. This average value is 0.5%.[69] PEG

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[66] Stretch factors are also sometimes referred to as "consumer dividends" or "consumer productivity dividends."

[67] Frontier Economics/PPA, *Jamaica Electricity Tariff Study: Final Report*, Office of Utilities Regulation, July 2002, p. 64.

[68] There are both short-run and long-run equilibria in competitive markets. In the short run, equilibrium occurs whenever quantity supplied equals quantity demanded. But the industry will not be in long-run equilibrium if average returns in the industry are not equal to the competitive rate of return, defined to be the opportunity cost of capital. For example, if average industry returns exceed the competitive rate of return, long-run equilibrium is established as new firms enter the industry and existing firms expand their production, thereby increasing supply and driving down prices and average returns. This process continues until the industry's average return equals the competitive rate of return. For evidence that superior performers continue to earn above-average returns even in the long run, see L. Schwalbach, U. Grabhoff, and T. Mahmood, "The Dynamics of Corporate Profits," *European Economic Review*, October 1989, 1625-1639.

[69] There are many precedents for stretch factors in North American regulation. The first such factor was in the price indexing plan approved by the US Federal Communications Commission (FCC) for AT&T in 1988. The approved stretch factor in this plan was 0.5%, which was equal to 20% of AT&T's estimated TFP growth of 2.5%. In both the original and updated PBR plans for the interstate services of Local Exchange telecom carriers, the FCC also imposed

therefore recommends the stretch factor for JPS be no greater than 0.5%. However, we also recognize that there is always an element of judgment involved in setting a stretch factor. We believe it would be appropriate for the OUR to select a stretch factor in the range between 0 and 0.5%. If a stretch factor within this range is added to the baseline productivity differential, the overall X factor for JPS' PBRM would be between 0.8% and 1.3%.

This represents a considerable reduction from the 2.72% value for X that was previously approved by the OUR, but we believe a significant downward adjustment for two reasons. First, compared to the previously approved PBRM, PEG has presented far more evidence on JPS' TFP performance and pattern of TFP gains. This increases confidence in the robustness of our estimate of achievable TFP gains over the next PBRM. In addition, there is strong evidence that JPS has made substantial efficiency gains in recent years. This implies that the Company's ability to achieve incremental TFP gains is limited, and the X factor should be lowered commensurately. It should also be noted that there are many precedents for X factors for electric utilities in the 0.8% to 1.3% range.

For the Q-factor, PEG recommends that CAIDI be eliminated as a quality indicator during the next PBRM. Including this indicator when SAIFI and SAIDI are part of the same service quality incentive can only lead to perverse penalties or rewards. We also believe that there are significant uncertainties regarding an appropriate benchmark for MAIFI. We accordingly recommend that MAIFI simply be monitored, rather than subject to explicit penalties or rewards, in the next PBRM. We also believe more attention should be devoted to understanding customers' willingness to pay for quality improvements, including the willingness to pay for reductions in MAIFI. More knowledge of customer preferences can help JPS make appropriate investments and ensure that any quality improvements actually improve customer welfare.

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stretch factors of 0.5%. These values were again equal to approximately 20% of the industry's estimated TFP growth.

Similar values for X factors have been approved in indexing plans for North American energy utilities. However, since TFP growth in energy utility industries is less than in telecom, these factors represent relatively more rapid acceleration in TFP relative to historical experience. Below we present the industry TFP and stretch factors approved in the eight comprehensive indexing plans for which North American regulators made specific findings on these elements.

Company	Jurisdiction	TFP	Stretch
Southern California Edison	California	0.9%	0.56%
Southern California Gas	California	0.5%	0.8%
San Diego Gas and Electric – Gas	California	0.68%	0.55%
SDG&E-Electric	California	0.92%	0.55%
Boston Gas	Massachusetts	0.4%	0.5%
Boston Gas – update	Massachusetts	0.6%	0.3%
Ontario power distributors	Ontario, Canada	1.25%	0.25%
Union Gas	Ontario, Canada	0.9%	0.5%
Average		0.77%	0.50%

APPENDIX ONE: DETAILS OF TFP ESTIMATION

This appendix contains additional details of our TFP work. Section A.1.1 addresses the input quantity indexes, including the calculation of capital cost. Section A.1.2 addresses our method for calculating TFP growth rates and trends.

A.1 Input Quantity Indexes

The growth rates of the input quantity indexes were defined by formulas. As noted, these formulas involved sub indexes measuring growth in the amounts of various inputs used. Major decisions in the design of such indexes include their form and the choice of input categories and quantity sub indexes.

A.1.1 Index Form

Each regional input quantity index was of Törnqvist form.[70] The annual growth rate of each index was determined by the formula:

$$\ln\left(\frac{Input\ Quantities_t}{Input\ Quantities_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left(S_{j,t} + S_{j,t-1} \right) \cdot \ln\left(\frac{X_{j,t}}{X_{j,t-1}} \right). \quad [9]$$

Here in each year *t*,

$Input\ Quantities_t$ = Input quantity index

$X_{j,t}$ = Quantity sub index for input category *j*

$S_{j,t}$ = Share of input category *j* in applicable total cost.

It can be seen that the growth rate of the index is a weighted average of the growth rates of the quantity sub indexes. Each growth rate is calculated as the logarithm of the ratio of the quantities in successive years. For the output quantity index, weights are equal to the share of each quantity sub index's cost elasticity in the sum of cost elasticities for all outputs. Cost elasticities were estimated in our econometric work. For the input quantity indexes, data on the average shares of each input in the aggregate applicable total cost of sampled utilities during these years are the weights.

A.1.1.2 Output Quantity Sub indexes

Output quantity sub indexes were total electric customers and electric delivery volumes.

A.1.1.3 Input Quantity Sub indexes

The quantity sub index for other O&M inputs was the ratio of O&M expenses inputs to the Jamaican CPI. The approach to quantity trend measurement taken in each case relies on the theoretical result that the growth rate in the cost of any class of input *j* is the sum of the growth rates in appropriate input price and quantity indexes for that input class. Thus,

$$growth\ Input\ Quantities_j = growth\ Cost_j - growth\ Input\ Prices_j. \quad [10]$$

The quantity sub indexes for capital are discussed immediately below.

[70] For seminal discussions of this index form see Törnqvist (1936) and Theil (1965).

A.1.1.4 Capital Cost

A service price approach was chosen to measure capital cost. This approach has a solid basis in economic theory and is widely used in scholarly empirical work.[71] It facilitates the aggregation for purposes of industry TFP research of cost data for utilities with different plant vintages.

In the application of the general method used in this study, the cost of a given class of utility plant *j* in a given year *t* ($CK_{j,t}$) is the product of a capital service price index ($WKS_{j,t}$) and an index of the capital quantity at the end of the prior year (XK_{t-1}).

$$CK_{j,t} = WKS_{j,t} \cdot XK_{j,t-1}. \qquad [11]$$

For JPS, the capital quantity index is constructed using JPS data on the net value of utility plant plus the capacity costs on IPP purchased power contracts. The service price index measures the trend in the hypothetical price of capital services from the assets in a competitive rental market.

For the US utilities, used in the benchmarking work, each capital quantity index is constructed using inflation-adjusted data on the value of utility plant. In constructing indexes we took 1967 as the benchmark or starting year. The values for these indexes in the benchmark year are based on the net value of plant as reported in the FERC Form One. We estimated the benchmark year (inflation adjusted) value of net plant by dividing this book value by a "triangularized" weighted average of the values of an index of utility asset prices for a period ending in the benchmark year. Values were considered for a series of consecutive years with length equal to the lifetime of the relevant plant category. A triangularized weighting gives greater weight to more recent values of this index, reflecting the notion that more recent plant additions have a disproportionate impact on book value.[72] The asset-price index (WKA_t) was the applicable regional Handy-Whitman index of utility construction costs for the relevant asset category.[73]

The following formula was used to compute subsequent values of the capital quantity index:

$$XK_{j,t} = (1 - d) \cdot XK_{j,t-1} + \frac{VI_{j,t}}{WKA_{j,t}}. \qquad [12]$$

Here, the parameter *d* is the economic depreciation rate and VI_t is the value of gross additions to utility plant.

The economic depreciation rate was calculated as a weighted average of the depreciation rates for the structures and equipment used in the applicable industry. The depreciation rate for each structure and equipment category was obtained from the Bureau of Economic Analysis (BEA) of the US Department of Commerce. The weights were based on net stock value data drawn from the same source.

The full formula for a capital service price index is:

$$WKS_t = r_t \cdot WKA_{j,t-1} + d \cdot WKA_{j,t} \quad . \qquad [13]$$

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[71] See Hall and Jorgensen (1967) for a seminal discussion of the service price method of capital cost measurement.

[72] For example, in a triangularized weighting of 20 years of index values, the oldest index value has a weight of 1/210, the next oldest index has a value of 2/210, and so on. 210 is the sum of the numbers from 1 to 20. A discussion of triangularized weighting of asset price indexes is found in Stevenson (1980).

[73] These data are reported in the *Handy-Whitman Index of Public Utility Construction Costs*, a publication of Whitman, Requardt and Associates.

The two terms in this formula correspond to the opportunity cost of capital and depreciation.[74] The term r_t is the cost of funds. As a proxy for this we employ the user cost of capital for the respective economy (the US economy for US IOUs, the Jamaican economy for JPS). This reflects returns on equity as well as interest rates. We calculate the user cost of capital using data in the National Income and Product Accounts (NIPA). The accounts are published by the BEA in its *Survey of Current Business* series. Our cost of capital report for JPS calculates that the Company's cost of capital is a nominal 19.1%, so this was used for the opportunity cost of capital in our TFP and econometric work.

WKA_t for JPS was a weighted average of two inflation measures. The first was the product of the Handy-Whitman index and the US-Jamaican exchange rate. The second was the Jamaican CPI. In each year, the weight applied to the Jamaican CPI was equal to the share of capital costs accounted for by IPP capacity contracts in that year. The weight applied to the product of the Handy-Whitman index and the US-Jamaican exchange rate was equal to the share of capital costs accounted for by JPS' own capital stock in that year.

A1.2 TFP Growth Rates and Trends

The annual growth rate in the TFP index is given by the formula

$$\begin{aligned} \ln\left(TFP_t \big/ TFP_{t-} \right) = \ln\left(\textit{Output Quantities}_t \big/ \textit{Output Quantities}_{t\text{-}1} \right) - \\ \ln\left(\textit{Input Quantities}_t \big/ \textit{Input Quantities}_{t\text{-}1} \right) \end{aligned} . \qquad [14]$$

The results featured in this report are for the long-run trends of the indexes. Since the index formulas involve annual growth rates, some method is needed to calculate long run trends from the annual growth rates. The long run trend in each TFP index was computed using the formula

$$\begin{aligned} \text{trend TFP}_t &= \frac{\sum_t {}_{1990}^{2007} \ln\left(TFP_t \big/ TFP_{t-1} \right)}{17} \\ &= \frac{\ln\left(TFP \big/ TFP_{1990} \right)}{17} \end{aligned} . \qquad [15]$$

It can be seen that the long run trend is the average annual growth rate during the years of the sample period. The reported long run trends in other indexes and sub indexes were computed analogously.

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[74] The opportunity cost of capital is sometimes called the cost of funds.

APPENDIX TWO: FURTHER DETAILS OF THE BENCHMARKING RESEARCH

A.2.1 Form of the Cost Model

The functional form selected for this study was the translog.[75] This very flexible function is the most frequently used in econometric cost research and by some account the most reliable of several available alternatives.[76] The general form of the translog cost function is:

$$\begin{aligned}\ln C &= \alpha_0 + \sum_h \alpha_h \ln Y_h + \sum_j \alpha_j \ln W_j \\ &+ \frac{1}{2}\left(\sum_h \sum_k \gamma_{h,k} \ln Y_h \ln Y_k + \sum_j \sum_n \gamma_{j,n} \ln W_j \ln W_n\right) \\ &+ \sum_h \sum_j \gamma_{i,j} \ln Y_i \ln W_j\end{aligned} \qquad [16]$$

where Y_h denotes one of K variables that quantify output and the W_j denotes one of N input prices.

One aspect of the flexibility of this function is its ability to allow the elasticity of cost with respect to each business condition variable to vary with the value of that variable. The elasticity of cost with respect to an output quantity, for instance, may be greater at smaller values of the variable than at larger variables. This type of relationship between cost and quantity is often found in cost research.

Business conditions other than input prices and output quantities can contribute to differences in the costs of LDCs. To help control for other business conditions the logged values of some additional explanatory variables were added to the model.

