JPS RATE SUBMISSION 2004

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Preamble

This submission for a tariff review is made in accordance with the JPS All-Island Electricity Licence. The Licence stipulates that the current tariffs, which are fixed by the Office of Utilities Regulation (OUR), are due to expire on May 31, 2004. JPS is required to submit this application no later than March 1, 2004.

The tariff review will facilitate the introduction of a new regulatory framework, effective June 1, 2004, which is aimed at ensuring greater efficiency in the energy sector. The submission is therefore based on three primary objectives: the need to keep energy costs down; the need for continued improvement in the service provided by JPS; and the need to ensure continued viability of the company.

The new regulatory framework will be characterised by a price cap regime, which imposes a five-year limit on tariff increases above inflation rates, based on efficiency and quality of service targets to which JPS will be held. The objective of the price cap regime is to ensure that consumers pay fair prices for electricity, by simulating a competitive market environment. This will be done by the introduction of penalties and incentives to ensure that JPS operates as efficiently as possible, taking into consideration the constraints of the macroeconomic environment within which the company operates. JPS will face penalties for poor performance, while the benefits of any efficiency improvement will be ultimately shared with consumers.

The new operating environment will also include the introduction of competition in the development of new generating capacity. This will ensure that any future generation expansion is done in the most cost-effective manner, which will be in the best interest of consumers.

JPS shares the objectives of the Regulator, the Government and customers to keep the costs of energy down, while at the same time ensuring improvements in service. To this end, the company is focussed on the continued implementation of key initiatives started three years ago, as well as the introduction of new strategies. In order to reduce costs while improving operating efficiency, JPS is taking steps to reduce operating and maintenance expenditure and system losses - two critical areas that can yield cost savings in the near future. Significant service quality improvements are expected from continued system expansion, rehabilitation of older generating units and the power delivery network, as well as a review of the company's commercial operations.

Continued improvements in service require substantial investments, and in order to access the resources necessary to support continued investment in its operations, the company must remain financially viable. Efficiency measures must therefore be complemented by a fair opportunity to recover on investments while attracting new capital.

In this rate submission, therefore, JPS presents its recommendations for a new tariff with the following objectives:

- to further improve upon customer service and reliability;
- to provide the correct set of incentives for JPS to operate efficiently and to continue improving its productivity;

- to provide a fair rate of return to investors; and
- to ensure that, while the price cap regime imposes a constraint on the company to excessively pass on costs to customers, it does not unfairly impose upon the company risks that are outside of managerial control.

The proposals herein reflect an intention to balance the interests of all stakeholders.

Confidential Information

This rate submission to the OUR contains certain figures, tables and text that are confidential in nature. Accordingly, such information has been excluded from this published report.

The omissions are indicated by a note in the text or by the symbol ✂.

Contents

Glossary

ABNF = Non-fuel base rate

ADC = Average Dependable Capacity

CAPM = Capital Asset Pricing Model

CIS = Customer Information System

CML = Customer Minutes Lost

CPI = consumer price index

CRP = Country Risk Premium

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

IPP = Independent Power Purchase

IVR = Interactive voice response

MFP = Multifactor productivity

MVA = Mega volt amperes

MW = Megawatt

MWh = Megawatt-hours

NWC = National Water Commission

O & M = Operations and maintenance

OCB = Oil circuit breakers

PBRM = Performance based rate-making mechanism

PT = Potential transformer

RDC = Required Dependable Capacity

REP = Rural Electrification Programme Limited

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

TFP = Total Factor Productivity

TOU = Time of Use

WACC = Weighted Average Cost of Capital

Summary of Proposals

This submission is made in accordance with the JPS All-Island Electricity Licence. The Licence stipulates that current tariffs, which are fixed by OUR, are due to expire on May 31, 2004. Further, JPS is required to:

> "submit a filing with the Office, no later than March 1, 2004 and thereafter on each succeeding fifth anniversary, with an application for the recalculation of the non-fuel base rates. The new non-fuel base rate will become effective ninety (90) days after acceptance of the filing by the Office. This filing shall include an annual non-fuel revenue requirement calculation and specific rate schedules by customer class. The revenue requirement shall be based on a test year in which the new rates will be in effect and shall include efficient non-fuel operating costs, depreciation expenses, taxes, and a fair return on investment. The components of the revenue requirement which are ultimately approved for inclusion will be those which are determined by the Office to be prudently incurred and in conformance with the OUR Act, the Electric Lighting Act and subsequent implementing rules and regulations."

This submission is premised upon the understanding that generation expansion—including the expected Hunt's Bay expansion—will be treated separately and outside the scope of this submission. Costs associated with the planned expansion have not been included in this application. This submission would therefore not be applicable if the OUR decided to include the impact of future generation expansion within the base tariff.

As of June 1, 2004, in accordance with the Licence, a new regulatory framework—a price cap regime—will be introduced in the electricity sector in Jamaica. Under this regime, caps on tariffs will be effectively set for a five-year period. Specifically, tariffs are set in the first year, based on the revenue requirement of the company. Going forward, these tariffs are adjusted for:

- inflation;
- differentials in productivity trends between JPS and the US and Jamaican economies; and
- a bonus or penalty based on JPS' performance on selected quality of service indicators.

Interim adjustments during the price-cap period may also be allowed if there are events that occur, which are outside managerial control but which affect the company's costs.

The objective of a price cap regime is to mimic the outcome of a competitive market so that consumers face fair prices. This is achieved by providing JPS with the right incentives to continuously improve its efficiency, the benefits of which are ultimately passed on to the consumer. The success of a price cap regime depends critically on the company being incentivised to be as efficient as possible. This, in turn, is achieved only if the company is allowed to benefit from any efficiency improvements made. Hence, it is important that:

- Any targets that JPS would be subject to within the price cap period are set <u>at the start</u> of the price-cap period with no unexpected adjustments made <u>during</u> the period;

- The targets must be internally consistent so that JPS is not vulnerable to multiple risks. For example, JPS will be incentivised to reduce non-fuel costs through the X-factor. On the other hand, the heat rate and system losses targets would provide incentives towards improving fuel cost efficiency. As such, JPS' ability to recover its non-fuel revenue requirement should not be affected by its ability to meet the heat rate and system losses targets. JPS should not be exposed to a double penalty if it fails to meet its targets, or a double benefit if it out-performances the targets.

  Another example can be found in the Q-factor (quality of service targets) and the heat rate targets. Running JPS' system with greater spinning reserve would somewhat improve performance on the Q-factor, but would also hurt heat rate performance and fuel costs. It is therefore crucial to ensure that the targets set for heat rates and the Q-factor are compatible so that maximum value redounds to the consumer.

- JPS is allowed to share the benefits arising from any efficiency improvements made. Hence, cost savings should be passed down to the customers eventually—but not immediately.

- JPS should be allowed a reasonable opportunity to make a fair rate of return on its investments. Failure to do so would be detrimental to the long run sustainability of the industry as it would be difficult to continue to attract the financing for investments into the industry.

By giving JPS the incentives to be as efficient as possible, the actual cost out-turns will reflect improvements possible within the constraints with which the company operates. Actual they will trend towards efficient levels of costs. Any efficiency improvements can then be passed on to the customers when rates are next set. The incentives built into the price-cap regime would therefore reveal efficient levels of costs that can be expected of the company. The regulator can therefore avoid the risk and uncertainty of trying to forecast with great precision these costs over the future years. Indeed, the regulator can avoid the risk of imposing too harsh targets at the outset and set price caps that reflect efficiency giants that have not yet been realised—which can have a negative outcome on the viability of the company and industry to the ultimate detriment of the consumer.

As the price-cap regime is designed to replicate the outcome of competitive markets, regulators should be cognizant of two important features of such markets. The first is that, in competitive markets, prices are external to the costs or returns of any individual firm. By definition, firms in competitive markets are not able to affect the market price through their own actions. Rather, in the long run, the prices facing any competitive market firm will change at the same rate as the growth in the industry's unit cost.

Second, competitive market prices also depend on the *average* performance in the industry. Competitive markets are continually in a state of flux, with some firms earning more and others less than the "normal" rate of return on invested capital. Over time, the average performance exhibited in the industry is reflected in the market price.[1]

Taken together, these features have the important implication that in competitive markets, returns are commensurate with performance. A firm can improve its returns relative to its rivals by becoming more efficient than those firms. Companies are not discouraged from improving efficiency by the prospect that such actions will be translated into lower prices because the prices facing any individual firm are external to its performance. Firms that attain average performance levels, as reflected in industry prices, would earn a normal return on their invested capital. Firms that are superior performers earn above average returns, while firms with inferior performance earn below average returns. Regulation that is designed to mimic the operation and outcomes of competitive markets should allow for this important result. <u>Targets should therefore be set based on the expected average—not the best—performance in the industry and firms be provided the opportunity to earn superior returns through superior performance.</u>

The price cap regulatory regime has had a successful history in several countries. It is therefore not surprising that Jamaica has chosen to adopt such a regime as well. Nonetheless, in implementing the regime, a regulator should be cognizant of the possible need to adapt the regime to reflect domestic conditions. In the context of Jamaica, for example, the regime should have the flexibility to deal with potential factors such as:

- risk of currency devaluation;
- the impact and cost of sovereign risks;
- high level of theft of electricity due to poor socio-economic conditions; and
- hyperinflation.

These risks may not exist to the same degree in countries such as the UK and the US, where price cap regulatory regimes have long been in place. What may work in these countries, for example, may not necessarily be suitable, unmodified, in Jamaica. As such risks are due to factors that are outside managerial control, the regulated company should not be penalized and made to bear the costs of such risks. The price cap regime that the OUR implements in Jamaica should reflect this fact.

The following summarizes JPS' proposals in this submission. The proposals reflect an intention to fulfil the objectives of a price cap regime and to balance the interests of all stakeholders:

[1] This point has also been made in the seminal article, *Incentive Regulation for Electric Utilities* by P. Joskow and R. Schmalensee. They write, "at any instant, some firms (in competitive markets) will earn more a competitive return, and others will earn less. An efficient competitive firm will expect on average to earn a normal return on its investments when they are made, and in the long run the average firm will earn a competitive rate of return"; *op cit*, p. 11.

- to further improve upon customer service and reliability;
- to provide the correct set of incentives for JPS to operate efficiently and to continue improving its productivity;
- to provide a fair return to investors; and
- to ensure that, while the price cap regime imposes a constraint on the company to excessively pass on costs to customers it does not unfairly impose upon the company risks that are outside of managerial control.

As noted above, the proposals contained in this document, however, are premised upon the understanding that the generation expansion (including the expected Hunt's Bay expansion) will be treated separately and outside the scope of this submission. Costs associated with the planned expansion have not been included in this application. This submission would not be applicable if the OUR decided to include the impact of future generation expansion within the base ANBF.

The performance-based rate making mechanism: a global price cap system

According to Schedule 3, Exhibit 1 of the Licence, the non-fuel base rate (ABNF) shall be adjusted on an annual basis, commencing June 1, 2004 based on the following formula:

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

where:

$ABNF_y$ = non-fuel base rate for year y

$ABNF_{y-1}$ = non-fuel base rate for year y –1 (prior to adjustment)

dPCI = dI – X – Q – Z where dI is annual growth rate in an inflation and devaluation measure, X is the differential between the productivity trends of JPS and the US and Jamaican economies; Q is the adjustment reflecting quality of service; and Z are other special adjustments that may be required.

JPS proposes that a global instead of a specific price cap is applied. Specifically, JPS proposes that the adjustment factor (1+ dPCI) be applied to the tariff basket instead of each individual tariff.

A tariff basket formula is a mechanism for weighting increases in individual tariffs imposed by the utility in question. The increase in each tariff is weighted by an associated quantity for each tariff element, normally the proportion of revenues associated with each tariff. This weighted average increase of this tariff basket must not exceed the price adjustment factor, (1+ dPCI). Mathematically, a tariff basket price control can be implemented according to the following formulae:

$$(1 + dPCI_t) \geq \sum_{i=1}^{n} \sum_{j=1}^{m} s_{ij}^{t} \frac{P_{ij}^{t+1}}{P_{ij}^{t}}$$

where:

- s_{ij}^{t} = share of tariff *j* of customer rate category *i* in total revenue in period *t*

- P_{ij} stands for tariff *j* (e.g., customer, energy and demand charge in the case of JPS) of customer rate category *i* (e.g., RT10, RT20, RT40 and RT50). For example, in the customer charge for RT10, the RT10 category is referenced by the *i* subscript, and the customer charge by the *j* subscript;

- dPCI = dI – X – Q – Z; and

- Super- or subscript *t* refers to the year.

JPS further proposes that:

- any unused portion of the adjustment factor in any one year can be brought forward to the following year. For example, if dPCI were 10% in 2005 but JPS chose to increase tariffs such that the weighted average increase in the tariff basket were, say, only 7%. Then, in the following year 2006, if dPCI were 8%, then JPS is entitled to increase tariffs such that the weighted average increase in the tariff basket is up to 11% (8% plus the unused portion 3% from 2005).

- JPS would submit its proposed tariff increases (within the price cap) to the OUR each year. The company would ensure that the level of tariffs conforms with agreed established policies (for example, to ensure protection of low income customers).

The annual inflation adjustment factor (dI)

JPS proposes that the inflation adjustment formula (dI) to be used with the 2004 tariffs, be changed to reflect the true inflation costs incurred on JPS. Therefore, any inflationary movements should be applied to the base non-fuel tariffs using:

$$dI = f_{us}\Delta e\left(1 + (1 - d)i_{us}\right) + f_{us}(1 - d)i_{us} + f_j i_j$$

Instead of

$$dI = f_{us}\Delta e\left(1 + di_{us}\right) + f_{us}di_{us} + f_j i_j$$

as currently stated in the Licence, here:

$\Delta e \equiv$ Change in the Base Exchange rate

$i_{us} \equiv$ US inflation rate (as defined in the licence)

$i_j \equiv$ Jamaican inflation rate (as defined in the licence)

$f_{us} \equiv$ US factor, which refers to the portion of non-fuel costs that are denominated in US dollar terms

$f_j \equiv$ Local (Jamaica) factor, which refers to the portion of non-fuel costs that are denominated in local currency

$d \equiv$ Debt factor, where the debt factor, d accounts for portion of US related non-fuel cost that is accounted for by debt financing costs.

In addition, for 2004, JPS proposes resetting f_{us}, f_j and d to reflect the current proportions of US- and domestic-related costs as well as debt-financing costs, based on the audited accounts for the financial year 2003. That is, f_{us} should be set to be 76%, with a corresponding f_j factor of 24%. The debt factor, d, will also be revised to reflect 60% of US denominated costs being debt related. For 2005 onwards, JPS proposes that these figures be reviewed and reset accordingly, to reflect the current proportions of costs.

X-factor

Schedule 3 Exhibit 1 of the Licence's defines X-factor as follows:

> "The X-factor is based on the expected productivity gains of the Licensed Business. 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 reflect the price escalation measure "dI"."

Based on the Licence, JPS has commissioned a study analysing the TFP growth of JPS, the Jamaican economy and the US economy. The study suggests that the TFP growth of JPS is 0.15% while the long-run TFP growth trends of the US and Jamaican economies are estimated to be 1.0% and 0.5% respectively. The weights specified in the performance based rate-making mechanism (PBRM) for US and Jamaican inflation are 0.6 and 0.4, respectively. Overall TFP growth for firms whose output price indexes are reflected in the price escalation measure is therefore 0.8% (*i.e.* 0.6*1.0% + 0.4*0.5% = 0.8%).

The analysis also shows that JPS is an average non-fuel cost performer. There is therefore no evidence that a stretch factor should be further added to X. It is therefore appropriate that the X-factor be set based on the definition in the Licence:

$$X = 0.15\% - (0.6*1.0\% + 0.4*0.5\%) = -0.65\%$$

Based on the Licence, therefore, JPS considers that an X-factor of –0.65% is appropriate for the PBRM (i.e., dPCI = dI + 0.65%)

Q-factor

JPS proposes that the Q-factor be based on two quality indices:

- *System average interruption frequency index (SAIFI)*:

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

- *System average interruption duration index (SAIDI):*

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

The existing database, however, does not allow for the computation of SAIDI and SAIFI related to forced outages at the sub-feeder level. JPS therefore proposes that, during this price-cap period, the Q-factor be based on SAIDI and SAIFI that exclude forced outages at the sub-feeder level. This will ensure that the Q-factor is based upon comparing like with like.

Moving forward in the future, however, JPS will put in place the required systems to collect all data required for the full computation of SAIDI and SAIFI for both planned and forced outages at both feeder and sub-feeder levels. In the next rate review due in 2009, the OUR would have sufficient data to appropriately benchmark JPS' performance on SAIDI and SAIFI at both these levels. This approach will not compromise the performance standards to which JPS would be held.

The value of Q will be based upon actual values of SAIDI and SAIFI for each year of the performance based rate making as compared to the benchmark. JPS proposes that the benchmarks be based on 2003 performance with built-in incentives for continuous improvement. Specifically, the proposed targets are shown in Table 1.

Table 1: JPS Proposed Targets for the Q-factor 2004 —2009

Year	Target SAIDI	Target SAIFI
2004	$SAIDI_{2003}$	$SAIFI_{2003}$
2005	$SAIDI_{2003}$ (1 – 0.02)	$SAIFI_{2003}$ (1 – 0.02)
2006	$SAIDI_{2003}$ (1 – 0.04)	$SAIFI_{2003}$ (1 – 0.04)
2007	$SAIDI_{2003}$ (1 – 0.06)	$SAIFI_{2003}$ (1 – 0.06)
2008	$SAIDI_{2003}$ (1 – 0.08)	$SAIFI_{2003}$ (1 – 0.08)

In each year JPS would be awarded quality points based on its performance in that year relative to the target, as shown in Table 2.

Table 2: Proposed categories and points for SAIDI and SAIFI

Band	SAIFI and SAIDI performance relative to target	Quality points
Excellent	Beating the target by 1.0%	2
Deadband	Beating the target by between 0% to 1.0%	1
Unsatisfactory	Worsening of performance	0

JPS further proposes that:

- If the sum of Quality Points for SAIFI and SAIDI is 4, then Q = +0.5%
- If the sum of Quality Points for SAIFI and SAIDI is 3, then Q = +0.5%
- If the sum of Quality Points for SAIFI and SAIDI is 2, then Q = +0.0%
- If the sum of Quality Points for SAIFI and SAIDI is 1, then Q = -0.5%
- If the sum of Quality Points for SAIFI and SAIDI is 0, then Q = -0.5%

The Z-factor

As set out in the Schedule 3 (Exhibit 1) of the Licence:

> "The Z -factor is the allowed percentage increase in the price cap index due to events that:
>
> a) affect the Licencee's costs;
>
> b) are not due to the Licencee's managerial decisions; and
>
> c) are not captured by the other elements in the price cap mechanism."

JPS proposes that a general materiality threshold be set for items that fall under the Z-factor. For consistency and using the Licence (Schedule 3 (Section 5)) as guidance, JPS proposes that a *de minimis* threshold of J$13 million, adjusted for inflation be set.

Changes in the cost of insurance due to natural disasters or acts of terrorism would qualify under the Z-factor definition in the Licence. The cost of debt is another item that could affect JPS' costs but are, at least in part, outside managerial control as it has a lower bound that is set by Jamaica's sovereign cost of debt. Further, JPS faces risks with regard to its future cost of debt within the rate-cap period as US$130 million of loans are due for refinancing in 2006. If Jamaica's sovereign risk or global interest rates generally rise, these could lead to a material rise in JPS' costs in a manner that is outside managerial control.

JPS therefore proposes the following:

- If Jamaica's sovereign cost of debt—as measured by the estimated ten-year yield on Jamaican indexed bonds—changes; and

- JPS' cost of debt changes, upon refinancing, during the rate cap period; then

- JPS be allowed a Z-factor adjustment, provided that the weighted average cost of debt changes by more than 25 basis points and the materiality threshold of J$13 million (adjusted for inflation).

- The allowed adjustment can be capped by the extent of the change in the sovereign cost of debt. In other words, if JPS' interest rate on the refinanced portion of debt rises by less than the rise in sovereign cost of debt, *relative* to the sovereign cost of debt at time of submission—11.02%—then JPS is allowed the full adjustment based on the change in its cost of debt.

  If, however, if JPS' interest rate on the refinanced loans rises by more than the rise in sovereign cost of debt, *relative* to the sovereign cost of debt at time of this submission, then JPS is allowed the an adjustment that is calculated on the basis of the increase in the sovereign cost of debt.

  In the reverse scenario where the sovereign cost of debt falls, then the adjustment is again calculated based on a change in cost of debt that is no more than the change in the sovereign cost of debt.

Heat rate targets

The indicative heat rate target should be set and known at the outset, for the five-year price cap period. Further, the target should continue to be a system heat rate target—as opposed to a JPS target— to encourage the correct dispatching of IPPs.

JPS proposes the following heat rate targets:

- 11,500 kJ/kWh going forward from 2004; and

- 11,100 kJ/kWh when the generation expansion, as detailed in the least cost expansion model (LCEP), is fully implemented. This is expected to take place in 2007. However, in order to retain the right incentives, JPS proposes that the effective date of the new reduced target not be set now, but rather be dependent on the actual implementation date. This would ensure that JPS does not, for example, face the incentive to bring on the new plant even if sales growth and other factors suggest that the implementation should be delayed. Such a perverse incentive would be ultimately detrimental to the customer.

This proposal reflects a reduction in the target from the current level of 11,600 kJ/kWh.

System losses

The system losses target should adequately reflect the influence JPS can exercise towards reducing system losses. Specifically, while JPS is able to influence technical and some commercial losses, the most prevalent forms of commercial (non-technical) losses are primarily due to factors that are beyond JPS' control. It would be unfair of the OUR to set target losses that penalize JPS for such losses. A broader group of stakeholders, including the government and civil society must be involved in reducing these losses.

JPS' proposals regarding system losses are therefore based on the following:

- Technical losses—currently, about 9 percentage points of system loss is due to technical losses. This level of technical losses are not unreasonable in the context in which JPS operates.[2] Technical losses cannot be reduced via operational changes, but only through investment in new equipment such as transformers, conductor, insulators, etc. JPS would reduce technical losses by 1 percentage point if the OUR allowed for the recovery of these costs from the tariffs.

- Operational commercial losses—about 2.0 percentage points of system loss is due to 'operational commercial' losses. These losses can be reduced via operational improvements including meter-sealing program, billing determinant audits, meter inspections, meter reader controls, internal controls, etc. Reduction of these operational commercial losses requires much labour and diligence, but small amounts of capital expense. JPS has the expertise, tools and systems to reduce this type of loss and will continue to aggressively pursue this type of loss. This loss spectrum can conceivably be reduced from its present level of 2.0% to about 1.0% notwithstanding prevailing economic conditions.

- Social commercial losses—about 7.5 percentage points of system loss is due to out-right and blatant theft of electricity by residential users with no metering system or approved house wiring system. Such theft is largely due to socio-economic factors, which are out of JPS' control. JPS believes that this type of losses can only be reduced via a combined partnership between Government, civil society and JPS. Reduction of these losses will require technical items such as proper/safe house wiring and meter, plus education, cultural change and

[2] See PPA (2002), *OUR Electricity Tariff Study*, July; in association with Frontier Economics, page 20.

enforcement. Reduction of these losses will not take place in a few years, but rather over a generation. In the short-term neither operational changes nor investment in new assets will reduce this type of losses.

JPS therefore proposes that, over the 5-year period, a target be set to reduce technical losses by 1 percentage point and operational commercial losses by 1 percentage point. Therefore, the correct system loss target should, over the five-year period, be 8.0+1.0+7.5 = 16.5%. The proposed trend is summarized in Table 3.

Table 3: Proposed System Losses Targets 2004-2009

Year	2004	2005	2006	2007	2008	2009
System Losses targets (%)	18.0	17.7	17.4	17.1	16.8	16.5

Treatment of IPP costs

JPS proposes to continue embedding base level IPP non-fuel costs into the energy and demand charges. However, there is an inherent risk involved in keeping these costs static within the tariffs. If there are components of the IPP costs that fluctuate in any given month, this will not be reflected in the rates charged to customers. JPS therefore proposes to monitor the IPP costs on a quarterly basis and if there are differences between the current base costs and base costs at time of this submission, the difference will be passed on to the consumers. Inherently, this would be a symmetric adjustment applied as a surcharge (on a per kWh basis), i.e., there will a separate line item (credit or debit) on a customer's bill that is aimed at ensuring that JPS neither gains nor loses on its IPP non-fuel expense.

JPS proposes to pass through IPP costs calculated at base (contracted) capacity levels rather than actual dependable capacity for the following reason. If and when IPP capacity falls below contracted levels, direct IPP costs (i.e., payments to the IPPs) fall accordingly. However, JPS incurs other indirect costs, as a result of the fall in IPP capacity, over and above the costs taken into consideration in the revenue requirement for the test year period. These incremental costs are a result of the following factors:

- more frequent servicing required for the generation units, which are run harder to make up for the loss in IPP capacity;
- higher operating costs as units lower down the dispatch hierarchy are run;
- potentially poorer heat rate performance; and
- potential load shedding and the resultant loss in revenues as well as penalty under the Q-factor.

JPS believes that these incremental costs outweighs the liquidated damages that the IPPs are obliged to pay JPS, under the terms of the contract, when actual dependable capacity is below contracted level.

Rate class rationalization

JPS proposes to rationalize the customer classes to a simpler format, where all Low Voltage Customers above 25 KVA are grouped into a new RT40 grouping, and all Medium Voltage Customers above 25 kVA are classed as RT50. This change excludes some customers in RT40A who will remain as a separate group.

Modification to TOU rates

JPS proposed to modify the design of the TOU rates in the following ways:

- Introduction of a demand ratchet on partial-peak demand, in addition to the current ratchet on off-peak demand. The rationale for redefining the partial-peak billing demand is to provide stronger incentives for customers to shift their load towards the off-peak period. The current design is incomplete in this regard as a customer can realize savings without effective load management once they move from standard to TOU option.

- Increasing the on-peak charges by 5% above that implied by the loss of load probabilities. This is to further encourage the shifting of load from the peak- to partial- or off-peak period.

Modification of calculation of street light billing

JPS currently calculates street lighting bills on the basis of the assumption that streetlights function 100% of the time. To the extent that, when street lights fail and there is a time lag between when the fail and they are repaired, the assumption that they function 100% of the time (i.e., zero outage) is not realistic.

Going forward, therefore, JPS proposes to modify this assumption to one that reflects an outage rate of 1%, i.e., street lights function 99% of the time. This is based on the following:

- An estimated average lifespan of street lights of four years; and
- An average time period of 14 days taken for JPS to repair the failed streetlights.

Proposed tariffs

Table 4 shows the non-fuel base tariffs that JPS proposes, for the year starting June 1, 2004. These rates represent a real increase of 23% over (inflation adjusted) 2003 gazetted rates.

Table 4: Proposed Rates for 2004 (J$/kWh)

					Demand-J$/KVA			
Rate Class		Rate Option	Customer Charge	Energy Charge (J$/kWh)	Standard	Off-Peak	Part Peak	On-Peak
Rate 10	LV	Lifeline	87	6.127	-	-	-	-
Rate 10	LV	Non Lifeline	87	8.656	-	-	-	-
Rate 20	LV		816	6.433	-	-	-	-
Rate 40A	LV	Standard	2,497	3.882	417	-	-	-
Rate 40	LV	Standard	2,497	0.926	1,083	-	-	-
Rate 40	LV	TOU	2,497	0.926	-	45	469	600
Rate 50	MV	Standard	2,497	0.731	1,167	-	-	-
Rate 50	MV	TOU	2,497	0.731	-	49	513	664
Rate 60	LV		611	9.110	-	-	-	-
Standby Tariff (Reserve Capacity Charge):					60			

The key drivers behind the required tariff increase are:

- the investment in additional generating capacity in Bogue and GT11, along with the corresponding return on investment, depreciation, operations and maintenance (O&M) and tax costs; and
- increase in taxes.

The comparison between the current test year revenue requirement and the (inflation and sales growth adjusted) allowed revenue in 2001 is shown in Table 5.

Table 5: Comparison of 2001 allowed revenue requirement and test year revenue requirement

	2001 allowed revenue adjusted for inflation and sales growth. (a)	Test year revenue requirement (b)	Change (c = b – a)
Bogue	-	1,767,040	1,767,040
GT11	-	193,029	193,029
Return on investment (excluding Bogue and GT11)	5,102,257	3,968,232	(1,134,025)
Depreciation (excluding Bogue and GT11)	2,486,484	1,978,842	(507,642)
Operations & maintenance	10,238,980.97	10,443,790.64	204,810
JPS O&M cost (excluding OUR fees, Bogue and GT11)	5,968,428	6,730,801	762,373
IPP's Energy & Capacity payments	4,220,247	3,666,489	(553,757)
street light acceleration cost	-	-	-
OUR licence fees	50,306	46,500	(3,806)
miscellaneous adjustments	(632,517)	1,361,771	1,994,288
Taxes	-	1,483,368	1,483,368
Other operating revenue[1]	(632,517)	(121,597)	510,920
Total non-fuel revenue requirement	17,195,204	19,712,704	2,517,500
Carib Cement revenue	(273,666)	(210,467)	63,199
Non-fuel revenue requirement (excluding Carib Cement)	16,921,539	19,502,237	2,580,699
Sales (including sales to Carib Cement) (MWh)		3,102,602	
Sales (excluding sales to Carib Cement) (MWh)		3,013,591	

[1] The return on investment in 2001 was calculated on the basis of a rate base of $17,437 millions and an ROE of 19.83% (the rate base was 100% equity-financed then).

As shown in Table 6, the new proposed non-fuel tariffs are expected to lead to average increases of between 11%—18% in monthly customer bills, depending on the particular rate class.

Table 6: Estimated impact of proposed non-fuel tariffs on customer bills[1]

Rate class	Estimated increase in monthly bills due to inflation and currency movements	Estimated increase in monthly bills due to real increase in rates	Total estimated increase in monthly bill
Rate 10 Life Line customer (99kWh/month)	3.27%	13.04%	16.32%
Rate 10 typical customer (250kWh/month)	3.15%	13.80%	16.95%
Rate 20 typical customer (1000kWh/month)	3.23%	12.60%	15.83%
Rate 40A average customer (10,933 kWh/month and 85 kVA/month)	3.22%	12.73%	15.95%
Rate 40 Standard average customer			
-40 LV (35,128 kWh/month and 114kVA/month)	3.71%	11.15%	14.87%
-50 LV (264,172kWh/month and 795kVA/month)	3.72%	7.54%	11.26%
Rate 40 TOU average customer			
-40 LV (76,336kWh/month and 189kVA/month)	3.91%	10.77%	14.68%
-50 LV (181,811kWh/month and 498kVA/month)	3.80%	8.55%	12.35%
Rate 50 Standard average customer			
-40 MV (91,778kWh/month and 322kVA/month)	3.69%	14.12%	17.81%
-50 MV (493,323kWh/month and 1,359kVA/month)	3.81%	9.05%	12.86%
Rate 50 TOU average customer			
-40 MV (124,077kWh/month and 365kVA/month)	3.84%	14.49%	18.33%
-50 MV (462,001kWh/month and 1,302kVA/month)	3.84%	10.85%	14.69%

Note: [1] The results are based on the estimated change between the (expected) May 2004 and June 2004 bills. The fuel cost (in US-dollar terms) is assumed to remain constant over the two months. [2]The TOU consumption is based on the sum of the energy (kWh) used in each time period and the average of the demand (kVA) used in each period.

Reconnection fees

According to the Rate Schedule 2003, the reconnection fee is to be determined by June 30 each year and shall be based on the actual cost of undertaking reconnection in the preceding year plus a 10 percent service charge. The current 2003 gazetted reconnection fee is $1,325. Based on 2003 data, JPS estimates that the costs incurred for each reconnection is $1,310. Adding a 10% service charge yields in a reconnection fee of $1,441. JPS proposes that this fee be implemented for the year starting June 1, 2004.

Penalties of guaranteed standards

Currently, when JPS fails to meet the guaranteed standards, customers are currently entitled to the following compensation of $150 and $750 for residential and industrial/commercial customers respectively. JPS proposes that, as of June 1, 2004, the penalties be increased by 100% to the following:

- Residential: $300; and
- Industrial/Commercial: $1500.

The exemption of the guaranteed standards during periods of *force majeure* should be retained.

Part A: Introduction: Achievements and Challenges Ahead

Section 1. Introduction

According to Schedule 3(2) of the All-Island Electricity Licence 2001, the rates of electric power shall compose of the following components:

- A non-fuel base rate (ABNF) which is adjusted annually by a component to incorporate a performance based PBRM.
- A fuel rate which is adjusted monthly to reflect fluctuations in fuel costs.
- Both the ABNF rate and the fuel rate are adjusted monthly to account for movements in the monetary exchange rate between the US Dollar and the Jamaican Dollar.
- Other extraordinary costs related to Government imposed obligations.

As stipulated under the Licence, current tariffs, which are fixed by OUR, are due to expire on May 31, 2004. Further, JPS is required to:

> "submit a filing with the Office, no later than March 1, 2004 and thereafter on each succeeding fifth anniversary, with an application for the recalculation of the non-fuel base rates. The new non-fuel base rate will become effective ninety (90) days after acceptance of the filing by the Office. This filing shall include an annual non-fuel revenue requirement calculation and specific rate schedules by customer class. The revenue requirement shall be based on a test year in which the new rates will be in effect and shall include efficient non-fuel operating costs, depreciation expenses, taxes, and a fair return on investment. The components of the revenue requirement which are ultimately approved for inclusion will be those which are determined by the Office to be prudently incurred and in conformance with the OUR Act, the Electric Lighting Act and subsequent implementing rules and regulations."

Further, according to Section 3(B) of Schedule 3 of the Licence, JPS is required to:

> "submit to the Office no later than September 1, 2003, and every succeeding five (5) years thereafter, a proposal for new baseline values for their performance indicators contained in the Performance Based Rate-making Mechanism, the first of which shall become effective simultaneously with the Non-fuel Base Rate. The Licensee shall also have the option of proposing new performance indicators of mechanisms for the Office's consideration.
>
> Upon receipt of any such proposal, the Office shall conduct a review of the Licensee's proposed performance indicators or mechanisms and shall have full discretion to accept, modify, reject or order the implementation of alternative performance indicators or mechanisms; provided, however, that any Performance Based Rate-making Mechanism shall include (I) an applicable price index (including, if necessary, a factor thereof) which serves as a reasonable proxy index for the measurement of the periodic change in the Licensee's non-fuel costs; and (II) a performance-based discount factor which rewards or penalizes the Licensee (as the case may be). The filing to support the application for a new PBRM will include:
>
> - Audited financial report for the Licensed Business for the most recent financial year;
> - A proposed X-factor for the next five-year period including a total factor productivity study used in determining the appropriate X-factor;

- A report on the quality of service provided by the Licensee during the previous five-year period.
- Proposed revisions to any of the components of the PBRM with justifications;
- Other things specified.

Further, Section 3(C) of Schedule 3 states that:

> "The Non-Fuel Base Rate shall be capped under the Performance Based Rate-making Mechanism".

According to Section 3(D) of Schedule 3:

> "The Licensee shall apply the Fuel rate Adjustment Mechanism that is in force on the date of this Licence…. The Licence shall include with its filing schedules giving the distribution of fuel costs across the rate categories."

In accordance with the Licence, JPS submits this filing of:

- an application for the recalculation of the ABNF;
- a proposed X-factor for the next five year period;
- a proposal for the performance indicators to be included in the PBRM;
- proposed revisions to several components of the PBRM, with justifications.

This submission however is conditional upon the future generation expansion within the price cap period 2004 – 2008/09 be considered separately costs associated with generation expansion have not been included in this submission.

This filing is organized as follows:

Part A:

- Section 2 lays out JPS' initiatives towards achieving the right balance between stakeholders—customers, investors, employees and the community and environment.
- Section 3presents JPS' strategic objectives for the next five years.
- Section 4 provides an overview of the macroeconomic outlook of the next five years and the possible impacts upon JPS.

Part B:

- Section 5: the weighted average cost of capital (WACC);
- Section 6: Revenue requirement for the test year period;
- Section 7: Proposals for the X-factor;
- Section 8: Proposals for performance indicators (the Q-factor);

- Section 9: The Z-factor;
- Section 10: proposed correction to the inflation adjustment factor;
- Section 11: Implementation of the performance-based rate-making mechanism based on the global price cap approach;
- Section 12: Proposed revisions to the foreign exchange adjustment factor;
- Section 13: Proposed revisions to the fuel adjustment factors (heat rate and system losses); and
- Section 14: Proposed revisions to the treatment of IPP costs.

Part C:

- Section 15: The Cost of Service Study;
- Section 16: Tariff design proposals;
- Section 17: Proposed non-fuel tariffs for 2004/05;
- Section 18: Proposed reconnection fee for 2004/05;
- Section 19: Proposed revision of penalties on guaranteed standards; and

Part D contains the appendices to the submission.