The econometric model of cost we wish to estimate can then be written as:

$$\begin{aligned}\ln C &= \alpha_o + \sum_h \alpha_h \ln Y_h + \sum_j \alpha_j \ln W_j \\ &+ \frac{1}{2}\left[\sum_h \sum_k \gamma_{hk} \ln Y_h \ln Y_k + \sum_j \sum_n \gamma_{jn} \ln W_j \ln W_n\right] \\ &+ \sum_h \sum_j \gamma_{ij} \ln Y_h \ln W_j + \sum_h \alpha_h \ln Z_h + \alpha_t T + \varepsilon\end{aligned} \qquad [17]$$

Here the Z_h's denote the additional business conditions, T is a trend variable, and ε denotes the error term of the regression.

Cost theory requires a well-behaved cost function to be homogeneous in input prices. This implies the following three sets of restrictions:

$$\sum_{h=1}^{N} \frac{\partial \ln C}{\partial \ln W_h} = 1 \qquad [18]$$

[75] The transcendental logarithmic (or translog) cost function can be derived mathematically as a second order Taylor series expansion of the logarithmic value of an arbitrary cost function around a vector of input prices and output quantities.

[76] See Guilkey (1983), et. al.

$$\sum_{h=1}^{N} \frac{\partial^2 \ln C}{\partial \ln W_h \partial \ln W_j} = 0 \qquad \forall j = 1,\ldots,N \qquad [19]$$

$$\sum_{h}^{N} \frac{\partial^2 \ln C}{\partial \ln Y_h \partial \ln Y_j} = 0 \qquad \forall j = 1,\ldots,K \qquad [20]$$

Imposing the above $(1+N+K)$ restrictions implied by Equations [18-20] allow us to reduce the number of parameters that need be estimated by the same amount.

Estimation of the parameters in Equation [17] is now possible but this approach does not utilize all information available in helping to explain the factors that determine cost. More efficient estimates can be obtained by augmenting the cost equation with the set of cost share equations implied by Shepard's Lemma. The general form of a cost share equation for a representative input price category, *j*, can be written as:

$$S_j = \alpha_j + \sum_i \gamma_{h,j} \ln Y_h + \sum_n \gamma_{jn} \ln W_n \qquad [21]$$

We note that the parameters in this equation also appear in the cost model. Since the share equations for each input price are derived from the first derivative of the translog cost function with respect to that input price, this should come as no surprise. Furthermore, because of these cross-equation restrictions, the total number of coefficients in this system of equations will be no larger than the number of coefficients required to be estimated in the cost equation itself.

A.2.2 Estimation Procedure

We estimated this system of equations using a procedure first proposed by Zellner (1962).[77] It is well known that if there exists contemporaneous correlation between the errors in the system of regressions, more efficient estimates can be obtained by using a Feasible Generalized Least Squares (FGLS) approach. To achieve even a better estimator, PEG iterates this procedure to convergence.[78] Since we estimate these unknown disturbance matrices consistently, the estimators we eventually compute are equivalent to Maximum Likelihood Estimation (MLE).[79] Our estimates would thus possess all the highly desirable properties of MLE's.

Before proceeding with estimation, there is one complication that needs to be addressed. Since the cost share equations by definition must sum to one at every observation, one cost share equation is redundant and must be dropped.[80] This does not pose a problem since another property of the MLE procedure is that it is invariant to any such reparameterization. Hence, the choice of which equation to drop will not affect the resulting estimates.

A.2.3 Predicting Cost

We now turn our attention to the topic of predicting the level of a utility's cost given its specific values for the explanatory variables. Fitting our cost model and cost share equations with the econometric parameter estimates, we obtain an econometric model of non-fuel cost. This can

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[77] See Zellner, A. (1962).

[78] That is, we iterate the procedure until the determinant of the difference between any two consecutive estimated disturbance matrices are approximately zero.

[79] See Dhrymes (1971), Oberhofer and Kmenta (1974), Magnus (1978).

[80] This equation can be estimated indirectly from the estimates of the parameters left remaining in the model.

then be used to predict the historical cost of a utility given its values for the specified business controls.

It is well known that the ability of the model to make accurate predictions depends, in part, on the characteristics of the data reported for the utility as compared to the sample averages. The closer the firm's data are to the sample averages, the more accurate is the model's prediction. Alternatively, the more the characteristics of the utility's data lie outside those of the sample means, the less reliable is its predicted cost.

APPENDIX THREE: APPROPRIATE QUALITY INDICATORS

The outage cost literature suggests that outages impose both fixed and variable costs on customers. Fixed costs are those that occur immediately when, for example, service interruptions disrupt an industrial customer's production plans. Variable costs are related to the duration of an outage. The relative proportions of these costs vary among customer groups. Industrial customers typically have a higher proportion of fixed costs, while residential customers usually have a lower proportion of fixed costs.

Let the system–wide cost for each outage, *i*, be given by

$$C_i = a + bh_i \qquad [22]$$

Here, C_i is the cost of the outage and h_i is the total duration of the outage experienced by customers on the system. This simple, linear expression says that outage costs can be decomposed into two components. The fixed costs, a, are incurred immediately as power interruptions disrupt production plans. The variable costs, bh_i, are related to the length of the outage. Total annual outage costs are obtained by summing the costs per outage in [22] over the number of outages in each year. Total outage costs in each year, t, are therefore equal to

$$TC_t = \sum_i \left(a + bhi\right) = N_t a + b\sum h_{i,t} \qquad [23]$$

Here, N_t stands for the number of interruptions experienced in year, t. The average outage costs experienced by customers on the system can be obtained by dividing [23] by the average number of customers served in year t, or C_t. Therefore

$$\frac{TC_t}{C_t} = a\frac{N_t}{C_t} + b\frac{\sum h_{i,t}}{C_t} \qquad [24]$$

In equation [24], $\frac{N_t}{C_t}$ corresponds to the average number of interruptions experienced by a customer on the system in year t. This is equivalent to the value of SAIFI in that year. Similarly, $\frac{\sum h_{i,t}}{C_t}$ stands for the total duration of outages experienced by an average customer on the system in year t. This is equivalent to the value of SAIDI in that year. Equation [24] therefore implies that the annual outage costs experienced by an average customer are a linear function of values for SAIFI and SAIDI. SAIFI is multiplied by the average fixed costs associated with an outage. SAIDI is multiplied by the average variable costs associated with a typical outage.

Annex J: Customer Count List

Feeder Name	Feeder ID	Premises Count
Annotto Bay S/S - 210 Fdr	218/6-210	5,862
Annotto Bay S/S - 310 Fdr	218/6-310	667
Blackstonedge S/S - 110 Fdr	199/4-110	2,459
Bogue S/S - 210 Fdr	001/6-210	13,684
Bogue S/S - 310 Fdr	001/6-310	12,834
Bogue S/S - 410 Fdr	001/6-410	461
Cane River S/S - 310 Fdr	200/6-310	2,536
Cane River S/S - 410 Fdr	200/6-410	2,818
Cane River S/S - 610 Fdr	200/6-610	683
Cardiff Hall S/S - 210 Fdr	053/6-210	4,681
Cardiff Hall S/S - 310 Fdr	053/6-310	16,049
Cement Company	268/6-110	1
Constant Spring S/S - 210 Fdr	191/5-210	9,931
Constant Spring S/S - 310 Fdr	191/6-310	2,775
Constant Spring S/S - 410 Fdr	191/6-410	9,883
D&G S/S - 210 Fdr	281/5-210	4
D&G S/S - 310 Fdr	281/5-310	2,622
Duhaney S/S - 210 Fdr	020/6-210	4,154
Duhaney S/S - 310 Fdr	020/6-310	14,031
Duhaney S/S - 410 Fdr	020/6-410	1,405
Duncans S/S - 110 Fdr	161/4-110	5,774
Good Year S/S - 210 Fdr	186/6-210	12,510
Greenwich S/S - 310 Fdr	223/6-310	938
Greenwich S/S - 410 Fdr	223/6-410	1,398
Greenwich S/S - 510 Fdr	223/6-510	1,958
Greenwich S/S - 710 Fdr	223/6-710	2,799
Greenwood S/S - 110 Fdr	006/4-110	5,667
Greenwood S/S - 210 Fdr	006/4-210	1,045
Highgate S/S - 110 Fdr	011/4-110	4,211
Highgate S/S - 210 Fdr	011/4-210	6,915
Hope S/S - 310 Fdr	041/6-310	535
Hope S/S - 410 Fdr	041/6-410	6,171
Hope S/S - 510 Fdr	041/6-510	6,294
Hunts Bay S/S - 110 Fdr	265/6-110	250
Hunts Bay S/S - 210 Fdr	265/6-210	622
Hunts Bay S/S - 310 Fdr	265/6-310	3,049
Hunts Bay S/S - 410 Fdr	265/6-410	15
Hunts Bay S/S - 510 Fdr	265/6-510	850
Hunts Bay S/S - 610 Fdr	265/5-610	3
Hunts Bay S/S - 710 Fdr	265/6-710	582
Hunts Bay S/S - 810 Fdr	265/5-810	2,399
Kendal S/S - 210 Fdr	237/6-210	17,562
Kendal S/S - 310 Fdr	237/6-310	7,167
Lyssons S/S - 410 Fdr	238/6-410	6,527
Maggotty S/S - 110 Fdr	031/6-110	5,344

FeederName	FeederID	PremisesCount
Maggotty S/S - 210 Fdr	031/6-210	18,490
Martha Brae S/S - 110 Fdr	007/4-110	3,860
May Pen S/S - 110 Fdr	201/6-110	11,244
May Pen S/S - 210 Fdr	201/6-210	2,535
Michelton S/S - 110 Fdr	013/4-110	10,136
Michelton S/S - 210 Fdr	013/4-210	4,682
Monymusk S/S - 210 Fdr	194/4-210	2,000
Monymusk S/S - 310 Fdr	194/4-310	3
Monymusk S/S - 410 Fdr	194/4-410	2,921
Naggos Head S/S - 510 Fdr	239/6-510	11,911
Naggos Head S/S - 610 Fdr	239/6-610	11,659
Ocho Rios S/S - 310 Fdr	167/4-310	5,398
Ocho Rios S/S - 410 Fdr	167/4-410	1,387
Ocho Rios S/S - 510 Fdr	167/4-510	1,893
Oracabessa S/S - 110 Fdr	126/4-110	3,607
Oracabessa S/S - 210 Fdr	126/4-210	4,618
Orange Bay S/S - 210 Fdr	017/6-210	2,836
Orange Bay S/S - 310 Fdr	017/6-310	13,365
Paradise S/S - 110 Fdr	019/6-110	10,846
Paradise S/S - 210 Fdr	019/6-210	11,725
Paradise S/S - 310 Fdr	019/6-310	9,731
Parnassus S/S - 210 Fdr	026/6-210	10,615
Parnassus S/S - 310 Fdr	026/6-310	8,293
Port Antonio S/S - 310 Fdr	297/6-310	5,829
Port Antonio S/S - 410 Fdr	297/6-410	10,033
Ports Authority	169/5-110	1
Porus S/S - 210 Fdr	014/6-210	5,453
Porus S/S - 310 Fdr	014/6-310	934
Queens Drive S/S - 310 Fdr	004/6-310	2,226
Queens Drive S/S - 510 Fdr	004/6-510	1
Queens Drive S/S - 610 Fdr	004/6-610	1
Queens Drive S/S - 710 Fdr	004/6-710	15,533
Queens Drive S/S - 810 Fdr	004/6-810	2,597
Rhodens Pen S/S - 210 Fdr	092/4-210	2,785
Rhodens Pen S/S - 310 Fdr	092/4-310	3,654
Rhodens Pen S/S - 410 Fdr	092/4-410	8,629
Roaring River S/S - 210 Fdr	009/4-210	7,069
Roaring River S/S - 310 Fdr	009/4-310	51
Roaring River S/S - 410 Fdr	009/4-410	5,439
Rockfort S/S - 210 Fdr	243/6-210	2,932
Rockfort S/S - 310 Fdr	243/6-310	1
Rockfort S/S - 410 Fdr	243/6-410	6,777

FeederName	FeederID	PremisesCount
Rose Hall S/S - 110	005/6-110	2,101
Rose Hall S/S - 210	005/6-210	1,811
Spur Tree S/S - 210 Fdr	064/6-210	15,441
Spur Tree S/S - 310 Fdr	064/6-310	16,418
Three Miles S/S - 310 Fdr	289/5-310	54
Three Miles S/S - 410 Fdr	289/5-410	193
Three Miles S/S - 510 Fdr	289/5-510	529
Tredegar S/S - 210 Fdr	197/6-210	7,254
Tredegar S/S - 310 Fdr	197/6-310	6,321
Tredegar S/S - 410 Fdr	197/6-410	12,324
Twickenham S/S - 210 Fdr	298/6-210	16,365
Twickenham S/S - 410 Fdr	298/6-410	5,791
Up Park Camp S/S - 310 Fdr	245/6-310	1,110
Up Park Camp S/S - 410 Fdr	245/6-410	2,426
Up Park Camp S/S - 510 Fdr	245/6-510	4,168
Upper White River S/S - 110 Fdr	010/4-110	5,517
Washington Blvd S/S - 310 Fdr	104/6-310	6,528
Washington Blvd S/S - 410 Fdr	104/6-410	2,034
Washington Blvd S/S - 510 Fdr	104/6-510	6,066
Washington Blvd S/S - 610 Fdr	104/6-610	5,984
Washington Blvd S/S - 710 Fdr	104/6-710	6,994
Washington Blvd S/S - 810 Fdr	104/6-810	3,508
West Kings House S/S - 210 Fdr	241/6-210	537
West Kings House S/S - 310 Fdr	241/6-310	3,347
West Kings House S/S - 410 Fdr	241/6-410	2,861
		587,507

Annex K: 2008 MAIFI Details

2008 MAIFI Outage Data (<= 5 minutes)

			SUB - TOTAL (NO SAIFI)			SUB - TOTAL (SAIFI RELATED)					
Substation	**Feeder**	**Under-frequency Stage No.**	**Cycle (<6 sec but NO SAIFI)**	**Cycle (>=6 sec but NO SAIFI)**	**Cycle (<=5 min but NO SAIFI)**	**Cycle (<6 sec results in SAIFI outage)**	**Cycle (>=6 sec results in SAIFI outage)**	**Cycle (<5 min results in SAIFI outage)**	**TOTAL # Outages**	**Number of customers**	**MAIFI (NO SAIFI)**
ANOTOBAY	A/BAY FDR 6-310		130	8	**138**	15		**15**	153	678	0.161
	DOVER FDR 6-210		233	11	**244**	23		**23**	267	5,735	2.408
	MAIN FDR 6-110		1		**1**				1	6,413	0.011
BLKSTONE	GUYSHL FDR 4-110		71	3	**74**	1		**1**	75	2,456	0.313
BOGUE	HOSP FDR 6-410		84	11	**95**	7		**7**	102	446	0.073
	LUCEA FDR 6-210		234	8	**242**	12	1	**13**	255	13,652	5.686
	MAIN FDR 6-110			1	**1**				1	26,852	0.046
	MOBAY FDR 6-310		142	3	**145**	2	2	**4**	149	12,754	3.183
CANERIVR	AIRPORT FDR 6-610		108	6	**114**	3	1	**4**	118	654	0.128
	BULL BAY FDR 6-310	3	37	7	**44**	2	2	**4**	48	2,448	0.185
	H/VIEW FDR 6-410		63	7	**70**	10		**10**	80	2,838	0.342
	MAIN FDR 6-110		3	7	**10**				10	2,838	0.049
	MAIN FDR 6-210		29	6	**35**	1		**1**	36	3,102	0.187
CARDHALL	MAIN FDR 6-110		1	7	**8**				8	20,109	0.277
CONSPRNG	LONG LANE FDR 6-310		85	4	**89**				89	2,671	0.409
	MAIN FDR 6-110		1	2	**3**				3	25,322	0.131
	MANNING FDR 6-210	1	45	20	**65**	28	11	**39**	104	9,756	1.091
	STONYHL FDR 6-410		64	24	**88**	7		**7**	95	12,895	1.953
DUHANEY	FERRY FDR 6-210		157	12	**169**	9	1	**10**	179	3,962	1.152
	MAIN FDR 6-110		15	1	**16**				16	19,443	0.535
	PEMBROKE FDR 6-310		5	7	**12**	1		**1**	13	14,078	0.291
	SP TWN RD FDR 6-410	3	2	2	**4**				4	1,403	0.010
DUNCANS	DUNCAN FDR 4-110		155	25	**180**	11		**11**	191	5,700	1.766
GRENWOOD	ROSE HALL FDR 6-210		16	1	**17**				17	1,047	0.031
GRWICHRD	MAIN FDR 6-110		1	3	**4**		1	**1**	5	3,718	0.026
	MAIN FDR 6-210		1		**1**				1	3,316	0.006
	MAXFIELD FDR 6-710	3	28	4	**32**	3	1	**4**	36	2,769	0.152

Substation	Feeder	Under-frequency Stage No.	SUB - TOTAL (NO SAIFI) Cycle (<6 sec but NO SAIFI)	Cycle (>=6 sec but NO SAIFI)	Cycle (<=5 min but NO SAIFI)	SUB - TOTAL (SAIFI RELATED) Cycle (<6 sec results in SAIFI outage)	Cycle (>=6 sec results in SAIFI outage)	Cycle (<5 min results in SAIFI outage)	TOTAL # Outages	Number of customers	MAIFI (NO SAIFI)
	NEW KGN FDR 6-510	4	32	13	**45**				45	1,947	0.151
	OHOPE RD FDR 6-410	4	39	5	**44**	1		**1**	45	1,369	0.104
	X RDS FDR 6-310	3	62	13	**75**	4		**4**	79	949	0.122
HOPE	EAST FDR 6-510	3	106	8	**114**	7		**7**	121	6,484	1.272
	LIGUANEA FDR 6-410	2	15	19	**34**	12		**12**	46	6,050	0.354
	MAIN FDR 6-110		1		**1**				1	12,534	0.022
	MAIN FDR 6-210			1	**1**				1	516	0.001
	PAPINE FDR 6-310		21		**21**				21	516	0.019
HUNTBAYB	B		15		**15**				15	233	0.006
	ESSO FDR 5-610		7	2	**9**	2		**2**	11	4	0.000
	HBR ST FDR 6-210	4	1	20	**21**		2	**2**	23	644	0.023
	NORTH ST FDR 6-510		9	2	**11**	3		**3**	14	859	0.016
	ORANGE ST FDR 6-410		1	14	**15**		1	**1**	16	15	0.000
	SP TWN RD FDR 5-810	1	5	20	**25**	2	6	**8**	33	2,193	0.094
	X RDS FDR 6-310	2	53	3	**56**	8		**8**	64	3,092	0.298
KENDAL	C/TIANA FDR 6-210	3	198	19	**217**	8	1	**9**	226	17,136	6.400
	M/GULLY FDR 6-310		91	14	**105**	16		**16**	121	6,923	1.251
	MAIN FDR 6-110			2	**2**		1	**1**	3	24,059	0.083
MAGGOTTY	B/RIV FDR 6-210		24	38	**62**	4	1	**5**	67	18,076	1.929
	MAGTY FDR 6-110		293	24	**317**	7		**7**	324	5,284	2.883
MICLETON	BOGWLK FDR 4-210		73	5	**78**				78	4,622	0.620
	LINSTD FDR 4-110		81	3	**84**	4		**4**	88	9,827	1.421
NAGOHEAD	B/LODGE FDR 6-610		16	10	**26**	3	1	**4**	30	11,552	0.517
	FDR 6-510		239	16	**255**	2		**2**	257	11,283	4.952
	MAIN FDR 6-210		1	2	**3**				3	22,835	0.118
OCHORIOS	FRANKFURT FDR 4-510		66	6	**72**	1	1	**2**	74	1,929	0.239
	MAIN FDR 4-110		1		**1**				1	8,494	0.015
	MAIN ST FDR 4-410		10	2	**12**	1		**1**	13	1,374	0.028
	OCHO RIOS FDR 4-310		98	11	**109**	8		**8**	117	5,191	0.974
ORANGBAY	LUCEA FDR 6-310	1	459	24	**483**	40	2	**42**	525	13,390	11.130
	MAIN FDR 6-110		1		**1**				1	24,201	0.042
	NEGRIL FDR 6-210		125	7	**132**	10		**10**	142	2,891	0.657

Substation	Feeder		SUB - TOTAL (NO SAIFI)			SUB - TOTAL (SAIFI RELATED)					
		Under-frequency Stage No.	Cycle (<6 sec but NO SAIFI)	Cycle (>=6 sec but NO SAIFI)	Cycle (<=5 min but NO SAIFI)	Cycle (<6 sec results in SAIFI outage)	Cycle (>=6 sec results in SAIFI outage)	Cycle (<5 min results in SAIFI outage)	TOTAL # Outages	Number of customers	MAIFI (NO SAIFI)
PARADISE	FERRIS FDR 6-210		48	14	**62**	26	1	**27**	89	11,919	1.272
	FROME FDR 6-110	1	40	23	**63**	4	10	**14**	77	13,806	1.497
	NEGRIL FDR 6-310		23	3	**26**	16		**16**	42	6,979	0.312
PARNASUS	HAYES FDR 6-310		107	18	**125**	2		**2**	127	8,413	1.810
	MAIN FDR 6-110		2		**2**				2	19,030	0.066
	MAYPEN FDR 6-210		150	15	**165**	3	1	**4**	169	10,617	3.015
PORTONIO	MAIN FDR 6-110		50	5	**55**	6		**6**	61	15,677	1.484
	SAN SAN FDR 6-310		386	22	**408**	23	1	**24**	432	5,713	4.011
	TOWN FDR 6-410		312	29	**341**	15	1	**16**	357	9,964	5.847
QUEENSDR	AIRPORT A FDR 6-510		9	8	**17**	1		**1**	18	1	0.000
	AIRPORT B FDR 6-610		4	4	**8**	1		**1**	9	1	0.000
	FLANKERS FDR 6-710		66	2	**68**	5	1	**6**	74	15,431	1.806
	HOTEL FDR 6-810		54	9	**63**	5		**5**	68	2,612	0.283
	MAIN FDR 6-110					1		**1**	1	2,613	
	MAIN FDR 6-210		2	2	**4**	1		**1**	5	17,621	0.121
	QUEEN S DR FDR 6-310		32	3	**35**	2	1	**3**	38	2,189	0.132
RHODEPEN	INDEST FDR 4-310		104	2	**106**	2		**2**	108	3,470	0.633
	MAIN FDR 4-110		3	1	**4**				4	14,717	0.101
	O/HBAY FDR 4-410		115	5	**120**	7		**7**	127	8,439	1.743
	SPRVIL FDR 4-210		88	4	**92**	6		**6**	98	2,808	0.445
ROARIVER	B/TOWN FDR 4-210		84	20	**104**	2	1	**3**	107	6,961	1.246
	MAIN FDR 4-110		4	5	**9**				9	12,255	0.190
	O/RIOS FDR 4-310		20		**20**				20	51	0.002
	S/ANNBY FDR 4-410		75	36	**111**	6		**6**	117	5,243	1.002
ROCKFORT	DOWNTWN FDR 6-410	4	63	16	**79**	2		**2**	81	6,809	0.926
	FLOURMIL FDR 6-310		13	1	**14**				14	1	0.000
	MAIN FDR 6-110		1	1	**2**				2	9,796	0.034
	ROLLTWN FDR 6-210		59	8	**67**	5	1	**6**	73	2,986	0.344
ROSEHALL	COR GARDEN FDR 6-110		84		**84**	2		**2**	86	1,783	0.258
	R/HALL FDR 4-210		76	1	**77**	1		**1**	78	1,804	0.239
SPURTREE	MAIN FDR 6-110		1	3	**4**				4	34,524	0.238
	NEWPORT FDR 6-310	1	213	25	**238**	5	16	**21**	259	15,859	6.496

Substation	Feeder	Under-frequency Stage No.	SUB - TOTAL (NO SAIFI) Cycle (<6 sec but NO SAIFI)	Cycle (>=6 sec but NO SAIFI)	Cycle (<=5 min but NO SAIFI)	SUB - TOTAL (SAIFI RELATED) Cycle (<6 sec results in SAIFI outage)	Cycle (>=6 sec results in SAIFI outage)	Cycle (<5 min results in SAIFI outage)	TOTAL # Outages	Number of customers	MAIFI (NO SAIFI)
	S/CRUZ FDR 6-210	1	169	27	**196**	5	11	**16**	212	15,078	5.086
THREEMLS	FREEZONE FDR 5-310		10	6	**16**	5		**5**	21	62	0.002
	M GARV DR FDR 5-510		29	6	**35**	2	1	**3**	38	510	0.031
	MAIN FDR 5-110	3	2	1	**3**				3	776	0.004
	SP TWN RD FDR 5-410		61	21	**82**	3		**3**	85	204	0.029
TREDEGAR	ELTHAM FDR 6-310		260	12	**272**	11		**11**	283	6,314	2.956
	ENSOM FDR 6-210		113	10	**123**	4		**4**	127	7,153	1.514
	MAIN FDR 6-110		10	2	**12**	3		**3**	15	25,885	0.535
	SP TWN FDR 6-410		192	20	**212**	21		**21**	233	12,418	4.531
TWICKNAM	G/DALE FDR 6-410	2	226	17	**243**	17	1	**18**	261	5,809	2.429
	MAIN FDR 6-110		2	2	**4**				4	22,203	0.153
	P/MORE FDR 6-210	2	47	14	**61**	5		**5**	66	16,394	1.721
UPPKCAMP	MAIN FDR 6-110		2		**2**				2	7,662	0.026
	MTVIEW FDR 6-510		2		**2**				2	4,182	0.014
	N/KGN FDR 6-310		46	4	**50**	3		**3**	53	1,131	0.097
	OXFORD FDR 6-410		36	2	**38**	1		**1**	39	2,349	0.154
WASHBLVD	CSPRNG FDR 6-510	2	55	3	**58**	2	1	**3**	61	2,940	0.293
	HWT RD FDR 6-410	2	77	11	**88**	7		**7**	95	2,032	0.308
	MAIN FDR 6-110		1		**1**				1	9,659	0.017
	MAIN FDR 6-210		1		**1**				1	15,676	0.027
	MOLYNES FDR 6-710	1	215	52	**267**	34	21	**55**	322	7,069	3.248
	RED HILLS FDR 6-810	1	43	19	**62**	7	10	**17**	79	3,591	0.383
	SHORTWD FDR 6-610	2	67	2	**69**	9		**9**	78	6,068	0.721
	WALTHAM FDR 6-310	2	34	11	**45**	5	1	**6**	51	6,575	0.509
WESTKHRD	HOPE RD FDR 6-310	4	22	13	**35**	3	2	**5**	40	3,293	0.198
	MAIN FDR 6-110	4	1		**1**				1	6,727	0.012
	N/KGN FDR 6-210	4	10	8	**18**	1		**1**	19	547	0.017
	W/LOO RD FDR 6-410	4	29	3	**32**	2		**2**	34	2,887	0.159
GRAND TOTAL			7904	1044	**8,948**	577	118	**695**	**9,643**		**117**