Section 2: Delivering on our Commitments: 2001-2003

The partnership between Mirant and the Government of Jamaica in March 2001 began a new phase in the history of JPS. With the acquisition of majority share-ownership in the company, Mirant gave a commitment to help JPS meet the country's expanding demand for energy, and to deliver greater operating efficiencies, better customer service, and more reliable power to more Jamaicans at a reasonable price. Beyond this, Mirant declared its intention to make JPS an active partner in the long-term social and economic development of Jamaica.

Acknowledging the challenges that existed, primarily in the core operational areas of electricity production and delivery, and in customer service, JPS' management team outlined its commitment to making the company a premier customer service organization in its strategic business plan. The primary objective of this strategic plan is to achieve the right balance for all stakeholders through the delivery of superior quality service to customers; the fostering of a productive workforce through a safe and rewarding environment; and maintaining financial viability to ensure the continued interest of investors. To achieve this, the company has established very clear customer service, financial and employee performance indicators in order to measure performance in both the short-term and the long-term.

In keeping with its strategic objectives, over the last three years JPS implemented a number of initiatives in all areas of its operations, with encouraging results. Stakeholders have begun to experience the tangible results of capital investments, operational improvements, organizational changes, and increased efficiencies. A solid foundation has been established as the company continues its journey towards operational excellence.

2.1 Commitment To Customers

2.1.1 Investing in New Generating Capacity

The need for expansion of electricity generating capacity was one reason the Government of Jamaica sold JPS to Mirant in 2001. A lack of funding had prevented JPS from investing in new capacity for some time, resulting in a gradual erosion of the generation reserve margin to less than 17% in 2001. This placed the company in a very vulnerable position, and stakeholders at a disadvantage. As the older generating units struggled, customers suffered severe inconvenience.

True to an undertaking given to the Government, Mirant responded quickly to the pressing need. The first move was the installation of a 20-megawatt (MW) gas turbine plant at JPS' Bogue complex in Montego Bay. This US$15 million installation was completed in a record five months.

Expansion at Bogue

Even as the installation was taking place, JPS was aggressively planning for a far greater expansion of generating capacity. With growing customer demand for electricity growing at approximately 5% per annum, the company's reserve margin had dwindled to unacceptable levels during the latter part of the last decade.

With Mirant's help, a plan was crafted for a new 120-MW generating plant at Bogue on land adjacent to the existing JPS complex. Ground was officially broken for the new plant in January 2002, one year ahead of schedule and the final phase of the construction completed in September 2003. The plant was constructed at a cost of approximately US$120 million.

At 120 MW, the combined cycle plant is the largest installed in Jamaica to date. This plant is the first in Jamaica to use the combined cycle technology and, as a result, is the most fuel-efficient in JPS' operating fleet. The installation of the plant has effectively boosted the company's reserve margin, moving it from 17% to approximately 30%. This has significantly improved JPS' ability to provide more reliable service to customers, who in 2003 were exposed to less than one fifth of the outages they experienced in 2001.

In order to improve even further on this level of reliability, the company has already put plans in place for further generation expansion, in order to keep ahead of the anticipated growth in demand for electricity.

Major Maintenance - Ensuring Continued Reliability of Generating Units

While pursuing plans to increase generating capacity, JPS also began implementation of a US$20 million rehabilitation programme to address the poor state of the older generating assets. Given the slim reserve margin that existed prior to the addition of new generating capacity, the older units had been forced to perform overtime, and were therefore in need of thorough rehabilitation. Persistent challenges on some of these units placed them at risk of failing unexpectedly and reducing JPS' ability to supply enough energy to satisfy customers' needs.

The rehabilitation programme therefore saw the company systematically taking units off line for intensive maintenance in order to ensure their continued efficiency and reliability over the long term. Work was undertaken on all categories of generating units: the oil fired steam plants, the gas turbines and the hydroelectric plants. These interventions are intended to restore the units to a maintenance regime that is fully compliant with the recommendations of the original manufacturers, while sustaining operations for the foreseeable future (see Appendix A1.1 for details of rehabilitation work undertaken by JPS).

Addressing Challenges on the Power Delivery System

Even as it focused heavily on addressing the need for improved generation over the last three years, JPS started to systematically analyse and address problems on its transmission and distribution network. A significant percentage of the outages experienced by customers over the years is the result of problems on the company's transmission and distribution network. JPS has already taken steps to address some of the challenges in this area.

Transmission

In keeping with its thrust to reduce outages to customers, JPS focussed its efforts on rehabilitating and expanding its substation and transmission capacity over the last three years. Specific initiatives include measures to address contamination on the transmission lines, protection of the system against the effects of lightning, and transformer protection at substations.

In order to address the problem of ‘flashovers’ due to contamination, the company invested in upgrading some of its insulators from porcelain to polymer. The contamination problem, which has been the source of serious reliability problems in coastal areas, has been effectively reduced by the installation of the new insulators.

Measures have also been taken to improve lightning protection and grounding, which is another source of concern. These include the installation of auto-reclose systems in some sections of the network. Previously lines would be kept out for unacceptable durations because of lightning faults. With the auto-reclose system, the system will reclose automatically after a fault. If the fault is temporary, power delivery will resume automatically and almost immediately after the initial opening. This reduces interruptions to customers.

Of utmost importance is the implementation of a transformer management programme that involves:

- Expanding loading and transformer capacity by 150 MVA to meet increased generation demand requirements.
- Replacement and rehabilitation of existing transformers for reasons of reliability or loading. This includes processing of oil using a state-of-the art oil-processing rig.
- Improved management systems for trending the performance of the units to prevent premature or untimely failures.

Distribution

The key challenges faced in maintaining and ensuring reliable service from the distribution system are: lightning related interruptions; insulation breakdowns; and poor secondary system performance in some zones.

The company has made significant effort to mitigate these problems. In 2002, JPS began an intensive preventative maintenance programme to address problems on the network, with the objective of reducing disruptions to customer’s supply. The intensive maintenance programme included:

- Transformer rationalization: the matching of transformer size to the expected load, as some transformers are now either over-loaded or under-utilized;
- Secondary circuit re-conductoring: changing and re-routing of power lines;
- Changing of corroded or old connectors and cleaning of corroded joints;
- Changing of poles under a structural integrity programme;
- Installation and upgrading of lightning arrestors; and
- Re-installation and re-establishment of grounding.

- Voltage standardization: determining secondary voltage profile and establishing voltage at the required levels to better satisfy customers' needs.

The distribution maintenance saw JPS linemen and engineering teams working in critical pockets across the island simultaneously. The benefits of the major maintenance programme on the distribution system include: fewer outages, improved safety for employees and customers, improvement in response time to customers, and a reduction in system losses. The company will be building on the initial successes of this thrust as it focuses more on creating a world-class power delivery network.

2.1.2 Linking Investment and Service Quality

The combined investment of approximately US$150 million in new generating capacity and rehabilitation work, has had an immediate impact on the reserve margin and availability of the units, thereby reinforcing the historical link between investment and service quality.

With the addition of the new generating units, reserve margin moved from 17% in 2001 to approximately 30% in 2003. The forced outage rate was reduced from 12% to 6%, with the availability of generating units improving from approximately 75% in 2001 to over 80% in 2003 (see Figures 2.1 and 2.2).

Figure 2.1: Annual Availability of Generating Units: 1990-2003

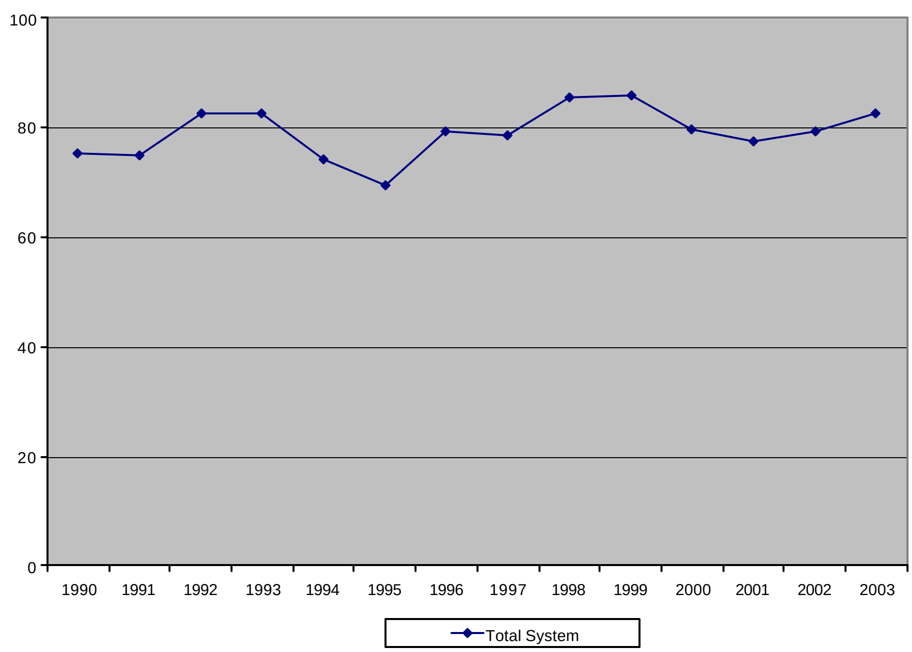
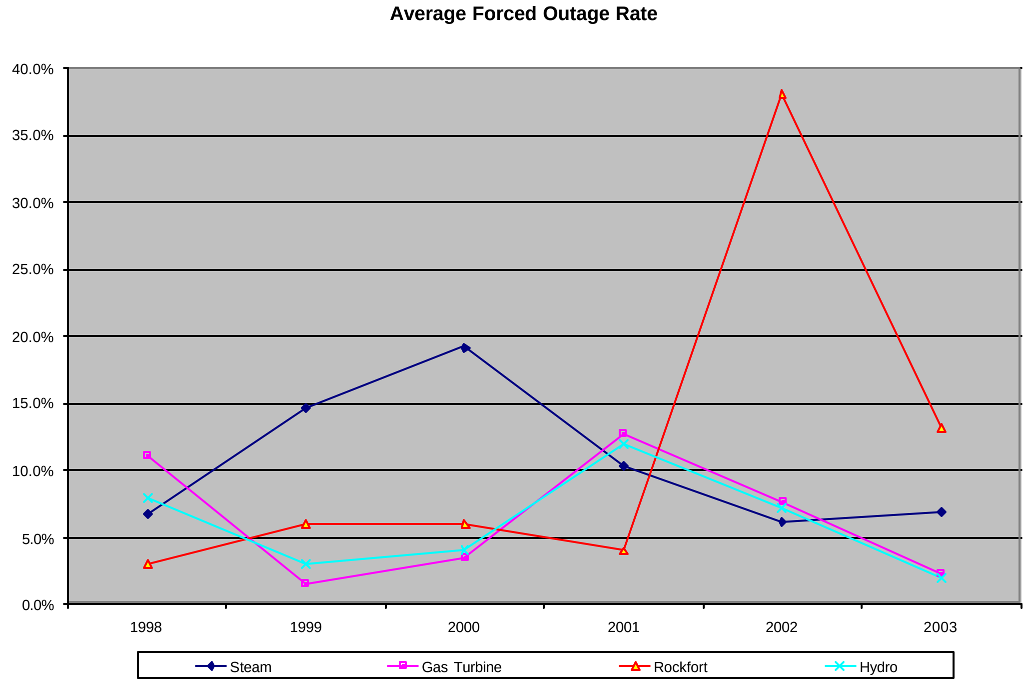
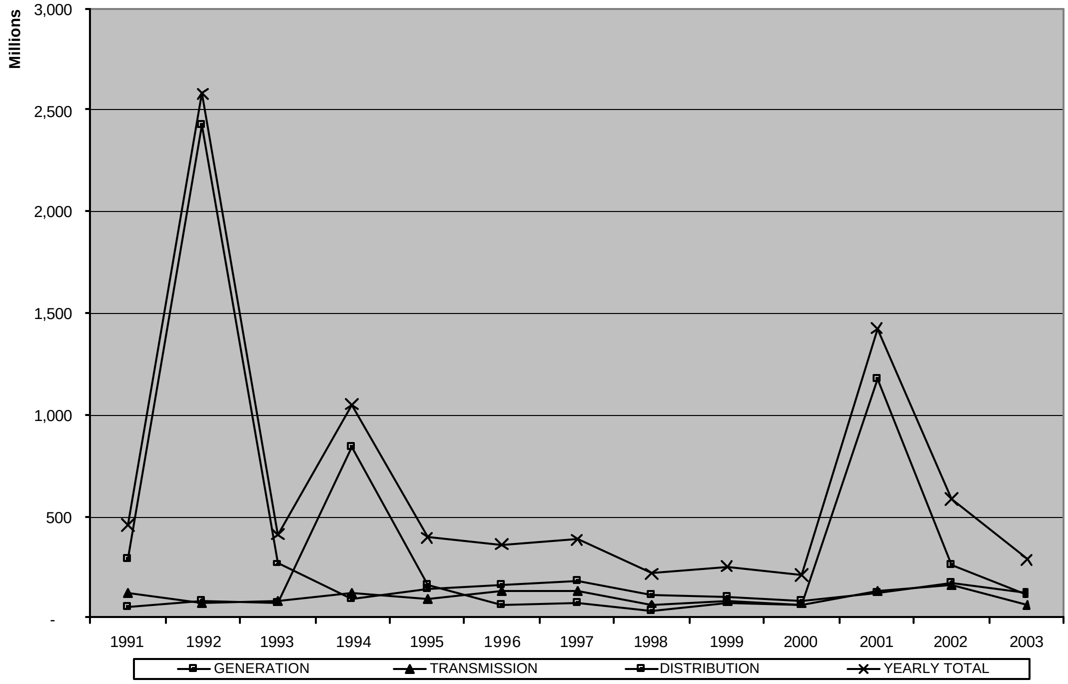


Figure 2.2: Average Forced Outage Rates from 1998-2003



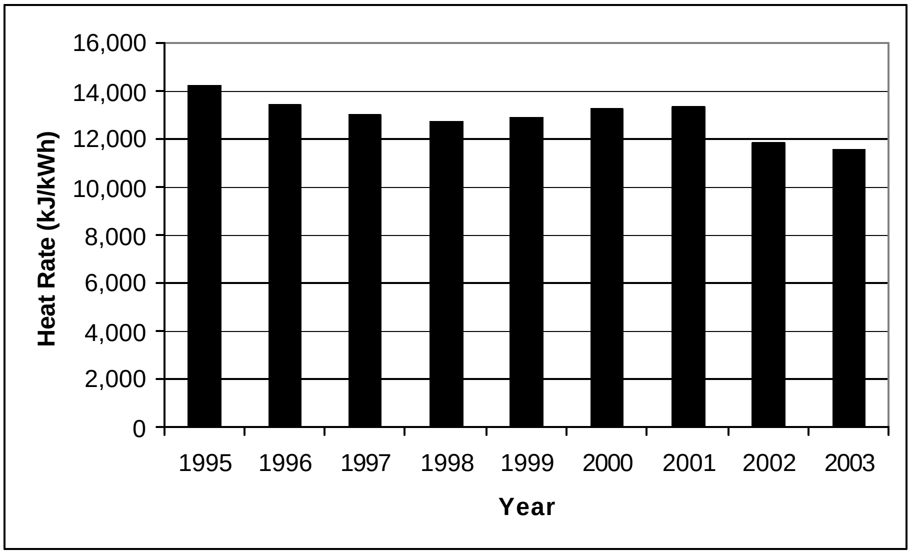
This is significant especially given the extensive generation rehabilitation undertaken by JPS in 2003. The impact on customers is reflected in the dramatic reduction in the number of minutes customers are without electricity. Customer Minutes Lost (CML) moved from approximately 3000 minutes per customer in 2001 to about 550 minutes per customer in 2003 (see Figure 2.3).

Figure 2.3 Customer Minutes Lost: 1991—2003



The improvement in performance coupled with the value added by installation of the most efficient technology – combined cycle – at Bogue has positively impacted heat rate performance over the period. This enabled the regulator to reduce the allowable rate of conversion from a high of 13,000 KJ/kWh to a low of 11,600 KJ/kWh in 2003 (see Figure 2.4).

Figure 2.4: JPS Total System Heat Rate Performance (1995 – 2003)



2.1.3 Serving Customers Better

New Customer Information System

A key component of customer service, and an area of great challenge for the business, is billing. JPS has made significant investments into improving the accuracy and efficiency of its billing systems through the introduction and implementation of a new and upgraded Customer Information System (CIS). Implemented in September 2002 at a total cost of US$5 million, the CIS allows for speedier responses in dealing with customer queries and complaints; greater accuracy in billing; and the production of an improved and more informative bill. In addition, it is an online system where information on accounts, bills and payments are available in real time. The CIS also allows for the analysis of multi-period billing and easy adjustments to bills where required (for example, when estimated readings are replaced by actual readings; incorrect readings due to defective meters or theft are corrected).

The implementation of the CIS was not without its share of teething problems. While it was anticipated that the CIS would result in greater efficiencies, the process placed JPS on a learning curve during which significant resources had to be devoted to its implementation and maintenance. Billing issues arose as JPS sorted out the glitches that were faced in the early phases of implementation, and restored normalcy to the bill delivery process. These challenges included the inability to:

- charge all accounts in a timely manner;
- produce a bill after the computation of charges;
- run the process required for the update of information used by external agencies; and
- update the interactive voice response (IVR) system.

The inconveniences experienced by our customers were significantly reduced by the end of the first quarter of 2003, and JPS has moved to regain their confidence through improved communication and the quality of service.

As the problems are ironed out and the system kept updated, the company expects to see more of the expected efficiency gains and benefits. Some of these have already resulted, such as: improved time in the processing of nightly batch jobs; improved response to customer queries resulting in less waiting time for the customer; daily update of the IVR system; and daily balancing instituted for better financial reporting. Further, as newer modules of the system are introduced, its functionality and benefits will also increase.

Better Invoice Format

JPS has also made improvements to its billing format. The new format provides more information for the customer, while being easier to read. In particular, the bill shows, in graphical form, each customer's energy consumption over the past 12 months. This has proved very useful to the consumer who is able to better monitor his or her energy consumption and bills. There is also a barcode on each bill, which can be scanned to identify the relevant account, thereby reducing processing time in offices. The bill also contains more information about the terms and conditions of service, as well as JPS' and the customers' responsibilities.

Serving Large Customers

JPS' large commercial and industrial customers make up a very critical segment of the company's customer base. Currently, JPS has 103 Rate 50 customers and 1400 Rate 40 customers, who collectively account for approximately 60% of total revenues. Among these customers, three were formerly self-generating - Caribbean Cement Company, Wyndham Rose Hall, and the Port Authority of Jamaica.

Through a special key account programme introduced in 2001, JPS formed a team of six key account managers dedicated to serving large customers, and forging closer partnerships in an effort to better understand and support their businesses.

The key account programme has seen significant improvements in communication between these customers and JPS, as well as the provision of value-added services such as consultations to facilitate greater understanding of the options available to them for improved efficiency in their operations. JPS also provided energy audits and energy management training seminars for employees from several companies, who have been trained to effectively plan and manage their energy usage.

24-Hour Call Centre

In order to better serve customers who prefer to do business from the comfort of their homes or offices, JPS expanded the capabilities of its 24-Hour call centre. This was in keeping with the thrust to shift from an over-the-counter approach to a telecommunications-based customer service.

To drive this, JPS introduced an IVR system—which provides customers with automated access to account information. The new CIS helped to enhance the capabilities of the call centre, enabling customers to do more transactions by phone, including opening and termination of accounts. The physical infrastructure of the call centre was improved and the facility expanded to accommodate up to 35 operators at any one time, twice the number that could be accommodated before.

Improving Payment Options

JPS has improved the range of payment options available to customers, by outsourcing a significant portion of its payment collection activities by expanding third-party services, i.e., payments through banks, building societies, Paymaster and Bill Express.

Based on the success of the strategy, JPS is considering fully outsourcing these services thus allowing our local offices to focus on providing superior quality customer service. In 2003, 68% of bill payment transactions were carried out through third parties compared to approximately 30% in 2001. This, coupled with our call centre-based services, allowed JPS to rationalise its local offices, reducing them from 21 to 15, without compromising customer service.

In addition to increasing the number of outlets where payments can be made, JPS also expanded the means by which customers may pay by accepting credit and debit cards in addition to cash payments. The prompt delivery of bills also improved, as the company increased the proportion of bills—from 5% in 2001 to approximately 20% in 2003 —handled outside the post office network and by delivery contractors.

With the changes and improvements made in the last two years, JPS now has the capacity to deliver even better service and convenience as customers develop greater comfort with the new modes of doing business.

While the progress in shifting customer behaviour has been significant, the transition is not yet complete. Although bill payment traffic via third party outlets has now exceeded the 65 percent mark, the transition to the call centre mode of making service contacts with the company has been somewhat slower— only between 30—40 percent of customer contacts are effected through this means. This is expected to increase as the company works to expand and improve the quality of service provided through its Call Centre.

Guaranteed Service Standards

Under the licence agreement, JPS is obliged to meet selected customer service standards. Customers are expected to hold the company accountable for performance against these guaranteed standards, which pertain to the time taken for JPS to provide:

- new installations;
- simple connections;
- complex connections (work estimates and construction);
- responses to service calls;
- bills for new accounts; and
- make reconnections.

Where JPS does not meet the requisite standard, customers are entitled to compensation, amounts of which are specified in the licence. JPS has internal targets of 90% compliance with these standards.

Performance against these standards has improved overall between 2001 and 2003, with a corresponding decline in the potential compensation payable (see Appendix A1.2 for details). However, while performance has been improving, it is on average still below JPS' internal target of 90% compliance. A number of factors have contributed to the slower than expected improvement in performance. These include material management problems and poor internal coordination resulting in delays in responding to customers.

Organisational and business process changes are being put in place to specifically target these issues. One significant move is the merger of transmission, distribution and customer service under one directorship. The result will be better coordination between these related arms of the business, and ultimately, improved customer service.

2.2 Creating Value For Investors

Since 2001, the emphasis on customer service has been balanced by a need to ensure fair returns to investors. Both these objectives are, in the long run, complementary. Compensating investors with a fair return is necessary to ensure that investments, which are needed to provide customers with good and reliable service, continue to be made.

Without the prospect of a fair return, investors will move capital to other investment opportunities. Given the global and fluid capital market, it is critical to ensure that JPS is able to provide a fair return to investors so as to retain and increase the capital that has been invested in it. This is particularly important, given the current weak macroeconomic environment of Jamaica, which exposes investors in the country to significantly higher risks compared to investments in many other countries. Investments made in Jamaica therefore require a premium over and above the cost of capital invested in countries with stable economic foundations, to compensate the investors for the higher risks faced. This is also significant given the need for JPS to continue to go to the capital market to support its expansion programme over the next decade.

2.2.1 Debt restructuring

When JPS was privatised in 2001, there was an immediate need to restructure JPS' debt. This was for two reasons—first, a substantial portion of existing short-term debt was maturing at that time, thus refinancing was required; and second, other portions of debt were previously backed by state guarantee, which would no longer stand following privatisation. In 2001, therefore, JPS negotiated for two tranches of financing totalling US$130 million. This replaced all the debt that existed prior to privatisation. The 5-year loans (maturing in 2006) were US dollar-denominated bullet loans (i.e., the principle would all be repaid only upon the maturation of the loan). Further financing was also required when JPS undertook the generation expansion at Bogue. Of the US$120 million invested, US$75 million took the form of long-term debt from the IFC and RBTT. The negotiations, which started in 2001, were completed in May 2003.

In addition to long term financing, JPS also negotiated for short-term loans (i.e., working capital financing). A total of US$16 million was raised, $10 million of which was secured by real estate owned by JPS. The short-term financing was critical in bridging the gap between the start of generation expansion at Bogue and the finalisation of the related long-term financing.

Currently, all of the debt on JPS' books is US dollar- instead of Jamaican dollar-denominated. This is for two reasons. The cost of Jamaican dollar denominated debt (which ranges between 22% and 24% in 2000) was higher than what JPS is willing to pay at that time, considering the expected level of devaluation then. Second, the capital market in Jamaica is tight, primarily due to the large presence of the Government, a major borrower. Borrowings by the Government has reduced the availability of Jamaican dollar denominated funds for private sector participants, such as JPS, and pushed up the interest costs. While JPS is considering hedging itself against currency fluctuations by having a proportion of its debt denominated in Jamaican dollars in future, it is unclear if this would be possible given the tight domestic capital market for such loans.

While the US dollar-denominated debt carries a lower interest rate, it leaves JPS exposed to currency fluctuations. This has important implications for JPS, particularly as the revenues earned are denominated in Jamaican dollars and reporting is based in Jamaican dollars. When the Jamaican dollar depreciates, both the interest cost in Jamaican dollar terms and the principal amount of debt in Jamaican dollar terms rise. The change in the debt principal due to foreign exchange (forex) fluctuations is a real cost of debt to the company. Indeed, the potential cost of forex fluctuations to US-denominated loans accounts for much of the difference in the interest rates on US-denominated loans compared Jamaican-dollar denominated loans.

2.2.2 JPS financial performance

Table 2.1 shows JPS' financial performance under IAS accounting rules between 2001-2003.

Table 2.1: JPS' financial performance (2001 - 2003)

Indicator	2001	2002	2002[a]	2003
Return on equity (%)	(6.8)	5.6	4.6	(3.7)
Net income (J$ billion)[b]	(1.5)	0.86	0.65	(0.7)

Notes: [a] 2002 represents a nine-month period, April—December 2002. [b] Net income from ordinary operations before taxation, as restated under IAS.

As can be seen, the return on equity has been low. There are three key reasons for this—losses due to forex movements; system losses; and the Bogue generation investment that had to be brought forward—JPS has not been compensated for the earlier-than-planned investment.

Forex movements

JPS currently recovers its revenue through tariffs that are set on an assumed base exchange rate. This imposes a high currency risk as a significant share of the JPS' costs is denominated in US currency. A foreign exchange adjustment factor is therefore applied to these base tariffs in billing customers, the intention of which is to offset any movement in the Jamaican currency relative to the US dollar.

Currently the foreign exchange adjustment factor adjusts the base tariffs by a factor of only 0.75. The formulation was set in the 2001 rate submission when, at the time, it was determined that approximately 75% of JPS' total costs were foreign related. In other words, the mechanism assumes that the cost structure of JPS remains fixed in the proportion highlighted above and accordingly applies a 75% adjustment each month. This assumption, however, does not hold true for two reasons:

- The first is that fuel price volatility over the last two years has led to shifts in the proportion of fuel cost relative to non-fuel costs. As fuel costs are 100% US-dollar based, increases in the price of fuel would, all else equal, lead to an increase in JPS' US-dollar denominated costs as a proportion of total costs.

- Secondly, depreciation in the Jamaican dollar has led to an increase in the proportion of US$ related non-fuel costs relative to the local component.

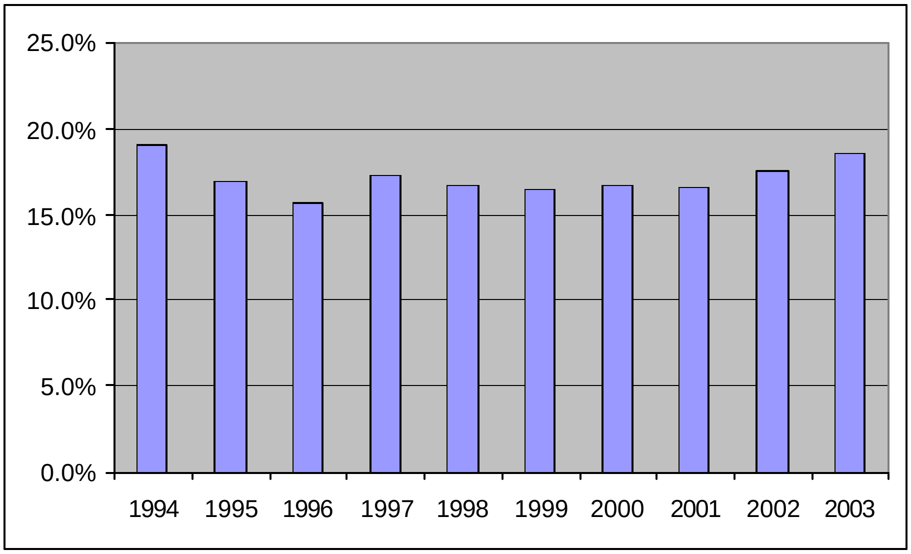
Both these resulted in the mix being closer to 86% of costs being foreign exchange related. However, the tariffs have not been adjusted to reflect the full extent of the impact of foreign exchange movements. This has had a negative impact on the returns JPS' profitability.

System losses

System losses have been a major operational challenge and focus for JPS for well over a decade.[3] Presently more than 18% of the energy produced is lost. Effectively, it represents lost revenue to the company. The losses incurred can be divided into two types—technical and commercial losses. While technical losses are occasioned by the physics of power delivery, and to some extent are within the control of the company, non-technical or commercial losses that are primarily related to the illegal abstraction of power by users, have turned out to be an intractable social problem (see Figure 2.5 for trend in JPS system losses).

[3] Specifically, systems losses are measured by the net energy produced less energy sold divided by net energy produced.

Figure 2.5: JPS System losses from 1994 - 2003



On the technical side, sustained programmes to upgrade the primary and secondary networks have yielded notable improvement (see Section 14 for more detail of JPS' efforts to reduce technical losses). While continued innovation in technology will continue to yield efficiency gains, that end of the loss spectrum is now within the tolerance band of 8.5% generally considered by the energy industry as acceptable for a utility within an operating environment such as JPS.

On the other hand, despite several initiatives and sustained campaigns, the company has had little success against pervasive and pernicious commercial losses. At 9.5% of total revenues, commercial losses is comparable to that of a number of countries within the development strata in which Jamaica is ranked by the World Bank.

The contributory factors to losses of this nature are many and complex, including social and economic conditions, business deficiencies, and the accessibility of the transmission and distribution network. Jamaica's less than robust social and economic environment over the past two decades has fostered conditions conducive and encouraging to electricity theft. Simultaneously, weak state law enforcement and several deficiencies in JPS' business operations have created opportunities for such losses that have been increasingly exploited.

JPS has attempted to deal with commercial losses from several angles (see Section 14 for more details on JPS' efforts taken to reduce commercial losses). Despite these efforts, the level of commercial losses remains high. Losses have tended to have a direct correlation to electricity prices. The effective cost of electricity rose appreciably commencing in 2001 due to a rate increase, coupled with adverse economic conditions that resulted in major currency devaluation. More specifically:

- the economic backlash from the September 11, 2001 strike on the US was only fully manifested in 2002, and Jamaica, like other countries experienced a significant reduction in economic activity for much of the year.

- Electricity rates went up in 2001 after being constant for over seven years.

Electricity theft has had a profound impact on the cost and quality of service that the JPS has been able to deliver to its customers. Financially, the cost has been staggering. The regulatory framework within which JPS operates allows for a maximum system loss of 15.8%. Losses above this value directly impair the company's bottom line. While the cost of fuel is generally a direct pass through to the customer, fuel costs incurred in producing incremental electricity above the 15.8% value are not recoverable. Based on net generation of 3,650,000 MWh for 2003, a fuel rate of US$0.035/kWh and 18.5% system loss, the company's bottom line is further impaired by approximately US$3.5 million per year.

Generation Expansion at Bogue.
In the business plan set in 2001, the generation expansion at Bogue was scheduled to start in 2003 for completion in 2004. However, due to the worse than anticipated state of the generation assets, the project was brought forward. Work started in January 2002 completed in September 2003. The cost of this project—which stands at more than US$100 million—was not factored into the tariffs set by the OUR in 2001. As such, JPS has not yet started to recoup the costs incurred, which has had an impact on net income and the ROE in 2003. It should be noted that the total cost of the Bogue expansion effectively stands at US$120 million, of which US$20 million was due to station improvements made.

The major impacts of the Bogue expansion on net income are as follows:

- *Depreciation charges*—approximately J$3 billion of the Bogue expansion costs was transferred from CWIP to plant-in-service on December 31, 2002 and, based on the average depreciation rate of 4%, had an impact of J$110 million on the income statement for the year ending December 31, 2003.

- *Loan interest costs*—these costs, which impacted on the income statement after the construction costs were transferred from CWIP to plant-in-service, are not yet recovered through the tariffs. Assuming an average interest rate of 12% on the loan financing, this impact is estimated to be approximately J$450 million, has affected the net income as well as the ROE in 2003.

- *Forex losses*—of approximately J$858.5 million on the loan principal, which are denominated in US dollars, have been recognized in the income statement. Although these losses are still materially unrealized, they have still impacted the reported net income and ROE figures.

2.3 Creating a More Productive Work Environment

2.3.1 Organizational Changes

In 2001, JPS completed a downsizing exercise, which reduced its workforce by approximately 20% as part of efforts to operate more efficiently. Despite this, there is the need for further improvements. As a result, in 2003 JPS embarked on a top-to-bottom organisational review aimed at improving its focus on service delivery, efficiency and performance. With the completion of the review process, a new organisational structure was created, with significant implications for how the company will operate in the future. The company's operations are now organized around four core divisions of generation; customer operations, finance and regulatory, and administration.

The new structure shows a much more streamlined organisation, and is expected to result in greater accountability, while strengthening the natural linkages between the different parts of the business. Of significance is the creation of a new customer operations division, which brings together the core functions of customer service, transmission and distribution. The aim is to place under one umbrella all the functions that have direct impact on customers. The changes are central to the company's efforts to become a more productive and customer focused organization. The streamlining of the organization is aimed at preparing the company to effectively accomplish the goals that have been set for us over the next five years and to operate in the competitive environment defined by the OUR.

2.3.2 Improving Employee Productivity

While pursuing the reorganization of business units within the organization, in December 2003 the company offered employees with more than two years of service the option of voluntary separation and early retirement. The exercise is expected to see improved efficiencies, as the company moves closer to its employee productivity target as measured by the number of customers per employee. These expected savings are reflected in the requested revenue requirement in this submission. While implementing the voluntary separation programme, JPS will continue to explore options of outsourcing elements of its operations where doing so will result in efficiency gains. It is expected that further redundancies will result from this ongoing exercise.

2.3.3 Training

Training has continued to be an integral part of the company's strategy to improve employee productivity. In 2003, the trend continued, with the delivery of approximately four training contact days per employee. Training courses of note during the year were: Managing the Business, Who Moved My Cheese, Values and Attitudes, intensive training for customer service employees, computer-based training, network supervisory training, substation technician training, live-line and distribution deadline training, and switching authorization.

2.3.4 Enforcing Policies and Procedures

Since 2001, the company has focussed on the enforcement of policies and procedures that, although in existence, had not been rigorously enforced in the past. The introduction of a Code of Ethics underscored JPS' commitment to operating in a manner consistent with that of a world-class organization. In 2003, the company introduced a new exchange of gifts and conflict of interest policy to assist employees in making ethical decisions. The new policy, which is in keeping with the existing personnel policies and procedures manual, is expected to guide employees in making ethical decisions and avoiding impropriety or the appearance of impropriety.

The enforcement of company policies is an integral part of the process of making JPS a more disciplined organization, operating according to rules, policies and appropriate procedures.

2.3.5 Performance Management Initiatives

Since privatisation, JPS has worked hard towards implementing and reinforcing a merit-based system that rewarded performance and accountability within the JPS team. There are two components to this effort:

- Setting goals and performance targets—prior to 2001, performance targets for each department and unit were not always linked and consistent. JPS has since changed this towards a system where goals for each department or sub-department is set based on the overall goals of the company. Performance targets were therefore consistent, ensuring that the company moved as one unit in one direction. The ultimate corporate goals are based on the need to improve customer service as well as financial performance.

- Implementing a reward system—in order to incentivise performance, promote responsibility and accountability within the JPS team, a system that rewards based on the achievement of the goals is necessary. JPS has implemented such a system at the senior management level whereby bonuses of between 3 – 5% of annual salary are paid, depending on whether the company meets its financial targets.

JPS has, however, had less success in implementing a performance incentive system at the lower rungs of the organization. The labour unions have been largely unwilling to accept a performance based compensation scheme. Every effort is therefore being made to educate the relevant parties and build the environment for this approach to bear fruit. It is hoped that, in the next round of labour negotiations, JPS will be able to extend the performance management system across the company.

2.3.6 Mirant Involvement

Since 2001, Mirant has been providing technical assistance and other support to JPS, particularly in following areas:

- *Technical engineering support*—Engineers, technicians and supervisors from the Mirant Service Center in Maryland and from Mirant Corporate in Atlanta have provided ongoing support for planned maintenance projects, emergency repairs and trouble-shooting at the JPS' generating plants. Because of Mirant's size, it is able to employ specialists and experts that smaller companies such as JPS cannot justify. Working together with JPS plant management, this expertise has led to better results at lower costs than JPS has been able to achieve acting on its own.