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Under-frequency Points	UF Stage	Substation	Feeder	Customer Count	2006 Trips	2007 Trips	2008 Trips
		ANOTOBAY	A/BAY FDR 6-310	678	96	306	153
		ANOTOBAY	DOVER FDR 6-210	5,735	144	282	267
		ANOTOBAY	**MAIN FDR 6-110**	**6,413**		7	1
		BLKSTONE	GUYSHL FDR 4-110	2,456	22	194	75
		BOGUE	HOSP FDR 6-410	446	53	84	102
		BOGUE	LUCEA FDR 6-210	13,652	139	214	255
		BOGUE	**MAIN FDR 6-110**	**26,852**	1		1
		BOGUE	MOBAY FDR 6-310	12,754	120	198	149
		CANERIVR	AIRPORT FDR 6-610	654	44	147	118
UF	3	CANERIVR	BULL BAY FDR 6-310	2,448	51	154	48
		CANERIVR	H/VIEW FDR 6-410	2,838	27	83	80
		CANERIVR	**MAIN FDR 6-110**	**2,838**		1	10
		CANERIVR	**MAIN FDR 6-210**	**3,102**		2	36
		CARDHALL	**MAIN FDR 6-110**	**20,109**	2	2	8
		CONSPRNG	LONG LANE FDR 6-310	2,671	43	88	89
		CONSPRNG	**MAIN FDR 6-110**	**25,322**	30	7	3
UF	1	CONSPRNG	MANNING FDR 6-210	9,756	14	54	104
		CONSPRNG	STONYHL FDR 6-410	12,895	36	67	95
		DUHANEY	**MAIN FDR 6-110**	**19,443**	23	2	16
		DUHANEY	PEMBROKE FDR 6-310	14,078	21	26	13
UF	3	DUHANEY	SP TWN RD FDR 6-410	1,403	19	21	4
		DUNCANS	DUNCAN FDR 4-110	5,700	101	200	191
		GRENWOOD	ROSE HALL FDR 6-210	1,047		76	17
		GRWICHRD	**MAIN FDR 6-110**	**3,718**		2	5
		GRWICHRD	**MAIN FDR 6-210**	**3,316**		1	1
UF	3	GRWICHRD	MAXFIELD FDR 6-710	2,769	24	45	36

Under-frequency Points	UF Stage	Substation	Feeder	Customer Count	2006 Trips	2007 Trips	2008 Trips
UF	4	GRWICHRD	NEW KGN FDR 6-510	1,947	47	77	45
UF	4	GRWICHRD	OHOPE RD FDR 6-410	1,369	16	34	45
UF	3	GRWICHRD	X RDS FDR 6-310	949	26	42	79
UF	3	HOPE	EAST FDR 6-510	6,484		191	121
UF	2	HOPE	LIGUANEA FDR 6-410	6,050	33	43	46
		HOPE	**MAIN FDR 6-110**	**12,534**		2	1
		HOPE	**MAIN FDR 6-210**	**516**	2	1	1
		HOPE	PAPINE FDR 6-310	516	27	41	21
		HUNTBAYB	B	233	11	26	15
		HUNTBAYB	ESSO FDR 5-610	4	6	19	11
UF	4	HUNTBAYB	HBR ST FDR 6-210	644	20	48	23
UF	2	HUNTBAYB	NORTH ST FDR 6-510	859	5	19	14
		HUNTBAYB	ORANGE ST FDR 6-410	15	12	12	16
UF	1	HUNTBAYB	SP TWN RD FDR 5-810	2,193	79	59	33
UF	2	HUNTBAYB	X RDS FDR 6-310	3,092	43	78	64
UF	3	KENDAL	C/TIANA FDR 6-210	17,136	161	253	226
		KENDAL	M/GULLY FDR 6-310	6,923	95	129	121
		KENDAL	**MAIN FDR 6-110**	**24,059**	7	2	3
		MAGGOTTY	B/RIV FDR 6-210	18,076	36	80	67
		MAGGOTTY	MAGTY FDR 6-110	5,284	75	243	324
		MICLETON	BOGWLK FDR 4-210	4,622	1	16	78
		MICLETON	LINSTD FDR 4-110	9,827			88
		NAGOHEAD	B/LODGE FDR 6-610	11,552	6	22	30
		NAGOHEAD	FDR 6-510	11,283	80	213	257
		NAGOHEAD	**MAIN FDR 6-210**	**22,835**	34	3	3
		OCHORIOS	FRANKFURT FDR 4-510	1,929	62	63	74
		OCHORIOS	**MAIN FDR 4-110**	**8,494**	18		1
		OCHORIOS	MAIN ST FDR 4-410	1,374		58	13

Under-frequency Points	UF Stage	Substation	Feeder	Customer Count	2006 Trips	2007 Trips	2008 Trips
		OCHORIOS	OCHO RIOS FDR 4-310	5,191	74		117
UF	1	ORANGBAY	LUCEA FDR 6-310	13,390	518	505	525
		ORANGBAY	**MAIN FDR 6-110**	**16,281**	25		1
		ORANGBAY	NEGRIL FDR 6-210	2,891	166	148	142
		PARADISE	FERRIS FDR 6-210	11,919		55	89
UF	1	PARADISE	FROME FDR 6-110	13,806		85	77
		PARADISE	NEGRIL FDR 6-310	6,979	19	34	42
		PARNASUS	HAYES FDR 6-310	8,413	73	135	127
		PARNASUS	**MAIN FDR 6-110**	**19,030**		1	2
		PARNASUS	MAYPEN FDR 6-210	10,617	89	235	169
		PORTONIO	**MAIN FDR 6-110**	**15,677**	43	80	61
		PORTONIO	SAN SAN FDR 6-310	5,713		229	432
		PORTONIO	TOWN FDR 6-410	9,964		325	357
		QUEENSDR	AIRPORT A FDR 6-510	1			18
		QUEENSDR	AIRPORT B FDR 6-610	1		1	9
		QUEENSDR	FLANKERS FDR 6-710	15,431	25	90	74
		QUEENSDR	HOTEL FDR 6-810	2,612		49	68
		QUEENSDR	**MAIN FDR 6-110**	**2,613**	3	1	1
		QUEENSDR	**MAIN FDR 6-210**	**17,621**		9	5
		QUEENSDR	QUEEN S DR FDR 6-310	2,189	64	99	38
		RHODEPEN	INDEST FDR 4-310	3,470	57	129	108
		RHODEPEN	**MAIN FDR 4-110**	**14,717**	2	1	4
		RHODEPEN	O/HBAY FDR 4-410	8,439		131	127
		RHODEPEN	SPRVIL FDR 4-210	2,808	56	94	98
		ROARIVER	B/TOWN FDR 4-210	6,961		104	107
		ROARIVER	**MAIN FDR 4-110**	**12,255**	3	16	9
		ROARIVER	O/RIOS FDR 4-310	51	4		20
		ROARIVER	S/ANNBY FDR 4-410	5,243	26	115	117

Under-frequency Points	UF Stage	Substation	Feeder	Customer Count	2006 Trips	2007 Trips	2008 Trips
UF	4	ROCKFORT	DOWNTWN FDR 6-410	6,809			81
		ROCKFORT	FLOURMIL FDR 6-310	1	66	3	14
		ROCKFORT	**MAIN FDR 6-110**	**9,796**	67	6	2
		ROCKFORT	ROLLTWN FDR 6-210	2,986	84	61	73
		ROSEHALL	COR GARDEN FDR 6-110	1,783		63	86
		ROSEHALL	R/HALL FDR 4-210	1,804		44	78
		SPURTREE	**MAIN FDR 6-110**	**30,937**		9	4
UF	1	SPURTREE	NEWPORT FDR 6-310	15,859			259
UF	1	SPURTREE	S/CRUZ FDR 6-210	15,078			212
		THREEMLS	FREEZONE FDR 5-310	62	20	23	21
		THREEMLS	M GARV DR FDR 5-510	510		18	38
UF	3	**THREEMLS**	**MAIN FDR 5-110**	**776**	16	1	3
		THREEMLS	SP TWN RD FDR 5-410	204	16	50	85
		TREDEGAR	ELTHAM FDR 6-310	6,314	105		283
		TREDEGAR	ENSOM FDR 6-210	7,153			127
UF	4	**TREDEGAR**	**MAIN FDR 6-110**	**25,885**	34	10	15
		TREDEGAR	SP TWN FDR 6-410	12,418			233
UF	2	TWICKNAM	G/DALE FDR 6-410	5,809	99		261
		TWICKNAM	**MAIN FDR 6-110**	**22,203**	53		4
UF	2	TWICKNAM	P/MORE FDR 6-210	16,394	39	65	66
		UPPKCAMP	**MAIN FDR 6-110**	**7,662**		4	2
		UPPKCAMP	MTVIEW FDR 6-510	4,182	61	62	2
		UPPKCAMP	N/KGN FDR 6-310	1,131	41	87	53
		UPPKCAMP	OXFORD FDR 6-410	2,349	47	89	39
UF	2	**WASHBLVD**	**CSPRNG FDR 6-510**	**2,940**	22	49	61
UF	2	WASHBLVD	HWT RD FDR 6-410	2,032	41	85	95
		WASHBLVD	**MAIN FDR 6-110**	**9,659**			1
		WASHBLVD	**MAIN FDR 6-210**	**15,676**	1		1

Under-frequency Points	UF Stage	Substation	Feeder	Customer Count	2006 Trips	2007 Trips	2008 Trips
UF	1	WASHBLVD	MOLYNES FDR 6-710	7,069			322
UF	1	WASHBLVD	RED HILLS FDR 6-810	3,591	113		79
UF	2	WASHBLVD	SHORTWD FDR 6-610	6,068	81		78
UF	2	WASHBLVD	WALTHAM FDR 6-310	6,575	17	48	51
UF	4	WESTKHRD	HOPE RD FDR 6-310	3,293	22	39	40
		WESTKHRD	**MAIN FDR 6-110**	**6,727**			1
UF	4	WESTKHRD	N/KGN FDR 6-210	547	17	21	19
UF	4	WESTKHRD	W/LOO RD FDR 6-410	2,887	16	57	34
		HUNTBAYB	M GARV DR FDR 5-710	589	14		
		DUHANEY	FERRY FDR 6-210	3,962	107	183	179
		CARDHALL	B/TOWN FDR 6-310	15,653	295	407	
		CARDHALL	SALEM FDR 6-210	4,456	161	279	
		GRENWOOD	GREENWOOD FDR 6-110	5,577		88	
TOTAL				**506,515**	**4,814**	**8,559**	**9,643**

Notes:

The communications devices were installed between 2006 to present. There are 6 substations remaining that will have communication capabilities by the end of 2009. This explains why several feeders had no trips registered in 2006 or 2007 (i.e. the lack of communication). Note the data is not reflecting that the number of trips has increased, just that JPS's monitoring capabilities have increased. JPS's total spends on installation of communications and automatic switching devices are approximately US$3 million

Annex L: Economic Study of Non Technical System Losses

Objective

The objective of the present report is to demonstrate that there is a strong relationship between Non Technical Losses (NTL) and the social conditions of the population living in the area served by JPS. In order to confirm the hypothesis that NTL are higher in those utilities operating in regions that have living conditions that are less favourable, in this study data about utilities of Argentina, Bolivia, Brazil, Guatemala, El Salvador, Dominican Republic and Venezuela corresponding to the year 2006 is used

JPS Case Study

Given the network between generation, transmission and distribution, non technical losses are obtained as a result of subtracting the total energy generated and purchased from the following flows:

- Energy sold (MV and LV Customers)
- Generation Losses
- Gen/Transmission Losses
- Transmission Losses
- Transmission / MV Losses
- MV Losses
- MV/LV Losses
- LV Technical Losses

JPS' 2008 energy movement is as follows:

Figure 1: System Losses By Voltage Levels

Concept	MWh	Losses / Net Generation (%)
Net Generation	**4 123 288**	
Gen / Tr Losses	16 493	0.40%
Energy entered in Tr	**4 106 795**	
Tr Losses	74 219	1.80%
Energy entered in Tr/MV	**4 032 576**	
Tr/MV Losses	16 493	0.40%
Energy entered in MV	**4 016 082**	
MV Losses	94 836	2.30%
RT 50 (Power Service)	599 294	
Energy entered in MV/LV	**3 321 953**	
MV/LV Losses	98 959	2.40%
RT 40 (Power Service)	789 468	
Energy entered in LV	**2 433 526**	
LV Technical Losses	123 699	3.00%
Total LV Demand w/o Tech. Losses	2 309 828	
Non Technical Losses	518 861	12.58%
RT 60 (Street Lighting)	68 028	
RT 20 (General Services)	638 265	
RT 10 (Residential)	1 084 674	

NTL represents:

- ***12.58***% of the total net generation.
- ***28.97***% with regards to LV energy sales

From the economic point of view is not optimal to reduce the non technical losses to zero, because the operational cost to achieve this is often greater than the savings which are achieved with the non technical losses avoided. Also, generally there are strong environmental factors (economics, social and legal) that in most of the cases make it unfeasible to eliminate the total NTL

Background

The linkage between NTL and the environment in which electricity distributors are located is a field of study of recent development, thus there does not exist an abundant amount of literature on the matter. However, two works applied to the case of Brazil can be mentioned. In one of them, carried out by ANEEL[81], antecedents that indicate that the respect for the law by the members of the society is a measure of governability that affects the performance of the electrical companies are mentioned. In addition, in the study mentioned it is noted that in comparing companies within the sector, environmental variables are not always considered, which, as it is demonstrated, affect the performance of the utilities. The study analyzes the relationship between demographic characteristics, violence, schooling, income, inequality, infrastructure, labour informality, the temperature and the market characteristics of the Brazilian electrical distributors for the period 2001-2006. The proposed model consists of a linear relationship between NTL and the variables mentioned. After running the model with the panel data, we concluded that the best fit variables are violence (measured by the murder rate in the concession area), poverty (measured by the proportion of people whose per capita income is half the minimum wage or less) and infrastructure, approximated with the proportion of homes with water coverage in the concession area. The mentioned variables explain 54% of the variations in NTL, being statistically significant, except the proportion of people with low income.

In another study, Araujo (2007)[82] claims that NTL can be explained by socio-economic variables (education, income, inequality), by infrastructure of the concession area, as well as by the characteristics of the market (percentage of residential clients) and by the average tariff charged by each utility. The author indicates the importance that the regulator considers these factors when recognizing NTL and presents statistically significant results that confirm the hypotheses that NTL and the bad debt of the distributors are negatively associated to the development of the region and the level of income of their inhabitants, and positively associated to the cost of electrical energy and the levels of violence and inequality.

The Model

The model considered in the study is based on the hypothesis that NTL are influenced by socio-economic characteristics of the concession area of the utilities and the inefficiency of each company to tackle them, which can be expressed as follows:

$$NTL_i = \alpha + X_i\beta + I_i + \varepsilon_i \quad (1)$$

where NTL_i represents the percentage of NTL of company i, X_i are the socio-economic variables of the concession area of company i (poverty, violence, among others), I_i is the level of efficiency to tackle NTL_i and ε_i is the error term of the model, which is assumed to be normally distributed

81 PNT: "Metodologia de tratamento regulatório para perdas não técnicas de energia elétrica", Nota Técnica No. 342/2008-SER/ANEEL . ANEEL: Agência Nacional de Energia Elétrica. [NTL: "Methodology for regulatory treatment of non technical energy losses" , Technical Note 342/2008-SER/ANEEL (Electrical Energy National Agency)].

82 Perdas em inadimplência na Atividade de Distribuição de Energia Elétrica. Tese de Doutorado. Coordenação dos Programas de Post Graduação em Engenharia, Universidade Federal de Rio de Janeiro, Rio de Janeiro [Losses and bad debt in the activity of electricity distribution. Thesis for PHD. Coordination of Post Graduate Programs in Engineering, Federal University of Rio de Janeiro, Rio de Janeiro]

with a zero mean and constant variance. The term α represents the effect of variables that affect NTL and are not specified in the model and β is the effect of socioeconomic variables on NTL.

The objective of this study is to determine to what extent the socio-economic variables, which are exogenous, that is to say, are out of control of the utilities, explain the level of NTL of the analyzed companies, without specifying the variables that capture the ability and the effort to tackle them.

From the information collected by Quantum, corresponding to utilities that were invited to participate in the present benchmarking study, and public access information mainly of Brazil, regression models were run and evaluated in order to identify the socio-economic variables of greater impact on NTL. It must be stated that the availability of information about different Brazilian utilities given the scale of the country as well as the diversity of regions with unique characteristics allowed us to significantly increase the sample size.

The NTL to LV sales ratio was the variable defined to be explained. The reason for choosing this variable is based on the following facts:

- Most NTL occur in LV; and
- The consideration of another ratio involving NTL might result in less robust results due to the existence of large industrial demand in the voltage levels upstream.

The proposed model to explain the percentage of NTL due to the social reality of the concession area is as follows:

$$lNTL_i = \alpha + \beta_1 lpoverty_i + \beta_2 lbill_{income_i} + \beta_3 lviolence_i + \varepsilon_i \quad (2)$$

where **lNTL**$_i$ is the logarithm of the percentage of NTL to LV sales of company i, **lpoverty**$_i$ is the logarithm of the proportion of population of the concession area that lives in conditions of extreme poverty**, lbill_income**$_i$ is the logarithm of the proportion of the annual average bill in relation to the income per capita of the area of concession and **lviolence**$_i$ is the logarithm of the amount of murders per each 100,000 inhabitants in the concession area of company i. The constant of (2) represents the independent level of NTL and □$_i$ is the difference between the observed NTL level and the estimated NTL level of each company.

The coefficients associated to the variables are their respective elasticities. The coefficient βi, associated to the proportion of poor population, is expected to have a positive sign, since the greater the amount of inhabitants who live in conditions of poverty the smaller their willingness to pay for electricity and the greater the possibility of them committing fraud. The second variable represents the percentage of the electricity bill relative to the average income. It is expected that its coefficient presents a positive sign since the more onerous the electricity bill the greater the incentive to commit fraud. Finally, the coefficient associated to the last variable that represents the magnitude of the violence of the zone in which the utility operates must also be positive, since it is expected that violence and disrespect for the law encourage the theft of energy and also make it difficult for the utility to control this problem.

The Data

In order to carry out the present study, numerous utilities were invited to participate, although only 11 had the time and resources to complete the information that was asked of them, as detailed below:

- %NTL
- Sales in USD
- Customers
- Energy

- Type of network
- Fraud Recovery Total Revenues
- Number of fines to customers committing fraud collected per year (cases/year)
- Other variables (Police Force Assistance during disconnection actions, Right to discontinue service in case of fraud, number of arrests for persons stealing electricity)

The number of companies that could complete and respond in time to the requested information was insufficient for applying regression models. For this reason, this information was complemented with the data from the previously mentioned study of the Brazilian distributors carried out by ANEEL.

The integration of these two sources of information determined the availability of consistent data for the year 2006. These data correspond to 63 distribution companies of Latin America and the Caribbean. The composition of the sample is as follows:

Table 2: Countries Included in Study

Countries	Companies
Argentina	4
Brazil	53
Bolivia	1
Dominican Rep.	1
El Salvador	1
Guatemala	2
Venezuela	1
Total	63

The sources from which the data were obtained to run the model are mentioned below:

- NTL. The percentage of NTL is the level of nontechnical losses referred to the energy sold in the low voltage level. For the companies of Brazil the information was taken from ANEEL, whereas for the rest the information was provided to Quantum by the individual companies.

- Population in conditions of poverty. For the companies of Brazil the percentage of people that earned less than a half of the minimum wage by municipality was considered. For the rest, except Jamaica in 2008, the proportion of the population living in conditions of extreme poverty was calculated by the SEDLAC[83]. The proportion of population in conditions of poverty of Jamaica for year 2008 was taken from Indexmundi[84].
- Proportion of the income devoted to electricity. It was calculated as the ratio between the average annual bill for a residential customer and the gross domestic product per capita of the area of concession of the utility.
  - Residential customer annual average bill. It was calculated as the product of the residential annual average consumption by the residential average tariff of each company. The residential annual average consumption was obtained by dividing the total of energy sold to the residential customers by the number of residential customers. The residential average tariff was calculated as dividing the income from

[83] Socio-economic Database for Latin America and the Caribbean

[84] http://www.indexmundi.com/, This site contains detailed country statistics, charts, and maps compiled from multiple sources

residential customers by the amount of energy sold to these customers. For the Brazilian companies, the information for these calculations was taken from the Web site of ANEEL, whereas for the remaining companies the calculations were made using the data provided by the companies.

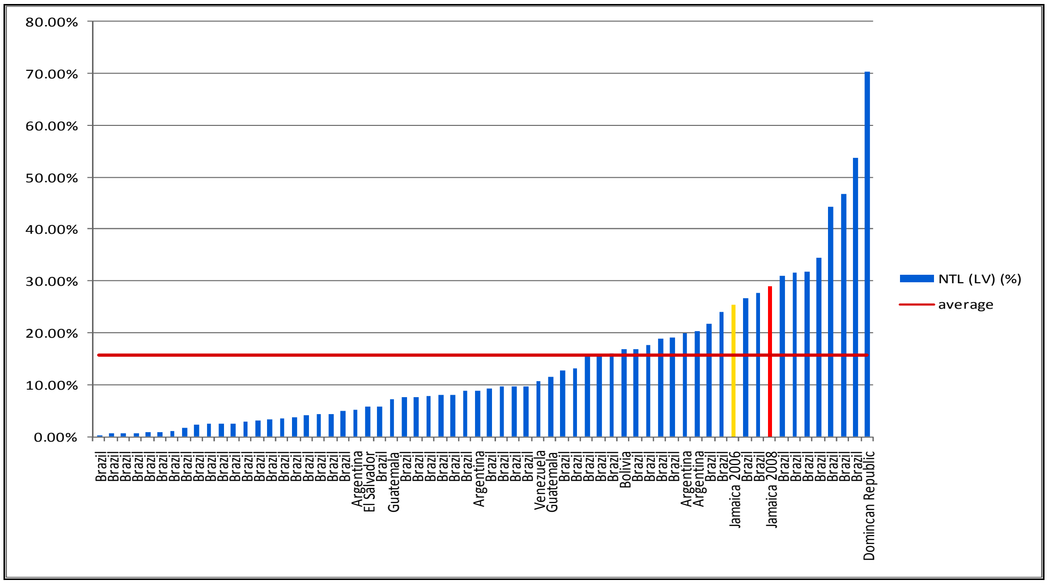
– Income per capita. For the utilities of Brazil, the GDP per capita of the municipalities of the concession area of each utility weighted by the amount of inhabitants was calculated. For the rest of the utilities outside of Brazil, the GDP per capita of the country where they are located, as published by the United Nations was used.

- Murders per each 100,000 inhabitants. For the utilities of Brazil, the average index of each 100,000 inhabitants of the municipalities of the concession area of each utility weighted by the amount of inhabitants was calculated. The rate of homicides by municipality of Brazil was obtained from the IBGE[85], whereas for the utilities of the remaining countries diverse sources were used. For Argentina and Bolivia information of the Latin American Institute in Sciences of Security was used, for Venezuela the "Annual report 2007-2008 on the Situation of the human rights in Venezuela" , for El Salvador, Guatemala and Dominican Republic the Central American Observatory on Violence and for Jamaica data from Jamaican Constabulary Force (JCF).