- *Operations and maintenance methods and practices*—Mirant uses various forums to share its extensive experience in utility operations and maintenance with JPS. Plant managers and supervisors have participated in overseas training exposure at Mirant's plants in the U.S. to observe Mirant's methods and practices first hand. They have implemented many of Mirant's programmes, for example root-cause analysis to identify and rectify the root cause of breakdowns so that similar events do not reoccur. Mirant has also provided written operating procedures and preventative maintenance procedures to JPS. In addition, Mirant senior managers have conducted assessments of JPS' operations and maintenance activities and provided recommendations for improvement. JPS recently began implementing new

O&M programs based on benchmark programs from Mirant's "Top Ten" best practices program.

- *Technical operations committee*—Senior technical managers from both Mirant and JPS meet monthly to review operational issues. The increased focus from senior management has contributed to progress on numerous technical issues.

- *Environment and safety*—Mirant's Safety and Environmental professionals are assisting JPS in establishing world-class programs to protect its workers and the environment.

The partnership between JPS' and Mirant's international and US operations is expected to continue to yield results both for the employees involved, as well as the organization as the JPS.

2.4 Safety Initiatives and Environmental Stewardship

2.4.1 Safety as Top Priority

Safety is a key item in JPS' priority list, as the company makes concerted efforts to establish an environment that is safe for all our employees and our contractors. The Mirant safety and health management system has been implemented in JPS, accompanied by a new Safety and Health Policy. The policy underscores JPS commitment to incorporate safety and health practices into our business every day, including the provision of a safe work environment, the application of a set of rules and procedures to promote the accident-free performance of duties, and the commitment to make employees conscious of their responsibilities in integrating safety and health in their activities. Each employee has been provided with a new safety manual, which is supported by training and orientation. This is accompanied by an ongoing programme to communicate the company's safety policies and to enforce compliance with these policies.

To spearhead the safety efforts, a Safety Council has been formed with responsibility for ensuring compliance with safety policies, communication of good safety practices and implementation of projects to improve safety performance.

2.4.2 A Friend of the Environment

JPS is committed to be good stewards of the environment, and has made environmental management one of its highest priorities, with a commitment to comply with all applicable environmental laws and regulations and to promote cost-effective energy management programmes among employees and customers.

In 2002, JPS adopted a new environmental policy, which is based on the principle of responsible business practices. The company's primary objective is to conduct its operations in a manner contributing to sustainable development, ensuring that it meets the needs of the present generation without compromising the quality of life for future generations. Over the last two years, JPS has invested J$163 million in efforts to improve our environmental performance.

The company has made significant effort to ensure that its current operations as well as its expansion plans are in keeping with, or surpass, the applicable standards. Since 2002 JPS has been implementing an Environmental Management System (EMS), which is a comprehensive approach to managing environmental issues affecting JPS operations. The implementation of the EMS has already begun to yield positive results. The successful elements of the EMS so far include:

- the cleaning up of PCBs from retired transformers that had been stored up from previous years;
- the cleaning up of accumulated waste and soil contamination in the company's generating plants,
- the introduction of a wastewater usage programme;
- the monitoring of ambient air quality standards; and
- increased utilisation of renewable energy.

Poly-chlorinated byphenyls (PCB) detoxification and disposal

PCBs are found in the oil used in transformers, capacitors and oil circuit breakers (OCBs) and may be carcinogenic. Over the years, more than 5000 retired transformers have been stored in various sites across the country. Without proper treatment, the leakage of PCBs from these transformers can be hazardous. In October 2002, JPS started on a programme to dechlorinate and remove these transformers from storage. By the end of May 2003 and after a cost of US$2.531 million, 5,781 transformers had been dechlorinated such that their PCB concentration fell to 2 parts per million (ppm) compared to the National Environment Protection Agency (NEPA) recommended standard of 50 ppm. The dechlorinated transformers' carcasses were scrapped and shipped off island for disposal while arrangements are being made with the local environmental regulatory agency to have the pure PCB waste shipped to Tredi, France. JPS aims to continue PCB removal and disposal programmes on a bi-annual basis on all oil-based transformers and capacitors.

Plant Improvement & Soil Contamination

Since 2001, JPS has carried out several plant improvement programmes. These include the upgrading and construction of facilities to reduce and eliminate soil contamination resulting from oil and chemical spills. Berm walls have been constructed around spill-prone areas to ensure that, if spills occurred, they would be contained to that area. The company is also in the process removing contaminated soil from various sites to landfills—where it is treated—and replacing it with clean soil. The elimination of soil contamination has been carried out at Bogue and Old Harbour in June and September 2003.

Removal of industrial waste

There has also been a massive effort towards the removal of solid and industrial waste that has accumulated over the previous years. Following improved landfill facilities by Metropolitan Parks and Markets Limited (MPM) and Western Parks and Markets (WPM), JPS has been able to remove industrial waste from 3 plants (Old Harbour, Hunts Bay and Bogue). Industrial waste removal from the Hunts Bay and Old Harbour plants are in the plan for completion by the end of 2003. In addition a system of ongoing solid waste management is being put in place to prevent a recurrence of massive accumulation.

Waste-water usage programme at Bogue

In addition to cleaning up existing waste and contaminated material, any new capital investments are also made to meet high standards. The new generating plant at Bogue has been developed as an environmental flagship; for example, it uses treated wastewater during the generation process.

At this plant, JPS has entered into an unprecedented partnership with the National Water Commission (NWC) to use treated wastewater from the NWC's Bogue treatment plants during the generation process. At a cost of US$5.5 million, JPS built its own facilities to treat and purify the grey water from the NWC effluent plants to potable standards. Installed underground pipes allows the water to be transmitted between the sites and to be used in the various processes in the plant, e.g., water injection for NOx emission control, the cooling water, fire water and boiler make up water. The water goes through four cycles before it is released. Given the significant water requirements in a power generation plant—the Bogue plant utilises up to 1 million gallons per day—the use of wastewater represents a significant savings on the demand of clean water.

JPS has also included a number of other features in the new power plant to make the Bogue facility a better environmental neighbour. The noise and emissions performance of the combined cycle plant are on par with the best in the world and will fully comply with local and international environmental standards. The combustion turbines are retrofitted with water injection for emission control, and acoustic management on these units make them hardly audible during operation.

Installation of Ambient Monitoring Station

The Bogue site is also be the first to have an online air quality monitoring station as part of JPS' overall EMS. Currently, the station monitors ambient levels of SOx. By January 2004, it will be upgraded to include the monitoring of NOx. Completed in April 2003 at a cost of US$70,000, the station gives hourly readings of air quality. It will allow the monitoring of air quality standards so that, if there is any indication that air quality is threatened—ambient air quality is also dependent on other factors such as traffic—JPS can reassess the environmental performance of the plants in that area and undertake remedial action if necessary.

Renewable energy

As part of an ongoing commitment to support the development of renewable sources, JPS entered an agreement in late 2001 to purchase electricity from a wind farm to be developed at Wigton, Manchester. The 20-MW wind farm is being built by Wigton Wind Farm Limited, a wholly owned subsidiary of the Petroleum Corporation of Jamaica, and commissioning is scheduled for 2004.

In addition, in February 2003 JPS completed a comprehensive rehabilitation of its hydroelectric units, which contribute a total of 21.4 MWs to the grid. The rehabilitation project, which started prior to privatisation, was implemented in partnership with the Government of the Republic of Germany at a cost of US$27 million.

2.5 Commitment to Communities

2.5.1 Community Outreach

JPS has offices and operational facilities in every parish across Jamaica, and touches the life of every Jamaican, so it is only natural that the company should take a keen interest in the communities it serves. This interest surpasses the installation of power lines and the generation of electricity, extending to the overall well-being of customers and their families.

Through its community outreach programme, the company has initiated and supported a number of projects in various communities across the island over the past three years, forging partnerships with other organizations to enhance the nation's social development. Our employees were integrally involved in several community outreach projects, giving of their time and skills to improve the lives of many. For example, JPS and Mirant joined forces with Habitat for Humanity to provide a home in record time for a rural family in need. JPS' contribution represented the very first time that a corporate entity had fully sponsored the construction of a house in a local Habitat for Humanity community.

JPS has focussed on the development of the youth by providing support for education and sports activities. One of JPS' main education projects was developed through an alliance with the Ministry of Education. This partnership saw children in various schools across the island being fed through an ongoing Early Childhood School Feeding Programme. Support for education also included the hosting of science fairs for students in secondary and tertiary institutions; sponsorship of awards for top performers in science subjects in the Caribbean Examination Council (CXC); sponsorship of scholarships for teachers and students; and donation of furniture and computers to schools.

JPS' launched its annual regional football league competition in 2002, successfully contributing to the development of the potential of the youth in communities across the island. The company's sponsorship of the national team of disabled athletes, helped to secure a place for the country in 2004 Special Olympics.

The company has also engaged in community projects, which include the refurbishing of police stations and schools, and assistance to homes for the elderly. Since 2002, the company, through its Community Relations Department, has undertaken close to forty major community projects at a cost of approximately J$6 million. JPS further demonstrated its commitment to the community through its contribution of J$3 million to the construction of a new wing at the University Hospital of the West Indies.

2.5.2 Economic Development

As part of a commitment to the growth and development of Jamaica, JPS has been working closely with local business organisations on initiatives aimed at supporting business expansion and retention. One such programme implemented in 2002 exposed international journalists of acclaimed publications to the economic opportunities that exist in Jamaica. JPS partnered with Mirant and the government promotions agency, Jamaica Promotions Corporation (JAMPRO), in an effort that generated over 20 positive press stories on Jamaica in the United States, Finland, Greece, Australia, Germany and Spain. The media representatives and site location consultants interviewed over 40 businesses and associations in a number of areas, including Agriculture, Tourism, Information Technology and Communication, Ports and Infrastructure Development.

In 2003, JPS was a major sponsor of the first Atlanta-Jamaica Business Exchange, which provided an opportunity for businessmen and women from Jamaica to forge lasting partnerships with persons with similar business interests in Atlanta. The contacts made during the event have resulted in ongoing discussions and collaboration between the Jamaica and Atlanta business communities.

JPS also provided sponsorship for a number of local companies, who would otherwise have been unable to participate in the event. The Atlanta-Jamaica Business Exchange was made possible through the collaboration of a number of agencies, including JAMPRO, the Private Sector Organization of Jamaica (PSOJ), the Jamaica Exporters Association (JEA), and Jamaica Manufacturers Association (JMA). Over 200 companies participated in the event.

Section 3. Looking forward: JPS Objectives: 2004 and Beyond

Looking ahead for the next five years, the company's strategy is to build on the foundation set over the last three years. Critical areas for success and accompanying strategies will include improving quality of service, improving financial viability, increasing operating revenues, and reducing expenses.

3.1 Improving Quality of Service

The strategies to be employed over the next five years to improve customer service are geared towards completing the overhaul of service delivery, a process that has been in progress for the past three years. Specific focus will be on the following areas:

- Aggressive maintenance and rehabilitation of older generating units to ensure reliability of service;
- Generation expansion to meet growing demand for electricity;
- Timely expansion of the transmission and distribution network to meet growth in demand;
- Improvement and expansion of the CIS and improved focus on the delivery of telephone-based customer service;
- Improvements in organizational discipline and business processes to ensure greater efficiency; and
- Training and reculturization of the workforce to be service oriented.

Improving reliability and delivery

Improving reliability and delivery of service will be a key focal point in JPS' operational improvements. At the top of the agenda is the further expansion of generating capacity to keep pace with the growth in demand, while maintaining a satisfactory reserve margin. Generating capacity requirements will be determined on the basis of a need to achieve and maintain the mandated level of reliability to customers as stipulated within the company's operating License. The capacity expansion plan will ensure that the company is able to have the two largest units, or their equivalent, off the grid and still be able to meet the forecast demand for electricity. This translates to a minimum requirement for approximately 25% reserve margin. In order to sustain this level of reliability, the company is currently pursuing a least cost expansion plan, which also takes into consideration the need for fuel diversity. The generation expansion is subject to a separate review by the OUR and is not part of this submission.

JPS plans to continue aggressive maintenance on the older generating units, as well as on the transmission and distribution network. At the same time, the company aims to also continue to expand its power delivery systems to ensure the reliable distribution of the additional energy produced. These objectives are reflected in the budgeted expenses included in this submission.

Call centre expansion

In the area of customer operations, the primary objectives are: to enhance customer convenience in accessing service from the company; to exceed the standards set under the service guarantees; and to introduce a range of value-added services. The company will continue the expansion of its customer service contact network to promote customer convenience, by increasing the capacity of its 24-hour Call Centre, while at the same time maximizing the partnership with third-party collection agents.

To promote the use of the call centre by customers as opposed to walk-in contacts, the supporting IT systems will be upgraded to improve the call-handling volumes from 2,000 to 5,000 per day. Agent availability will be improved by upgrades to the self-help features built into the Call Centre, namely the IVR and Messaging/Document Fax-back Systems.

The company, while promoting the call centre model, is cognizant of the fact that some customers will still demand office service. The plan therefore provides for the enhancement of the customer service office environment in keeping with an overall re-branding effort.

In particular, most customer service offices are not accommodating for senior citizens and the physically challenged. Over the next five years, it will be a standard to make each service office amenable to these target groups. Operationally, the customer service management will seek to minimize crowding by maintaining service turnaround standards for walk-in customers. This will be achieved through a number of variable staffing level strategies.

Expanding the collections network

There are presently over 350 non-JPS payment outlets available to customers island-wide. In order to ensure the continued and expanded use of this network, JPS will provide improved access to account information in these locations. The availability of this data in the third-party locations will minimize the need for customers to make contact with JPS prior to making a bill payment.

Improving customer service

Ultimately, the company's customer service performance will be measured against its achievement of the levels of service that customers will deem satisfactory. The principal customer issues that need to be addressed relate to quality and reliability of supply, billing issues, and equipment damage claims.

The company's approach to resolving customers' billing issues has the following elements:

- Public education on those bill components that are not controllable by the utility, specifically customer usage, fuel and foreign exchange rates;
- Improving both the accuracy and frequency of meter reading;
- Improving bill delivery;

- Proposals for rate design to mitigate billing impact on certain customer cohorts – contained elsewhere in this submission.

The guaranteed service standards are geared towards achieving prompt service response to: customers' needs for new power connections; emergency calls; reconnections after disconnection for debt; complaints; and bill delivery.

Over the next five years the company has set, as a minimum, the achievement of these service standards to the levels agreed with the OUR. The company intends to make the requisite investments to ensure service mobility and the availability of the appropriate tools and equipment to achieve the prescribed service standards. In addition, a number of processes and organisational changes will be required to ensure consistency in meeting these standards. The actions to be taken involve:

- changes in the organisational structure to create better efficiency in completing customer connections;

- out-sourcing of some ancillary functions to release internal resources for critical core functions in customer service delivery; and

- investments in work process and vehicular management technologies to improve productivity in field service operations

The customer's experience in making contact with the company and obtaining a satisfactory resolution to his or her issue is largely dependent on the quality of the human resources and supporting tools available. Over the course of the planning period, continuous training (refresher and development) of all customer contact staff will be the norm. The target for training is to expose each contact staff to a minimum of three days of training per year. Two days will be aimed at business knowledge improvement to facilitate empowerment for customer problem-solving at the primary contact level. The third day will be dedicated to the standardized GIFT of Service training that was developed in 2003 to facilitate the changing of the mindset and human relations skills of the existing customer service staff.[4]

The key account management programme that was specially developed for the larger commercial and industrial customers has proven to be successful and will be expanded. A similar service – the customer service executive programme – will be introduced for the remaining customer population. Specially trained staff will be appointed in each customer service parish to provide problem-solving services to assigned customers on an ad hoc basis.

[4] GIFT stands for 'Greet, Initiative, Follow Through and Thank the Customer.'

3.2 Improving Financial Viability

The second thrust of JPS' strategy going forward is to improve its financial viability. The previous years 2001—2003 have, for various reasons, been marked by less than satisfactory financial performance. In order to continue to attract the investments that are required if electricity is to meet the customers' needs, JPS' financial performance must improve. The business must allow JPS to provide a reasonable rate of return to investors if it is to compete for capital with other investment opportunities worldwide. Hence, balanced with its commitment to customers, JPS will also focus on improving financial viability and appropriately rewarding investors.

Key to JPS future financial performance is the current rate review by the OUR. JPS anticipates that the price-cap regulatory regime will present a tough challenge of balancing the need to increase efficiency, improve reliability and customer service while rewarding investors with a fair return. JPS believes it can rise to the challenge. However, it is crucial that these challenges, while tough, are fair and take into consideration the particular economic and business conditions under which JPS operates. It is particularly important that:

- The investors are allowed a fair rate of return that appropriately compensates them for the risks taken in making significant long-term investments in an economic environment such as Jamaica. The realities are that businesses in Jamaica face high investment costs as:

  - high government borrowing effectively squeezes out the private sector from the capital market;

  - Jamaica sovereign risks have increased recently, having repercussions on the business environment. Given the stagnant economy and the high government debt, the future is unpredictable.

  With the effective cost of investment set to a large extent by the set of circumstances, it is crucial that the rate determination does not punish investors for factors external to managerial control. The price cap mechanism must include provisions to deal with such exogenously determined factors, such as cost of debt (which move with global interest rates and country risk), inflation and forex movements. In the case of JPS, the costs associated with current power purchase agreements, are also outside JPS' control. While such factors may not be as important in other regulatory regimes in other more developed and stable economies, they can have significant impact in economies such as Jamaica.

- The price cap regime will incorporate incentives to JPS to increase efficiency and improve quality of service to customers. These are achieved through the X- and Q-factor as well as heat rate and system losses targets. Such incentives are important to ensure that customers enjoy competitive prices and good service. However, it is crucial that the targets set are realistic, achievable and do not lead to double penalization for JPS.

In addition to a fair rate determination, JPS will also aim to improve its financial viability through efforts to increase sales. While historically, JPS has enjoyed good sales growth, it is unclear that the trends will continue. Through the 1990s, JPS was a state-owned and state-subsidized monopoly. Tariffs did not reflect costs and the taxpayer ultimately picked up the difference. This is no longer the case. As tariffs reflect the costs of supplying electricity, sales growth may dampen - a portion is likely to be converted to theft, thereby contributing to system losses. If the economy fails to improve, unemployment and low-income growth would also reduce revenue growth.

While JPS faces these challenges, it will nevertheless focus on generating a strong revenue growth. Besides relying on overall economic growth to drive sales growth, JPS will continue to actively recruit new customers, particularly large customers who may otherwise self-generate. JPS will also continue its economic development initiatives designed to encourage new businesses in Jamaica, which will be beneficial to both Jamaica and JPS.

JPS would also strengthen initiatives to reduce theft and other forms of commercial losses. Part of this would convert to sales, thus increasing revenues. However, it would be highly unlikely that all or even a significant proportion of such losses, when prevented, would turn into sales.

3.3 Improving Efficiency and Reducing Costs

Increasing efficiency and reducing costs is also a key part of JPS' strategy to improve its financial performance. The company has already put in place initiatives to reduce labour costs. A voluntary separation and early retirement programme was implemented in early 2004, as part of a concerted effort to redefine and restructure work processes in order to improve efficiencies across the company. The company has also taken steps to outsource activities where this will result in improved efficiencies and cost reduction. The restructuring of the organization will be accompanied by more aggressive enforcement of the Performance Management initiative, which up to this point has been only partially implemented due to some resistance from the unions representing employees.

While there is scope for the reduction of costs by increasing JPS' internal efficiencies through the measures above, a substantial hurdle presents itself in the cost of fuel, which accounts for almost 50% of electricity cost. In light of this, even with the efficiency improvement measures being implemented by JPS, the battle of energy competitiveness cannot be won unless Jamaica diversifies to cheap and more stably priced fuel sources. As a result, JPS is working with Government to establish the feasibility of sourcing solid fuel or natural gas to Jamaica as an alternative to fuel oil, which is the company's primary source of energy today. Success in fuel diversity is fundamental to any future reduction in energy cost to customers.

3.4 Reducing System Losses

A key priority of JPS going forward is to put in renewed efforts to tackle system losses. As noted in Section 2.2, while the company has been successful in containing technical losses to an acceptable level, commercial losses have proven to be a more difficult obstacle to overcome.

While the key underlying factor that influences commercial losses—poor socio-economic conditions—is outside managerial control, JPS will nonetheless continue best efforts to stem the losses. Initiatives to reduce commercial losses going forward include the following:

- Wiring initiatives;
- Audits of large accounts;
- Improving meter control processes;
- Increase meter sealing activities;
- Raids, removal of throw-ups and prosecution;
- Insulation of conductors; and
- Multisector initiatives, including civic society, the political directorate, the business community, the regulator and the media.

In the area of technical losses, JPS has several planned initiatives to further reduce such losses through:

- Replacement of distribution transformers by those of low loss design;
- Voltage upgrade of select feeders; and
- Improvement of the feeder voltage profile.

The budget in this submission includes provisions for the necessary expenses to carry out these initiatives. Their allowance by the OUR is critical to our efforts to deal with a problem that has proven costly, both to JPS and our customers.

Section 4: The Post 2003 Macroeconomic Outlook

JPS' business operations are affected to a great extent by the macro-economic conditions of Jamaica. 2003 proved to be an eventful year, dominated by a 20 percent nominal devaluation of the currency, an exchange rate bubble that saw the rate spiking at $70. The driving factor behind these movements was the fiscal budget of the country, which had repercussions on the exchange rate, interest rates and inflation in the Jamaican economy, all of which impacted on all stakeholders in the electricity industry—including customers and investors. A key question therefore is, "in which direction can the Jamaican economy be expected to move within the next five years?"

This section looks back briefly at the macro-economic conditions in 2003 (Section 4.1) before looking ahead at the projections for 2004—2008 (Section 4.2). Section 4.3 outlines the risks and uncertainties surrounding the projections while Section 4.4 concludes.

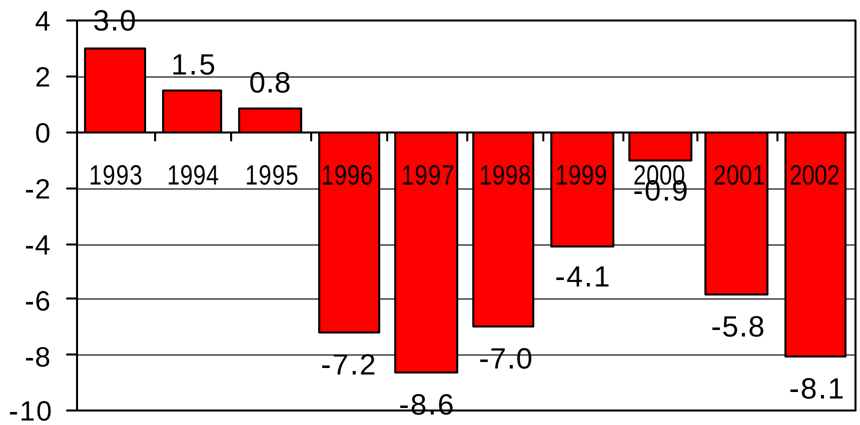
4.1 Looking back at 2003

4.1.1 The fiscal budget

Following a substantial deterioration in the government's accounts since 2000/01, the budget presented by the Minister of Finance in April 2003 for the current fiscal year to end March 2004 was to represent the reversal of public fortune. The fiscal deficit / gross domestic product (GDP) ratio, which was under one percent in 2000/01, had ballooned to 7.7 percent two years later. The budget promised an outturn of five to six percent for the current fiscal year.

However, the projections were made on an expectation of the continuation of the approximately 16 percent interest that the government was paying on rolled over debt at the time the budget was drawn up. As the capital market was becoming increasingly nervous about the sudden deterioration in the fiscal accounts, a foreign exchange bubble grew in March, provoking a jump in the Bank of Jamaica's benchmark 360-day repo rate from 14.5 to 35.95. This action raised the interest rate on the government's debt substantially, such that interest payments on the domestic portion of the debt, for which $60.5b was provided, will cost the government approximately $72b by fiscal year end. Largely due to this unexpected cost of debt servicing, the projected $25b deficit will end up close to $38b, or about 8.2 percent of GDP (see Figure 4.1). This would raise the total domestic debt, which averaged $408b this fiscal year, to approximately $452b for the next fiscal year.

Figure 4.1: Fiscal Deficit/GDP



4.1.2 Exchange rate

Following the fiscal deficit, 2003 witnessed a historically substantial depreciation of the exchange rate of almost 20 percent (see Table 4.1). This was the largest nominal depreciation in a decade and the largest real depreciation (above inflation) in an even long time period, part of which represents a significant correction to a currency that has been overvalued for many years.

Table 4.1: Exchange Rate

	1999	2000	2001	2002	2003
Exchange Rate US$/J$ (Annual avg.)	39.3	43.3	46.2	48.6	58.8
Depreciation (e.o.p., calendar year))	11.5	9.9	4.1	6.9	19.7

Source: Bank of Jamaica

4.1.3 Interest rates

Interest rate movements in 2003 defied the expectations made at the beginning of the year. The trend in interest rates at the time had been downward, as reflected in the sample of rates presented in Table 4.2. In the first quarter of 2003, the deterioration in the fiscal accounts and excess liquidity in the capital market created a sudden depreciation of the exchange rate, which the central bank responded to by raising its benchmark rates dramatically. Following this episode, rates on government instruments have been slow to moderate, as the market has remained nervous over the direction of the fiscal accounts.

Table 4.2: Interest Rates (Average Annual)

	1999	2000	2001	2002	2003
Commercial Bank	26.7	21.1	18.2	16.1	15.1
Treasury Bill	18.8	16.6	15.4	14.4	22.9
BOJ 30-day Repo	19.6	17	14.9	13.2	14.5
BOJ 360-day Repo	n/a	19.8	17.9	15.1	25.8

Source: Bank of Jamaica

4.1.4 Inflation

The inflation outturn for 2003 will be near to 13.5 percent, based on the consumer price index (CPI) information released for November 2003. This represents a substantial departure from the longest period of single-digit inflation that Jamaica has experienced since the 1960s. The inflation rate averaged 7.6 percent from 1997 to 2002 inclusive (see Table 4.3). There are two factors responsible for this deviation from recent experience – the pass through effect of the exchange rate depreciation early in the year and the tax package implemented in the 2003/04 budget.[5]

Table 4.3: Inflation Rate (percentage change, e.o.p CPI)

1997	1998	1999	2000	2001	2002	2003
9.2	7.9	6.8	6.1	8.7	7.3	13.5

Source: Bank of Jamaica.

4.1.5 GDP growth

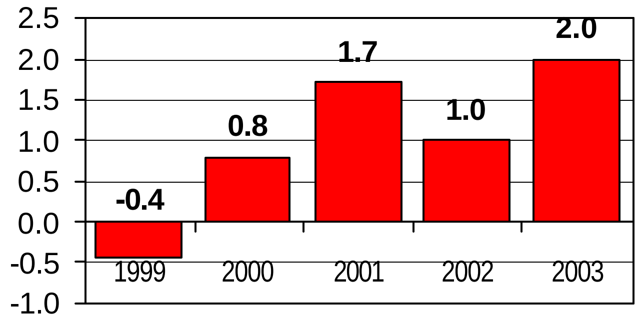
The Planning Institute of Jamaica estimates that the economy may have grown by two percent in 2003. This growth rate is an improvement compared to previous years (see Figure 4.2). The growth rate can be attributed to three factors:

- There was investment inflow in infrastructure, tourism, and retailing, with most it financed offshore;
- The increase in interest rates on government and central bank instruments did not filter down completely to the rest of the interest rate structure. Thus, commercial bank credit on commercial loans continued to attract rates in the mid-teens.
- The substantial real depreciation may have generated some expenditure switching to local producers and stimulated exports.

These helped to offset the effects of the substantial rise in interest rates on government borrowing and the implementation of a $13.8b tax increase.

[5] As a result of the deterioration of the central government's accounts last fiscal year, the Ministry of Finance imposed a tax package expected to raise $13.8b over the course of the fiscal year. A part of that package is a two percent cess that has been levied on the c.i.f. value of all imports. That levy would be expected to cause an increase in retail prices of an almost equal proportion.

Figure 4.2: Jamaica GDP Growth Rates (1999 – 2003)



4.2 Looking ahead: 2004—2008

The outlook for the price cap period 2004—2008 is critical to JPS. While tariffs would be capped, JPS' costs would are dependent on key factors such as:

- interest rates—particularly as JPS seeks to refinance up to US$130 million of its loans in 2006.
- foreign exchange—as a significant portion of its costs, both on the fuel and non-fuel side, are pegged to the US dollar while its revenues are recovered in the local currency. As the forex movements pass down to the customers, it affects the demand for electricity growth.
- inflation—which affects its costs as well as prices to customers.
- GDP growth—which affects its sales growth outlook as well as determines the socio-economic conditions in Jamaica that contribute to electricity theft and system losses.

Mid-range forecasts of these factors over the five-year price cap period as shown in Table 4.4.

Table 4.4: Macro-economic Outlook 2004 - 2008

	2004	2005	2006	2007	2008
Inflation Rate	10.0	8.5	7.5	7.5	7.5
Treasury Bill Rate	20.0	19.0	18.0	17.0	17.0
Exchange Rate	62.6	65.4	70.3	76.0	82.0
GDP Growth Rate	2.5	3.0	3.0	3.0	3.0

In reaching these forecasts and expectations, the government's fiscal accounts are the most important determinant. The quantitatively important components of expenditure are interest and wages. In 2004, with $452b of domestic debt to service, even with an expected moderation of the interest rate (see below) paid on newly acquired, rolled over, and re-priced debt, the debt servicing requirement will be slightly higher than that of 2003/04 at $92b. The fiscal budget for 2004 will also depend on the success of the negotiated agreement on the public sector wage bill. On the basis of an expected debt stock of 141% of GDP, the debt servicing on that almost $680b, along with the expected moderation in the growth of the public sector wage as a result of current negotiations, the deficit GDP ratio for the new fiscal year should be near six percent of GDP, implying a public sector borrowing requirement of approximately $31b.

It should be emphasised this is all extrapolation. There is no certainty that the government will be able to raise the remainder of this year's $38b or next year's $32b. With the domestic capital market already heavily subscribed in government debt, while changes in the Financial Services Commission's capital adequacy requirements for securities dealers makes it challenging to absorb additional public instruments, it is not to be taken for granted that this debt can in fact be acquired. The risk of the government not being able to refinance its debt is further considered in Section 4.3.

4.2.1 Inflation

Inflation is projected to slow down from 13.5% in 2003 to 10% in 2004, gradually reducing to 7.5% by 2006. Inflation is expected to slow down as last year's burst of double-digit inflation was due to two events which should not repeat – the currency depreciation and the tax package. For reasons that are discussed in the section below on the exchange rate, the likelihood of further 20 percent depreciation in 2004 is slim, with a modest depreciation more likely. Following last year's tax package, and with the precarious state of the current economy, there is unlikely to be another tax package, of any size.

In the absence of the two factors that generated higher inflation in 2003, and in light of the modest growth of base money last year, the room for renewed inflation seems to be slim. Nonetheless, the pass through effect of last year's 20 percent depreciation will not have completely been incorporated in a single year. We can therefore expect a moderation of inflation next year, but not an immediate return to the inflation rates of the recent past. The likeliest path for the inflation rate, then, is a reduction to near 10 percent this year, with a return to the single digit average of near to 7.5 percent in the following years.

It should be noted, however, that the forecast range of possible outcomes for this variable is wide, possibly by as much as ten percentage points on the positive side, which means that an inflation rate as high as 18 percent is possible over the medium term. This is due to the considerable risk that a more inflationary policy will be necessary if the government's debt dynamics do not respond to corrective measures. Further, higher than expected oil prices or another bout of rapid uncontrolled currency depreciation can also lead to higher inflation.

4.2.2 Interest rates

As the memory of the currency bubble in March 2003 recedes, interest rates should continue on the downward trend that they have been on since then. However, the fundamental condition that maintains interest rates at the high levels that have obtained in Jamaica for several years is the presence of a large borrower in the form of the government in the context of a small credit pool made up of reluctant lenders. With domestic debt of over $400b, the necessity of a large public sector borrowing requirement would not be expected to diminish for some time yet. Furthermore, with the expected fiscal deficit of 2003/04 being near to $37b, the immediate expectation is for the public sector borrowing requirement to expand. For the medium term, the large public sector borrowing requirement is likely to keep rates on government paper in the mid teens for some time and that is expected to continue to hold rates on commercial bank loans near to that level as well.

The reluctance of the lenders derives from the lack of confidence in the value of currency over the medium term, partly from the experience of decades of inflation and depreciation, and partly from recognition of the precariousness of the fiscal accounts and the implications of that for medium term currency value. Those considerations are not going to change much over the next year.

The nervousness surrounding interest rates was heightened by the exchange rate bubble that appeared in March. That nervousness has receded somewhat in the nine months since, though some of it remains. On the one hand, with the increase in the public sector borrowing requirement from the domestic capital market in 2004, in the context of an already large debt burden of 145 percent of GDP, there should be upward pressure on interest rates. On the other, as the legacy of the foreign exchange bubble of March 2003 further recedes and somewhat more confidence returns, rates should continue to moderate from the stratospheric heights of early in 2003.

The balance of these opposing forces suggests, in the short run, continued reduction of rates on government paper, but not by much more than a couple of percentage points. Over a longer horizon, it is much more difficult to forecast because of the precariousness of the public accounts. On the best of assumptions, the moderation will continue.

4.2.3 Exchange rate

The default assumption in exchange rate forecasting, in the absence of exogenous shocks or balance-of-payments corrections, is 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. That differential for 2004 is expected to be approximately 7.5 percent, which would yield an exchange rate of $65.0 by year-end. Obviously, if there is further deterioration in the fiscal accounts then another exchange rate run is likely. At the same time, however, there are a number of sources of revaluation pressure on the currency which are more likely to produce an outcome lower, possibly much lower, than $65.

Both credit and foreign exchange are freely traded in markets in Jamaica, so the reason why the Jamaican currency was overvalued in the first place would be instructive. With interest rates on government securities in Jamaica substantially higher than that on corresponding instruments in U.S. dollar economies, lending in Jamaica represented a relative bargain. This differential attracted portfolio capital and therefore a demand for Jamaica currency that was greater than it would otherwise be, and that demand was sufficient to create an appreciated currency.

With the fiscal deterioration and currency bubble in the first quarter, depreciation in 2003 therefore represented the elevation of fear over return. Thus, there was sufficient flight from the currency to generate the substantial depreciation that was observed.

At the beginning of 2004, the substantial interest differential that underpinned the overvaluation of the Jamaica currency in recent years remains. If the event that the present uncertainty surrounding the sustainability of the fiscal accounts were to diminish, it can be expected that the revaluation pressure from the interest differential will re-emerge. Moreover, to any extent that the nascent Partnership for Progress initiative builds confidence in the near future, that will have exchange rate consequences as well. Finally, two potential sources of capital inflows may be significant: any improvement in confidence will restore the government's ability to resume borrowing offshore; expected investment in infrastructure, mining, and tourism are almost all financed overseas.

Whether these revaluation pressures will be manifest as actual currency movement depends simply on the Bank of Jamaica's policy decisions with regard to international reserve accumulation. With significant loss of reserves over the last 18 months, 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 difficult to predict since it is based straightforwardly on a policy decision rather than market forces. Nevertheless the likeliest outcome for the near term is for the central bank to do some rebuilding of reserves. Beyond that, it is expected that the eventual narrowing of the interest differential to remove the revaluation pressure over time.

4.2.4 GDP growth

Notwithstanding the weak performance of the macro economy in recent years and the precariousness of the debt dynamics, the economy is inheriting some investment momentum at the start of 2004. The continuation of that investment in infrastructure and tourism, along with new investment in mining, should be positive influences this year. In addition, wages have increased by less than prices, the exchange has depreciated by more than prices, and interest is trending down. GDP growth is therefore forecasted to increase to 2.5% in 2004—a slight improvement compared to growth rate in 2003—and then to 3.0% in 2005 to 2008.

In the absence of external shocks or the failure of the government to meet its payment obligations, and in the presence of the positive signs listed above, the economy should continue to show positive GDP growth. This growth potential, however, must be accompanied by the greatest of caution in the presence of a significant level of risk in the government's ability to meet its payment obligations and a non-negligible probability of a severe contraction. This risk is compounded by the dependence of the economy on tourism and its vulnerability to external shocks.

4.3 Risks and uncertainties

Central forecast estimates presented in Table 4.4 show that the range of possibilities remains wide, as the economy is vulnerable to two particular risks. First, the government may fail to make a timely payment on its obligation to service a part of its debt. In this case the government will be declared in default. Since the government would then be unable to acquire new loans in order to roll over the remainder of its debt, the fallout from the default will be large. A rise in interest rates and a severe contraction of the economy would ensue. The second possibility is an interruption of foreign exchange inflows, which may derive from a catastrophic event in one of country's major foreign exchange earnings sources – mining or tourism.

That there is a real risk of default can be seen from the size of the public debt and the fiscal deficit. The larger the amount of the public debt, the greater the debt service obligations are in relation to the budget and the economy's capacity to service that debt. The convention is to measure this variable relative to GDP. The higher this ratio is, the greater the default risk. This measure has steadily risen over the last decade to the present level of almost 150 percent of GDP. This makes Jamaica one of the most indebted economies in the world.

The size of the fiscal deficit reflects not only the rate at which debt is being accumulated, but also the ability of the government to absorb negative shocks without adjustments to expenditure or revenue. Again, the conventional basis for comparison across countries and time is the ratio of the fiscal deficit to GDP. For Jamaica, this metric is now very high. It last approached its current worrying levels in 1997.

The relatively benign projection of gradual economic growth amidst moderate inflation must therefore be placed in the context of the significant risk present in the economic environment. The combination of a large fiscal deficit, enormous public debt, diminished international reserves, and large dependence on tourism earnings, create an economic climate in which the government will be unable to absorb any negative shock to the economy or the fiscal accounts without the economy descending into higher inflation and renewed recession, and possibly even a currency collapse. The risk is sufficient that corporate planning should include some provision for this eventuality.

In the midst of this uncertainty about meeting debt obligations, the threat of long-term inflation, and the prospect of continued interest volatility, the conditions are present for another exchange rate bubble as occurred in March of last year. Robust international reserves can, in principle, provide a cushion in that, with the failure to roll over foreign debt, reserves can be drawn down to meet payments in the short term and also to smooth currency jitters. However, while the central bank successfully accumulated reserves throughout the nineties to an impressive peak of US$1.8b or 54 percent of annual imports in 2001, the reserves have sharply declined to the current level of approximately US$1.1b or 32 percent of the current import bill. While the current level of reserves is adequate for the usual function of market smoothing, it is at a level below which the bank would be reluctant to go. The authorities are therefore likely to tolerate some sharpness in currency movements before intervening.

This risk if further compounded by the extent that the Jamaican economy depends for a substantial part of its foreign exchange earnings on a volatile and fickle industry like tourism. The ratio of tourism earnings to exports of goods has been trending upwards, from 60 percent in 1995 to a high of 90 present in 2002, though the ratio has fallen slightly for 2003 to 85 percent. This measure reveals that the foreign exchange market and the value of currency are highly dependent on tourism inflows.

4.4 Conclusion

The problems that currently affect the Jamaican economy are fundamental – unbalanced fiscal accounts, large debt, low social capital, weak infrastructure, poor schooling. None of these can therefore change dramatically in the near to medium term. Nonetheless, with the investment that occurred in the economy last year, and the expectation of further investment this year, in combination with improvement in the relevant “macro prices” – wages, the real exchange rate, interest rates – the probability of slow economic recovery exists. However, the risk analysis suggests that in corporate planning JPS must take account of the very great risk of higher future inflation, renewed interest rate hikes, and the possibility of a recession, even though, in the absence of such shocks, the expectation is for modest improvement in all the relevant macroeconomic signals. Similarly the OUR should also take these factors into account when implementing the price cap regulation. These risks do not exist to the same degree in other countries where models of such regulatory regimes are in place. Hence, the OUR is encouraged to allow room for modifications, where appropriate, to adapt to the specific environment in which JPS operates.

Part B: Key Components

Section 5: Ensuring a Fair Return to Investors: The Weighted Average Cost of Capital

According to Schedule 3 (Section 2(C)) of the Licence, the ABNF is set based on the revenue requirement of a test year period. Further, the Licence stipulates that the revenue requirement shall include efficient non-fuel operating costs, depreciation expenses, taxes and a fair return on investment. The return on investment is calculated based on the approved rate base of JPS and the required rate of return, which allows JPS the opportunity to earn a return sufficient to provide for the requirements of consumers and acquire new investments at competitive costs. Specifically, the Licence states that:

> "The allowed 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 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 should be adjusted by any known and measurable changes which are expected to occur during the test year."

The WACC is an estimate of the price a company must pay to raise the capital that it employs. It is commonly a combination of the cost of debt (i.e., the effective interest rate on debt) and the cost of equity. Broadly speaking, the WACC reflects the return required by investors to invest in the company's activities rather than elsewhere. The required return will reflect the level of risk associated with the investment. Given that investors are in general risk-averse, the greater the risk accepted, the greater the required rate of return. The WACC used in setting the ABNF should therefore be fair, reasonable and sufficient to assure investor confidence in the financial soundness of JPS under efficient management; and maintain and support JPS' credit worthiness and enable JPS to raise funds necessary to provide the required services to customers.

The WACC can be written as follows:

$$\text{WACC} = g \times r_d + (1-g) \times r_e \qquad \text{Equation 5.1}$$

where g is the gearing level (i.e., debt divided by the sum of debt and equity), r_d is the return required on debt investments, and r_e is the return required on equity investments.

The WACC calculation described in Equation 5.1 above has ignored taxation and the different tax treatment of corporate equity and debt. Interest payments on debt are deductible for corporation tax purposes, whereas returns on equity are not. There are two main approaches to take tax into account in the WACC.

- *Pre-tax WACC*—this is the WACC grossed up by the tax wedge. The tax adjustment is made using the following formula:

$$\text{Pre-tax WACC} = g \times r_d + (1-g) \times r_e \times \left(\frac{1}{1-t_c} \right) \qquad \text{Equation 5.2}$$

The tax wedge $1/(1 - t_c)$, is calculated with reference to t_c, the corporation tax rate. Intuitively, the pre-tax WACC shows the level of returns that the company has to make before corporation taxes are paid, in order to generate the minimum returns required by investors.

- *Post-tax WACC*—this is the WACC after taxes, taking account of the differential tax treatment of debt and equity. It is calculated using the formula:

  $$\text{Post-tax WACC} = g \times r_d \times (1 - t_c) + (1 - g) \times r_e \qquad \text{Equation 5.3}$$

In calculating JPS' return on investment, the post-tax WACC, as shown in Equation 5.3, is used. The corporate tax rate, t_c, in Jamaica is 33%. To calculate JPS' pre-tax real WACC, the following components have to be estimated:

- the cost of debt;
- the cost of equity; and
- the gearing level.

The estimation of each of these components—cost of debt, cost of equity and gearing—for JPS is discussed in the following.

As will be seen, the cost of debt and equity for JPS is estimated on the basis that the debt and equity are denominated in US-dollars. This reflects the fact that most of JPS' debt is denominated in US-dollars (the only exception being a small portion that is denominated in Euros). The equity component is also denominated in US dollars as the required returns of US-based utilities have been used as the basis of estimating the appropriate return on equity of JPS. As such, the interest cost and net income in the revenue requirement is denominated in US-dollars for the purposes of the foreign exchange adjustment factor (see Section 12). If the OUR were minded to denominate the interest cost and net income as Jamaican-dollar cost components, then the cost of debt and equity in this section must also be adjusted appropriately to reflect the additional risk and higher required return to Jamaican-dollar denominated investments.

5.1 Principles of estimating the cost of debt

There are two ways to estimate the cost of debt of a company:

- The incremental debt cost method—this method, in essence, sets a 'target' for the company. The incremental cost of debt (r_d) is calculated as the sum of the risk-free rate (r_f) and the debt premium (dp):

  $$r_d = r_f + dp \qquad \text{Equation 5.4}$$

  The risk-free rate is the rate of interest required by an investor on an investment with no perceived risk of default. Typically, the yield on government bonds, which are perceived as virtually default-free securities, is used for the measurement of the risk-free rate. In the case of JPS, the Government of Jamaica (GoJ) bonds assessed will be those issued as U.S. Dollar obligations. The debt premium is the additional return demanded by debt investors for holding companies' debt.

- The actual cost of debt—The alternative method is to use the actual rate paid by JPS for its debt as the basis for estimating the cost of debt.

JPS proposes to use the actual cost of debt conditional upon the following:

- Consideration is given to JPS' need to refinance a substantial portion of its loans—US$130 million—in 2006. If the loans are refinanced on different terms and conditions, the impact on the cost of debt and the WACC may be substantial.

  This is an important issue as JPS' cost of debt has a floor that is set by market interest rates generally and the Government of Jamaica's cost of debt. If, for example, US Treasury bond rates were to rise or if sovereign risk were to rise—of which there is a real possibility—then JPS' cost of debt would also rise. Both of these are real possibilities. Interest rates in the US are currently at a historical low. Value Line, for example, forecasts a 2003 average rate for 3-month Treasury bills of 1.1% and 2.5% for 2004-06. The yield on ten-year Treasury notes is projected to rise from 4.0% this year to 5.5% for 2006-2008. These data strongly indicate that the cost of capital will increase from current low levels. Further, the high debt burden of the Government of Jamaica makes it probable that the cost of sovereign debt of Jamaica will rise in the future.

  Hence, JPS agrees with using current cost of debt if, to the extent that JPS cost of debt changes when the loans are refinanced, the OUR allows for an interim review under the Z-factor (see Section 9).

- The capital expenditure required for future generation expansion is treated separately outside of this rate review.

The estimation of JPS' cost of debt is further discussed in the following.

5.2 Estimation of JPS' cost of debt

Table 5.1 shows JPS' actual cost of debt, by source, principal and coupon rate. The weighted average coupon rate of actual debt is 12.17%. In addition, the transactions costs of financing amounts to an estimated 0.39%. An adjustment for transactions costs is necessary because it reflects the cost incurred by investors to obtain financing. Adding this to the weighted average coupon rate gives a weighted average actual cost of debt of 12.56%.

Table 5.1: JPS' actual cost of debt as of February 15th, 2004

Long Term Loan	Outstanding Principal (US$ "000s)	Interest Rate	Weighted interest rate
[✂]	[✂]	[✂]	[✂]
[✂]	[✂]	[✂]	[✂]
[✂]	[✂]	[✂]	[✂]
[✂]	[✂]	[✂]	[✂]
[✂]	[✂]	[✂]	[✂]
[✂]	[✂]	[✂]	[✂]
[✂]	[✂]	[✂]	[✂]
[✂]	[✂]	[✂]	[✂]
[✂]	[✂]	[✂]	[✂]
[✂]	[✂]	[✂]	[✂]
[✂]	[✂]	[✂]	[✂]
Total	253,900		12.17%
Plus Existing Transaction Cost:			
- Arrangement Fees			[✂]
- Administrative Fees			[✂]
- Legal Fees			[✂]
Subtotal			*0.39%*
Total Cost of Debt			**12.56%**

Note: [*Text omitted. See note on page iii.*]

5.3 Principles of estimating the cost of equity

The cost of equity of a company can be estimated using either market- or book-based tests. Among the market-based tests, the discounted cash flow (DCF) method and the capital asset pricing model (CAPM) are commonly used. The DCF method uses future cash flows that are discounted to their present value, as a basis for calculating the cost of equity. Cash flow consists of two parts— dividends and the final sale value of the stock. The discount rate represents the investor required return, and in this analysis, the internal rate of return was used to determine the discount rate. The internal rate of return is the discount rate that equates the present value of future cash flows to the market value of the company.

The CAPM estimates the cost of equity (r_e) using the following formula:

$$r_e = r_f + b \times \text{ERP} \qquad \text{Equation 5.5}$$

where r_f is the risk-free rate (see above), ERP is the equity risk premium and ß is the company-specific risk parameter (the 'equity beta'). The ERP is the expected additional return demanded by investors for holding equities above that required for holding risk-free assets. The equity beta captures the riskiness of a company in the CAPM.[6]

A third method, the comparable earnings method, is a book-based test. It utilizes the book return on common stock equity to estimate the return expected by investors.

As JPS' stock is not traded, the cost of equity of JPS cannot be directly measured using either of the CAPM or DCF methods. As an alternative, the estimated cost of equity of JPS can be based on the estimated cost of equity of a group of comparable companies, such as US electric utilities. The estimates must then be adjusted to reflect risk differences between JPS and the comparable US companies.

In estimating the cost of equity of JPS using the cost of equity of comparable US utilities as a starting point the following factors should be taken into consideration:

- *Comparable companies*—perfect comparability is impossible, and therefore, there will always be some difference in risk between the subject company and its comparable companies. Any risk differences should be considered in one's analysis. To the degree possible, it is best to stay in the same industry as the subject company since risks differ among industries.
- *Adjustments for risk differentials*—additional measures such as company size, type of economic regulation (price cap versus rate of return) should also be given consideration especially where the difference is substantial. Such adjustments should be applied consistently across the different models, be it the DCF, the CAPM or the comparable earnings method.
- *Current dividend trends*—in the case of the DCF, using projected dividend growth in a single-stage DCF analysis is unrepresentative of investor growth expectations at this time (see Volume II of this submission for a description of single- and multi-stage DCF analysis). For example, there have been many dividend cuts, omissions, and a lack of dividend growth for U.S. electric power companies, which is contrary to the constant dividend growth rate assumed by the DCF model. Over the last five years, instead of dividends increasing every year at a constant growth rate as assumed by the DCF model,

[6] Beta measures the degree to which the returns of the company's equity move in line with returns to the market as a whole. In contrast to the risk-free rate and ERP, it is therefore a company-specific parameter. Beta is not measurable directly from market data, but can be estimated by regressing total returns of the particular stock or portfolio of stocks on total returns of the market.

an average of 61% of U.S. electric utilities failed to do so thus failing to comply with the theoretical underpinnings of the single-stage DCF model.

Because dividends flow from earnings, and dividends do not serve in the short-run at least as a reliable guide to growth prospects for U.S. electric utilities, investors primarily rely on projected earnings growth instead. Alternatively, the two-stage DCF model could be used instead.

- *Current low interest rate levels*—current interest rates are at low level. For example, the US federal funds rate is currently below the rate of inflation implying a negative real return, which is unusual and reflects a very aggressive stimulus policy by the Federal Reserve to jump-start a recovery in the economy. As the economy gains strength and the economic recovery matures, it is likely that inflation will rise from current low levels, which is likely to lead to higher interest rates. Since common stocks have a perpetuity life, it is appropriate to recognize higher future interest rates in determining investor-required returns.
- *Forward looking market risk premium*—since investors look forward when making investments, or the return that they expect to earn rather than the return that has been earned, it is important to use projected data where available.

5.4 Estimation of JPS' cost of equity

JPS commissioned an analysis of JPS cost of equity based on the methods discussed above. The complete analysis is presented in Volume II of this submission. The results are summarized here.

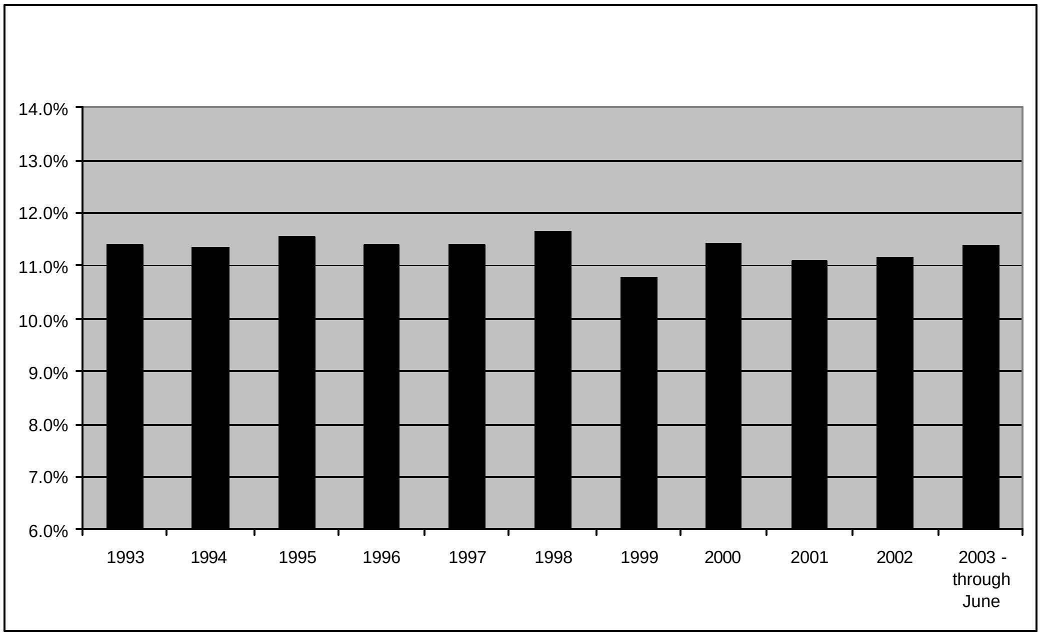
The analysis began with the selection of companies comparable to JPS. Electric utilities in the United States were used because of their large number and related ability to find companies most like JPS in terms of broad measures of risk. Where significant risk differences between JPS and its comparable companies exist, such as JPS' relatively small size, judgment and where possible quantification measures were employed.

Three tests- the DCF, CAPM and Comparable Earnings- were used to measure the cost of JPS' equity. It should be noted that a two-stage DCF and CAPM were used, instead of the conventional single-period models. This is because short-term interest rates in the US at are at lowest levels in decades and forecasts point to higher, or more normal, interest rate levels in the future. Consequently, it would be inappropriate to apply the conventional DCF or CAPM model.

In the case of the DCF particularly, projected dividend growth in a single-stage DCF analysis is also unrepresentative of investor growth expectations at this time. For example, there have been many dividend cuts, omissions, and a lack of dividend growth for U.S. electric power companies, which is contrary to the constant dividend growth rate assumed by the DCF model. Because dividends flow from earnings, and dividends do not serve in the short-run at least as a reliable guide to growth prospects for U.S. electric utilities, investors primarily rely on projected earnings growth instead.

Overall, the test results indicated that the cost of equity is in a range of 10.5% to 11.6% before adjustment for significant risk differences between JPS and its comparable companies, and average 11.2%. These results are in line with the average approved return on equity by state utility commissions in the US, before adjusting for size, regulatory and country risk factors specific to JPS (see Figure 5.1). As can be seen, the average approved ROEs have consistently been above 11% since 1993 and have only dropped below 11% (10.77%) in 1999.

Figure 5.1: Approved ROE for US Electric Utilities (1993 – 2003)



Source of data: Regulatory Research Associates, Inc. (RRA)

Having assessed various potential sources of risk differences between JPS and the comparable US companies, the assessment concluded that the results should be modified to take into account of:

- Differences in financial risk;
- the size premium effect;
- the regulatory risk effect; and
- the country risk premium (CRP).

5.4.1 Financial risk

JPS is likely to have lower financial risk, compared to the sample of other utilities used in the study. JPS' debt ratio used in this proceeding is 43.3% compared to 49.7% for its comparable companies (2006-08 normalized level). To determine the appropriate adjustment to the return on common stock equity for JPS' lower financial risk, debt-to-capital utility financial targets by credit ratings (AA, A, and BBB credit ratings for companies with business profiles of 4 and5 used for determining JPS' comparable companies) provided by Standard & Poor's were compared to corresponding bond yields.

The results show a lower yield of 10 basis points for companies with a 43.3% versus 49.7% debt to capital ratio. Since JPS' cost of common stock before adjustment for country risk is 12.2% compared to an average yield for double A to triple B utility bonds of 6.2%, the debt cost of 0.10%, or 10 basis points, was extended to common stock equity by multiplying 0.10% by 2.0 (12.2%/6.2%), which results in a lower cost of common stock for JPS of 0.2%.

5.4.2 Size Premium

Numerous studies of the returns to firms according to various characteristics suggest that company size plays an important role in determining investors' expectations. Ibbotson Associates notes:

> One of the most remarkable discoveries of modern finance is that of a relationship between firm size and return. The relationship cuts across the entire size spectrum but is most obvious among smaller companies, which have higher returns on average than larger ones.[7]

Failure to acknowledge this effect could have considerable consequences for the ability of small companies to finance their activities. It is therefore often appropriate to apply a small-company premium to the cost of capital of small companies.

In the CAPM, only systematic or beta risk is rewarded. Small company stocks have had returns in excess of those implied by their betas.[8] Consequently, it is appropriate to adjust for the higher business risk associated with the much smaller size of JPS than its comparable companies.

The average market capitalization of JPS' comparable companies is $6.6 billion U.S. dollars, which would be a "mid-cap," or decile 2 company in the Ibbotson study compared to an estimated $350 million U.S. dollars for JPS (shareholders' equity in U.S.$ times price to book ratio for its comparable companies), which is a decile 8 company, or "low-cap" company. Using a beta adjusted size premium, the Ibbotson study shows a higher return requirement for decile 8 versus decile 2 companies of 1.64 percentage points.[9]

Further, a study of the Electric, Gas and Sanitary Service group, according to Ibbotson, shows that the small company component of the group, or the smallest one-half of the companies, had excess CAPM returns of 2.9 percentage points above those of the large company group component.[10] The Ibbotson results suggest a substantial size premium for JPS. Nonetheless, because of assumed constructive OUR regulation,

[7] "Stocks, Bonds, Bills, and Inflation, Valuation Edition, 2003 Yearbook, Ibbotson Associates, page 117

[8] Ibid, page 122.

[9] "Risk Premia over Time Report 2003," Ibbotson Associates, page 6.

[10] Industry is split into a large and small portfolio with an equal number of companies. "Stocks, Bonds, Bills, and Inflation,: Valuation Edition, 2003 Yearbook, Ibbotson Associates, page 141.

investors are unlikely to require a size premium as large as indicated by the Ibbotson studies. The analysis employed a size premium for JPS of 0.5%.

5.4.3 Price-Cap Premium

Price-cap regulation increases JPS' investor risk, relative to the rate of return regulation faced by the US companies. This is because profits are limited on the upside, but the "inability to pass on cost changes to customers means that the company faces risk from uncontrollable cost fluctuations."[11]

The OUR has provided insight into the higher risk for price-cap versus rate-of-return regulation for JPS' comparable companies, and shows that price-cap regimes have asset betas of 0.57, rate of return regimes 0.35, and those falling between the two preceding regimes 0.41. The equity beta for JPS' comparable companies with an asset beta of 0.45 used by OUR for JPS, and a 43.3% gearing ratio, is 0.79. The CAPM with a 0.79 equity beta shows a cost of common stock of 12.3%, which is higher than the rate-of-return CAPM study with a 0.68 Value Line equity beta that showed a cost of 11.6%. Taking into account the higher riskiness of price-cap regulation therefore indicates a higher cost of common stock of 0.7 percentage points.

5.4.4 Country risk premium

The CRP represents the additional risk of investing in a particular country's government bonds versus investing in U.S government bonds. This risk is often referred to as "sovereign risk". There are numerous factors, both economic and political, that contribute to this risk differential. The CRP is not a "published" number and therefore must be estimated. This can be done by looking at current yields in $U.S. of Jamaican government bonds and comparing them to the yields of U.S. government bonds of the same maturity. Since we are using U.S. bonds of 10-year maturity to establish a risk free rate, we will use 10 years for the purpose of establishing the CRP as well.

Bloomberg's On-Line provides the yields for five GoJ bonds in $U.S. with varying maturities. These bonds range in maturity from 1.5 to 18.1 years (see Table 5.2). This data was retrieved on January 9, 2004.

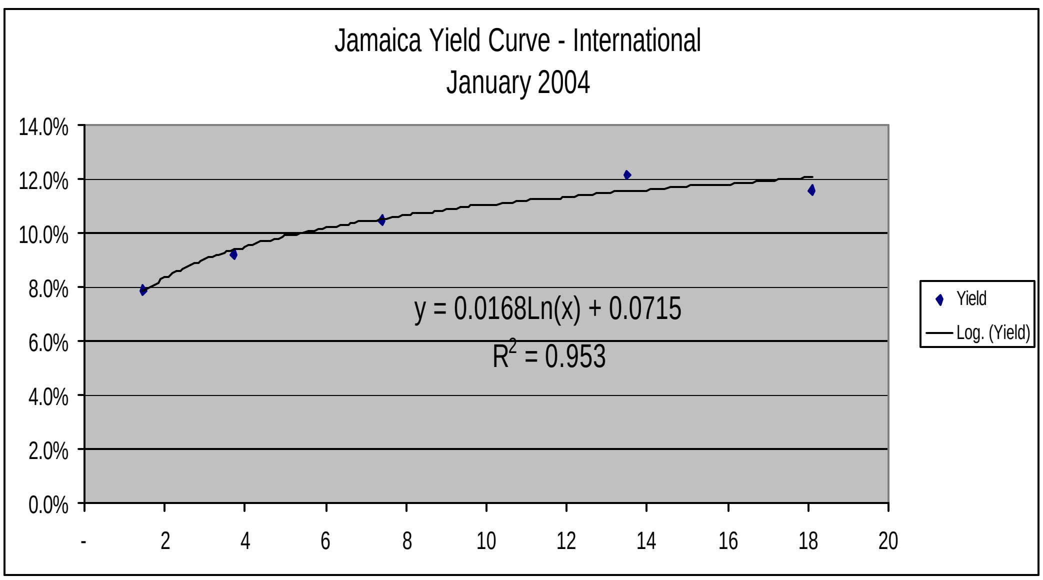
[11] "Regulatory Structure and Risk and Infrastructure Firms, An International Comparison," Alexander, Mayer, and Weeds, page 7.

Table 5.2: Data on bond issues used in estimation of Jamaica indexed bond yields

Maturity	June 05	Sept 07	May 11	June 17	Jan 22
Today	Jan 04	Jan 04	Jan 04	Jan 04	Jan 04
Years To Maturity	1.5	3.7	7.4	13.5	18.1
Current Yield - Ask	6.38%	8.67%	10.17%	11.51%	11.36%
Current Yield - Bid	9.33%	9.75%	10.74%	12.75%	11.83%
Current Yield - Average	7.86%	9.21%	10.46%	12.13%	11.60%

None of these bonds mature in exactly 10 years but it is possible to create a yield curve regression equation from these yields and then estimate a yield for a given maturity. An average of the bid and ask yields was used to estimate the curve. This regression curve has an r-square of 95.3% indicating a very good fit. Figure 5.2 shows the results of the curve fit. The line at 10 years intersects the curve at about 11%. Inserting 10 years into the regression equation yields an estimate of 11.02%.

Figure 5.2: Jamaica indexed bond estimated yield curve



To be consistent with these yields, the U.S. Treasury rates must also be retrieved from the same time period. The average yield of 10-year U.S. treasury bonds for the week ending January 9, 2004 was 4.27% [14]Jamaica's CRP is therefore estimated as follows:

CRP = 11.02% - 4.25% = 6.77%

5.4.5 Summary

Allowing for the higher risk of JPS versus its comparable companies, the nominal cost of JPS' common stock is 12.2% (11.2% minus 0.2% for lower financial risk plus 0.5% size risk and 0.7% price-cap risk) before adjusting for country risk. Adjusting for country risk gives a cost of equity of:

JPS cost of equity = 12.2% + 6.75% = 18.95%

5.5 Gearing

The gearing level measures the capital structure of the company and determines the relative weights attached to the cost of debt and equity in the WACC calculation. In general, gearing is the level of net debt divided by total value, which is the sum of equity, debt, and net current liabilities.[12]

JPS proposes that the current gearing level of the company be used to compute the WACC. Based on 2003 (unaudited) financial accounts, JPS has 43.3% of capital employed in form of debt and 56.7% in the form of equity.[13]

The current capital structure is an appropriate one to apply as, moving forward, JPS is unlikely to be able to further increase its leverage. Even when part of the current debt matures, it is unclear if the capital markets would support a 100% financing. It is possible that JPS may only be able to refinance part of the debt and may have to increase the equity component of its capitalization. This constraint reflects that fact that at least some lenders would consider JPS' IPP contractual commitments as having the same features as long-term debt such that increasing JPS' leverage further would be risky. It is therefore unlikely that JPS would be able to further increase its leverage without a material increase in its cost of debt.

5.6 Computation of JPS' post-tax WACC

JPS' post-tax WACC can therefore be calculated as follows:

[12] Value can be either book- (accounting-) based or market-based. Since the cost of capital measures returns that investors require on the current value of their investments, market-value measurement might be preferable. On the other hand, market values are difficult to obtain for debt, so only equity can be measured at market value. In some cases, it may be preferable to use book valuation even for equity in order to ensure that the gearing parameter is not unduly affected by share-price movements and is more stable.

[13] At time of submission of this report, audited accounts are not available. Audited accounts will be available in March 2004.

post-tax WACC= $g \times r_d \times (1-t_c) + (1-g) \times r_e$

= 43.3% X 12.56% X (1 – 1/3)] + [(1 – 43.3%) X 18.95%]

= 14.37%

Section 6. Revenue Requirement for the Test Year Period

According to the Licence, along with its application for the recalculation of the ABNF, JPS shall file an annual revenue requirement calculation and specific rate schedules by rate 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."

The Licence also defines the test year period as follows:

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

This section puts forward JPS' revenue requirement for the test year period in accordance with the Licence.

6.1 Revenue requirement

Table 6.1 show JPS' revenue requirement for the test year period, broken down according to main categories. (Details of sales growth forecast are presented in Appendix A4.)

Table 6.1: Revenue Requirement for Test Year Period

Components of Revenue requirement	J$ '000s
Operational Expenses	**10,483,237**
PPA	3,666,489
Maintenance	2,784,835
SG&A	4,021,598
Interest expense on short term debt	101,814
Interest expense on customer deposits	121,561
Interest Income	-107,597
AFUDC	-217,463
Other income	-14000
Sinking (self-insurance) fund contribution	126,000
Depreciation & Amortization	**2,299,443**
Depreciation	2,180,524
Amortization of Redundancy Costs	118,919
Return on Investment	**5,044,381**
Cost of Equity	3,771,287
Cost of Long Term Debt	1,273,094
Taxation	**1,885,643**
Revenue Requirement	**19,712,704**
CCC Revenue[1]	210,467
Adjusted Revenue Requirement	**19,502,237**

Note: [1] The revenues from Caribbean Cement Company (CCC) is deducted from the revenue requirement as it is subject to a special tariff.

As can be seen, the revenue requirement consists of the following:

- *Purchase Power Agreement (PPA) costs*—which are expected to amount to $3.6 billion annually. Details of these costs are provided in Appendix A3.
- *Maintenance and selling, general and administration (SG&A) costs*—of $6.8 billion annually. Details are provided in Appendix A3.
- *Interest expense on short-term debt*—which is the interest expense on current liabilities. Current liabilities, together with current assets, comprise working capital that is required for the day-to-day operations of the business. As current liabilities are deducted from the rate base such that JPS does not recover a WACC on them, it is appropriate for the interest expense incurred on them be included in the revenue requirement.
- *Interest expense on customer deposits*—which is the amount that JPS pays as interest to customers for holding their deposits. This expense item is included as part of the revenue requirement for two reasons:
  - customer deposits are deducted from the rate base; and

- interest income from customer deposits and interest-earning assets are deducted from the revenue requirement.

- *Interest income*—which is deducted from the revenue requirement. This includes interest earned on customer deposits and cash holdings. The exclusion of interest income from the revenue requirement is consistent with:
  - the inclusion of interest expense on customer deposits in the revenue requirement;
  - the inclusion of cash holdings in the rate base onto which the WACC is applied, for the calculation of the return on rate base; and
  - the inclusion of interest expense on short-term debt in the revenue requirement.

- *Allowance for funds used during construction (AFUDC)*—which is capitalized interest incurred during the construction phase of a project. AFUDC is deducted from the revenue requirement as the equivalent item 'construction work in progress (CWIP)' is included in the rate base. The inclusion of both AFUDC and CWIP in the computation of the revenue requirement would lead to double counting. The exclusion of both would mean that JPS would be under-recovering on its financing costs incurred (interest expense on debt are incurred even during the construction phase and not only when the project is completed).

- *Other income*—this refers to income generated from the rental of some properties owned by JPS from pole attachments. This income arises from the use of assets for purposes other than the supply of electricity.

- *Contribution to the sinking (self-insurance) fund*—which is a proposed form of self-insurance for JPS transmission and distribution assets (see further discussion in Section 16.4).

- *Depreciation*—which is calculated based on the depreciation rates in Schedule 4 of the Licence.

- *Amortization of redundancy costs*—in the first quarter of 2004, JPS undertook a voluntary redundancy programme so as to reduce labour costs and increase efficiency. The estimated savings from the redundancy programme is estimated to be $490 million annually (see Table 6.5). The redundancy programme, however, has one-off costs in the form of redundancy payments. JPS believes that it is appropriate to spread (amortize) these costs over the five-year rate cap period. This has been done be capitalizing the redundancy costs (see rate base) and amortizing it.

- *Return on investment*—which is calculated based on a post-tax WACC of 14.37% applied to the rate base. The calculation of JPS' rate base is detailed in

Section 6.2. Further details of JPS capital expenditure programme for the test year period is provided in Appendix A3.

- *Taxation*—which is calculated based on a 33 1/3% tax rate on pre-tax income. As stated in the Licence (Schedule 3 (2C)):

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

6.2 JPS rate base

The Rate Base is the investment basis established by a regulatory authority upon which a utility is allowed to earn a fair return. In defining the Rate Base the Licence states in Schedule 3, Section 2:

> 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 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."

It is therefore evident that the constituents of the Rate Base as specified by the Licence are threefold:

- *Net investments*—which, for an electric utility such as JPS, comprises of generation, transmission, distribution and general fixed assets.

- *Working capital*—which is required for a business to maintain the operational supply inventories required to meet its prepayment obligations and to provide the cash needed to meet its operating expenses between the time it renders service and when it collects revenues for those services.[14] Working capital represents the net amount of capital employed in the firm, which is not invested in long-term assets or plant assets.

  The components of the working capital can be broken down into two major groups:

[14] Electricity Utility Cost Allocation Manual, NARUC (1992), pp 29.

– *Cash Working Capital*—which the utility must hold for the purpose of enabling it to satisfy ordinary requirements for minimum bank balances and to bridge the gap between the time the expenses of rendering utility service are paid and the time revenues derived from the sale of those services are collected.

– *Non-Cash Working Capital*—which includes items such as materials, supplies and fuel that are needed to meet operating exigencies from time to time.

- *Offsets*—The licence speaks to the exclusion of appropriate offsets from working capital. Such offsets would include items that derive from non-investor items that are 'cost-free' to the utility, i.e., they do not derive from either loans or equity capital, and they do not require a return. Since such capital is cost-free to the Utility then it is not reasonable and appropriate for the utility to earn a return on the components of the Rate Base that this capital supports.

Table 6.2 shows JPS' forecasted balance sheet for the year ending December 31, 2004.

Table 6.2: JPS (forecast) Balance Sheet for year ending December 31st, 2004 (J$'000s)

Items	$'000s
Gross fixed assets	83,178,789
Accumulated depreciation	51,678,463
Net fixed assets	31,500,326
Construction work in progress	1,541,834
Pension plan asset	1,069,798
Deferred expenditure	0
Capitalized redundancy costs	475,676
TOTAL LONG-TERM ASSETS	34,587,633
CURRENT ASSETS	9,327,552
Cash and short-term deposits	149,655
Receivables	7,594,914
Inventories	1,582,983
CURRENT LIABILITIES	3,355,164
Short-term loans	140,753
Payables	3,214,412
NET CURRENT ASSETS	5,972,388
TOTAL NET ASSETS	40,560,021
Financed by:	
SHAREHOLDERS' EQUITY	19,901,250
Share capital	19,901,250
LONG-TERM DEBT	15,204,146
CUSTOMER DEPOSITS	1,838,277
EMPLOYEE BENEFIT OBLIGATIONS	911,572
DEFERRED TAX LIABILITY	2,704,776
TOTAL NET ASSETS	40,560,021

As can be seen, the balance sheet items consist of the three categories of rate base items defined in the licence:

- *Net investments*—i.e., total long term assets, which comprise of:
  - *Net plant in service*—JPS' net plant assets are revalued annually based on a formula that incorporates (a) the relevant industry indices for equipment purchased abroad (i.e., the Handy-Whitman index - a utility construction index), adjusted where applicable for movements in the Jamaican dollar relative to the US dollar; and (b) using relevant price indices for local costs (CPI). The split of assets between (a) and (b) is based on predetermined relationships for particular asset categories as determined by an independent Stone & Webster valuation.

- *Construction work in progress (CWIP)*—which in turn represents the balance of funds invested in the utility plant under construction, but not yet placed in service. As and when the capital works are completed, the relevant amount is removed from the CWIP line and transferred into the net plant assets category.

- *Pension plan assets*—JPS operates a defined benefit pension plan. The annual net pension cost is actuarially determined using the projected unit credit method and is charged against the income statement. Additionally, the net present value of the pension obligation is compared to the fair value of the plan's assets, and a net asset or liability is reflected in the balance sheet, representing JPS' obligation to the fund.