Next graphs and frequency distributions of the data used for the estimation of the model corresponding to year 2006 and the data of Jamaica of 2006 and 2008 are presented:

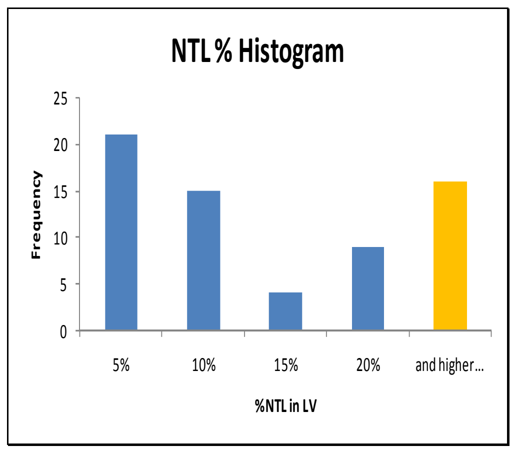
[85] Instituto Brasileiro de Geografia e Estatística

Figure 1: NTL % - Non Technical Losses to LV Energy Sales Ratio

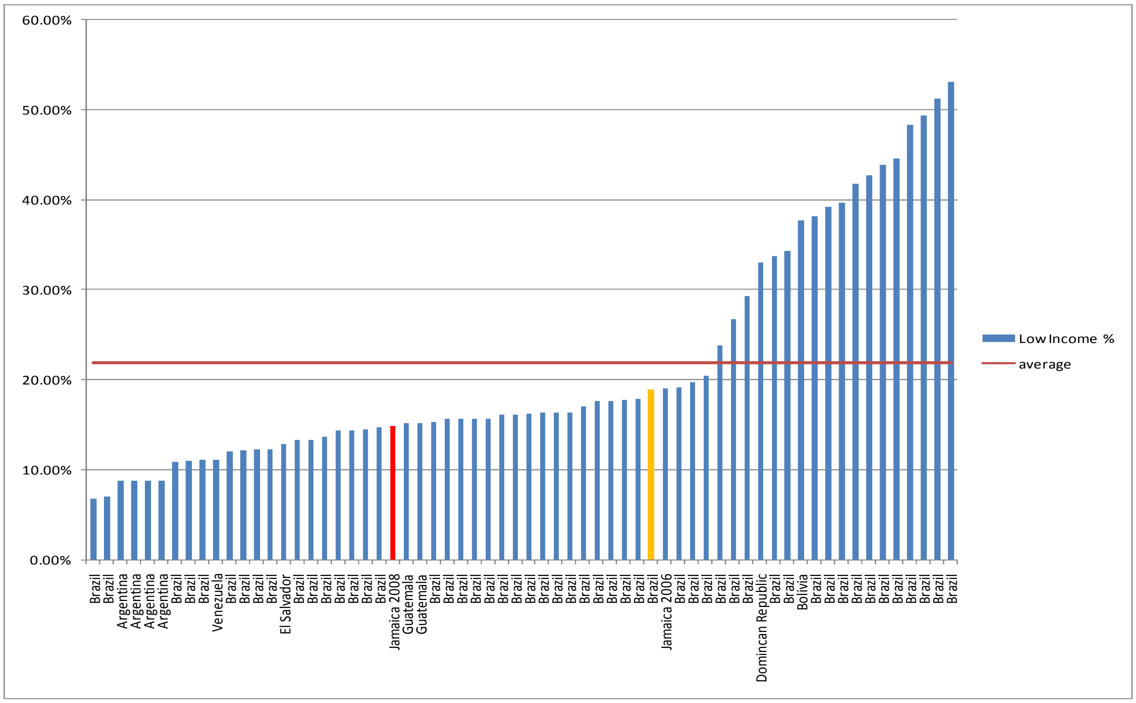


Class	Frequency	%	% Accumulated
5%	21	32%	32%
10%	15	23%	55%
15%	4	6%	62%
20%	9	14%	75%
and higher...	16	25%	100%

JPS 2006	25.6%
JPS 2008	29.0%

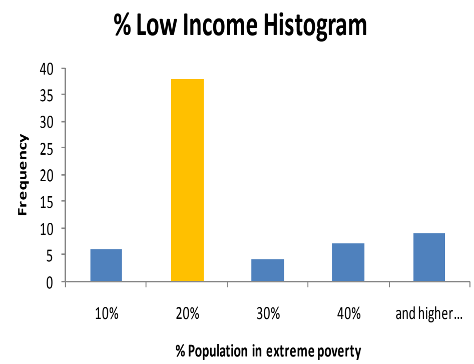


Low income % - Percentage of population below extreme poverty threshold

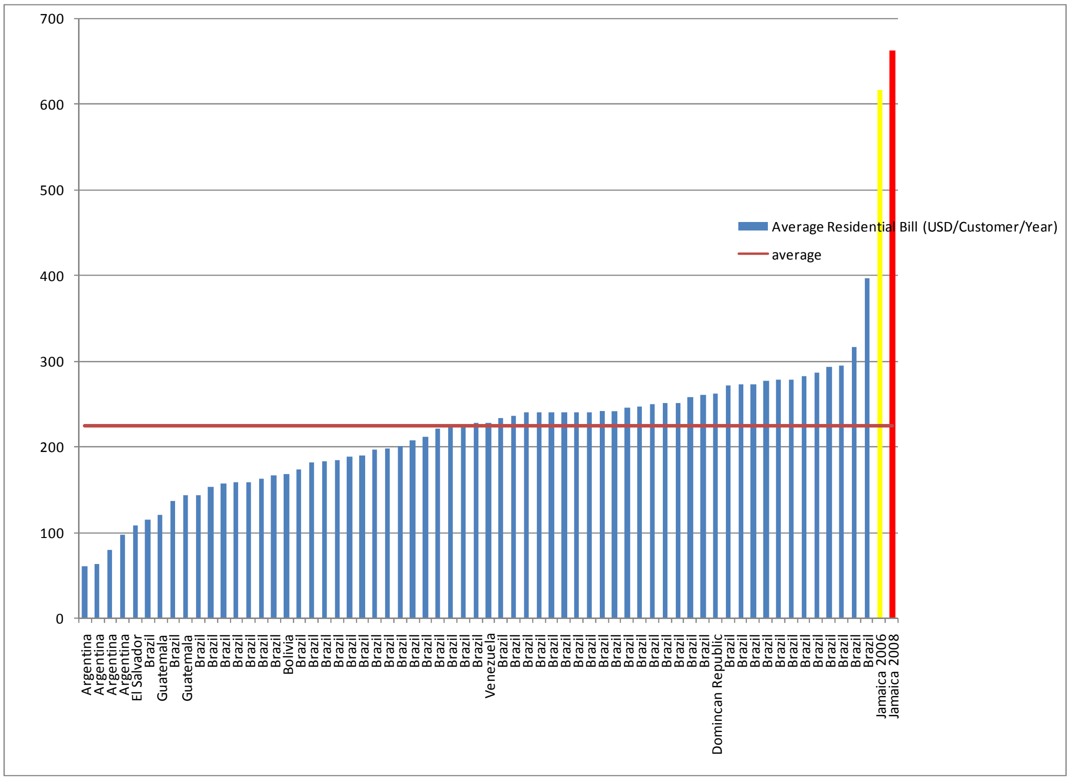


Class	Frequency	%	% Accumulated
10%	6	9%	9%
20%	38	59%	69%
30%	4	6%	75%
40%	7	11%	86%
and higher...	9	14%	100%

Jamaica 2006	19.0%
Jamaica 2008	14.8%

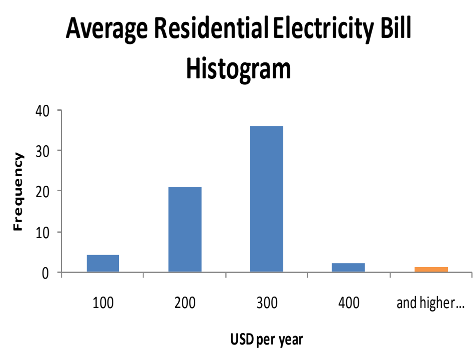


Average Residential Electricity bill (in US dollars)

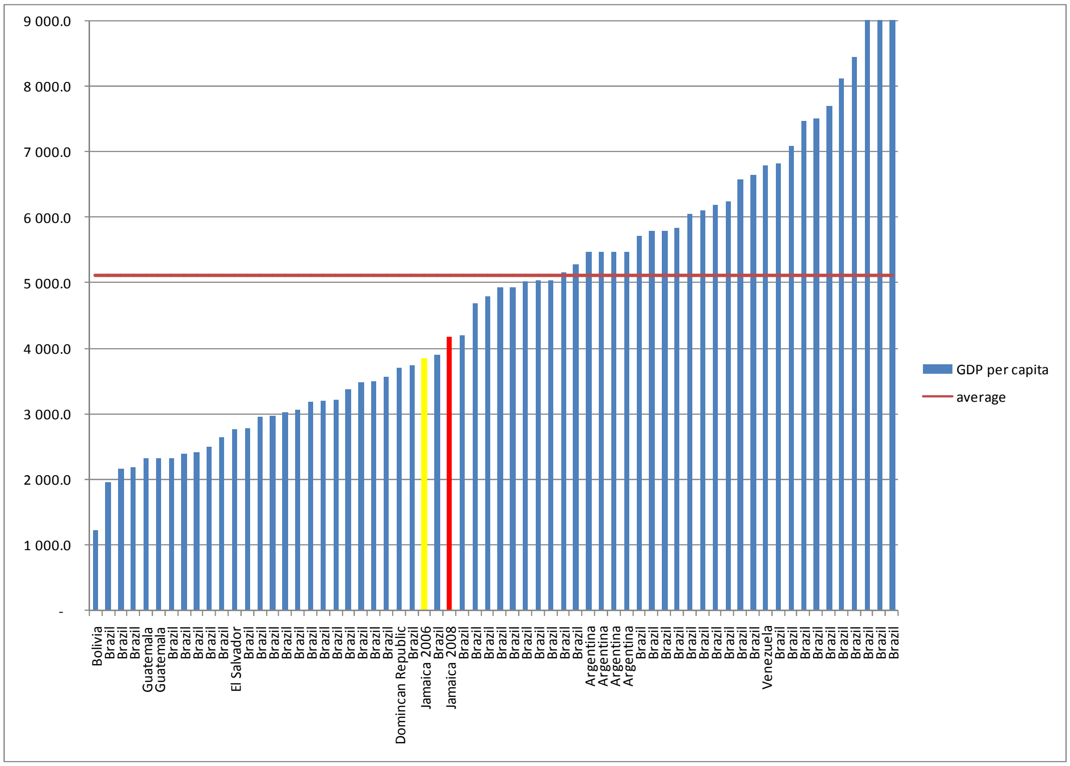


Class	*Frecuency*	*%*	*% Accumulated*
100	4	6%	6%
200	21	33%	39%
300	36	56%	95%
400	2	3%	98%
and higher...	1	2%	100%

JPS 2006	616	USD/Year
JPS 2008	662	USD/Year

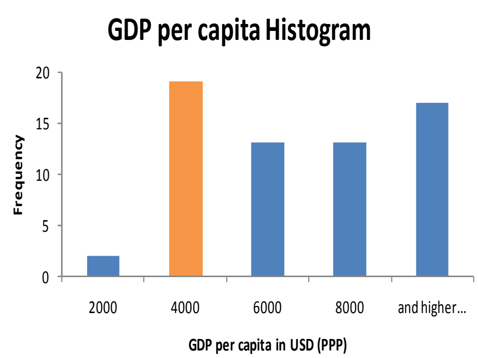


GDP per capita (in US dollars)

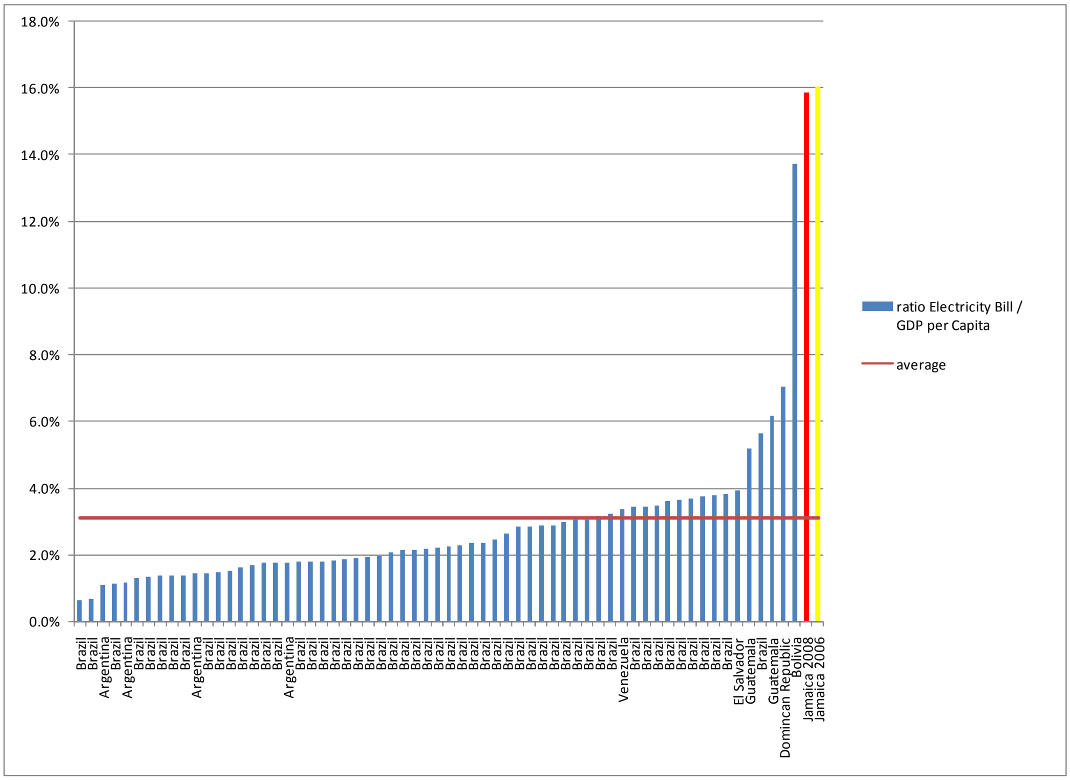


Class	*Frecuency*	*%*	*% Accumulated*
2000	2	3%	3%
4000	19	30%	33%
6000	13	20%	53%
8000	13	20%	73%
and higher...	17	27%	100%