• *Working capital*—which is simply current assets less current liabilities. Current assets include cash, trade and other receivables (net of a provision for doubtful debts) and inventories (fuel, materials and supplies). With regard to fuel inventory, it is JPS' policy to maintain at least ten days of fuel inventory. This comes against the background that this is an island utility which rules out the possibility of interconnectivity with other grids, should there be any crisis, which interrupts the importation of fuel.

  Current liabilities take the form of short-term loans, trade payables and provisions, related company balances (in the case of JPS, Mirant) —which reflect transactions that are undertaken in the normal course of business and that comprise the provision of technical support and related professional services, as well as the acquisition of generation equipment and parts— and the current portion of long-term debt.

• *Appropriate offsets*—These, as described above would include cost-free capital, i.e., funds that JPS has access to, but was provided by externals sources outside of the funds normally accessed through capital financing i.e. long term loans or equity financing. JPS holds three types of cost-free capital, which would be offset against the other items above:

  - *Customer advances and deposits*—it should be noted that JPS incurs an interest charge on customer deposits held. If, customer deposits are considered as an offset, then JPS must recover elsewhere the interest costs incurred. It is therefore further proposed that these interest charges be recovered as an additional line item in the revenue requirement.

  - *Employee benefits*—a provision is made for the cost of unutilised vacation and sick leave in respect of services rendered by employees up to the balance sheet date, in accordance with their employee service contracts. Similarly, a provision is made in respect of post retirement benefits to be provided to employees upon retirement. The post retirement benefit obligation is actuarially determined at the balance sheet date on a basis similar to that used for the pension plan. This policy ensures proper recognition of employee service costs in the period when the service is actually provided.

– *Deferred income tax*—this represents the provision for temporary differences arising between the tax bases of assets and liabilities and their book values in the financial statements, using current corporation tax rates. A deferred tax liability arises primarily in relation to the revaluation surplus on fixed assets, which exceeds the accumulated taxation losses of JPS. This change in accounting policy will allow proper recognition of JPS' tax expense in future years as JPS utilises its accumulated tax losses through taxable profits.

Table 6.3 shows the calculation of JPS' rate base, following the definition in the Licence. As shown, JPS rate base for the test year period is $35.1 billion.

Table 6.3: Rate Base for Test Year Period (J$'000s)

	$'000
Total long-term assets	34,111,957
Net current assets	6,448,064
Total net assets	40,560,021
Customer deposits and construction advances	-1,838,277
Employee benefit obligations	-911,572
Deferred tax liability	-2,704,776
Rate base	**35,105,396**
Long-term debt	15,204,146
Total shareholders' equity	19,901,250
Rate base	**35,105,396**

Table 6.4 shows the calculation of the return on investment (rate base).

Table 6.4: Return on Investment for Test Year Period (J$'000s)

Pre-Tax Cost of Debt (%)	A	12.56
Return on Equity (%)	B	18.95
Tax Rate (%)	C	33 1/3
Gearing Ratio (%)	D=E/G	43.31
Long-Term Debt ($'000)	E	15,204,146
Shareholders' Equity ($'000)	F	19,901,250
Total Capitalization ($'000)	**G=E+F**	**35,105,396**
Cost of Debt ($'000)	H=A*(1-C)*E	1,273,094
Return on Equity ($'000)	I=B*F	3,771,287
Return on Investment ($'000)	**J=H+I**	**5,044,381**

6.3 Reconciliation of Revenue Requirement with 2003 financials

Tables 6.5 - 6.9 show the reconciliation between 2003 costs and test year revenue requirements of the following cost components:

- O&M (maintenance and SG&A) costs (Table 6.5);
- IPP costs (Table 6.6);
- depreciation costs (Table 6.7);
- long-term debt (Table 6.8); and
- equity (Table 6.9).

Table 6.5: Reconciliation of 2003 O&M costs with test year O&M requirements

	2003	Salary Increase	Inflation	ER	Efficiencies	Transport Divestment	Increase Mtce at Bogue	Insurance Savings	Rate Case Activities	Health Insurance	Other Increases	Increase T&D Mtce	NIS increase	GCT	Non-Recurring	Total
ALL EXPENSES	**6,189**	**343**	**60**	**135**	**(490)**	**267**	**111**	**(65)**	**25**	**27**	**133**	**19**	**12**	**113**	**(73)**	**6,806**
PAYROLL AND RELATED EXPENSES	**3,427**	**343**	**-**	**-**	**(490)**	**(53)**	**-**	**-**	**-**	**20**	**-**	**-**	**12**	**-**	**(42)**	**3,217**
Payroll	2,219	222			(313)	(37)										2,091
Benefits	777	78			(115)	(11)				20			12		(42)	719
Expense Account	431	43			(61)	(5)										407
NON-PAYROLL EXPENSES	***2,762***	***-***	***60***	***135***	***-***	***320***	***111***	***(65)***	***25***	***7***	***133***	***19***	***-***	***113***	***(31)***	***3,589***
3rd Party	910		30	28	-		15		14		84	15		41	(10)	1,127
Supplies	79		3	2	-		33					4			(2)	119
Material	433		-	38	-		20									491
Office	311		3	22	-						27			13		376
Transport	132		1	9	-	322										465
Miscellaneous	176		9	-	-					7					(19)	172
Training	36		2	0	-						12					50
Building	158		7	1	-	(2)	5									170
Insurance	398		1	33			38	(65)						59		464
Advertising	38		2	-	-				11							51
Taxes	20															20
Bad Debt/Customer Accts Expense	71		4	-							10					85

Table 6.6: Reconciliation of 2003 IPP costs with test year IPP requirements

	2003 costs	Increase/decrease (US$)								Increase/decrease (J$)			Test year costs	Energy output (MWh)	
	J$	Capacity Payment	Fixed O&M Charge	Debt Service	Insurance	Other	Variable Payment	Net Change	Net change in J$	LD	Other	ER effect	J$	2003	Test year
JPPC	1,769,989	0	101	-1,317	203	-677	148	(1,542)	(89,283)		(26,584)	154,133	1,808,256	448,063	478,120
JEP	1,592,455	0.00	85			596	(3,368)	(2,688)	(155,632)		(21,367)	142,783	1,558,239	495,667	274,318
Jamalco	125,394	(573)					(235)	(808)	(46,766)		(5,854)	10,883	83,657	73,614	43,920
Jamaica Boilers	(11,327)	(309)	(77)				(51)	(437)	(27,525)	40,509	(1,656)		0	5,091	0
Monroe	827										(827)		0	0	0
Wigton Wind Project	0						3,434	3,434	216,337				216,337	0-	61,320
Total	3,477,338	(882)	108	(1,317)	203	(82)	(71)	(2,040)	(102,869)	40,509	(56,288)	307,800	3,666,489	1,022,436	857,678

Table 6.7: Reconciliation of 2003 depreciation costs with test year depreciation requirements

Category	2003 cost	Increase/Decrease					Test year cost
		Revaluation	Disposal	Fully Depreciated Asset	Additions	Bogue Full Year Effect	
Generation	850,529	59,803		-72,671	8,197	163,800	**1,009,658**
Transmission	265,086	18,639			8,503		**292,228**
Distribution	522,311	36,725			48,183		**607,218**
General Plant	322,648		(61,475)		10,247		**271,420**
Total	1,960,574	115,167	(61,475)	(72,671)	75,130	163,800	**2,180,524**

Table 6.8: Reconciliation of 2003 long-term debt with test year long term debt requirement

Loan Type	2003	Increase/Decrease Draw down	Repayment	Revaluation	Test year
RMB # 1 - US$80M	4,849,504	-	-	190,622	**5,040,126**
RMB # 2- US$51M	3,114,291	-	-	122,415	**3,236,706**
Republic Bank - US$1.45M	36,440	-	(30,451)	1,432	**7,421**
KFW Loan (EUR)	405,221	-	(26,002)	15,928	**395,147**
IFC - US$45	2,727,846	-	-	107,225	**2,835,071**
RBTT US$30	1,623,718	-	(270,007)	63,824	**1,417,536**
RBTT US$30	0	1,890,046	(202,505)	-	**1,687,541**
Republic Bank US$2.5M	137,173	-	(52,501)	5,392	**90,063**
Republic Bank US$10M	484,950	-	(126,003)	19,063	**378,010**
DB&G US$5M	212,758	-	(104,595)	8,363	**116,526**
Total	**13,591,901**	**1,890,046**	**-812,065**	**534,264**	**15,204,147**

Table 6.9: Reconciliation of 2003 equity with test year equity requirement

	Dec-03	Revaluation	Net Income	Dividends	Dec-04
Cumulative Preference Shares	2,933	0	0	0	2,933
Ordinary Shares	10,914,099				10,914,099
Share Premium	269				269
Capital Reserve	5,469,057	539,424			6,008,481
Retained Earnings	3,374,625		-399,155		2,975,470
Total	**19,760,982**	539,424	-399,155	0	**19,901,251**

6.4 Introducing a sinking (self-insurance) fund

6.4.1 Background

Over the last two decades, due to the devastating damage done by hurricanes and flood rains in the region, insurance for transmission and distribution (T&D) lines has become increasingly expensive and insurance deductibles have increased significantly. Annual insurance premiums for the Northern Caribbean region, where available, have peaked at between 15% to 20% of the sum insured, with insurance deductibles of 5% to 10% of the sum insured. Insurance was often only available in limited instances and offered by few insurance providers. This trend in the insurance market was further exacerbated by the September eleventh (2001) incident in the USA.

The prohibitive insurance premiums, deductibles and exclusions have created the need for many utility companies in the region (and indeed worldwide) to resort to some form of self-insurance as an alternate strategy for covering their risks and exposures. These premiums are prohibitive for small to medium sized utility companies functioning in emerging markets with volatile economies. The result has been that most utility companies throughout the region have operated without formal insurance for their T&D lines over the last two decades.

Jamaica has been exposed to numerous natural disasters over the last two decades with the most notable incident being Hurricane Gilbert which caused damage to JPS' T&D lines amounting to approximately US$9 million in 1988, excluding the effects of loss revenues due to business interruption. There has also been damage as a result of earthquakes and floods over the same period, albeit, none as significant as the Hurricane Gilbert experience. However, the flood rains of last year and the increasing number of near misses during the hurricane season, constantly remind us of the imminent danger faced by Jamaica to natural disaster. Indeed, the need for the government to increase the fiscal budget for 02/03 as a result of the effects of damages caused by flood rains, also reminds us of the vulnerability of the entire country to natural disaster.

It is worth noting that even premiums for more traditional insurance has increased as a result of the above trends and events, resulting in insurance deductibles for JPS' property/machinery breakdown for the generating plants increasing from a low of US$400,000 to US$5 million currently. This means that for each and every loss JPS must cover the first US$5 million. Additionally, the deductibles for the substations are US$250,000 and for other buildings they are US$100,000 and the deductible in relation to earthquake damage is US$5 million.

The insurance market (JPS has solicited up to 45 different qualified insurers each year) is not willing to reduce deductibles any further currently, as the insurers clearly wish to mitigate their own risk and signal the need for increased self insurance and encourage the greater practice of preventative risk management.

It is also worth noting that JPS' former liability insurer (Independent Insurers) went into liquidation in the late 1990's which has created a situation where JPS has assumed their liabilities and has been settling all outstanding claims for employers and public liability which occurred during Independent's policy period. A number of cases are still pending in the courts, and the total liabilities could be in the region of J$30 million.

6.4.2 Concept

The need for insurance has resulted in the development of a sinking fund reserve concept, which is a structured methodology for self insurance practiced worldwide. This concept is considered relevant to JPS for the following reasons:

- Most insurance providers have stopped covering T&D lines in the region because of the significant exposure to natural disaster due to hurricanes and floods. Those insurers that still offer coverage are few and their terms are restrictive and prohibitively expensive;

- With insurance deductibles of 5% to 10% per incident, companies are still left with significant exposure to small or multiple disasters;

- T & D line owners would merely be trading dollars with the insurers to mitigate their risk, with premiums at 15% of the sum insured resulting in the virtual buy-back of the sum insured within five to six years depending on assumed investment yields on insurance premiums.

- Because of the nature of the insurance and the risk profile, insurance is not likely to become cheaper in the near future, or would the company be able to negotiate cheaper rates over time as a result of past premiums paid. Additionally, because of the potential for significant claims due to natural disaster, there would be no guarantee of continued insurance after a single event claim. Insurance companies could easily decide not to renew insurance after an event, thus making the availability of insurance in the medium to long run uncertain.

- Because of the introduction of the 'average clause' in the insurance industry, partial insurance of the sum insured, as a means of economically obtaining partial insurance coverage, has not been a plausible option.

The concept of the sinking fund reserve is to essentially set aside cash savings each year as a form of self insurance (i.e. preparing for a rainy day). These annual savings are accumulated in a special purposes bank account for the sole purpose of creating an adequate reserve that could be used in the event of some form of natural disaster. The annual savings are determined based on some predetermined criteria with the objective of achieving a minimum level of accumulated funds to protect against estimated damages that could be caused by natural disaster. This fund would be increased by the annual savings each year as well as the interest earned on the investment of the funds. The fund would be reviewed periodically based on changes in the level of desired risk protection, or as a result of any depletion that has occurred as a result of approved expenditure in relation to natural disaster.

Over the medium to long run, this methodology allows the company to build up a reserve, through mock insurance premiums, but, it does not result in the company actually paying out funds to a third party for an event which may not occur, such premiums not being refundable. It mitigates the business risk caused by having a significant amount of uninsured property and minimizes any potential rate shock impacts, which would otherwise be required as a result of natural disaster and the need to make a 'Z-factor' adjustment to the tariffs.

6.4.3 Proposal

The vulnerability of the country to external shocks, as noted under Section 9 ("Coping with Exogenous Shocks: the Z-factor"), suggests that we ought to be proactive in managing all stakeholders' risks in relation to the significant amount of uninsured property which currently exists. This current rate submission provides an opportunity to be proactive in this regard rather than leaving this to be addressed as an item under the Z-factor, in the event of a natural disaster.

Accordingly, JPS proposes to create a sinking fund reserve through an approved annual insurance premium to be charged to the income statement each year based on predetermined criteria (see the following recommendation on calculating the allowed annual insurance premium). This annual premium would form part of JPS' revenue requirement (i.e. to be embedded in the tariffs). The cash collected from the approved annual premium in the form of rates charged to customers would be set aside in a special purpose bank account along with any interest earned thereon. This bank account balance would represent the sinking fund reserve. The sinking fund reserve would be utilized to pay for approved qualifying disaster repair costs (i.e. costs which meet a predetermined criteria).

The sinking fund reserve balance should be reviewed every five years, at the time of each rate case filing, to assess its adequacy based on actual empirical experience and any changes which may have occurred as it relates to the desired level of self insurance. This review would be conducted particularly with the view of revising the allowed annual insurance premium, along with any other recommended changes.

Any major natural disaster, which results in qualifying damage repair costs in excess of the actual sinking fund reserve balance, would be subject to review under the Z-factor of the license. This is considered to be worth noting since adequate protection through a sinking fund reserve account would likely take numerous years to achieve, based on proposed annual premiums of 5% of the sum insured (see below).

6.4.4 Determinants for calculating the allowed annual insurance premium

- *Sum insured and desired level of self insurance*—JPS' Transmission and Distribution (T&D) lines are currently included in the rate base at a net book value of approximately US$40 million. JPS is desirous of achieving some meaningful level of self insurance and while 100% coverage would be ideal, JPS is mindful that such coverage would not be practical from a self-insurance perspective. Accordingly, based on the experience over the last two decades and the known growth in the T&D network over the same period, JPS proposes to seek to create over time a sinking fund reserve of US$10 million, or 25% of the value of the T&D lines. This coverage is considered reasonable after noting that the largest damage sustained as a result of a single event in any one year was US$9 million in 1988. While the past is no indication of likely future exposure, given the proposed insurance rate, it is worth noting that the proposed coverage would take a minimum of five years to achieve, assuming that there were absolutely no qualifying disaster expense claims during that period.

  While no one can predict with certainty what the actual future expenditures will be, the sinking fund reserve would be reviewed after five years with a view of resetting the allowed annual insurance premium and the desired insurance reserve balance based on the updated actual experience.

- *Insurance rate*—JPS proposes an annual premium based on 5% of the sum insured, or US$2 million per annum. This is considered to be reasonable as such insurance, if it were available, would likely result in annual premiums of 15% of the sum insured (or US$ 6 million) from a third party insurance provider. The proposal of a lower rate has been recommended primarily because of JPS' sensitivity to customers and the desire to minimize the effects on rates. Of course, this naturally results in a longer time frame for achieving any meaningful level of insurance; self insurance relative to the sum insured.

Table 6.10: Example of the estimated growth in the sinking fund reserve without any claims

Duration in years	1	2	3	4	5
			US$000's		
Sinking fund balance at beginning of year	-	2,050	4,203	6,463	8,836
Proposed annual premium	2,000	2,000	2,000	2,000	2,000
Interest earned, assuming 5% p.a.	50	153	260	373	492
Sinking fund balance at end of year	2,050	4,203	6,463	8,836	11,328

The example in Table 6.10 demonstrates that it would take approximately five years, provided that there were no actual natural disasters, to achieve the recommended minimum level of desired self insurance.

Section 7: Improving Efficiency: the X-Factor

According to Schedule 3, Exhibit 1 of the Licence, the ABNF shall be adjusted on an annual basis, commencing June 1, 2004 based on the following formula:

$$ABNF_y = ABNF_{y-1}(1 + dPCI) \qquad \text{Equation 7.1}$$

where:

$ABNF_y$ = non-fuel base rate for year y

$ABNF_{y-1}$ = non-fuel base rate for year y –1 (prior to adjustment)

dPCI = annual rate of change in non-fuel electricity prices

In turn, dPCI is defined as follows:

$$dPCI = dI - X - Q - Z$$

where dI is annual growth rate in an inflation and devaluation measure, X is the efficiency gains from productivity increases; Q is the adjustment reflecting quality of service; and Z are other special adjustments that may be required.

This section puts forward JPS' proposals with regard to the determination of X. Section 7.1 discusses the theoretical basis for price cap regulation which should form the basis of the determination of X. Section 7.2 highlights some key principles arising. Section 7.3 discusses the estimation of JPS' TFP trend relative to indexed firms while Section 7.4 discusses the benchmarking analysis carried out to establish JPS' efficiency levels relative to like firms. Section 7.5 summarizes the conclusions to be drawn from these analyses on JPS' X-factor.

7.1 Theoretical basis for price cap (CPI-X) regulation

The objective of utility regulation should be to replicate the operation and outcomes of competitive markets. One reason is that competitive market forces create maximum incentives to operate efficiently. Firms in competitive markets that do not produce efficiently have lower profits, as sales are lost to more efficient rivals. Reduced profits, in turn, create pressures to reduce costs. Similarly, firms that choose non-optimal prices or do not produce the products that consumers demand lose sales to competitors. Profits thereby decline, leading to changes in marketing behaviour that satisfy consumer demands. Economic theory has also established that competitive markets often create the maximum amount of benefits for society.[15] For these and related reasons, a "competitive market paradigm" is useful for establishing effective regulatory arrangements. The

[15] This is sometimes known as the "First Fundamental Welfare Theorem" of economics.

following considers how competitive markets operate and the implications for economic regulation.

One important aspect of competitive markets is that prices are external to the costs or returns of any individual firm. By definition, firms in competitive markets are not able to affect the market price through their own actions. Rather, in the long run, the prices facing any competitive market firm will change at the same rate as the growth in the industry's unit cost.

Competitive market prices also depend on the *average* performance in the industry. Competitive markets are continually in a state of flux, with some firms earning more and others less than the "normal" rate of return on invested capital. Over time, the average performance exhibited in the industry is reflected in the market price.[16]

Taken together, these features have the important implication that in competitive markets, returns are commensurate with performance. A firm can improve its returns relative to its rivals by becoming more efficient than those firms. Companies are not discouraged from improving efficiency by the prospect that such actions will be translated into lower prices because the prices facing any individual firm are external to its performance. Firms that attain average performance levels, as reflected in industry prices, would earn a normal return on their invested capital. Firms that are superior performers earn above average returns, while firms with inferior performance earn below average returns. Regulation that is designed to mimic the operation and outcomes of competitive markets should allow for this important result.

Another implication of the competitive market paradigm bears a direct relationship to the calibration of CPI-X (or, in the case of JPS, dI – X) formulas. As noted above, in the long run, competitive market prices grow at the same rate as the industry trend in unit cost. Industry unit cost trends can be decomposed into the trend in the industry's input prices minus the trend in industry total factor productivity (TFP). Thus if the selected inflation measure is approximately equal to the growth in the industry's input prices, the first step in implementing the competitive market paradigm is to calibrate the X factor using the industry's long-run TFP trend (see Appendix A5) for an algebraic decomposition of industry unit cost trends into industry input price and industry TFP trends). Specifically, in a competitive industry, if the inflation measure used reflects economy-wide inflation, then the average firm's X factor would be the difference between the industry's long-run TFP trend and the economy-wide long-run TFP trend.[17]

[16] This point has also been made in the seminal article, *Incentive Regulation for Electric Utilities* by P. Joskow and R Schmalensee. They write, "at any instant, some firms (in competitive markets) will earn more a competitive return, and others will earn less. An efficient competitive firm will expect on average to earn a normal return on its investments when they are made, and in the long run the average firm will earn a competitive rate of return"; *op cit*, p. 11.

[17] If the inflation measure used were the industry's input cost inflation, then X would simply be the industry trend of TFP growth.

The theoretical underpinnings described above are reflected in the Licence's definition of the X-factor (see Schedule 3 Exhibit 1):

> "The X-factor is based on the expected productivity gains of the Licensed Business. 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 reflect the price escalation measure "dI"."

Therefore:

- If JPS' productivity is expected to increase at a faster rate than that of the firms whose price index of outputs reflect the price escalation measure "dI" (henceforth referred to as the "indexed firms"), then X would be a positive number and the ABNF would increase at a rate less than inflation (assuming that Q and Z are zero).

- Conversely, if JPS' productivity is expected to increase at a slower rate than the productivity of the indexed firms, then X would be negative and the ABNF would increase at a rate faster than inflation.

- Finally, if JPS' productivity is expected to increase at the same rate as the productivity of the indexed firms, then X would be zero.

Effectively, the formulation of X as defined in the Licence seeks to ensure that all productivity gains made by the company are passed onto the consumer.

As noted above, if JPS' level of productivity were equal to the industry average (if the industry were to be competitive), then JPS' X-factor would simply be determined as the difference between the industry's long-run TFP trend and the economy-wide long-run TFP trend. However, some will argue that utilities such as JPS are likely to display greater cost inefficiency on average than firms in competitive markets because utilities have historically not operated under the competitive market pressures that naturally create incentives to operate efficiently.

If it is shown that the regulated utility in question is inefficient relative to like firms in competitive markets, then economic regulation should encourage the utility to increase their efficiency so that their cost levels converge towards the average efficient level of a competitive industry. This convergence may be achieved by adding a convergence or stretch element to the X-factor, in addition to the difference between the industry's long-run TFP trend and the economy-wide long-run TFP trend.

In other words, if it is shown that JPS is inefficient relative to like firms in competitive markets, the X-factor would consist of the sum of:

- the difference between long run TFP growth of JPS and that of the indexed firms; and

- a convergence or stretch element, to the extent that JPS' cost levels are above what would be expected of the average firm, operating in like conditions, if the industry were competitive.

7.2 Key factors to be considered when establishing the X-factor

The question therefore arises as to how these two elements that collectively make up the X-factor can be established. There are various options that can be taken towards implementing the competitive market paradigm. Regulators should be aware of the diversity of available approaches and how they differ in terms of risk and benchmarking emphasis. The approach that is most appropriate in any given situation will depend on a number of factors, including the institutional environment and the amount and quality of data that are available. In all cases, however, several factors must be kept in mind in making the competitive market paradigm operational.

- First, in competitive markets, movements towards long-run efficiency levels will take place gradually. One reason is that adjusting company operations to achieve greater efficiencies is usually costly. Companies must in general devote resources towards improving their performance, and payoffs from those actions in improved efficiency typically take time to materialize. This process can be expected to be especially long for industries such as electric utilities where assets are dedicated to serving particular customers (e.g. directly delivering to a customer's premises) and therefore have less value in alternative uses.[18]

- Second, 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.[19] 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. 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

[18] It is particularly costly to adjust operations for electric utilities since many of their assets are "sunk," *i.e.* many assets have secondary market values far below their current values. Discarding existing capital can therefore lead to large capital losses that, in turn, tend to increase the rigidity of capital stocks. Many electric utility assets, like generating stations and distribution lines and poles, are literally "sunk" into a particular location and thus have far less value outside their particular location and dedicated uses. By way of contrast, consider the airline industry, which is similarly capital intensive but whose primary assets (airplanes) can be readily resold to competing firms.

[19] 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.

outcome is clearly contrary to having returns be commensurate with performance and thus is not consistent with effective regulation.

- Third, it is also important to recognize that there will be considerable uncertainty about what constitutes a "frontier" performance level. Targets established through benchmarking should be cognizant of this uncertainty. Regulators should not impose performance standards for which there is significant probability that well-managed utilities will fail to achieve these targets. The benchmarks should therefore make appropriate allowance for the uncertainty associated with attaining the target performance levels.

7.3 Establishing JPS' TFP Trend Relative to Indexed Firms

7.3.1 Principles and methodology

To the extent that the input cost inflation of the indexed firms inflation is a good proxy for the input cost inflation of JPS, the first component in the X-factor is the difference between long run TFP growth of JPS and that of the indexed firms. The inflation measure is a weighted average between the Jamaican economy inflation and the US economy inflation. Hence, the first step in establishing the X-factor is to estimate the following:

- the long run TFP growth of JPS;
- the long run TFP growth of the Jamaican economy; and
- the long run TFP growth of the US economy.

These three long-run productivity growth trends can be estimated using a TFP study. A TFP index is a comprehensive measure that includes all of the inputs and outputs of an economic unit. It is the ratio of an output quantity index to an input quantity index. A TFP analysis can control for differences in business conditions, such as differences in input prices across companies, differences in the scale of operations and local demand conditions that may, for example, be affected in output growth.

JPS has commissioned a TFP analysis for JPS, the Jamaican economy and the US economy. The full analysis is contained in Volume III of this submission. The results are summarized as follows.

7.3.2 Estimating the Total Factor Productivity for JPS

The TFP trend of JPS in the provision of power generation, transmission, distribution and retailing services was estimated. The output quantity index for JPS included trends in the number of customers served, MWh volumes delivered, and MW of peak demand. The input quantity index summarized trends in capital and 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 the ABNF, 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 1991-2002.

The growth rate in the TFP index was the difference between the growth rates in JPS output and input quantity indexes. The TFP trend for JPS was 0.15% per annum. Output quantity grew at an average annual rate of 4.62% over the sample period. This outpaced input quantity growth, which grew at an average rate of 4.47% per annum.

Table 7.1 displays details of the growth in the output quantity index. It can be seen that customer numbers increased at an average annual rate of 4.2%. Volumes delivered to customers increased more rapidly, at an average rate 5.0% per annum. Peak demand grew by an average of 4.7% per annum over the 1991-2002 period. These data show that volumes and demand per customer increased modestly over the sample period. Growth in all outputs has also been fairly steady.

Table 7.1: JPS output quantity index

Year	Output Quantity	No. of Customers	Volume (MWh)	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
Average	4.62%	4.21%	4.97%	4.74%

Table 7.2 shows details of the growth in the input quantity index. It can be seen that O&M inputs grew at an average annual rate of 2.75%. O&M inputs have declined substantially since 1998, in part because of a downsizing of the JPS workforce.

Table 7.2: JPS Input Quantity Index

Year	Input Quantity	O&M Inputs	Total Capital	JPS Capital	IPP Capacity
1991	1.000	1.000	1.000	1.000	
1992	1.125	1.221	1.014	1.014	
1993	1.288	1.115	1.473	1.473	
1994	1.251	1.275	1.253	1.253	
1995	1.532	1.412	1.664	1.419	1.000
1996	1.509	1.313	1.708	1.191	2.115
1997	1.586	1.214	1.950	1.254	2.849
1998	1.688	1.591	1.788	1.187	2.458
1999	1.639	1.312	1.969	1.316	2.671
2000	1.716	1.376	2.059	1.334	2.964
2001	1.615	1.372	1.860	1.322	2.200
2002	1.634	1.353	1.916	1.244	2.747
Average	4.47%	2.75%	5.91%	1.98%	14.44%

There are sharply different trends in JPS' own capital inputs and in generation capacity purchased from IPPs. JPS' own capital input increased at an average rate of 2.9% per annum. 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. However, there has been a dramatic increase in capacity purchased from IPPs.

7.3.3 Estimating the 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 2000, US private business sector MFP grew at an average annual rate of 1.0%. This is the best estimate of the US economy's long-run TFP growth trend.

There are no comparable, official estimates of TFP growth for the Jamaican economy. Estimates of TFP growth in Jamaica were developed using a standard growth accounting framework and data developed both within and outside of the country. Research indicates 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. However, there are signs that economic performance has begun to improve in the last few years. 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). The best period for estimating Jamaica's long-term TFP trend is therefore likely to be 1981-2002, since this corresponds to the country's entire, post-oil shocks economic experience. The TFP for the Jamaican economy is estimated to have grown at an average annual rate of 0.5% over this period.

7.4 Establishing the stretch element of the X-factor

7.4.1 Principles and methodology

As discussed in Section 7.2, to the extent that JPS' current cost levels are above that of the average firm, in like conditions, if the industry were competitive, then the X-factor may also incorporate a stretch element. There are various ways to incorporate a stretch element, two of which are as follows:

- Applying a benchmarking analysis—which assesses and compares the cost levels of JPS relative to the average firm operating in comparable but competitive conditions and, to the extent that JPS cost levels are higher than that average firm (i.e., JPS is relatively inefficient), establishes an appropriate period within which JPS' efficiency level is expected to converge to that of the average firm.

  Methodologies that can be adopted include parametric approaches—such as econometric cost modelling and stochastic frontier analysis (SFA)—and non-parametric approaches—such as Data Envelope Analysis (DEA). Both these approaches are discussed in greater detail in Appendix A6 and the PPA/Frontier study commissioned by the OUR.[20]

- Applying a negotiated stretch factor—that shares short-run performance gains with customers. There are many precedents for negotiated 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 negotiated 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 negotiated 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 telecommunications, these factors represent relatively more rapid acceleration in TFP relative to historical experience. Table 7.3 presents the industry TFP and stretch factors negotiated and approved in the seven

[20] See PPA (2002), *OUR Electricity Tariff Study*, July; in association with Frontier Economics, page 20.

comprehensive indexing plans for which North American regulators made specific findings on these elements.[21]

Table 7.3: Application of Negotiated Stretch Factors in North America

Company	Jurisdiction	TFP growth	Stretch
Southern California Edison	California	0.90%	0.56%
Southern California Gas	California	0.50%	0.80%
San Diego Gas and Electric – Gas	California	0.68%	0.55%
SDG&E-Electric	California	0.92%	0.55%
Boston Gas	Massachusetts	0.40%	0.50%
Ontario power distributors	Ontario, Canada	1.25%	0.25%
Union Gas	Ontario, Canada	0.90%	0.50%
Average		0.79%	0.53%

7.4.2 Estimation

Benchmarking analysis in general entails some risks, the most important of which are the availability of accurate data and comparator companies against which JPS would be benchmarked. Further, these methods are in their infancy in utility regulation and will be particularly uncertain about what constitutes the industry's performance "frontier."

While these risks apply to both parametric and non-parametric benchmarking approaches mentioned above, the risk of inaccurate results and their application is likely to be higher in non-parametric approaches than parametric approaches. Amongst other reasons, this is because parametric approaches at least provide a statistical basis to analyse the probability of the results being inaccurate thus allowing the regulator to exercise the appropriate degree of caution in applying the results. In contrast, non-parametric approaches such as DEA are not statistical methods so that it is much less conducive to dealing with uncertainties surrounding the benchmarking measures. It is generally not possible to test the statistical precision of benchmarks that are estimated through DEA. DEA also does not naturally lend itself to the construction of confidence intervals around benchmarks. (See Appendix A7 for a discussion on the limitations of the DEA approach.[22]

[21] In some other plans, approved X factors were determined via negotiation among various interested parties. The stretch factors here are also average stretch factors over the term of the plan; in some cases, the value of the stretch factor differs during the term of the plan.

[22] In two cases regulatory commissions have changed from DEA to other methods in the second X factor review. In New South Wales, the Independent Pricing and Regulatory Tribunal (IPART) switched from DEA to a more basic engineering-based benchmarking approach. In the Netherlands, after utilities took the Regulator to court, DEA was removed and a negotiated stretch factor was implemented.

Nonetheless, in view of the use of DEA by some regulators, JPS has also commissioned a benchmarking analysis of its efficiency levels, using both parametric (econometric cost modelling) and non-parametric (DEA) methods. The former approach compares JPS to *average* efficiency levels in the electric power industry, while the latter compares the company to a *frontier* efficiency standard. Details of the analysis are contained in Volume III of this submission. The results are summarized as follows:

- Guided by economic theory, an econometric model was developed 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 87 US investor-owned US electric utilities and the business conditions they faced. The sample period used to estimate the econometric cost model was 1995 to 2000. All key parameters were plausibly signed and highly significant.

- The model was used to predict the average non-fuel cost of bundled power services for JPS given the business conditions that it faced. JPS 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. It also faces high prices for capital services.

- JPS' actual non-fuel costs were compared with those predicted by the econometric model. Two comparisons corresponding to two different measures of the JPS capital stock were undertaken. The first was based on the *regulatory* asset base, or the capital value that is actually used to set JPS' current ABNF. The regulatory asset base incorporates a substantial downward adjustment in the capital stock in 1997 due to a government policy decision to limit JPS price inflation. The second comparison was based on the *replacement* cost of JPS assets. This value was obtained by eliminating the 1997 downward adjustment from JPS' capital stocks. The replacement cost measure for JPS is more comparable to the US cost measures used in the econometric model, so JPS costs associated with replacement capital value generate more "apples to apples" comparison with US electric utilities.

- Using the regulatory asset base, JPS' non-fuel cost was found to be 34.5% below the value predicted by the cost model over the 1999 to 2002 period. This difference was statistically significant. This implies that the costs that JPS is allowed to recover in its non-fuel rates are significantly lower than what would be expected for a utility operating under its business condition. Using the replacement costs of JPS assets, JPS' non-fuel cost was about 1.8% below the value predicted by the econometric cost model over the 1999 to 2002 period. This difference was not statistically significant. This results implies that JPS is an average cost performer vis-à-vis US utilities.

- JPS was also benchmarked using DEA methods. DEA is a non-parametric benchmarking approach that essentially evaluates input-output ratios in a multi-dimensional context. Utilities are deemed to be more efficient if they use relatively fewer inputs to produce a given amount of output. Six different DEA models were investigated, using different specifications for inputs and outputs. JPS' DEA score was an average of 14% below the frontier on these models. This compares with DEA scores for the US sample that are, on average, 19.5% below the performance frontier. Evidence from competitive markets also shows that the average firm in an industry has efficiency levels that are about 10%-20% below the industry's performance frontier. The DEA benchmarking results therefore also support the conclusion that JPS is an average cost performer relative to US electric utilities.

7.5 Summary: Implications of TFP and benchmarking analysis for JPS' 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 estimates that TFP for JPS has historically grown at 0.15% per annum.

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. The long-run TFP growth trends of the US and Jamaican economies are estimated to be 1.0% and 0.5% respectively. The weights specified in the PBRM for US and Jamaican inflation are 0.6 and 0.4, respectively. Overall TFP growth for firms whose output price indexes are reflected in the price escalation measure is therefore 0.8% (*i.e.* 0.6*1.0% + 0.4*0.5% = 0.8%).

The analysis also shows that JPS is an average non-fuel cost performer. There is therefore no evidence that a stretch factor should be further added to X. It is therefore appropriate that the X-factor be set based on the definition in the Licence (see Schedule 3 Exhibit 1):

> "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 reflect the price escalation measure "dI"."

$$X = 0.15\% - (0.6*1.0\% + 0.4*0.5\%) = -0.65\%$$

Based on the Licence, therefore, JPS considers that an X-factor of –0.65% is appropriate for the PBRM.

Section 8: Ensuring Quality of Service: The Q-Factor

A second 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:

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

The PBRM proposed above requires that a benchmark level be determined for each specified service component.

The Office of Utilities Regulation (OUR) consultants, PPA/Frontier Economics (PPA/FE), in their Electricity Tariff Study 2002, put forth two main ways that quality standards could be translated into an index that could be included within the electricity price cap—the "Relative Q" option and the "Absolute Q" option:[23]

- *"Relative Q" option*—under this option, Q could be set based on the proportionate difference between pre-defined actual measures of quality and a target level of quality. PPA/Frontier suggested aspects of quality that include frequency of interruptions, duration of planned interruptions and duration of unplanned interruptions. Standards would be set for each and JPS' deviation from that standard would be calculated and a Q derived from the deviation and weighted importance. PPA/Frontier noted that the Office of the Regulator General in Victoria, Australia uses this form of index.

- *"Absolute Q" option*—under this option a starting absolute quality index is fixed. Quality indices could be weighted for perceived differences in value to customers. If JPS performs better than the fixed index then the calculated Q would be added to PCI, if JPS performs worse than the fixed index then the calculated Q would be subtracted from PCI. PPA/Frontier noted that the Office of Gas and Electricity Markets (OFGEM) in the UJ use this form of index.

PPA/Frontier noted that both approaches require the OUR to assess the willingness of customers to pay for different levels of quality of supply in order to set a value of Q. Predicting the value that customers put on quality of supply is difficult, especially when dealing with several classes of customers and high-users and low-users within the same class.

JPS recommends that the development of the Q-factor meet the following criteria:

- The Q-factor should provide the proper financial incentive to provide a level of service quality based on customers' view of the value of that service quality.

[23] See PPA (2002), op. cit.

- The measurement and calculation of the Q-factor should be straightforward 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 generators; natural disasters; and other *force majeure* events, as defined under the licence.[24]

- It should be symmetrical in application, as stipulated in the Licence, with appropriate caps or limits of effect on rates.

JPS' proposed choice of indicators and methodology for assessing performance is outlined in the following.

8.1 Proposed performance indicators and methodology

JPS proposes that a method generally in agreement with the "Absolute Q" option described by PPA/Frontier[25] be utilized for the first 5-year rate cap period. Specifically, JPS proposes that measurements approximating SAIDI and SAIFI for ***Sustained Interruptions***, as defined in the Institute of Electrical and Electronics Engineers Standard (IEEE Std. 1366, 2001) become the quality measures used to determine JPS' level of service quality. By this definition, Sustained Interruption is any interruption not classified as a momentary event, i.e., any interruption longer than five minutes.

[24] *Force Majeure* (as defined in the All Island Electricity License 2001) means any event or circumstance or combination of such events or circumstances that (i) occurs inside Jamaica, except as provided in clause (h) below, (ii) is outside the reasonable control of the Licensee, (iii) cannot be prevented or overcome by the exercise of reasonable diligence, and (iv) materially or adversely affects the performance of the Licensee of its obligations under this License, to the extent that such event(s) or circumstance(s) meet the foregoing requirements (i) through (iv), including:

(a) acts of God, fire, explosion, chemical contamination, earthquakes, flood, lightning, drought, tsunami, torrential rain, storm, cyclone, typhoon or tornado, pestilence or other natural catastrophes, epidemics or plague, or any strikes, work to rule, go slows or labour disturbances that directly affect the Assets of the Licensee,

(b) any failure or inability by the Licensee to obtain or renew any licenses (other than this License), concessions or permits or other *Governmental Requirements* that are necessary for the Licensee to conduct its business on terms and conditions at least as favourable as those contained in the original licence (and not this Licence), concession or permit after the submission of an application that fulfills all the applicable requirements of the relevant *Government Requirements* and the exercise of due diligence to obtain such licence (other than this Licence), concession or permit,

(c) any strikes, work to rule, go-slows or other labour disturbances that extend beyond the Assets of the Licensee, are widespread or nation-wide or are of a political nature, including labour actions associated with or directed against a ruling political party, or those that are directed against the Licensee (or its contractors or suppliers) as part of a broader pattern of labour actions against companies or facilities with foreign ownership or management,

(d) expropriation, requisition, confiscation, nationalization or compulsory acquisition by a *Governmental Authority* of the Licensee or any substantial portion of the Assets,

(e) acts of war (whether or not declared), invasion, blockade or embargo,

(f) acts of threats of terrorism or threat from terrorists, widespread riot, widespread violent demonstrations, widespread armed insurrection, widespread rebellion or revolution,

(g) the closing or drastic reduction in capacity of public harbours, ports, docks, canals, roads, airports or other infrastructure, the rationing thereof or any import or export restrictions, or

(h) to the extent that they result in disruption of the Licensee's ability to receive shipments or fuel, major equipment or critical spare parts, any strikes, work to rule, go-slows or other labour disturbances that occur outside of Jamaica.

[25] See PPA (2002) op. cit.

The IEEE Standards definition for the SAIDI and SAIFI quality of service indices is as follows:

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

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

- *System average interruption duration index (SAIDI)*—this index is designed to provide information about the average time the customers are interrupted.

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

The value of Q will be based upon actual values of SAIDI and SAIFI for each year of the performance based rate making as compared to the benchmark. JPS proposes that the benchmarks be set such that, in each year between 2004 - 2008, JPS will be incentivised to continuously improve its performance on SAIDI and SAIFI, relative to 2003. Specifically:

SAIDI benchmark in year 2004 + t = $\text{SAIDI}_{2003}(1 - 0.02t)$

SAIFI benchmark in year 2004 + t = $\text{SAIFI}_{2003}(1 - 0.02t)$

In other words, SAIDI and SAIFI should be continuously improving by 2%, relative to the 2003 performance level, in each year from 2004 to 2008. The targets would show in Table 8.1.

Table 8.1: JPS Proposed Targets for the Q-factor 2004 - 2009

Year	Target SAIDI	Target SAIFI
2004	SAIDI_{2003}	SAIFI_{2003}
2005	$\text{SAIDI}_{2003}(1 - 0.02)$	$\text{SAIFI}_{2003}(1 - 0.02)$
2006	$\text{SAIDI}_{2003}(1 - 0.04)$	$\text{SAIFI}_{2003}(1 - 0.04)$
2007	$\text{SAIDI}_{2003}(1 - 0.06)$	$\text{SAIFI}_{2003}(1 - 0.06)$
2008	$\text{SAIDI}_{2003}(1 - 0.08)$	$\text{SAIFI}_{2003}(1 - 0.08)$

In each of the five years following 2003:

- if the SAIDI and SAIFI calculations show marked improvement relative to the target, Q will be a fixed positive adder to the inflation adjustment factor, dI.

- If the SAIDI and SAIFI calculations show little or no improvement relative to the target, Q will be zero (a dead band).

- If SAIDI and SAIFI calculations show deterioration relative to the target, Q will be a fixed negative reducer to dI.

8.2 Scope of measurement of SAIDI and SAIFI

As noted above, JPS' performance on SAIDI and SAIFI in 2003 will form the basis on which benchmarks for Q are set in the future years. Calculation of both these indices require data on:

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

JPS' database currently holds historical information on CML at the aggregate level. Specifically, the data on historical CML covers all outages at the feeder level but planned outages only at the sub-feeder level. Detailed data on specific outages, in terms of duration of outages and the number of customers affected have only been retained for feeder level forced outages subsequent to September 2001 Hence, JPS does not have sufficient data to calculate SAIDI and SAIFI for a long historical period.

There is currently sufficient data to estimate SAIDI and SAIFI related to planned outages in 2003 at both the feeder and sub-feeder level and there is data to calculate these indices for forced outages at the feeder level only for 2003. The existing database does not allow for the computation of SAIDI and SAIFI related to forced outages at the sub-feeder level. In other words, 2003 data for SAIDI and SAIFI only exist for:

- planned and forced outages at the feeder level; and
- planned outages only at the sub-feeder level.

JPS therefore proposes that, for this price-cap period, the Q-factor be based on SAIDI and SAIFI related to these types of outages, i.e., excluding forced outages at the sub-feeder level. This will ensure that the Q-factor is based upon comparing like with like.

Moving forward in the future, however, JPS will put in place the required systems to collect all data required for the full computation of SAIDI and SAIFI for both planned and forced outages at both feeder and sub-feeder levels. In the next rate review due in 2009, the OUR will have sufficient data to appropriately benchmark JPS' performance on SAIDI and SAIFI at all these levels. This approach would not compromise the performance standards to which JPS would be held during this price cap period (2004 – 2008).

8.3 JPS historical performance on SAIDI and SAIFI

Table 8.2 shows JPS' performance on SAIDI and SAIFI for 2001—2003, the only years for which there is sufficient data to calculated the indices.

Table 8.2: JPS historical performance on SAIDI and SAIFI

Year	2001	2002	2003
No. of customers (a)	496,461	506,390	516,518
Total planned outages (feeder and subfeeder levels)			
CML (b)	23,936,234	27,202,980	40,292,142
No. of customer interruptions (c)	49,867	56,673	83,942
SAIDI (b/a)	48.21	53.72	78.01
SAIFI (c/a)	0.10	0.11	0.16
Total forced outages (feeder level only)			
CML (d)	-	1,067,797,880	381,235,057
No. of customer interruptions (e)	-	18,171,382	9,080,706
SAIDI (d/a)	-	2,108.65	738.09
SAIFI (e/a)	-	35.88	17.58
Total planned and forced outages			
SAIDI ((b+d)/a)	-	2,162.37	816.09
SAIFI ((c+e)/a)	-	36.00	17.74

8.4 Q-Factor Method of Calculation

JPS proposes that quality of service performance be classified into three categories, with the following point system (see Table 8.3):

- Excellent Performance—which would be worth 2 Quality Points on either SAIFI or SAIDI;
- Dead band Performance—which would be worth 1 Quality Point on either SAIFI or SAIDI; and
- Unsatisfactory Performance—which would be worth 0 Quality Points on either SAIFI or SAIDI.

Specifically, for SAIFI, beating the target by 1.0% or more will be considered excellent performance. Beating the target by less than 1.0% will be considered a dead band result. Performance that is worse than the target (increase in SAIFI) will be considered unsatisfactory performance.

For SAIDI, beating the target by (decrease of) 1.0% or more will be considered Excellent Performance. Beating the target by less than 1.0% will be considered a dead band result. Performance that is worse than the target (increase in SAIDI) will be considered unsatisfactory performance.

Customer interruptions that are a result of events or circumstances defined as *force majeure* events in the License, will not be counted in the SAIDI and SAIFI calculations.

JPS further proposes that:

- If the sum of Quality Points for SAIFI and SAIDI is 4, then Q = +0.5%
- If the sum of Quality Points for SAIFI and SAIDI is 3, then Q = +0.5%
- If the sum of Quality Points for SAIFI and SAIDI is 2, then Q = +0.0%

- If the sum of Quality Points for SAIFI and SAIDI is 1, then Q = -0.5%
- If the sum of Quality Points for SAIFI and SAIDI is 0, then Q = -0.5%

Table 8.3: Proposed categories and points for SAIDI and SAIFI

Band	SAIFI and SAIDI performance relative to target	Quality points
Excellent	Beating the target by 1.0%	2
Dead band	Beating the target by between 0% to 1.0%	1
Unsatisfactory	Worsening of performance	0

Based on the proposed methodology proposed above, if, for example, F_{2003} and F_{2004} refer to SAIFI for the year 2003 and 2004 respectively, then:

- If $F_{2004} < F_{2003}$*(1-0.01), then 2 Quality Points (Excellent Performance) would be awarded for that year.
- If $F_{2004} > F_{2003}$*(1-0.01) but < F_{2003}*, then 1 Quality Point (Dead band Performance) would be awarded for that year.
- If $F_{2004} > F_{2003}$*, then 0 Quality Points (Unsatisfactory Performance) would be awarded for that year.

In the case of SAIDI, if D_{2003} and D_{2004} refer to SAIFI for the year 2003 and 2004 respectively, then:

- If $D_{2004} < D_{2003}$*(1-0.01), then 2 Quality Points (Excellent Performance) would be awarded.
- If $D_{2004} > D_{2003}$*(1-0.01) but < D_{2003}*, then 1 Quality Point (Dead band Performance) would be awarded.
- If $D_{2004} > D_{2003}$*, then 0 Quality Points (Unsatisfactory Performance) would be awarded.

Consider the following example where F_{2003} = 4.20; F_{2004} = 3.80; D_{2003} = 423; and D_{2004} = 420. Under this scenario:

- F_{2004} is less than F_{2003} x (1-0.01) so JPS receives 2 Quality Points for performance as measured under SAIFI in 2004.

- D_{2004} is equal to D_{2003} x (1-0.008), which is greater than D_{2003} x (1-0.01) but less than D_{2003}, so JPS receives 1 Quality Point for performance as measured under SAIDI in 2004.

- The sum of quality points as received under SAIFI and SAIDI totals 3, therefore Q = +0.5% for that year.

In the year 2005 then, for SAIFI:

- If $F_{2005} < F_{2003}$*(1-0.02)*(1-0.01), then 2 Quality Points (Excellent Performance) would be awarded for that year.
- If $F_{2005} > F_{2003}$*(1-0.02)*(1-0.01) but < F_{2003}*(1 – 0.02), then 1 Quality Point (Dead band Performance) would be awarded for that year.

- If $F_{2005} > F_{2003}*(1-0.02)$, then 0 Quality Points (Unsatisfactory Performance) would be awarded for that year.

In the case of SAIDI,

- If $D_{2005} < D_{2003}*(1-0.02)*(1-0.01)$, then 2 Quality Points (Excellent Performance) would be awarded for that year.
- If $D_{2005} > D_{2003}*(1-0.02)*(1-0.01)$ but $< D_{2003}*(1 – 0.02)$, then 1 Quality Point (Dead band Performance) would be awarded for that year.
- If $D_{2005} > D_{2003}*(1-0.02)$, then 0 Quality Points (Unsatisfactory Performance) would be awarded for that year.

8.5 Data Collection, Security and Storage

As noted above, for the calculation of SAIDI and SAIFI indices, the key information to be collected going forward are as follows:

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

The data required for calculating approximate SAIDI and SAIFI values will build upon JPS' existing data acquisition capabilities together with JPS' best approximation of the number of customers on each feeder, as described in more detail below.

JPS electronic data capture mechanisms are at various stages of development and no one system presently exists which could capture ALL the information required for an exact calculation of SAIDI and SAIFI indices. Supervisory Control and Data Acquisition (SCADA) status and analogue information are available on the majority of transmission and generation equipment with status information available for just over 80% of feeder level circuits on the distribution system. At the local distribution level, some data is also electronically captured using the Sentry Trouble Call System. Customer reported data is also manually captured and stored electronically using the call centre logging system.

8.5.1 Data on outage start and end times

Outages can occur at the feeder or sub-feeder level, and can either be planned outages or forced outages. The sources and availability of data required for SAIDI and SAIFI vary depending on the type of outages.

Feeder level outage

JPS collects and stores data on all its planned and forced interruptions down to the feeder recloser level in a Microsoft Access-based outage logging database (developed in-house) located at its system control centre. The data collected is stored under unique event codes and includes information related to the equipment affected, the start and end times of the outage, classification of the outage cause, approximate number of customers interrupted, protection devices that operated, etc.

At the feeder recloser level, data will be captured on any forced outages (generation, transmission and distribution). There are four possible sources of outage time data at the feeder level:

- *SCADA system*—Where feeder status monitoring via SCADA exists, the start and end times of outages will be logged by the system control engineer at the System Control Centre utilizing SCADA timestamps. Where available, SCADA will serve as the primary source of outage information at the feeder level.

- *DCI sentry outage monitors*—at present, not all feeder reclosers are monitored via SCADA. For feeder reclosers without feeder status monitoring via SCADA, outage start and end times will be logged by the system control engineer utilizing timestamp information captured from the DCI Sentry outage monitors. There are a total of 13 substations (19% of total substations and 19% of all customers) across the island that we currently do not have SCADA monitoring or control all of which have DCI Sentry monitors installed feeding information to the outage detection system.

- *Outage log database*—For planned outage duration at the feeder recloser level, the planned start and end times will be captured and recorded in the outage log database from outage requests submitted by field personnel requesting outages. The system control engineer will also record the actual planned start and end times of each outage, needed for calculation of the reliability indices on the day of the actual outage in the same database.

- *Central call centre logs*—in the event of a failure of the SCADA monitoring and/or the DCI sentry outage detection monitors, the central call centre logs will be used to provide outage start. This will be determined by the first customer call received, which confirms a feeder outage start time. The outage end times will be determined by the recloser or switch closing time as reported to the system control engineer by the field personnel and also recorded in the call centre log.

Sub-feeder level outage

- Planned outages—for planned outages at the sub-feeder level, data would be available primarily from outage log database. Where the DCI sentry system is available, it could also be used as a source of data.

- Forced outages—where available, the DCI sentry system will be used to provide information on start and end times of forced outages at the sub-feeder level. The DCI sentry system, however, does not monitor all sub-feeder outages. Therefore, where the DCI system is not available, the central call centre logs will be used to provide outage start times. The outage end time will be determined by the recloser or switch closing time as reported to the system control engineer by the field personnel and also recorded in the call centre log.

As noted above, the historical database does not contain all the data required to estimate historical SAIDI and SAIFI levels for forced outages at the sub-feeder level. However, going forward, JPS will ensure that the database is structured and that all the required data is collected to calculate SAIDI and SAIFI. Hence, in the rate reviews to follow, JPS and the OUR will have sufficient data to set appropriate benchmarks for SAIDI and SAIFI that include sub-feeder forced outages. At that point, the Q-factor can then be set to include this set of outages.

8.5.2 System total number of customers

Data regarding the company's total active customer count is captured in the CIS billing records. Between January and August of 2003 active customer count varied between a high of 521,444 and a low of 506,324. The variation is due to factors such as customer additions; disconnection of accounts for non-payment, termination of accounts and billing of previously missed accounts.

8.5.3 Number of customers affected by the outage

Feeder level outages

JPS' total customer base is disaggregated among the twelve parishes with the Kingston/St. Andrew Parish being further split into north and south sectors. Within the distribution operations division, an engineer is assigned operation and maintenance responsibility for each feeder. The responsible engineer therefore tends to have an excellent working knowledge of individual and total customers supplied via the feeder.

To determine the customer count per feeder, a census was carried out in the following manner. The engineer used the billing address from the CIS database and mapped this information to the feeder route getting a total count of customers per feeder. In instances where feeders go across parish boundaries, the engineer was required to disaggregate the count and conduct a physical count of those customers.

The managers with responsibility for each of the three operating regions, into which the distribution organization is split, have also performed a similar exercise. JPS has compared both sets of data against data gathered during a physical count of customers serviced by several feeders performed a few years earlier. Where data sets showed good comparison among them as well as comparing favourably with the parish count, the data was accepted. In instances of less than favourable comparison, a more exhaustive examination was done. Compared to the billing register count of 507,843, the customer to feeder mapping data initially resulted in a variance. However, after various iterations, the count was matched to the billing register count on a parish-by-parish basis.

Where outages (planned and forced) are concerned at the feeder level, it is therefore proposed that the estimated number of customers on each feeder be determined from this derived customer count listing. This list will be updated at the end of every year to be used in the next years' calculations. See Appendix A8 for the current customer count list for the year ending 2003.

Sub-feeder level outages

JPS does not currently have customer count data at the sub-feeder level. Therefore, it is proposed that, for sub-feeder section outages, the number of customers affected will be estimated utilizing the feeder peak loading and the average utilization (MW) per customer for that feeder.

Feeder peak loadings are determined locally at the substation level from the maximum loading as recorded at the recloser per month (substation loading report). For some feeders, 24-hour substation feeder level measurements exist via electronic substation meters downloaded monthly. For these cases, this loading information will be utilized as the primary source. Utilizing this load reading, and the total number of customers per feeder from the customer count list, an *average utilization* per customer can be computed as follows. (See Appendix A8 for the current listing of MW/customer for each feeder).

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

For each planned outage on a feeder section, it is normal that during the submission of outage requests the requesting engineer indicates the number of customers to be affected and/or the load to be interrupted. The load to be interrupted is normally a clip-on reading (amperes) at the switch point done on a similar day to the day of the outage and recorded on the outage request form sent to the system control centre. Where the number of customers is not provided and the load to be interrupted is provided, the number of customers on the section can be estimated from the average customer utilization (kW/Customer) for that feeder circuit. Specifically, the estimated kW loadings to be interrupted as determined above will be used along with the average customer utilization for that feeder to determine the number of customers to be interrupted, i.e.:

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

Where neither is provided, the rating of the fuse (amperes) to be opened will be used a proxy to estimate the load on the line section.

Load Transfers

Where there are load transfers, the customer count on any feeder or sub-feeder will differ from the normal count. At the present time, the outage log database at system control is manually updated whenever a feeder circuit is fully transferred. The load demand and the number of customers are updated for the feeder to which the load has been transferred. In this way, the number of customers interrupted can be consistently calculated.

A strategy will have to be looked into for partial load transfers, which will either be a physical count of customers on the transferred section or a calculation using the load on the section and the Average customer utilization. JPS proposes that the customer count be estimated in the same was as proposed above for planned outages at the sub-feeder level, i.e., by using the estimated load (kW) transferred and the average kW per customer on that feeder.

$$\text{Number of customers to be transferred} = \frac{\text{Estimated load (kW)}}{\text{KW per Customer for that feeder}}$$

Data Security

One concern regarding the measurement of any performance measure is data security. JPS believes that the security of the relevant data is satisfactory. Specifically, the main database system to be utilized to store critical information (outage log database) related to outages operates in a secure environment and keeps a log of user access and data entry/change. Once data is entered, changes can only be made via authorized access

In addition, the customer count and the feeder loading information are only accessible to the system administrator and the user is only required to enter times, dates, causes for outages etc. Should discrepancies ever arise in the database, it is highly possible that easy validation or crosschecking can be obtained via the other independent data capture mechanisms aforementioned (SCADA, substation metering, call centre logging system, or the DCI sentry system) and also from written logs kept by the operating personnel.

Section 9: Coping with Exogenous Shocks: The Z-factor

As set out in the Schedule 3 (Exhibit 1) of the Licence:

> "The Z -factor is the allowed percentage increase in the price cap index due to events that:
>
> d) affect the Licencee's costs;
>
> e) are not due to the Licencee's manage rial decisions; and
>
> f) are not captured by the other elements in the price cap mechanism."

Further, according to the Licence, such events will include the government-imposed obligations as specified in Schedule 3 (Section 5) of the Licence. This means any obligation imposed by the Government or its agencies in the areas of:

- environmental standards, laws and regulations;
- licence fees;
- taxes other than general income, corporate or general consumption tax; and
- any condition that applies specifically to the licens ed business.

Schedule 3 (Section 5) also specifies that a government-imposed obligation shall be deemed to be material only if the annual incremental costs of savings to the Licensee that result amount to at least J$10 million adjusted annually for Jamaican inflation from the date of the Licence. At 2003 prices, this would amount to J$12.87 million.[26]

In the event that JPS' cost increases due to events that are outside of managerial control, such effects should be taken into consideration under the Z-factor. JPS proposes that a general materiality threshold be set for items that fall under the Z-factor. For consistency and using the Licence as guidance, JPS proposes that a *de minimis* threshold of J$13 million, adjusted for inflation be set. This figure is based on the threshold set in the Licence for government-imposed obligations of J$10 million adjusted for inflation.

There are two specific examples of items (this is not an exclusive list) that could affect JPS' costs but that are outside of managerial control. The first is the cost of insurance that may rise due to natural disasters or events such as acts of terrorism. JPS suggests that, in the event of such increases in costs, a Z-factor adjustment be allowed.

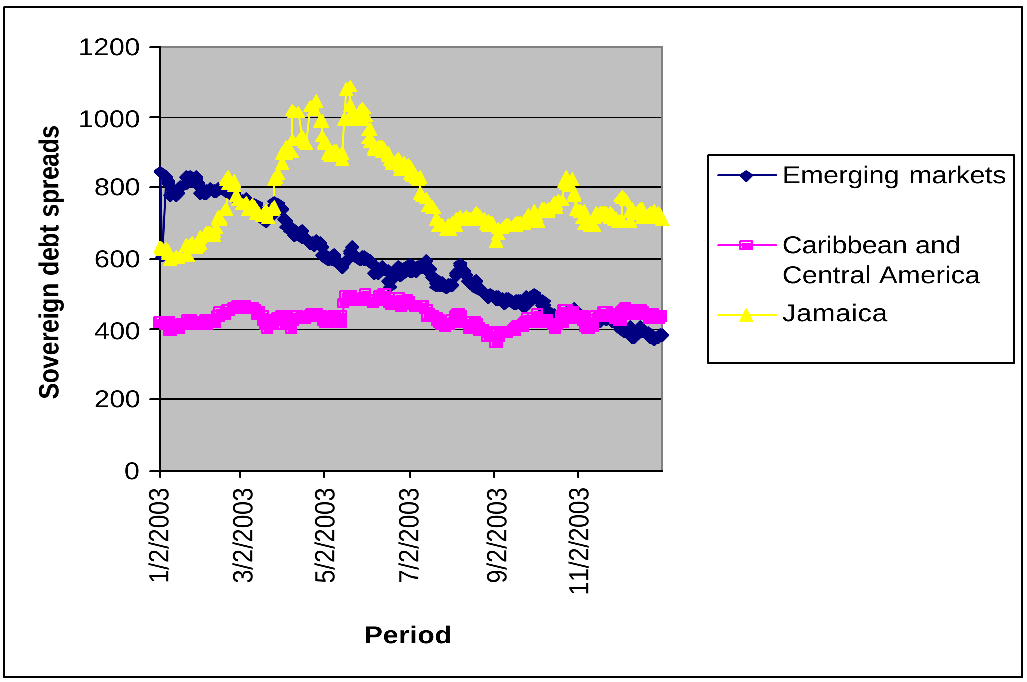
The cost of debt is a second example of items that would qualify under a Z-factor adjustment. In particular, JPS' cost of debt has a lower bound that is set by Jamaica's sovereign cost of debt. Jamaica's sovereign risk has increased over the past year, as evidenced by rating downgrades from S&P and Moody's, Jamaica's inability to access international capital markets at reasonable rates, and a still-high fiscal deficit and level of debt. Jamaica's sovereign risk outlook will depend upon the country's ability to

[26] This is derived by applying inflation rates of 7.7%, 5.8% and 13% for 2001, 2002 and 2003 respectively to the original amount of J$10 million.

aggressively reduce the fiscal deficit, control its debt burden while preserving social stability. This will prove a challenge. Jamaica is among the most heavily indebted countries in the world, at least amongst the rated sovereigns that have issued debt on the international capital markets. Debt ratios and the burden of debt service on the government's budget are at virtually unprecedented levels.

Due to the precarious debt situation, the government has very little room to use macroeconomic policy to stimulate the economy or to insulate the economy against adverse shocks that can arise unexpectedly. The country therefore remains vulnerable to external shocks. Hence, due to the lack of policy flexibility that stems from the high debt burden, macroeconomic and fiscal sustainability relies on an unstable equilibrium of a stable Jamaican dollar, economic growth, and falling interest rates. There is very little room for any deviation from stability in these variables. Any deviation can lead to severe outcomes for the economy and sovereign risk. Figure 9.1 below shows Jamaica's sovereign debt spreads in 2003 as well as those of other emerging markets and the Caribbean and Central America region.

Figure 9.1: Sovereign debt spreads of Jamaica and other regions (2003)



JPS faces risks with regard to its future cost of debt within the rate-cap period as US$130 million of loans are due for refinancing in 2006. If Jamaica's sovereign risk or global interest rates generally rise, these could lead to a material rise in JPS' costs in a manner that is outside managerial control.

JPS therefore proposes the following:

- If Jamaica's sovereign cost of debt—as measured by the estimated ten-year yield on Jamaican indexed bonds—changes; *and*

- JPS' cost of debt changes, upon refinancing, during the rate cap period; then

- JPS be allowed a Z-factor adjustment, provided that the weighted average cost of debt changes by more than 25 basis points and the materiality threshold of J$13 million (adjusted for inflation).

- The allowed adjustment can be capped by the extent of the change in the sovereign cost of debt. In other words, if JPS' interest rate on the refinanced portion of debt rises by less than the rise in sovereign cost of debt, *relative* to the sovereign cost of debt at time of submission - i.e., 11.02% - then JPS is allowed the full adjustment based on the change in its cost of debt.

  If, however, if JPS' interest rate on the refinanced loans rises by more than the rise in sovereign cost of debt, *relative* to the sovereign cost of debt at time of this submission, then JPS is allowed an adjustment that is calculated on the basis of the increase in the sovereign cost of debt.

  In the reverse scenario where the sovereign cost of debt falls, then the adjustment is again calculated based on a change in cost of debt that is no more than the change in the sovereign cost of debt.

For example, the current interest rate on one portion of the RBTT loan that is due for refinancing is 11.90%. The ten-year yield for Jamaica indexed bonds is estimated to be 11.02%. Assume that, in 2006, the ten-year yield for Jamaican indexed bonds is estimated to be 12.02%, i.e., a rise of 100bps. Then:

- If the loans are refinanced at a cost of 12.5%, this represents a change of 60bps (relative to 11.90%). Since the change is less than the change of the sovereign cost of debt of 100bps, the full cost impact of the change of 60bps will be passed through the Z-factor, provided that it leads to the weighted average cost of debt changing by more than 25bps and has cost implications of more than J$13 million (in 2004 prices).

- If, however, the loans are refinanced at a cost of 13.5%, this represents a change of 160bps. Since the change is *more* than the change of the sovereign cost of debt of 100bps, the only the cost impact of a change of 100bps will be passed through the Z-factor, provided that it leads to the weighted average cost of debt changing by more than 25bps and has cost implications of more than J$13 million (in 2004 prices).

Section 10: Inflation Adjustment Factor

The annual inflation adjustment clause is the mechanism through which JPS adjusts its non-fuel tariffs to reflect annual changes in the US and Jamaican consumer price indices. The procedure involves the application of an adjustment formula, dI to the base non-fuel tariffs to keep these tariffs constant in real terms. It is important therefore that dI accurately accounts for price movements to ensure cost reflective tariffs.

In reviewing the components of the current annual inflation adjustment formula, as contained in the Licence and the 2003 Rate Schedule, two observations were made:

- The formula in the Rate Schedule is a stylised equation, which overlooks an element of the expression. Consequently, successive application of the formula as it now exists to the rate base leads to under-recovery of revenues.

- The formula in the Licence is different from the formula in the Rate Schedule. The difference is caused by an omission of an exchange rate term, which seems to be typographical in nature.

- Neither formula accurately derives the correct inflation adjustment required.

The following details JPS' proposal for a modification of the annual inflation adjustment formula. The modification would adjust the versions of the current formula, as presented in the rate schedule and the Licence, so that it reflects the correct formula, as derived from first principles.

10.1 Derivation of the Annual Adjustment Formula

Under the current tariff structure it is assumed that 60% of JPS' non-fuel costs are foreign (US) related and 40% domestic related. In addition, part of JPS' non-fuel US related cost is debt-financing costs. It is assumed that these debt-financing costs are affected only by foreign exchange movements and not by US inflation. However, all other US related costs are affected by both US inflation and foreign exchange movements.

Accordingly, for the adjustment formula to accurately capture the impact of inflation on the rate base it should be formulated as follows:

Let,

$b_0 \equiv$ Base non-fuel tariff at time period t = 0

$b_1 \equiv$ Base non-fuel tariff at time period t = 1

$\Delta e \equiv$ Change in the Base Exchange rate

$i_{us} \equiv$ US inflation rate (as defined in the licence)

$i_j \equiv$ Jamaican inflation rate (as defined in the licence)

$f_{us} \equiv$ US factor = 0.6

$f_j \equiv$ Local (Jamaica) factor = 0.4

$d \equiv$ Debt factor = 0.4, where the debt factor, d accounts for portion of US related non-fuel cost that is accounted for by debt financing costs. Under the current licence, this is set at 40%.

Then, the base non-fuel rates at time 1 is given by:

$$b_1 = b_0 \left[d(1+\Delta e) f_{us} + (1-d)(1+\Delta e) f_{us} (1+i_{us}) + f_j (1+i_j) \right]$$

Equation 10.1

Equation 10.1 states that the debt portion of US related costs (d) are affected by exchange rate movements only, while all other US non-debt costs (1-d) are affected by both the exchange rate and US inflation. The final term accounts for the Jamaican inflation movement, which is applied to the local cost component. Equations 10.2 – 10.5 below outline in detail how the inflation adjustment formula is subsequently derived. Simplifying equation 10.1 gives:

$$b_1 = b_0 \left[(1+\Delta e) f_{us} \left[1 + (1-d) i_{us} \right] + f_j (1+i_j) \right]$$
$$b_1 = b_0 \left[(f_{us} + f_{us} \Delta e) \left[1 + (1-d) i_{us} \right] + (f_j + f_j i_j) \right]$$
$$b_1 = b_0 \left[f_{us} + f_{us} (1-d) i_{us} + f_{us} \Delta e + f_{us} \Delta e (1-d) i_{us} + f_j + f_j i_j \right]$$

Equation 10.2

Rearranging equation (10.2) gives:

$$b_1 = b_0 \left[(f_{us} + f_j) + f_{us} \Delta e + f_{us} \Delta e (1-d) i_{us} + f_{us} (1-d) i_{us} + f_j i_j \right]$$

Equation 10.3

Since $f_{us} + f_j = 1$, then

$$b_1 = b_0 \left[1 + f_{us} \Delta e \left(1 + (1-d) i_{us} \right) + f_{us} (1-d) i_{us} + f_j i_j \right] \qquad \text{Equation 10.4}$$

Therefore, if we let dI be the inflation adjustment formula, then the ABNF at time 1 is given by:

$$b_1 = b_0 \left[1 + dI \right] \qquad \text{Equation 10.5}$$

Where,

$$dI = f_{us} \Delta e \left(1 + (1-d) i_{us} \right) + f_{us} (1-d) i_{us} + f_j i_j$$
$$= \left[0.6 \Delta e (1 + 0.6 i_{us}) + 0.6^2 i_{us} + 0.4 i_j \right] \qquad \text{Equation 10.7}$$

$$= \left[0.6 \Delta e + 0.6^2 \Delta e i_{us} + 0.6^2 i_{us} + 0.4 i_j \right] \qquad \text{Equation 10.8}$$

Equation 10.8 gives the correct escalation factor, assuming that the US-related and domestic-related non-fuel costs account for 60% and 40% of total costs respectively (note that JPS proposes that this assumption be revisited, see Section 12). However, the Rate Schedule gives this factor as,

$$dI = \lfloor 0.6\Delta e(1 + 0.6 i_{us}) + 0.4 i_j \rfloor \quad \text{Equation 10.9}$$
$$= \lfloor 0.6\Delta e + 0.6^2 \Delta e i_{us} + 0.4 i_j \rfloor \quad \text{Equation 10.10}$$

Comparison of equations 10.8 and 10.10 reveal that the term $0.6^2 i_{us}$ is omitted from the Rate Schedule factor in equation 10.10.

Similarly, the Licence (Schedule 3, Exhibit 1) states that the annual inflation factor should be set as:

$$dI = \lfloor 0.6\Delta e + 0.6^2 i_{us} + 0.4 i_j \rfloor \quad \text{Equation 10.11}$$

which was derived by expanding equation 7 above. However, a typographical error was apparently made as Δe was omitted from the second term in equation 10.11 (compare equation 10.10 and 10.11).

10.2 JPS' Proposal

In light of the justifications provided above, JPS proposes two modifications to the annual inflation adjustment factor:

- First, JPS proposed that the inflation adjustment formula (dI) to be used with the 2004 tariffs, be changed to reflect the true inflation costs incurred on JPS. Therefore, any inflationary movements should be applied to the base non-fuel tariffs using:

  $$dI = f_{us}\Delta e(1 + (1 - d)i_{us}) + f_{us}(1 - d)i_{us} + f_j i_j \quad \text{Equation 10.6 (restated)}$$

  Additionally, subsequent reviews of Schedule 3 in the 2001 Electric Licence should include this amendment to the dI formula.

- Second, while the f_{us}, f_j and d components are currently assumed to be fixed, the actual cost structure (US-related cost relative to domestic costs) of JPS will vary depending, for example, on foreign exchange movements, even if the cost items remain unchanged. When the Jamaican dollar devalues relative to the US dollar, the proportion of US-related costs rises relative to domestic costs. In other words, fixed levels of f_{us}, f_j and d over the five-year period is not likely to reflect the correct cost proportions as the foreign exchange moves. JPS therefore proposes that these factors f_{us}, f_j and d be updated to reflect these movements.

Specifically, for 2004, JPS proposes setting f_{us}, f_j and d be set based on the audited accounts for the financial year 2003. As shown in Table 10.1, this would imply that f_{us} be revised to reflect a 76% US factor, with a corresponding change in the f_j factor to 24%. The debt factor d will also be revised to reflect 60% of the US non-fuel costs being debt related.[27] For 2005 onwards, JPS proposes that these figures be reviewed and reset accordingly, to reflect the current proportions of US- and domestic-related costs as well as debt-financing costs (See Section 12).