Jamaica 2006	3 844	USD/Year
Jamaica 2008	4 177	USD/Year

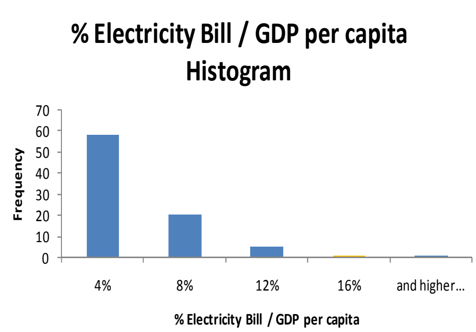


Ratio Electricity bill/GDP per capita (in %)

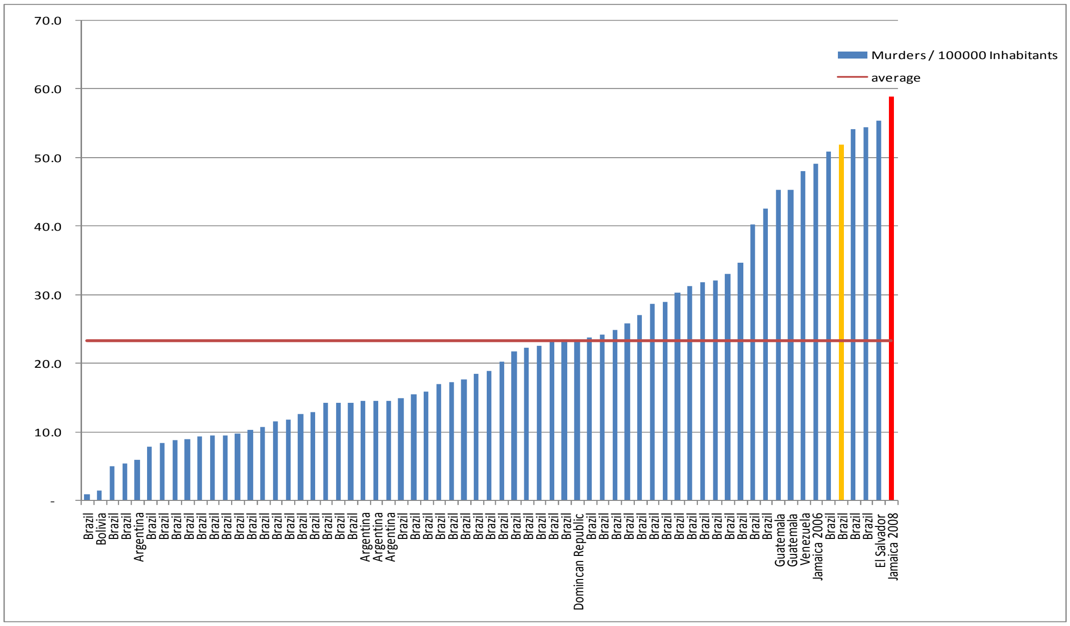


Class	*Frequency*	*%*	*% Accumulated*
4%	58	68%	68%
8%	20	24%	92%
12%	5	6%	98%
16%	1	1%	99%
and higher...	1	1%	100%

Jamaica 2006	16.0%
Jamaica 2008	15.9%

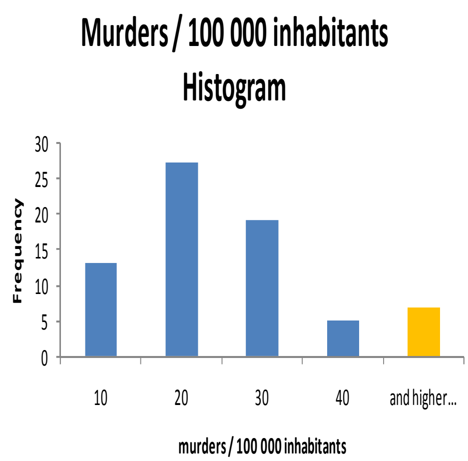


Murders /100,000 inhabitants



Class	Frequency	%	% Accumulated
10	13	18%	18%
20	27	38%	56%
30	19	27%	83%
40	5	7%	90%
and higher...	7	10%	100%

Jamaica 2006	49 /100 000 inhabitants
Jamaica 2008	59 /100 000 inhabitants



Results

The model formulated in function (2) was estimated by ordinary least squares corrected by heteroscedasticity, using the data of the 63 utilities previously indicated. The software Stata 8.0 was employed in the estimation. A coefficient of determination (R^2) of 0.855 was obtained, which indicates that 85.5 % of the variability of the NTL of the companies in the study is explained by the variables included in the model.

All the coefficients estimated present the expected sign and are highly statistically significant, as it can be observed in the following table

Variable	*Coefficient estimated*	*t - statistics*
Poverty	0.9078868	4.51
Electricity bill/GDP pc	0.5256652	2.94
Violence	0.342431	4.35

A model of stochastic frontier (SFA) was also run, confirming that the model of ordinary least squares is efficient, which means that the deviations of the model are only attributed to random errors.

SFA is a statistic approach that considers a production function (in this case a function for NTL) and segregates the error term into inefficiency and random errors. The NTL function has a structure similar to the one presented at point 0 with a breakdown of the error term into the two components mentioned above:

$$NTL_i = \alpha + X_i\beta + v_i + u_i \quad (2)$$

$$v_i \sim N(0, \sigma_v^2)$$
$$u_i \geq 0$$

where NTL_i is the percentage of NTL in logarithm of firm i, X_i are the NTL drivers in logarithm of firm i. The βX_i term is the deterministic component of the NTL function and $v_i + u_i$ is the total error component. The v_i term is the random noise, deviations from the deterministic component due to omission of some explanatory variable or measurement errors in the variables. The mean of these errors is supposed to be zero, since positive deviations compensate the negative ones, and its variance is constant. $\beta X_i + v_i$ define the stochastic frontier, which is not observable because v_i errors are not observable. The u_i term reflects the inefficiency of the firms, the distance between the stochastic frontier and the observed value. Note that u_i is positive, because it indicates the excess of the NTL level over the NTL level of the stochastic frontier and is null in case the firm is efficient. It is generally assumed that u_i follows a semi-normal, exponential or normal truncated distribution, in order to assure that, it always assumes greater or equal to zero values.

By estimating the NTL function (2), it is possible to test the statistical significance of $\boldsymbol{u_i}$. In this study the hypothesis test for $\boldsymbol{u_i} \geq 0$ was rejected at a confidence level of 99%, so it is concluded that the model estimated by OLS[86] is compatible with the frontier approach. In other words, on average utilities' NTL levels in the sample are not linked to inefficiencies of the utilities in tackling fraud.

Conclusions

[86] OLS: Ordinary Least Square

The estimated model indicates that 85.5% of the variability in the NTL are explained by socio-economic variables. It has been confirmed that NTL depend positively on the poverty level, on the payment capabilities of the population and the violence of the environment of the utility. In fact, for each 1% of increase in the proportion of the population that lives in conditions of poverty, the NTL level increases in 0.91%. This result confirms the importance of the social dimension on the performance of the electric utilities, indicating that the companies that operate in regions with high levels of inequality face more adverse conditions to tackle the fraud.

The result associated with the proportion of the electrical residential bill to the income is also significant and has the expected positive sign. According to this, an increase of 1% in the proportion of the electricity bill to the income of the families increases the level of NTL by 0.53%. It can be concluded that the utilities in whose concession areas where the electricity service represents a significant burden for the population have a more elevated level of NTL on average.

Finally, it is remarkable the significant impact of violence and the disrespect for the law on the NTL level. The results confirm a direct relationship between the murder rate and the level of NTL. The elasticity estimated is 0.34, which suggests that the ineffectiveness of the police force and justice system favor the occurrence of fraud.

Given the robustness of the estimated model and considering that all the explanatory variables for Jamaica in the year 2008 (Test to year) are available, the level of NTL for JPS in this year were estimated. The value of the variables and the obtained result are shown below:

Variable	**Value**	**Source**
% poverty	14.8	Indexmundi
Electriciy bill (US dollars)	662	JPS Data
GDPpc (US dollars)	4,177	Indexmundi
% Electricity bill/GDPpc	15.86%	Own calculation
Murders/100,000 inhabitants	58.9	JCF

The value of the resulting NTL is of ***27.07***% that indicates that if the level of the NTL were only determined by the exogenous conditions to the company, that is to say, by the poverty, the payment capacity and the violence of the country, that the NTL level would reach this value. These results suggest that the difference between this NTL level and the real one can be attributed to variables not considered in this study such as the efficiency of the company to deal with fraud.

For the Test Year if we redo the energy movement replacing the real NTL by the ones calculated with the percentage predicted by the model we have:

Concept	MWh	Losses / Net Generation (%)
Net Generation	**4 084 412**	
Gen / Tr Losses	16 338	0.40%
Energy entered in Tr	**4 068 075**	
Tr Losses	73 519	1.80%
Energy entered in Tr/MV	**3 994 555**	
Tr/MV Losses	16 338	0.40%
Energy entered in MV	**3 978 217**	
MV Losses	93 941	2.30%
RT 50 (Power Service)	599 294	
Energy entered in MV/LV	**3 284 982**	
MV/LV Losses	97 858	2.40%
RT 40 (Power Service)	789 468	
Energy entered in LV	**2 397 657**	
LV Technical Losses	121 875	2.98%
Total LV Demand w/o Tech. Losses	2 275 781	
Non Technical Losses	484 815	11.87%
RT 60 (Street Lighting)	68 028	
RT 20 (General Services)	638 265	
RT 10 (Residential)	1 084 674	

NTL represents ***11.87***% points of the total system losses.

Total system losses are ***22.15***% regarding Net Generation.

Annex M: Impact of Proposed Tariff

Bill Comparison for a Typical Rate 10 Customer in Tier 1 (0 – 100 kWh per month)

Average Usage: 75 kWh per month

Description	2008 RATES	2009 RATES	Change	
	$	$	$	%
Energy First 100 Kwh	490.58	465.00	(25.58)	(5.2)%
Energy Next	0.00	0.00	0.00	0.0%
Customer Charge	102.00	190.00	88.00	86.3%
Sub Total	**592.58**	**655.00**	**62.43**	**10.5%**
Hurricane Recovery Charge	6.60	5.06	(1.54)	(23.3)%
F/E Adjust	16.52	18.26	1.74	10.5%
NON-FUEL TOTAL	**615.70**	**678.32**	**62.63**	**10.2%**
FUEL AND IPP TOTAL	855.00	855.00	0.00	0.0%
BILL TOTAL	**1,470.70**	**1,533.32**	**62.63**	**4.3%**

Unit Charges Used for Billing	2008	2009	Change	
	$	$	$	%
Energy First 100 Kwh (J$/kWh)	6.541	6.200	(0.34)	-5.2%
Energy Next (J$/kWh)	11.420	17.650	6.23	54.6%
Fuel and IPP Charge (J$/kWh)	11.400	11.400	0.00	0.0%
Customer Charge	102.00	190.00	88.00	86.3%
Hurricane Recovery Charge	0.088	0.068	(0.02)	-23.3%
Base Exchange Rate	85.00	85.00	0.00	0.0%
Billing Exchange Rate	88.00	88.00	0.00	0.0%
Usage (kWh)	75	75		

Note:

Approximately 204,000 in **tier 1**

Bill Comparison for a Typical Rate 10 Customer in Tier 2 (101 – 500 kWh per month)

Average Usage: 200 kWh per month

Description	2008 RATES	2009 RATES	Change	
	$	$	$	%
Energy First 100 Kwh	654.10	620.00	(34.10)	(5.2)%
Energy Next	1,142.00	1,765.00	623.00	54.6%
Customer Charge	102.00	475.00	373.00	365.7%
Sub Total	**1,898.10**	**2,860.00**	**961.90**	**50.7%**
Hurricane Recovery Charge	17.60	13.50	(4.10)	(23.3)%
F/E Adjust	52.92	79.74	26.82	50.7%
NON-FUEL TOTAL	**1,968.62**	**2,953.24**	**984.62**	**50.0%**
FUEL AND IPP TOTAL	**2,280.00**	**2,280.00**	**0.00**	**0.0%**
BILL TOTAL	**4,248.62**	**5,233.24**	**984.62**	**23.2%**