Table 10.1: Foreign and Local Cost Component for financial period ended December 2003[1]

	Actual Costs		US$ component of Actual Costs (J$ Equivalent)	
	J$000	% of Total Expense	%	J$000
TOTAL NON-FUEL EXPENSES	**18,365,676**	**59%**	**76%**	**13,949,690**
Purchased Power (non-fuel)	**3,477,385**	**11%**	**100%**	**3,477,385**
O&M Expenses	**6,189,680**	**20%**	**31%**	**1,925,465**
Sinking (self-insurance) fund contribution[2]	**126,000**	**0%**	**100%**	**126,000**
Debt Related Expense[3]	**8,572,611**	**28%**	**98%**	**8,420,841**
Depreciation	*1,960,574*	*6%*	*100%*	*1,960,574*
Interest on Customer Deposits	*151,770*	*0%*	*0%*	*-*
Net Financing costs[4]	*-262,731*	*-1%*	*100%*	*-262,731*
Return on Debt	*1,091,442*	*4%*	*100%*	*1,091,442*
Pre-Tax Return on Equity	*5,631,556*	*18%*	*100%*	*5,631,556*

Notes: [1]Figures are based on unaudited accounts, as on February 15th 2004. At time of submission of this report, audited accounts are not available. They will be available in March 2004; [2] Self-Insurance Fund Contribution taken from the Revenue Requirement for the Test Year Period (see Table 6.1). [3]Debt Related Expense captures those US costs that do not move with US inflation. [4]Net Financing Costs excludes Interest on long-term debt, which is captured in the WACC.

[27] Figures in Table 10.1 are based on unaudited accounts. At time of submission of this report, audited accounts are not available. They will be available in March 2004.

Section 11. Implementation of the Performance-Based Rate-Making Mechanism: the Global Price Cap

This section contains JPS' proposal on how the price adjustment factor, (1+ dPCI), should be applied. Two possibilities exist:

- a specific price cap—where each individual tariff is adjusted by (1+dPCI) annually; or
- a global price cap—where the adjustment factor (1+dPCI) is applied to a basket of tariffs. Within that basket, JPS would retain the flexibility of adjusting the individual tariffs to different degrees.

JPS proposes that a global instead of a specific price cap is applied. There are several advantages for having a global rather than a specific price cap:

- It is more flexible and easier to administer for JPS.
- Economic theory suggests that JPS is in the best position to set customer-specific cost-reflective and revenue-maximising tariffs. This point was also made in the report done by PPA/Frontier Economics on the commission of the OUR.
- JPS' current tariffs, like most electricity tariffs worldwide, reflect a cross-subsidisation between customer classes due to socio-political reasons. To apply the price adjustment factor to individual tariffs could imply a freeze on the pattern of cross-subsidisation over the five-year period.
- There are other sound public policy reasons for having a global price cap. Some economic literature shows that global caps create incentives for utility rates to converge over time to Ramsey prices.[28] This work supports the view that global caps can promote efficient relative prices for utility services.

Specifically, JPS proposes the following:

- the adjustment factor (1+ dPCI) be applied to the tariff basket. This is described in the following;

[28] This result has been demonstrated in various contexts; prominent examples include I. Vogelsang and J. Finsinger, "A Regulatory Adjustment Process for Optimal Pricing by Multiproduct Monopoly Firms", *Bell Journal of Economics*, 1979, 151-171; I. Bradley and C. Price, *op cit*; I. Vogelsang, "Price Cap Regulation of Telecommunications Services: A Long-Run Approach", *Deregulation and Diversification of Utilities*, 1988, Boston: Kluwer Academic Publishers, 21-42; T. Brennan, "Regulating by Capping Prices", *Journal of Regulatory Economics*, 1989, 133-147; and M. Armstrong and J. Vickers, "Welfare Effects of Price Discrimination by a Regulated Monopolist", *RAND Journal of Economics*, 1991, 571-580.

- any unused portion of the adjustment factor in any one year can be brought forward to the following year. For example, if $dPCI_{2005}$ were 10% in 2005 but JPS chose to increase tariffs such that the weighted average increase in the tariff basket were, say, only 7%. Then, in the following year 2006, if $dPCI_{2006}$ where 8%, then JPS is entitled to increase tariffs such that the weighted average increase in the tariff basket is up to 11% (8% plus the unused portion 3% from 2005); and

- JPS would submit its proposed tariff increases (within the price cap) to the OUR each year. The company would ensure that the level of tariffs conforms to agreed established policies (for example, to ensure protection of low income customers).

A tariff basket formula is a mechanism for weighting increases in individual tariffs imposed by the utility in question. The increase in each tariff is weighted by an associated quantity for each tariff element, normally the proportion of revenues associated with each tariff. This weighted average increase of this tariff basket must not exceed the price adjustment factor, (1+ dPCI).

Mathematically, a tariff basket price control can be implemented according to the following formulae:

$$\left(1+dPCI_t\right) \geq \frac{\sum_{i=1}^{n}\sum_{j=1}^{m} P_{ij}^{t+1} q_{ij}^{t}}{\sum_{i=1}^{n}\sum_{j=1}^{m} P_{ij}^{t} q_{ij}^{t}} \qquad \text{Equation 11.1}$$

where:

- P_{ij} stands for tariff *j* (e.g., customer, energy and demand charge in the case of JPS) of customer rate category *i* (e.g., RT 10, 20, 40 and 50). For example, in the customer charge for Rate 10, the Rate 10 category is referenced by the *i* subscript, and the customer charge by the *j* subscript;

- q_{ij} stands for the associated quantity for each tariff element (for example, the number of customers on Rate 10, the kWh consumption of those Rate 10 customers, etc);

- dPCI = dI – X – Q – Z; and

- Super- or subscript *t* refers to the year.

Equation (11.1) can be re-expressed as follows:

$$\left(1+dPCI_t\right) \geq \frac{\sum_{i=1}^{n}\sum_{j=1}^{m} P_{ij}^{t+1} q_{ij}^{t}}{R_t}$$

$$\left(1+dPCI_t\right) \geq \frac{\sum_{i=1}^{n}\sum_{j=1}^{m} \frac{P_{ij}^{t+1}}{P_{ij}^{t}}\left(q_{ij}^{t} P_{ij}^{t}\right)}{R^t}$$

$$\left(1+dPCI_t\right) \geq \frac{\sum_{i=1}^{n}\sum_{j=1}^{m} \frac{P_{ij}^{t+1}}{P_{ij}^{t}} r_{ij}^{t}}{R_t}$$

$$\left(1+dPCI_t\right) \geq \sum_{i=1}^{n}\sum_{j=1}^{m} s_{ij}^{t} \frac{P_{ij}^{t+1}}{P_{ij}^{t}} \qquad \text{Equation 11.2}$$

where:

r_{ij}^{t} = revenue associated with tariff j of customer rate category i in period t

s_{ij}^{t} = share of tariff j of customer rate category i in total revenue in period t = $\left(\frac{q_{ij}P_{ij}}{R}\right)^{t}$

R_t = total revenue in period t.

In words, this proposed formula is mathematically equivalent to a weighted average of price changes for tariff components, where weights are equal to each component's share of revenue in the *previou*s year.

The application of the price cap to a tariff basket, as characterised by Equation (11.2), would work as follows. On June 1, 2004, tariffs that have been approved by the OUR and based on the allowed revenue requirement submitted in the rate filing, would be implemented. These tariffs would include the customer, energy and demand charge for each of the customer categories. In Equation 11.2 these are denoted as P_{ij}. In the following year on June 1, 2005, the tariffs would be adjusted as follows.

- Step 1—The revenues recovered under each tariff for the financial year ending December 30, 2004 would be recorded. The proportion of total revenues accounted for by each tariff would be calculated. In the notation above, this would give us s_{ij}^{t}.

- Step 2—For each tariff, calculate the ratio between proposed new rate, P_{ij}^{t+1}, relative to the old rate, P_{ij}^{t}. In the notation above, this gives $\frac{P_{ij}^{t+1}}{P_{ij}^{t}}$.

- Step 3—Multiply each the ratio of the new to old rate of each tariff (calculated in step 2 above) with its corresponding proportion of total revenues, calculated in step 1 above. This gives the increase in each tariffs weighted by it proportion of revenues. In the notation above, this gives $s_{ij}^{t}\,\dfrac{P_{ij}^{t+1}}{P_{ij}^{t}}$.

- Step 4—Sum up the weighted increase of each tariff calculated in step 3. This gives the weighted average increase in each tariff across all customer rate categories, denoted by $\sum_{i=1}^{n}\sum_{j=1}^{m} s_{ij}^{t}\,\dfrac{P_{ij}^{t+1}}{P_{ij}^{t}}$.

- Step 5—This weighted average increase must not be greater than the price adjustment factor (1+dPCI).

Section 12: Foreign Exchange Adjustment Factor

JPS currently recovers its revenue through tariffs that are set on an assumed base exchange rate. This imposes a high currency risk as a significant share of JPS' costs is denominated in US currency. A foreign exchange adjustment factor is therefore applied to these base tariffs in billing customers, to offset any movement in the Jamaican currency relative to the US dollar.

The mechanism is outlined in the gazetted 2003 JPS Rates Schedule. It states that the foreign exchange adjustment formula is applied to the total base tariff (which includes fuel and IPP costs) for all customer classes, on a monthly basis, using the following adjustment mechanism.

$$Tariff_m = Tariff_b * \left[1 + 0.75 * \left(EXC_{m-1} - EXC_b\right) / EXC_b\right] \qquad \text{Equation 12.1}$$

where:

$Tariff_m$ = Adjusted tariff for the month

$Tariff_b$ = Unadjusted tariff for the month

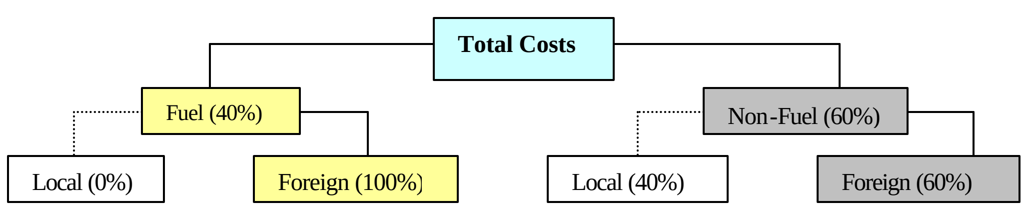
EXC_b = Base exchange rate for Jamaican Dollars into United States Dollars.

EXC_{m-1} = Billing Exchange Rate, defined as the daily weighted average for the last day of the month prior to the billing month

Equation 12.1 above shows a 75% foreign exchange adjustment factor. This implies that movements in the exchange rate will adjust the base tariffs by a factor of only 0.75. The formulation was set in the 2001 Rate Submission when, at the time, it was determined that approximately 75% of its costs were foreign related. (See Table A9.1 in the Appendix A9 for details).

Figure 12.1 below illustratively shows the (then) proportion of fuel and non-fuel local/US related costs.

Figure 12.1: US Component of Total Costs in 2000[29]:



[29] For the 2001 Tariff Submission, the actual cost for 2000 was used to derive the foreign exchange adjustment factor. See table A1 in the Appendix for details.

The foreign exchange adjustment factor was derived as a weighted average of the US component of fuel and non-fuel costs, i.e.:

Foreign exchange adjustment factor = (40% x 100%) + (60% x 60%) ≈ 75%

Analysis of the revenue stream since April 2001 has however revealed that the adjustment mechanism does not fully recover on foreign exchange movements. Specifically, the mechanism assumes that the cost structure of the JPS remains fixed in the proportion highlighted above and accordingly applies a 75% adjustment each month. This assumption, however, does not hold true for two reasons:

- The first is that fuel price volatility over the last two years has led to shifts in the proportion of fuel cost relative to non-fuel costs. As fuel costs are 100% US-dollar based, increases in the price of fuel would, all else equal, lead to an increase in JPS' US-dollar denominated costs as a proportion of total costs.

- Secondly, depreciation in the Jamaican dollar has led to an increase in the proportion of US$ related non-fuel costs relative to the local component.

Table 12.1 summarises the cost structure of JPS for the financial years ended December 2002 and December 2003. As can be seen, the weighted average of US$ related costs (non-fuel and fuel) increased to approximately 86% of total costs. Tables A9.1 – A9.5 in Appendix A9 outline in detail how these proportions were originally derived. It is important to note that even if the US related portion of non-fuel costs had remained at 60%, the weighted average would have increased due to rising fuel costs.

Table 12.1: Summary Analysis of Overseas and Local Costs

	Approved Allocations		**Financial Year ended Dec 2002**		**Period ended Dec 2003**[1]	
	% of Total	**% US Component of Actual**	**% of Total**	**% US Component of Actual**	**% of Total**	**% US Component of Actual**
Non-Fuel Expense (incl. IPP)	60%	60%	62%	76%	59%	76%
Fuel Expense (incl. IPP)	40%	100%	38%	100%	41%	100%
Total Expense	100%	**75%**	100%	**85%**	100%	**86%**

Note: [1]Figures are based on unaudited accounts, as on February 15th 2004. At time of submission of this report, audited accounts are not available. They will be available in March 2004.

In an attempt to correct the inherent limitations of the current mechanism while maintaining cost reflective tariffs, JPS proposes the following modifications to the foreign exchange adjustment mechanism:

- Separate fuel and non-fuel foreign exchange adjustment mechanisms, which involves:

  – Conversion of the fuel rates from US currency to Jamaican currency using the prevailing billing exchange rate; and

– Apply a foreign exchange adjustment formula to the **non-fuel** base tariffs only;

- Allowance for an annual review of the non-fuel adjustment factor to check the relative movements in JPS' domestic and foreign non-fuel costs.

The proposed changes are further described in subsections 12.1—12.4.

12.1 Separate recovery of total fuel costs (including costs incurred due to foreign exchange movements)

12.1.1 Current procedure

Fuel costs are currently treated as a direct pass through to customers each month. The rates applied to customers' bills however do not capture any movement in the exchange rate over the month as these rates are converted from US dollars to Jamaican dollar terms using a fixed base exchange rate.

Any foreign exchange movement above or below the base exchange rate is dealt with by applying the foreign exchange adjustment clause outlined in Section 1. By so doing, the JPS is assuming that the non-fuel to fuel ratio remains at the 60:40 level for that month and that the revenue from billing customers will capture 100% of fuel cost (and 60% of non-fuel costs).

12.1.2 Proposed procedure

With the implementation of the 2004 tariffs, the fuel rates should reflect the actual fuel costs for the particular month converted using the prevailing billing exchange rate instead of the fixed exchange rate as is currently done. There will consequently be no need to have a foreign exchange adjustment applied to fuel charges.

12.2 Separate non-fuel foreign exchange adjustment formula

JPS recommends that the fuel costs be removed from the derivation of the foreign exchange adjustment factor and that a factor be derived based solely on non-fuel costs. This foreign exchange adjustment will be treated as a separate line item on customers' bills as is currently done. The applicable factor for Equation 12.1 will however now be determined based on the cost items listed in Table 12.2 below. The cost figures in Table 12.2 are for the financial year ending December 2003, during which the US-related non-fuel costs accounted for 76% of total non-fuel costs. JPS proposes that for the first year of the 2004 tariffs, the proportion of US-related non-fuel costs be determined at 76%, based on actual proportions of US currency denominated cost and domestic currency-related costs in the financial year 2003, as indicated in Table 12.2. It should be noted that this ratio may not remain constant in subsequent years and so will no longer be assumed fixed. (see Section 12.3 below).

Table 12.2: Analysis of overseas and local non-fuel costs for the period ended December 2003[1]

	Actual Costs		US$ component of Actual Costs (J$ Equivalent)	
	J$000	% of Total Expense	%	J$000
TOTAL NON-FUEL EXPENSES	**18,365,676**	**59%**	**76%**	**13,949,690**
Purchased Power (non-fuel)	**3,477,385**	**11%**	**100%**	**3,477,385**
O&M Expenses	**6,189,680**	**20%**	**31%**	**1,925,465**
Payroll, Benefits & Training	3,476,293	11%	2%	69,526
Third party services	909,778	3%	35%	318,422
Materials & Equipment	432,635	1%	100%	432,635
Office & Other expenses	924,274	3%	80%	739,419
Insurance expense	384,697	1%	95%	365,462
Bad debt write-off	62,003	0%	0%	-
Other Expenses	**1,975,613**	**6%**	**92%**	**1,823,843**
Depreciation	1,960,574	6%	100%	1,960,574
Interest on Customer Deposits	151,770	0%	0%	-
Net Financing costs[2]	-262,731	-1%	100%	-262,731
Sinking (self-insurance) fund contribution[3]	126,000	0%	100%	126,000
Return on Rate Base (WACC)	**6,722,998**	**22%**	**100%**	**6,722,998**
Cost of Debt	1,091,442	4%	100%	1,091,442
Pre-Tax Return on Equity	5,631,556	18%	100%	5,631,556

Note: [1]Figures are based on unaudited accounts, as on February 15th 2004. At time of submission of this report, audited accounts are not available. They will be available in March 2004; [2]Net Financing Costs excludes Long Term Debt, which is captured in WACC; [3] Self-Insurance Fund Contribution taken from the Revenue Requirement for the Test Year Period (see Table 6.1)

12.3 Annual review and adjustment to the foreign exchange clause

In light of the potential exposure that foreign exchange movements imposes on the JPS, it is proposed that an annual cost review be done using the audited financial statements for the calendar year prior to the rate adjustment. This is to check the relative movements of non-fuel US$ denominated and local costs. JPS will accordingly modify its adjustment factor to reflect this change. To facilitate this, JPS could provide audited information to the OUR on the proportions of US- and domestic related costs, along with the audited financial statements.

12.4 Implications for annual Inflation adjustment

Any amendment to the adjustment factor would also have implications for the Annual Inflation Adjustment Formula (dI in the PBRM mechanism). Specifically, the inflation formula also incorporates the relative proportion of foreign and local non-fuel costs (currently assumed to be 60% and 40% respectively). Therefore, changes to these proportions will be reflected in the dI factor as well (see Section 11). This can be expected to reduce to annual inflation adjustments, as US inflation is currently significantly below the domestic (Jamaican) inflation.

Section 13: Fuel Cost Adjustment Factors: Heat Rate and System Losses

Schedule 2 ("Overall Standards") of the licence authorizes the OUR to specify a total system losses target for JPS. According to the Licence, total system losses is the difference between energy generated and energy for which revenue is received. Specifically, it is the total generation less sales, divided by total generation.

Further, 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 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)"

It is clear that the Licence contemplates that under the price cap tariff period commencing June 2004, total system losses and heat rate will remain discrete indices of JPS' efficiency in fuel cost management. These measures are in addition to the introduction of other productivity and service quality measures embodied in the "X" and "Q" factors. The Licence is however silent on the methodology to be applied in determining the target values for JPS or the terms and conditions of implementation of these efficiency measures. The treatment of the system losses target for calendar year 2003 from Schedule 2, implied that the Licence has ceded discretion to the OUR and JPS to agree on this process.

This section puts forward JPS' proposals for the determination of heat rate targets and total system losses for the price cap period 2004 - 2009.

13.1 Heat Rate Targets

13.1.1 Key Expectations

The objective of setting a heat rate target for JPS is to assure customers of least cost unavoidable fuel rates by providing an incentive for JPS to:

- improve its relative efficiency of converting chemical energy to electrical energy; and
- ensure the economic dispatch of all available generation sets.

JPS believes that the following principles should be applied in setting any heat rate target:

- 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 without unpredictable target changes. This is particularly important in the context of the price cap regulatory regime.

- 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.

13.1.2 JPS' Heat Rate Variables

JPS' heat rate performance over the five-year price cap period will depend on several factors:

- the economic dispatch of all generation units;
- the addition of new units; and
- the improvements made to existing units.

Each is discussed in the following sections.

Economic Dispatch

The economic dispatch of units refers to running only the most "efficient" units to meet the instantaneous demand. In this case the most 'efficient' units are those units that have the lowest variable operating costs. The factors affecting economic dispatch include the following:

- Reliability - i.e., making sure that units are up and running when needed;

- Transmission constraints - for reasons of system security, security-constrained economic dispatch is sometimes necessary under contingency situations, to serve the demand and keep the power quality within acceptable limits; and

- Spinning reserve - this is used to provide some level of security for the power system by allowing for spare capacity on the operating units at any instant. This spare capacity is used to offset any shortfall in online available capacity in the shortest possible time. Combustion turbines, and diesels have the capability to increase load significantly over short duration. In contrast, steam turbines take longer due to thermodynamic considerations. Run of river hydros operate at a MW output consistent with their available stream flow.

  The heat rate of most units is best at loading levels close to maximum loading and increases (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 utilization of combustion turbines in normal operating modes. The cost of fuel to these combustion turbines would also 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 employed therefore 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 combustion turbines 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. It is therefore crucial to ensure that the targets set for heat rates and Q are compatible so that maximum value redounds to the consumer.

New Generating Units

The introduction of new generating units to the system is dictated by several interrelated variables. The extent to which new generators affect the system heat rate depends on:

- the size of the new unit relative to the size of the existing system;
- the difference between the new unit’s heat rate and the system heat rate;
- the capacity factor or level of utilization of the new unit; and
- the time within which the new unit is added to the system.

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. As JPS’ system grows, any single new unit will have a lower impact on the total system heat rate.

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 system over the past years to effect operating improvements. The heat rate performance of these existing units represent the best levels that will be achievable even with this investment stream sustained over the next five years.

Greater levels of efficiency may be achievable with some design improvements but possibly with greater investment requirements. At present, no direct plans have been formulated to achieve any such design improvements. Given a target heat rate however, JPS feels that it should be given the latitude to decide the extent to which it invests in undertaking heat rate improvement through design improvement activities with the commensurate gains being treated as return on these investments.

13.2 JPS’ heat rate performance 2003

Prior to 2002, the heat rate target was set for JPS thermal units only (12,976 kJ/kWh) and represented a disadvantage to JPS as the system cost optimization process included the IPPs; sometimes to the detriment of the JPS heat rate performance. However, the target was changed in 2002 to 11,900 kJ/kWh with the inclusion of the IPPs and the hydro energy in the system heat rate calculation. The current heat rate target of 11,600 kJ/kWh was approved by the OUR effective April 1, 2003 on the same basis. Table 13.1 shows the actual system heat rate achieved for the years 1999 to 2003 versus the targets.

Table 13.1 System Annual Heat Rate (kJ/kWh): 1998 - 2003

Year	System heat rate	Target System Heat Rate
1999	12,872	12,976
2000	13,234	12,976
2001	13,384	12,976
2002	11,888	11,900
2003	11,554	11,600 *

* Target changed to 11,600 KJ/kWh in April 2003

As shown in Table 13.1, in 2003, JPS has outperformed the heat rate target. Going forward, however, JPS will face challenges in beating the 2003 performance. This is for the following reasons:

- JPS is likely to lose 6MW capacity from Jamalco; and
- Coupled with demand growth, this will reduce margins and cause JPS to utilize more of the less efficient units to meet demand. This will tend to reduce performance on heat rates.

13.3 Proposals for Heat Rate Targets 2004 - 2009

Based on the composition (present and planned) of the system's generation set and the projected availability and dispatch, JPS proposes the following heat rate targets:

- 11,500 kJ/kWh going forward from 2004; and
- 11,100 kJ/kWh when the generation expansion, as detailed in the LCEP, is fully implemented. This is expected to take place in 2007. However, in order to retain the right incentives, JPS proposes that the effective date of the new reduced target not be set now, but rather be dependent on the actual implementation date. This would ensure that JPS does not, for example, face the incentive to bring on the new plant even if sales growth and other factors suggest that the implementation should be delayed. Such a perverse incentive would be ultimately detrimental to the customer.

  Appendix A10 contains the supporting details of the forecasted generation mix over the period. The targets are based upon average historic performance of the generation units as well as estimated performance of future units that are expected to be commissioned over the five-year timeframe.

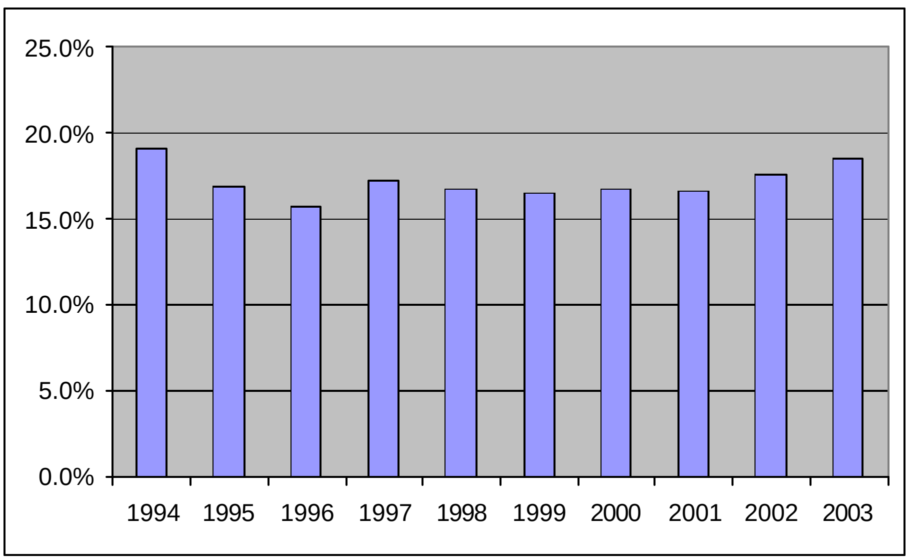
- While tariffs, as well as the "Q" and "X" factors will be set and known for the 5-year rate cap period, the indicative heat rate target should also be set and known at the outset, for the 5-year period.
- The heat rate target should continue to be a system heat rate target - as opposed to a JPS target - to encourage the correct dispatching of IPPs.

13.4 System Losses Target

In keeping with Schedule 2 (EOS6) of the Licence, the OUR and JPS agreed on a permissible system loss target at 15.8% of total net system generation from January 2003 to May 2004. Overall losses have remained stubbornly high over more than ten years, ranging from a high of 21.38% in 1992 to a low of 16.03% in 1996. Over the past 20 months, losses have risen relatively sharply, in spite of significant revenue protection/loss reduction efforts. The average system loss for 2002 was 17.2%. At year-end 2002 the figure was 17.8%. A marked increase in losses was seen during the latter half of 2002 that has continued well through 2003.

For the twelve months ending December 2003, total system losses approximated to 18.6%, a negative variance of 2.8 percentage points from target. This represents a consistent and growing negative variance since the target was established resulting in year-to-date revenue impairment of $259 million, due to the penalty incurred under the Rate Schedule restricting the full recovery of fuel revenue. The deterioration in losses is considered to be principally related to Jamaica's worsening economic climate over the past 12 months, particularly the decline in the value of the Jamaican Dollar and a significant increase in inflation. Figure 13.1 shows the trend in JPS' system losses between 1994 and 2003.

Figure 13.1: JPS System Losses 1994 - 2003



Total system losses can be categorized into the following three groups:

- Technical losses;
- Operational commercial losses; and
- Social commercial losses (theft).

The following documents the various initiatives JPS has undertaken to stem system losses and in particular commercial losses over the past five years:

13.4.1 Technical losses

There have been several ongoing initiatives aimed at trimming technical losses. Within the past five (5) years, seventeen (17) feeders were upgraded from 13.8 kV to 24 kV, simultaneously increasing feeder capacity while reducing technical losses by 0.80%. Service to a 15,000-kVA customer was upgraded to 69 kV from 24 kV, yielding a 0.38% loss reduction. Distribution transformers added to the system during the period have been of a low-loss design with some 3000 high-loss distribution transformers being replaced at failure by low-loss units over the period. Installation of a number of bulk capacitor banks within substations and feeder capacitors aimed at boosting voltage and reducing technical losses, was also implemented.

JPS' technical loss spectrum is presently disaggregated as shown in Table 13.2:

Table 13.2: JPS' technical loss spectrum

Generator Step Up Transformers	0.3%
Transmission Lines (138/69 kV)	1.5%
Substation Transformers	0.4%
Medium voltage Distribution (24/13.8 kV)	2.2%
Distribution Transformers	1.6%
Low Voltage Distribution	3.0%
Total	9.0%

13.4.2 Commercial losses

At 9.5% of net generation, commercial losses are comparable to that of a number of countries within the development strata in which Jamaica is ranked by the World Bank. In Ecuador, total system losses average 23%; in Mexico, the loss is 18%, approximately 9% technical and 9% commercial. Nevertheless, by the industry best standards to which JPS has been benchmarked, this level of losses is high.

The contributory factors to losses of this nature are many and complex. Jamaica's less than robust social and economic environment over the past two decades have fostered conditions conducive and encouraging to electricity theft. Simultaneously, weak state law enforcement and several deficiencies in JPS' business operations have created opportunities for such losses that have been increasingly exploited.

Contributory factors include:

- Social and economic factors:
  - Ten-year economic depression
  - High rate of unemployment
  - Generally high crime rate
  - Weak law enforcement
  - Relatively low penalty/fine for electricity theft
  - Garrison communities phenomenon

- Business Deficiencies
  - Past unavailability of meters resulting in direct connections
  - Collusion by field operatives (company and contractor)

- Weak internal controls over adjustments to accounts
- Deficient record keeping
- Weak audit procedures
- Improper accounts set-up

- Network access
  - Large stretches of un-insulated secondary network offering easy access
  - Unsealed Meters
  - Exposed, energised terminals when meters withdrawn from service.

For the vast majority of electric utilities, the commercial component of system losses is generally due to factors fully within the utility's control, for example:

- Polarity reversal of a current transformer (CT) in a three phase system during installation will result in only 30% of energy consumed being recorded on the customers' meter.

- Improper set up of accounts contribute to significant losses, e.g. a multiplier entered as 60 instead of 600, will result in an account being billed for only one-tenth the actual consumption.

- Potential transformers (PTs), CTs and meters, which become defective while in service are also major commercial loss contributors.

Within Jamaica, the largest components of commercial losses are due to factors not entirely within the utility's control.

An analysis of JPS' commercial loss profile yields the breakdown as shown in Table 13.3. Energy consumption by "throw-ups" is primarily based on a February 2001 survey of 12,850 illegal connections in nine inner city communities, which revealed average consumption of 189 kWh per month per connection. Inner city communities are estimated to account for approximately 50% of the 150,000 throw-ups scattered across Jamaica. These communities likely all consume similar levels of electrical energy as the communities surveyed. The balance of "throw-ups" are estimated to each consume a "life line" quantum of electricity energy, i.e. 100 kWh per month. Total annual energy consumption due to "throw-ups" is 260,100,000 kWh, i.e. 7.0% of net generation. Disaggregation into the remaining categories is based on statistical data arising from various audits.

Table 13.3: JPS' commercial loss spectrum

Cause	Losses
Operational commercial losses	
Defective equipment	1.7%[30]
Incorrect Installations	0.2%
Improper account set up	0.1%
Sub-total	2.0%
Social commercial losses	
Throw-ups	7.0%[31]
Other theft	0.5%
Subtotal	7.5%
Total	9.5%

In recent years JPS has pursued a "carrot and stick" strategy in its effort to control and reduce commercial losses. These initiatives have distilled to focus on three primary areas:

- Removal of illegal connections, throw ups and other direct connections;
- Tightening of internal controls (including audits of large accounts); and
- Conversion of illegal users to legitimate consumers.

More specifically, JPS' efforts to reduce commercial losses are summarized in the following.

- Removal of "throw-ups" - Wires thrown up and hooked onto JPS' open, low voltage, secondary conductors, remain the most visible, obvious and public manifestation of commercial losses. They are also the most prevalent form of electricity theft. In terms of individual energy use, however, this mode of electricity theft ranks a distant second to other more sophisticated versions of illicit abstraction, such as meter bypasses by commercial enterprises and large residential customers, in its impact on energy losses. Nevertheless, as can be seen from the analysis, throw-ups cumulatively account for the lion's share of commercial losses and JPS has historically placed great emphasis on this mode of electricity theft in its system loss reduction initiatives. Based on intelligence data, in most communities, throw-ups are restored not very long after being removed. In a limited number of communities, the restoration rate has been a low 50%.

[30] Defective equipment includes equipment that has failed as well as equipment that has been tampered with.

[31] Losses attributable to throw-ups based on average 189 kWh/month energy consumption for inner city communities and 100kWh/month life line energy consumption for others.

- Tightening of internal controls - One of the clear weaknesses identified in an early management audit consequent on the change of ownership of JPS was the porosity of its internal controls. This presented abundant potential for revenue leakage. Such leakage would be most readily obvious, verifiable and of greatest revenue impact in the large customer rate categories. Audit of these accounts was therefore considered an effective strategy for loss reduction.

- Community outreach - The third axis of JPS' strategy was a campaign to convert illegal consumers into customers. This it attempted to do through a community outreach programme working in conjunction with local political leaders. Inner-city communities, and in particular those identified as "garrison" communities, were offered assistance in regularizing their electricity supply in exchange for a minimum number of residents signing on. In an effort to reduce losses, recover some revenue from these consumers and transition to the normal applicable residential rates, a flat rate tariff was introduced in several communities. Data from 10 communities surveyed indicated an average monthly energy consumption of 189 kWh/illegal connections. However, the flat rate was set up assuming a monthly consumption of only 109 kWh/customer. While this effort succeeded in legitimising about 1,600 consumers, it has not been particularly successful, as only a handful of these consumers have consistently honoured their commitments. Given the extremely volatile nature of many of these communities, the normal enforcement mechanism (disconnection of delinquent accounts) cannot be routinely employed, thus weakening the "stick" element of the strategy.

JPS' commercial loss reduction efforts are summarized in Table 13.4.

Table 13.4: JPS' commercial loss reduction efforts 2003

RPD operations	No. of activities
Raids	250
Arrests	164
Throw-ups removed	34,260
Metered accounts investigated/corrected	10,061
Customer service investigations	
Meter inspections	42,027
Defects identified/corrected	17,211
Large account audits	
Accounts audited	1,734
Defects identified/corrected	848

Between January and December 2003, JPS' Revenue Protection Department (RPD) conducted 250 operations resulting in 164 arrests and the removal of 34,260 illegal connections (throw-ups). RPD also investigated 10,061 metered accounts and identified and corrected 3,214 irregularities. The large account audit team audited 1,734 accounts and identified 848 irregularities.

13.4.3 Future Initiatives

JPS' planned initiatives to reduce commercial losses include the following.

- Wiring initiatives - The domestic, lifeline rate makes electricity in Jamaica affordable to almost the entire population spectrum. A major impediment to affordability of the product, however, is the cost to wire and have the premises certified for connection of the electricity supply. JPS has an ongoing relationship with the Rural Electrification Programme Limited (REP) whereby REP requires rural households to pay 10% of the cost for basic house wiring following which the REP will wire the house. A house wiring loan account payable over three years, is set us for the individual as an integral part of the individual's electricity account. Funds collected by JPS under the loan account are remitted to REP. REP has recently been mandated to provide a similar service to urban, inner city communities. JPS plans to work closely with the REP in furtherance of this new mandate.

  Another significant impediment to affordability of the product has been the cost of extending power lines. A more customer friendly line extension policy has recently been put in place to help overcome this problem. Closer collaboration with REP has been initiated to ensure that the needs of consumers who do not meet JPS criteria but may meet REP criteria are addressed.

  In order to be responsive to those limited instances where extensions may satisfy neither JPS' or REP's criteria or where an individual is unable to afford the cost of basic house wiring, discussions will be initiated with the Government Electricity Inspector to allow medium term "temporary", metered accounts to be established at the terminal point of the JPS supply. Such accounts will not only be metered but will also be required to include a breaker/fused disconnect. Rather than resorting to stealing electricity, an individual could then run service from the metered location to the point of eventual use. Incorporation of a breaker/fused disconnect will also afford such individuals some degree of safety from electrical shock or fire.

- Audits - Audit of large (RT 50, RT40 and select RT20) accounts has recently been assigned to the audit department. Their mandate is to ensure all RT50 and RT40 accounts are audited within three months of being set up and annually thereafter. The purpose is to identify and correct record-keeping deficiencies (such as incorrect billing multipliers), meter defects, etc.

  Audit of RT20 accounts is to be accomplished every five years. Audits not only ensure meters accurately record energy consumed but also that correct potential and CT data are used for billing. These audits have already identified a number of issues that had not been previously noted.

- Meters - The meter-ordering process has improved therefore avoiding the need to direct connect customers. Improvement in the meter control process, particularly at customer service centres, is being implemented to minimise the risk of meters being withdrawn from stock and installed without proper authorisation. Particular attention is being given to the timely return of meters to the Meter Department after withdrawal from service.

  A large number of installed meters are unsealed. This condition has arisen because most disconnections are performed through contractors who have not previously been trusted with disconnection seals. The Customer Service Department has implemented the practice of issuing seals to contractors while ensuring such issues are strictly accounted for.

The Customer Service Department has also implemented a project to ensure all in service meters are resealed. A similar effort attempted some years back was not successful. At that time, withdrawal of each meter, inspection of meter socket internals for shunts and meter testing prior to reinstallation and resealing was required. The process proved extremely lengthy and the effort was aborted without being concluded. Conditions have deteriorated further since that effort.