Unit Charges Used for Billing	2008	2009	Change	
	$	$	$	%
Energy First 100 Kwh (J$/kWh)	6.541	6.200	(0.34)	(5.2%)
Energy Next (J$/kWh)	11.420	17.650	6.23	54.6%
Fuel and IPP Charge (J$/kWh)	11.400	11.400	0.00	0.0%
Customer Charge	102.00	475.00	373.00	365.7%
Hurricane Recovery Charge	0.088	0.068	(0.02)	(23.3%)
Base Exchange Rate	85.00	85.00	0.00	0.0%
Billing Exchange Rate	88.00	88.00	0.00	0.0%
Usage (kWh)	200	200		

Note:

Approximately 306,000 in **tier 2**

Bill Comparison for a Typical Rate 10 Customer in Tier 3 (> 500 kWh per month)

Average Usage: 600 kWh per month

Description	2008 RATES	2009 RATES	Change	
	$	$	$	%
Energy First 100 Kwh	654.10	620.00	(34.10)	(5.2)%
Energy Next	5,710.00	8,825.00	3,115.00	54.6%
Customer Charge	102.00	475.00	373.00	365.7%
Sub Total	**6,466.10**	**9,920.00**	**3,453.90**	**53.4%**
Hurricane Recovery Charge	52.80	40.50	(12.30)	(23.3)%
F/E Adjust	180.27	276.57	96.29	53.4%
NON-FUEL TOTAL	**6,699.17**	**10,237.07**	**3,537.89**	**52.8%**
FUEL AND IPP TOTAL	**6,840.00**	**6,840.00**	**0.00**	**0.0%**
BILL TOTAL	**13,539.17**	**17,077.07**	**3,537.89**	**26.1%**

Unit Charges Used for Billing	2008	2009	Change	
	$	$	$	%
Energy First 100 Kwh (J$/kWh)	6.541	6.200	(0.34)	(5.2%)
Energy Next (J$/kWh)	11.420	17.650	6.23	54.6%
Fuel and IPP Charge (J$/kWh)	11.400	11.400	0.00	0.0%
Customer Charge	102.00	475.00	373.00	365.7%
Hurricane Recovery Charge	0.088	0.068	(0.02)	(23.3%)
Base Exchange Rate	85.00	85.00	0.00	0.0%
Billing Exchange Rate	88.00	88.00	0.00	0.0%
Usage (kWh)	600	600		

Note:

Approximately 17,000 customers in **tier 3**

Bill Comparison for a Typical Rate 20 Customer in Tier 1 (0 – 100) kWh per month

Average Usage: 75 kWh per month

Description	2008 RATES	2009 RATES	Change	
	$	$	$	%
Energy First 100 Kwh	761.33	628.50	(132.83)	(17.4)%
Energy Next	0.00	0.00	0.00	0.0%
Customer Charge	234.00	475.00	241.00	103.0%
Sub Total	**995.33**	**1,103.50**	**108.18**	**10.9%**
Hurricane Recovery Charge	6.60	5.06	(1.54)	(23.3)%
F/E Adjust	27.75	30.77	3.02	10.9%
NON-FUEL TOTAL	**1,029.67**	**1,139.33**	**109.65**	**10.6%**
FUEL AND IPP TOTAL	855.00	855.00	0.00	0.0%
BILL TOTAL	**1,884.67**	**1,994.33**	**109.65**	**5.8%**

Unit Charges Used for Billing	2008	2009	Change	
	$	$	$	%
Energy First 100 Kwh (J$/kWh)	10.151	8.380	(1.77)	(17.4)%
Energy Next (J$/kWh)	10.151	14.800	4.65	45.8%
Fuel and IPP Charge (J$/kWh)	11.400	11.400	0.00	0.0%
Customer Charge	234.00	475.00	241.00	103.0%
Hurricane Recovery Charge	0.088	0.068	(0.02)	(23.3)%
Base Exchange Rate	85.00	85.00	0.00	0.0%
Billing Exchange Rate	88.00	88.00	0.00	0.0%
Usage (kWh)	**75**	**75**		

Note:

1. Approximately 19,000 in **tier 1**

2. 2009 represents the first time that a discount has been introduced on the first 100 kWh for Rate 20 customers (similar to Rate 10 customers)

Bill Comparison for a Typical Rate 20 Customer in Tier 2 (101 – 1,000) kWh per month

Average Usage: 400 kWh per month

Description	2008 RATES	2009 RATES	Change	
	$	$	$	%
Energy First 100 Kwh	1,015.10	838.00	(177.10)	(17.4)%
Energy Next	3,045.30	4,440.00	1,394.70	0.0%
Customer Charge	234.00	955.00	721.00	308.1%
Sub Total	4,294.40	6,233.00	1,938.60	45.1%
Hurricane Recovery Charge	35.20	27.00	(8.20)	(23.3)%
F/E Adjust	119.73	173.78	54.05	45.1%
NON-FUEL TOTAL	**4,449.33**	**6,433.78**	**1,984.45**	**44.6%**
FUEL AND IPP TOTAL	**4,560.00**	**4,560.00**	**0.00**	**0.0%**
BILL TOTAL	**9,009.33**	**10,993.78**	**1,984.45**	**22.0%**

Unit Charges Used for Billing	2008	2009	Change	
	$	$	$	%
Energy First 100 Kwh (J$/kWh)	10.151	8.380	(1.77)	(17.4%)
Energy Next (J$/kWh)	10.151	14.800	4.65	45.8%
Fuel and IPP Charge (J$/kWh)	11.400	11.400	0.00	0.0%
Customer Charge	234.00	955.00	721.00	308.1%
Hurricane Recovery Charge	0.088	0.068	(0.02)	(23.3)%
Base Exchange Rate	85.00	85.00	0.00	0.0%
Billing Exchange Rate	88.00	88.00	0.00	0.0%
Usage (kWh)	**400**	**400**		

Note:

1. Approximately 32,000 in **tier 2**
2. 2009 represents the first time that a discount has been introduced on the first 100 kWh for Rate 20 customers (similar to Rate 10 customers)

Bill Comparison for a Typical Rate 20 Customer in Tier 3 (1,001 – 2,000) kWh per month

Average Usage: 1,400 kWh per month

Description	2008 RATES	2009 RATES	Change	
	$	$	$	%
Energy First 100 Kwh	1,015.10	838.00	(177.10)	(17.4)%
Energy Next	13,196.30	19,240.00	6,043.70	45.8%
Customer Charge	234.00	2,385.00	2,151.00	919.2%
Sub Total	**14,445.40**	**22,463.00**	**8,017.60**	**55.5%**
Hurricane Recovery Charge	123.20	94.50	(28.70)	(23.3)%
F/E Adjust	402.74	626.27	223.53	55.5%
NON-FUEL TOTAL	**14,971.34**	**23,183.77**	**8,212.43**	**54.9%**
FUEL AND IPP TOTAL	**15,960.00**	**15,960.00**	**0.00**	**0.0%**
BILL TOTAL	**30,931.34**	**39,143.77**	**8,212.43**	**26.6%**

Unit Charges Used for Billing	2008	2009	Change	
	$	$	$	%
Energy First 100 Kwh (J$/kWh)	10.151	8.380	(1.77)	(17.4)%
Energy Next (J$/kWh)	10.151	14.800	4.65	45.8%
Fuel and IPP Charge (J$/kWh)	11.400	11.400	0.00	0.0%
Customer Charge	234.00	2,385.00	2,151.00	919.2%
Hurricane Recovery Charge	0.088	0.068	(0.02)	(23.3)%
Base Exchange Rate	85.00	85.00	0.00	0.0%
Billing Exchange Rate	88.00	88.00	0.00	0.0%
Usage (kWh)	**1,400**	**1,400**		

Note:

1. Approximately 5,200 in **tier 3**

2. 2009 represents the first time that a discount has been introduced on the first 100 kWh for Rate 20 customers (similar to Rate 10 customers)

Bill Comparison for a Typical Rate 20 Customer in Tier 4 (> 2,000) kWh per month

Average Usage: 3,500 kWh per month

Description	2008 RATES	2009 RATES	Change	
	$	$	$	%
Energy First 100 Kwh	1,015.10	838.00	(177.10)	(17.4)%
Energy Next	34,513.40	50,320.00	15,806.60	45.8%
Customer Charge	234.00	4,775.00	4,541.00	1940.6%
Sub Total	**35,762.50**	**55,933.00**	**20,170.50**	**56.4%**
Hurricane Recovery Charge	308.00	236.25	(71.75)	(23.3)%
F/E Adjust	997.06	1,559.41	562.35	56.4%
NON-FUEL TOTAL	**37,067.56**	**57,728.66**	**20,661.10**	**55.7%**
FUEL AND IPP TOTAL	**39,900.00**	**39,900.00**	**0.00**	**0.0%**
BILL TOTAL	**76,967.56**	**97,628.66**	**20,661.10**	**26.8%**

Unit Charges Used for Billing	2008	2009	Change	
	$	$	$	%
Energy First 100 Kwh (J$/kWh)	10.151	8.380	(1.77)	(17.4)%
Energy Next (J$/kWh)	10.151	14.800	4.65	45.8%
Fuel and IPP Charge (J$/kWh)	11.400	11.400	0.00	0.0%
Customer Charge	234.00	4,775.00	4,541.00	1940.6%
Hurricane Recovery Charge	0.088	0.068	(0.02)	(23.3)%
Base Exchange Rate	85.00	85.00	0.00	0.0%
Billing Exchange Rate	88.00	88.00	0.00	0.0%
Usage (kWh)	**3,500**	**3,500**		

Note:

1. Approximately 5,500 in **tier 4**
2. 2009 represents the first time that a discount has been introduced on the first 100 kWh for Rate 20 customers (similar to Rate 10 customers)

Bill Comparison for a Typical Rate 40 Customer

Average Usage: 35,000 kWh per month
Average Demand: 125 kVA per month

Description	2008 RATES	2009 RATES	Change	
	$	$	$	%
Energy	97,195	183,050	85,855	88.3%
Demand	129,125	180,625	51,500	39.9%
Customer Charge	3,245	10,956	7,711	237.6%
Sub Total	**229,565**	**374,631**	**145,066**	**63.2%**
Hurricane Recovery Charge	3,080	2,363	(718)	(23.3)%
F/E Adjust	6,400	10,445	4,044	63.2%
NON-FUEL TOTAL	**239,045**	**387,438**	**148,393**	**62.1%**
FUEL AND IPP TOTAL	**399,000**	**399,000**	**0**	**0.0%**
BILL TOTAL	**638,045**	**786,438**	**148,393**	**23.3%**

Unit Charges Used for Billing	2008	2009	Change	
	$	$	$	%
Energy	2.777	5.230	2.45	88.3%
Demand	1,033.00	1,445.00	412.00	39.9%
Fuel and IPP Charge (J$/kWh)	11.400	11.400	0.00	0.0%
Customer Charge	3,245.00	10,956.00	7,711.00	237.6%
Hurricane Recovery Charge	0.088	0.068	(0.02)	(23.3)%
Base Exchange Rate	85.00	85.00	0.00	0.0%
Billing Exchange Rate	88.00	88.00	0.00	0.0%
Usage (kWh)	**35,000**	**35,000**		
Demand (kVA)	**125**	**125**		

Bill Comparison for a Typical Rate 50 Customer

Average Usage: 300,000 kWh per month
Average Demand: 1,000 kVA per month

Description	2008 RATES	2009 RATES	Change	
	$	$	$	%
Energy	754,200	1,482,000	727,800	96.5%
Demand	929,000	1,369,000	440,000	47.4%
Customer Charge	3,245	10,956	7,711	237.6%
Sub Total	**1,686,445**	**2,861,956**	**1,175,511**	**69.7%**
Hurricane Recovery Charge	26,400.00	20,250.00	(6,150)	(23.3)%
F/E Adjust	47,018.09	79,791.33	32,773	69.7%
NON-FUEL TOTAL	**1,759,863**	**2,961,997**	**1,202,134**	**68.3%**
FUEL AND IPP TOTAL	**3,420,000**	**3,420,000**	**0**	**0.0%**
BILL TOTAL	**5,179,863**	**6,381,997**	**1,202,134**	**23.2%**

Unit Charges Used for Billing	2008	2009	Change	
	$	$	$	%
Energy	2.514	4.940	2.43	96.5%
Demand	929.00	1,369.00	440.00	47.4%
Fuel and IPP Charge (J$/kWh)	11.400	11.400	0.00	0.0%
Customer Charge	3,245.00	10,956.00	7,711.00	237.6%
Hurricane Recovery Charge	0.088	0.068	(0.02)	(23.3)%
Base Exchange Rate	85.00	85.00	0.00	0.0%
Billing Exchange Rate	88.00	88.00	0.00	0.0%
Usage (kWh)	**300,000**	**300,000**		
Demand (kVA)	**1,000**	**1,000**		