While sealing of meters without inspection risks the possibility of some by-passes being 'legitimised' behind a company seal, leaving meters unsealed facilitates meter removal and reinstallation without detection with far greater potential for theft. The Customer Service Department will also more rigorously review field inspections and corrections to advancing meters reflecting significant (i.e., greater than 100 kWH) monthly consumption.

- Persistence and prosecution - While just less than half of the commercial loss component of system losses is due to the conditions mentioned earlier, the remainder is due to approximately 150,000 highly visible "throw-ups" providing service to structures primarily within informal, inner-city communities. Because of a perception of lack of consequences associated with this practice, the phenomenon has infiltrated into many formal middle-income communities. A much higher profile is now being given to the removal of the "throw-ups". Several of these raids have received coverage by both the electronic and print media. Arrest and imprisonment of persons responsible, are being pursued to remove the perception of lack of consequences. Additionally, in past times, areas were likely to escape being raided more than once a year. Individuals therefore restored "throw-ups" shortly after a raid with little chance of being disturbed for another year. The present focus is to not only arrest and prosecute individuals for theft, but also conduct repeated raids into areas to remove the feeling of comfort.

  Several individuals, including commercial customers, have already been arrested, convicted and fined under this new thrust. In some areas the "throw-up" phenomenon appears largely due to less than satisfactory socio-economic conditions. In others the problem appears to be primarily due to prevailing attitudes of lawlessness.

- Insulation of conductors - Insulated secondary conductors (duplex, triplex and quadruplex) are now used almost exclusively. A number of existing, open secondary circuits are also being rehabilitated using insulated conductors. At the same time secondary runs are being shortened (and the size of associated distribution transformers also reduced). The measures will make theft more difficult.

- Multi-sector initiatives - In addition to continued vigilance and enforcement of the measures outlined earlier, one of the primary strategies now being pursued by JPS is to forge a broader coalition of forces for a renewed thrust at reducing commercial losses. At the centre of this renewed effort is an acknowledgement that many of the factors driving the growth of commercial losses are outside the ability of JPS to control or significantly influence. JPS has therefore initiated a multi-sector, multi-prong approach canvassing support from the regulator, civic society, the political directorate, commerce and the media. Closer ties will be forged with law enforcement agencies to ensure adequate security protection is available to afford safe passage into and out of garrison communities to address theft problems.

Beyond the next few months, it is anticipated that the stigma associated with the risk of arrest, fines, imprisonment, etc., will cause individuals involved in more sophisticated means of illegal abstraction of electrical energy to desist. Progressive audits of more R20 installations and audits of select apartment complexes, comparing cumulative, billed energy consumption to consumption recorded by a temporary, master meter will aid in detecting concealed by-passes and yield further system loss reductions.

JPS' planned initiatives to control technical losses include the following:

- New distribution transformer additions will continue to be of low loss design. Transformers that fail will also be replaced by units of low loss design. Over a five (5) year period, fifteen thousand (15,000) new transformers, totalling 750,000 kVA, will be added to the system. Four thousand (4,000) replacement units, totalling 200,000 kVA will be installed over the same period. The distribution system will change from a mix of about 34% low loss/66% high loss transformers to 54% low loss/46% high loss transformers over the period. The contribution of distribution transformers to the technical loss spectrum should decline from 1.6% to 1.2%, with total technical loss also declining 0.4%.

- Voltage upgrade of select feeders will also be targeted to enhance load transferability/feeder capacity while at the same time reducing system losses. Six feeders have been targeted for upgrade during 2004. A further six feeders are targeted to be upgraded during the five year review period. These upgrades should reduce the technical loss spectrum by 0.4%.

- The feeder power factor target has recently been revised to 0.98 from 0.95. Improvement in feeder voltage profile, to be achieved by installation of capacitors distributed along feeders, will reduce technical losses. About 22,000 kVAR of new capacitors were installed during 2003. A similar capacity of defective banks were repaired and returned to service. A further 20,000 kVAR of new capacitors is earmarked for installation in 2004 with incremental additions in subsequent years to satisfy the new power factor target.

  Approximately 18,000 kVAR of substation capacitors will be relocated to corporate area substations, to be used on a contingency basis for voltage support when major generating units in the corporate area must be removed from service. This will also yield minor reduction in the technical loss spectrum.

13.5 Proposed System Loss Targets

JPS' proposals regarding system losses are based on the following:

- Technical losses - As noted above, about 9 percentage points of system loss is due to technical losses. This level of technical losses are not unreasonable in the context in which JPS operates.[32] Technical losses cannot be reduced via operational changes, but only through investment in new equipment such as transformers, conductor, insulators, etc. JPS would reduce technical losses by 1 percentage point if the OUR allowed for the recovery of these costs from the tariffs.

- Operational commercial losses - About 2.0 percentage points of system loss is due to 'operational commercial' losses. These losses can be reduced via operational improvements including meter-sealing, billing determinant audits, meter inspections, meter reader controls, internal controls, etc. Reduction of these operational commercial losses requires much labour and diligence, but small amounts of capital expense. JPS has the expertise, tools and systems to reduce this type of loss and will continue to aggressively pursue this type of loss. This loss spectrum can conceivably be reduced from its present level of 2.0% to about 1.0% notwithstanding prevailing economic conditions.

- Social commercial losses - About 6 percentage points of system loss is due to out-right and blatant theft of electricity by residential users with no metering system or approved house wiring system. Such losses are predominantly due to socio-economic factors that are largely outside of of JPS' influence. JPS believes that this type of losses can only be reduced via a combined partnership between Government, civil society and JPS. Reduction of these losses will require technical items such as proper/safe house wiring and meter, plus education, cultural change and enforcement. Reduction of these losses will not take place in a few years, but rather over a generation. In the short-term neither operational changes nor investment in new assets will reduce these type of losses. Persistent attention is, however, required to deter further expansion of the problem.

The target should adequately reflect the influence JPS can exercise towards reducing system losses. Specifically, while JPS is able to influence technical and some commercial losses, the most prevalent forms of commercial losses are beyond JPS' control. It would be unfair of the OUR to set target losses that penalize JPS in part for a loss that JPS cannot reduce on its own. A broader group of stakeholders, including the government and civil society must be involved in meeting the system loss target.

JPS therefore proposes that, over the five-year period, a target be set to reduce technical losses by 1 percentage point and 'operational commercial' losses by 1.0 percentage points. Therefore, the correct system loss target should, over the five-year period, be 8.0+1.0+7.5 = 16.5%. The proposed trend is summarized in Table 13.5.

[32] See PPA (2002), *OUR Electricity Tariff Study*, July; in association with Frontier Economics, page 20.

Table 13.5: Proposed System Losses Targets 2004 - 2009

Year	2004	2005	2006	2007	2008	2009
System Losses (%)	18.0	17.7	17.4	17.1	16.8	16.5

Section 14: Treatment of IPP costs

JPS has Independent Power Purchase (IPP) contracts with three private power generators—JPPC (60MW), JEP (74.1MW) and Jamalco (11MW).[33] The earliest of these contracts were agreed on in 1994 with JPPC and JEP. The contract with Jamalco followed in 2000. The then state-owned JPS entered into IPP arrangements in order to meet growing electricity demand through private investment. JPS at that point did not have the capital required to invest in generation capacity itself. All these IPP contracts were for 20 years effective from the commercial operation date.

The IPP charges incurred by JPS are intended to be fully recovered from customers. However, while the fuel cost of power purchased is passed through directly to the customers, the non-fuel costs are recovered through the tariffs. The tariffs in turn are set based on anticipated costs levels. In essence, apart from the inflation adjustment and forex adjustment the level of non-fuel costs that JPS can recover from customers are fixed.

Such a mechanism would allow tariffs to appropriately reflect IPP costs incurred by JPS, if such costs are relatively fixed and predictable. This, however, has proven not to be the case. The levels of some variable IPP cost components passed through to JPS have changed while the tariffs recovered by JPS have not been correspondingly adjusted. In sum, there is an incongruence between the IPP contracts to which JPS is obligated, and the manner in which the resulting costs are reflected in the tariff structure. As will be shown below, some costs have declined, while others have shown a net increase. Due to a fixed tariff, this is not correspondingly reflected in the tariffs.

JPS therefore proposes that the way IPP costs are treated in the tariff be modified so as to ensure that JPS is revenue-neutral with respect to these costs—any increases or decreases in charges will be passed on to consumers. This is particularly important as these costs are defined in contracts that JPS is obligated to fulfil; and that are fixed for a long period.

The following sections describe the charges that JPS incurs (Section 14.1); the divergence between the actual and budgeted IPP charges (Section 14.2); and set out JPS' proposal going forward (Section 14.3).

14.1 IPP Charges Incurred by JPS

[Text omitted. See note on page iii].

14.2 Divergence between IPP Fixed Payment Base Charges Incurred and Recovered

[Text omitted. See note on page iii].

[33] The contract with a fourth IPP, EAL/ERI, was terminated in December 2003.

14.3 JPS Proposal

The inconsistency between the structure of the inherited IPP contracts—under which several types of costs are passed through to JPS—and the way in which IPP costs are recovered through the tariffs, which are fixed in levels, means that JPS may not be revenue neutral with respect to IPP charges. Increases or decreases in these charges are not reflected in the tariffs. JPS therefore proposes the following method to ensure base cost pass-though and revenue-neutrality with respect to IPP contracts.

This method would be implemented as follows:

- Estimated base fixed non-fuel IPP costs would be embedded in the demand charge. These costs would be estimated based on the contracted levels of capacity.

- Estimated base variable non-fuel IPP costs would be embedded in the energy charge. These costs would be estimated based on the contracted levels of capacity.

- A computation would be done on a quarterly basis to determine whether the actual base charges deviate from the estimated base charges.

- The surplus or deficit is returned or recovered over the kWhs billed by way of a separate line item surcharge in the following quarter.

JPS proposes to pass through IPP costs calculated at base (contracted) capacity levels rather than actual dependable capacity for the following reason. If and when IPP capacity falls below contracted levels, direct IPP costs (i.e., payments to the IPPs) fall accordingly. However, JPS incurs other indirect costs, as a result of the fall in IPP capacity, over and above the costs taken into consideration in the revenue requirement for the test year period. These incremental costs are a result of the following factors:

- more frequent servicing required for the generation units, which are run harder to make up for the loss in IPP capacity;
- higher operating costs as units lower down the dispatch hierarchy are run;
- potentially poorer heat rate performance; and
- potential load shedding and the resultant loss in revenues as well as penalty under the Q-factor.

JPS believes that these incremental costs outweighs the liquidated damages that the IPPs are obliged to pay JPS, under the terms of the contract, when actual dependable capacity is below contracted level (see Appendix A11 for details on liquidated damages under the respective contracts.).

Part C: Tariff Design

Section 15: The Allocated Cost of Service Study

15.1 Purpose of an Allocated Cost-of-Service Studies

The Licence (Schedule 3, Section 2(B)) requires that JPS:

> "co-operates with *the Office* to conduct a cost of service study, the results of which will form the basis for rebalancing the tariffs in order to remove cross subsidies across rate classes."

The purpose of JPS' allocated cost-of-service study is to determine the cost to serve its individual customer rate classes, and to show the rate of return on investment and equity JPS is currently earning from each rate class for the services rendered. This is accomplished by separating the revenues, investments, and expenses of the Company between the rate classes of the customers to which it provides electric service, based on an analysis of the causative nature of the costs incurred for the service provided. Cost of service studies are required because utilities, such as JPS, maintain their books and records in accordance with conventional accounting systems that do not separate accounts between the customer's individual rate classes. From an analysis of these accounts, it is possible to prepare a cost-of-service study that reflects the Company's overall earnings from the electric service it provides. However, since the books and records of the Company only reflect investment, certain revenues, and expenses at the total company level, an allocated cost-of-service study is required to separate these costs between the customer rate classes.

While certain costs are readily identifiable to a particular customer or customer class, many parts of an electric system are planned, designed, constructed, operated and maintained jointly to serve all customers. Costs incurred to serve all customers are referred to as joint or common cost and must be allocated to the customer rate classes based on the type or classes of customers, their load characteristics, their number, and various other implied customer-related investment and expense relationships.

15.2 Principles of a Cost-of-Service Study

In performing an allocated cost of service study, the overall objective is to allocate costs fairly and equitably to all customers. This objective is accomplished when the resulting allocated cost of service study reflects "cost causation". Cost causation is the fundamental and essential principle underlying the development of any cost-of-service study. Cost causation addresses the question as to which customers or groups of customers caused the Company to incur a particular type of cost, i.e., it establishes a linkage between a utility's customers and the particular costs incurred by the utility in serving those customers. Cost causation focuses upon the selection and development of an allocation methodology that recognizes the relationships between customer requirements, load profiles and usage characteristics on the one hand and the costs incurred by the Company in serving those requirements on the other.

Cost causation becomes intuitively obvious when a specific cost can be directly linked and specifically assigned to an individual customer, as in the case of plant and facilities related to the street lighting rate class (Rate 60). However, since most of JPS' costs are joint or common costs, and have been incurred to serve all customers, there are few opportunities to specifically assign costs. Consequently, joint or common costs must be allocated, and that allocation process must incorporate the concept of "cost causation if the results of the allocated cost-of-service study are to reflect the Company's cost of providing service in a manner that is fair and equitable to all customer rate classes.

15.3 Steps Required to Develop JPS' 2003 Allocated Cost-of-Service Study

Typically, there are three fundamental steps required to develop a cost-of-service study of any type. These are:

- functionalization;
- classification and
- allocation.

15.3.1 Functionalization

This first step separates the investment and expenses of the Company into specific categories based upon utility operations involved in providing electric service. For JPS, the functional investment categories associated with providing electric service are production, transmission, distribution, and general plant. The functional expense categories include production, transmission, distribution, customer services, and administrative and general expenses.

15.3.2 Classification

The second step, classification, identifies the "cost causative" characteristics of the investment and expenses within each function. Typically, these "cost causative" characteristics are:

- *Energy-related*—those costs that vary with the customers' energy consumption; this generally refers to costs incurred by the utility that vary with the megawatt-hours (MWh) of energy consumed by the customer.

- *Demand-related*—those costs that are incurred as a consequence of the loads imposed on the system by all customers; this generally refers to costs incurred by the utility in order to provide the capacity necessary to serve the customers' maximum load throughout the year.

- *Customer-related*—those costs that vary with the number of customers; this generally refers to costs incurred by the utility just to connect a customer to the distribution system, and for customer metering, customer billing and administrative costs.

15.3.3 Allocation

The third and final step is the allocation of costs that have been functionalised and classified as previously described.

- *Energy costs*—energy costs are associated exclusively with fuel costs and the variable operations and maintenance expenses related to the production function. These costs are allocated based on the annual MWh consumed by the customers in the various rate classes, adjusted for losses.

- *Demand costs*—demand costs are associated with the production, transmission and distribution functions. Demand costs at each respective service level are allocated based on the MW demand imposed by the customers in the various rate classes, adjusted for losses.

- *Customer costs*—customer costs are associated with the customer component of certain distribution facilities along with the costs associated with the customer service function. The customer component of distribution facilities is that portion of costs that vary with the number of customers. Thus, the number of poles, conductors, transformers, service drops and meters are directly related to the number of customers on the JPS system. Customer service costs are also associated with meter reading, customer accounting, collections, uncollectable expenses, etc. Customer costs are analysed on an account-by-account basis to determine the rate classes that cause these costs to be incurred.

The functionalization, classification and allocation steps are necessary and essential to the preparation of any cost-of-service study, and the process is fundamentally the same whether analysing gross plant, accumulated provisions for depreciation, materials and supplies, other rate base items, revenues, operation and maintenance expenses, depreciation expenses, taxes, etc. Items that can be specifically identified with a particular customer class are so assigned, as in the case of rate revenues. All other costs are of a joint use nature and must be functionalized and classified in order to insure that the final allocation of costs reflect "cost causation."

As a practical matter, in many instances one cost will be directly related to another and allocated accordingly. One example of this type of cause and effect relationship is that which exists between gross plant, accumulated provisions for depreciation and depreciation expense. Both accumulated provisions for depreciation and depreciation expense occur as a function of gross plant. Therefore, however a given gross plant account is allocated, the corresponding amounts of accumulated provisions for depreciation and depreciation expenses are allocated accordingly.

15.4 Summary of Results of JPS Allocated Cost-of-Service Study

The complete allocated cost-of-service study, including the results summarized in Table 15.1 below, are contained in Volume IV of this submission. Also included in Volume IV is the development of the 2003 revenue required from each rate class in order for the Company to earn a fair rate of return for the services it provides to each rate class. This analysis also quantifies the corresponding demand, energy, customer and fuel charges that would be required for each class's rate to be fully justified and cost based.

Table 15.1 shows the return on rate base and return on equity for JPS under present rates, based on the financial year ended December 31, 2003. As shown in Table 15.1, the total return on rate base for the Company is 9.36%. The rate of return on equity is 8.64%. Table 15.1 also shows the return on rate base and equity of each customer rate class.

Table 15.1: JPS rate of return by rate class (financial year ending December 31, 2003)[1]

(J$'000)	Total electric system	Residential	General	Power service (Rate 40)				Large power			Street lighting
		Rate 10	Rate 20	40A	40LV	40MV	Total	50LV	50MV	Total	Rate 60
Total rate base	33,502,940	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Total revenues	26,463,096	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Total operating expenses	24,632,589	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Operating income before income taxes	1,830,507	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Total income taxes	38,329	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Net income from operations	1,792,178	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Total other income	1,343,287	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Total net income	3,135,465	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Return on rate base	9.36%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]
Return on equity	8.64%	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]	[✂]

Note: [1]Figures are based on unaudited accounts, as on February 15th 2004. At time of submission of this report, audited accounts are not available. They will be available in March 2004.

Section 16: Tariff Design Proposals

This section discusses principles and methodologies in tariff design and puts forward JPS' proposed non-fuel tariffs for 2004. Currently, JPS has five standard rate classes:

- Rate 10 (residential service).
- Rate 20 (general service).
- Rate 40 (power service)—of which there are three subcategories:
  - Rate 40A;
  - Rate 40LV;
  - Rate 40MV.
- Rate 50 (large power service)— of which there are two subcategories:
  - Rate 50LV;
  - Rate 50MV.
- Rate 60 (street lighting).

Customers in all rate classes incur the following charges:

- *Customer charge*—designed to recover investment and expenses incurred by the utility based on the number of customers served, independent of load;
- *Demand charge*—designed to recover investment and expenses incurred by the utility to provide readiness to serve expected load;
- *Energy charge*—designed to recover non-fuel costs that vary with the number of kWh supplied to the customer.
- *Fuel charge*—designed to recover the total cost of fuel which varies with cost of fuel and the number of kWh supplied to the customer

However, for Rates 10, 20 and 60, the demand charge is effectively rolled into the energy charge. These customers therefore incur only two categories of non-fuel charges—the customer and energy charges.

In addition, the JPS offers special non-fuel tariffs to specific customer groups as outlined below:

- *Lifeline rates*—JPS has a universal lifeline tariff structure within the rate 10 category, which allows all residential customers to get reduced energy charge for the first 100 kWh of electricity consumed, regardless of total consumption. This procedure was done to facilitate low-income earners who typically consume below this threshold level of 100 kWh. Only the energy charge is discounted for the "lifeline" customer. That is, the customer charge and fuel charge is the same regardless of total consumption for the month. (See details in Section 16.2)
- *Time of Use rates*—These rates are an optional rate classification and are applicable to Rates 40 and 50 customers only. Time of Use (TOU) rates are designed to reflect the fact that JPS' cost to provide electricity to consumers varies

according to the time of the day the electricity is produced. At the peak time, for instance, JPS incurs its highest costs since it is during this time that peaking plants, which operate at higher cost than the base load plants, are brought onto the system. Conversely, the company's cost is at its lowest during the "off-peak" hours when only the base load plants are in operation. A customer under this TOU option will have to demonstrate proper load management to effectively see savings on its bills relative to the standard (flat) rate option. (See details in Section 16.4).

- *Standby rates*—These rates were designed for those companies who own and operate generating equipment capable of meeting its own power requirement. These companies may at times find it necessary to take power from the JPS when their demand exceeds their supply, including times of either planned or forced outages at their generating plant. (See details in Section 16.3).

The current charges in each rate class (as taken from the gazetted Rates Schedule 2003) are summarized below in Table 16.1.

Table 16.1 Current Non Fuel Rates Summary

Rate Category		Customer Charge J$ per month	Energy Charge J$ per kWh	DEMAND CHARGE J$ per kVA per Month			
				STANDARD	OFF-PEAK	PARTIAL-PEAK	ON-PEAK
10	RESIDENTIAL First 100 kWH Over 100 kWh	 58 58	 4.102 5.795				
20	GENERAL	552	4.350				
40A LV	POWER Low Voltage	1,642	2.625	282			
40 LV	POWER Low Voltage	1,642	0.642	706	29	304	373
40 MV	POWER Medium Voltage	1,642	0.597	695	29	299	367
50LV	LARGE POWER Low Voltage	2,124	0.483	820	34	350	436
50 MV	LARGE POWER Medium Voltage	2,124	0.467	803	34	345	425
60	STREETLIGHT	413	6.160				
60	METER CIRCUITS	413	4.147				

The remainder of this section presents the following:

- JPS' proposed rationalization of rate classes (Section 16.1);
- JPS proposals on special tariffs, in particular, the lifeline rates, standby tariffs, TOU option and TOU rates (Section 16.2—16.5);
- JPS proposed revision of assumptions on the calculation of street lighting bills (Section 16.6);
- JPS proposed methodology for setting and realigning tariffs towards cost-reflectiveness (Section 16.7); and
- design of the customer charge (Section 16.8).

16.1 Rate class rationalization

Customers are categorized into different rate classes on the basis of their demand profile and the voltage level at which they are connected to the JPS system. This is done against the background that customers with similar demand and voltage characteristics impose a similar cost on JPS and as such should bear the same charges. Additionally, amongst non-residential customers, the load demand profiles of the Rate 40LV and Rate 50 LV customers (Standard and TOU) are very similar; as are those of the Rate 40MV and Rate 50MV.

JPS therefore proposes to combine:

- Rate 40LV Standard and Rate 50LV Standard customers into a single LV Standard grouping;
- Rate 40LV TOU and Rate 50LV TOU customers into a single LV TOU grouping;
- Rate 40MV Standard and Rate 50MV Standard customers into a single MV Standard grouping;
- Rate 40MV TOU and Rate 50MV TOU customers into a single MV TOU grouping;

The proposed structure would eliminate the need for low and medium voltage sub-groupings rendering a simpler arrangement.

It should be noted that this proposal was also made by PPA/Frontier[34], with the exception that they recommended the inclusion of the Rate 20 class into the Rate 40LV and Rate 50LV grouping as well.[35] JPS, however, takes the view that the Rate 20 should be kept separately. This is because to initiate the new structure would require the replacement of a large number of meters (about 40,000 meters at an average of US$425/meter) in this category to facilitate the recording of demand. Although this would be a one-time operation it represents a demanding administrative exercise. Secondly, the load for the majority of the customers in this category is minimal and therefore the benefits of measuring individual customer demand is likely to be outweighed by the high cost of meter replacement.

Table 16.2 below summarizes the results of the rate class rationalization proposals outlined above. The analysis was done using the 2002 billing determinants with the 2003 gazetted non-fuel tariffs. A class that sees a decrease will, on average, see lower rates when combined with another rate class. This leads to an average decrease in revenue

[34] See PPA (2002) op. cit.

[35] Consultative Document done by Power Planning Associates Ltd and Frontier Economics for the Office of Utilities Regulation, *Electricity Tariff Study: Final Report*, July 2002

recovered from that class. The converse occurs if a class experiences an increase. It is important to note however that the analysis does not examine the impact on individual customers, but instead focuses on the class totals.

- Alternate Rate 1: Combination of Rate 40 LV Standard / Rate 50 LV Standard;
- Alternate Rate 2: Combination of Rate 40 LV TOU / Rate 50 LV TOU;
- Alternate Rate 3: Combination of Rate 40 MV Standard / Rate 50 MV Standard; and
- Alternate Rate 4: Combination of Rate 40 MV TOU / Rate 50 MV TOU.

Table 16.2: Average Impact of Combining the Rate Classes

Current Rate Class	Alternate Rate 1	Alternate Rate 2	Alternate Rate 3	Alternate Rate 4
Rate 40 LV Standard	1.3%			
Rate 40 LV TOU		1.2%		
Rate 40 MV Standard			6.8%	
Rate 40 MV TOU				8.2%
Rate 50 LV Standard	-6.1%			
Rate 50 LV TOU		-4.9%		
Rate 50 MV Standard			-1.6%	
Rate 50 MV TOU				-0.5%

Note: These results are derived using 2002 billing determinants with the 2003 gazetted non-fuel tariffs.

The Rate 40A category was designed in 2001 as a temporary rate class to facilitate those Rate 40 LV customers with poor load factors who would have realized substantial rate shock if kept in the Rate 40LV class. The intent was that the rate class would have been phased out within the three-year period as these customers made their operations more efficient. However, at the end of the three years, there has still been little change in the performance of these customers and so, any attempt to incorporate all 40A customers within a normal rate category would, on the average, result in severe rate shock. As a result, the 40A class will remain as a specialised rate category.

16.2 Lifeline rates

It is common for utilities to include, in their rate design, a special rate that subsidizes low-income users. JPS achieves this through its lifeline rate. This rate may be described as a universal lifeline rate in the sense that all residential customers up to a certain consumption point (100 kWh) benefits from the subsidy. In addition, it is an intra-class subsidy because above the subsidy ceiling (100 kWh) residential customers progressively pay the subsidy of the lifeline rate.

In assessing the effectiveness of lifeline rates two issues are key:

- *Are low-income consumers benefiting from the subsidy?* — Fundamental to the universal lifeline scheme is the assumption that low-income consumers and low-consumption consumers of electricity are one and the same. However, while the assumption may hold in many cases it is not always true. Some low-income users are not low electricity consumers. For instance, a poor household with a large family might consume more electricity than a high-income household with a small family. On the other hand, some low users of electricity are not low-income consumers – an affluent consumer with a holiday cottage, that's only used in the summer. The typical bill for the cottage would be at the lifeline rate even though the consumer clearly belongs to a high-income group. It is evident that the existing scheme has the weakness of not being able to specifically identify and target true low-income users.

Another drawback to the universal lifeline scheme is that it comes with considerable cost to other consumers. This approach to subsidisation is referred to as a restricted lifeline scheme and it results in a lower mark-up on rates since the subsidy is more targeted than it is under the universal scheme.

However, despite all its shortcomings the universal lifeline has the advantage of being administratively easier to handle and present less of a public relation challenge when it comes to dealing with crossover increases between the subsidized and the non-subsidized rates. Tariff consultants, PPA/Frontier, in their *Jamaica Office of Utilities Regulation Electricity Study 2002* after examining the restricted and universal mechanisms recommended that the present scheme of subsidising all consumers below the lifeline ceiling be maintained.[36]

- *Is the level of subsidisation adequate?* —On the matter of the appropriate level of subsidization, PPA/FE examined this issue drawing on the Jamaica Survey of Living Condition 2000. In the end they concluded that the lifeline ceiling should be somewhere between 64 and 111 kWh and as such the 100 kWh level at which its now at is about correct.

The JPS therefore proposes that the present lifeline mechanism and ceiling be maintained in the 2004 rate structure.

16.3 Standby tariffs

The standby tariff was designed for those companies who own and operate generating equipment capable of meeting its own power requirement. These companies may at times find it necessary to take power from the JPS when their demand exceeds their supply, including times of either planned or forced outages at their generating plant.

Whenever power is taken from JPS, the standby customer is billed according to voltage classification, using the applicable customer charge, energy charge and the time-of-use rates for demand and fuel. However, for those months during which the customer generates its own power, JPS bills it a reserve capacity demand charge and a customer charge only. This reserve capacity charge is a fixed monthly charge that is applied to the contracted demand or the maximum demand in the customer's monthly consumption

[36] See PPA (2002) op. cit.

whichever is higher. This serves to compensate JPS for the cost incurred in ensuring that there is sufficient capacity, in the event that the standby customer takes up the service.

The derivation of the standby tariff is predicated on the probability of a cogeneration or self-generation outage (a Utilization Factor). Specifically, the reserve capacity charge is computed by finding the product of the average peak demand for Rate 50 (LV/MV), the coincidence factor and the utilization factor.[37] The PPA/Frontier[38] study made brief mention of this tariff class and outlined a similar standby tariff proposal. In light of this, the JPS' suggests that the procedure outlined above be maintained for the 2004 tariff submission.

16.4 Time of Use (TOU) option

Regardless of the overall load factor, the system peak is what determines the level of capacity that JPS needs to serve its customers. It is the fixed cost associated with this system capacity that is captured in the demand charge. Therefore, it seems only reasonable that the charge arising from demand during the system peak should be higher than those applicable at other times.

Fuel costs per kWh also vary, depending on the type of plants used in production. In the generation process, plants with the lowest variable cost (base load) are loaded on first and those with highest variable cost (peaking plants) are reserved for peak load hour. Consequently, fuel cost per kWh generated during the off-peak is lower than it is during the peak. As a result, price signals differentiating the time of day that service is used is often reflected in the demand charge and fuel rates.

PPA/Frontier suggested that TOU rates should be offered to all consumers.[39] They noted that meter costs will typically outweigh TOU benefits for a residential customer, but if the customer agrees to pay increased meter cost, they should have the option of obtaining TOU rates. Although ideal from the perspective of price signalling there are certain challenges associated with universal TOU rates:

- TOU metering costs are significantly higher than energy metering cost and if the meter cost is passed on to a residential customer it is very high relative their monthly usage.

- Residential customers who are the bulk of the utility's consumers prefer simpler bills to the more complex TOU representations.

Against this background, JPS recommends against the offering of TOU rates for either its residential (RT10) or small commercial (RT20) customers. Admittedly, a more complex

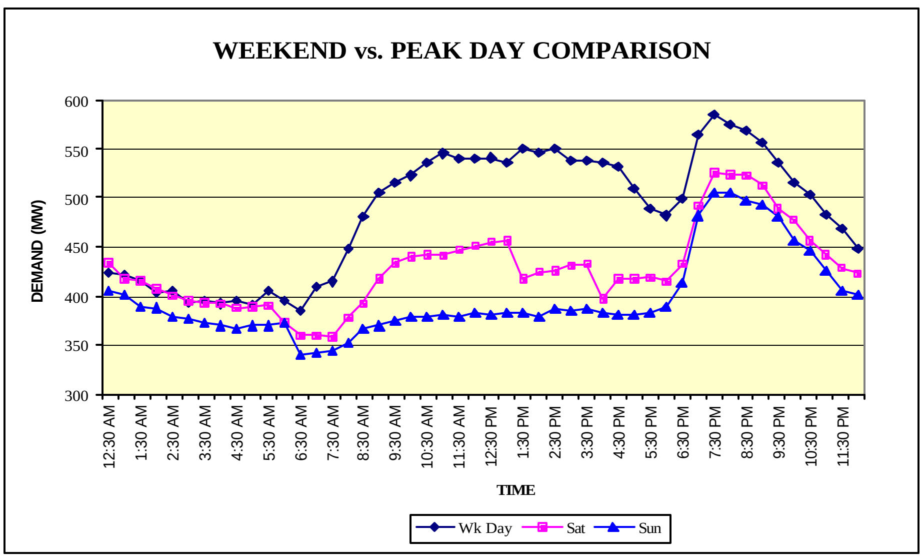
[37] The coincident factor is the probability of outage occurring during system peak.
[38] See PPA (2002) op. cit.
[39] See PPA (2002) op. cit.

bill should not cause too much of a problem to RT20 customers, but given relative low level of demand and the expected low acceptance of costs to change meters, JPS proposes to maintain the current rate structure for Rate classes 10 and 20.

With respect to the large commercial and industrial groups (RT40 and RT50), JPS also recommends that the current arrangement of a standard rate with optional TOU rates be kept intact. The reason for this is that converting all standard customers to TOU customers presents a revenue recovery risk, since detailed billing data on demand patterns during the TOU periods is not available from the existing standard meters. What, however, is important is that consumers who identify an opportunity to derive costs savings are free to move to the optional TOU rates.

JPS also recommends that the present arrangement with off-peak rates over the entire weekends and public holidays should be changed to partial-peak between 6:00pm and 10:00 pm and off-peak at all other times. The historical trend has shown a significant growth in weekend demand during the 6:00pm – 10:00 pm period, which makes it more consistent with the partial-peak classification than with the present off-peak categorisation (see Figure 16.1).

Figure 16.1: Comparison of Load Pattern on a typical Weekend versus the Peak Day



16.5 Modifying the Time of Use (TOU) rates

Under the existing structure, all customers who take up the TOU option will be billed under TOU rates for demand and fuel, based on the time of day electricity is consumed. There are currently three TOU periods used for billing:

- On-peak period: Monday – Friday 6:00 pm to 10:00 pm;
- Partial-peak period: Monday – Friday 6:00 am to 6:00 pm; and
- Off-peak period: Monday – Friday 10:00 pm to 6:00 am; Weekends and Public Holidays.

The TOU rates are derived from the standard rates according to the loss of load probabilities, which vary according to the time of day. The loss of load probability associated with the on-peak period is the highest of the three periods, due to the increased likelihood of load shedding during this period. This is also the period in which JPS bears its highest generating costs. Consequently, the peak period has the highest TOU rates relative to the partial- and off-peak periods.

Another feature of the current TOU design is that the billing demands for the on-peak and partial-peak periods are not ratcheted, but set as the maximum registered demand for the respective on-peak and partial-peak hours of that month. The billing demand for the off-peak is however set as:

- the maximum demand for the month (regardless of the time of day it was registered in), or
- 80% of the highest maximum demand during the six-month period ending with the month for which the bill is rendered, whichever is higher.

That is, the off-peak period is the only time of day period for which the demand is set as the global maximum and for which the demand is ratcheted.

The JPS proposes to modify the current TOU rate design in the following ways:

16.5.1 Modification of demand ratchet and partial peak billing demand

JPS proposes that the billing demand in the partial-peak be ratcheted according to the following definitions:

The on-peak billing demand will remain unchanged.

- The partial-peak billing demand will be set as the maximum registered demand for the combined <u>partial-peak and the on-peak</u> hours of that month, or 80% of the highest maximum demand for the <u>partial and the on-peak</u> hours during the six-month period ending with the month for which the bill is rendered, whichever is higher.

- The off-peak billing demand will remain unchanged.

The rationale for redefining the partial-peak billing demands is to provide an additional incentive for customers to shift their load to the off-peak period. The current design is incomplete in this regard as a customer can realize savings without effective load management once they move from standard to TOU option.

16.5.2 Increase in on-peak rates to encourage improvement in load profile

JPS proposes to increase the on-peak rates by 5% more than that implied by the loss of load probabilities. The TOU rates will therefore no longer sum to the standard rate and would further encourage the shifting of load from the peak- to partial- or off-peak period.

The modifications to the current TOU rate listed in Sections 16.5.1 and 16.5.2 above will result in additional revenues from current TOU customers. The majority of these revenues will come from customers who have significant demands in the part-peak and on-peak time periods. This is appropriate because these customers were getting an undue break due to the weakness in the previous rate design. The vast majority of these customers will still be paying less on this modified TOU rate than they would on the standard rate. Customers who have a majority of their usage in the off-peak period will be largely unaffected by these changes and will still receive significant rewards for consuming in the off-peak period. These rate modifications will also help to ensure that future migration to the TOU rate will only benefit customers who have load profiles consistent with the TOU rate concept. JPS proposes that the remainder of the shortfall be recovered from all customers. The effect on all rates is much less than 1%

16.6 Calculation of street light bills

JPS currently calculates street lighting bills on the basis of the following two assumptions:

- Street lights function 100% of the time;
- Street lights burn for 12 hours each day (this is based on information on the number of hours between dusk and dawn from the Meteorological Office).

To the extent that, when street lights fail and there is a time lag between when the fail and they are repaired, the assumption that they function 100% of the time (i.e., zero outage) is not realistic.

Going forward, therefore, JPS proposes to modify this assumption to one that reflects an outage rate of 1%, i.e., street lights function 99% of the time. This is based on the following:

- An estimated average lifespan of street lights of four years; and
- An average time period of 14 days taken for JPS to repair the failed street lights.

The calculation of the 1% outage rate is shown in Table 16.3.

Table 16.3: Estimation of outage rate of street lights

Average Life of Street Light (a)	4 years
Average Length of Outage (b)	14 days
Failures in one year (c - 1/a)	25%
Total yearly outage (d=c x b/365)	0.959% ≈ 1%

16.7 Realigning tariffs towards cost-reflectiveness

The OUR has indicated that the criteria of cost reflectiveness and economic price signalling are principles that should be a part of the rate setting exercise. This is a view that JPS shares. From an economic perspective, marginal cost tariffs are ideal for sending price signals since theoretically decision makers within an economy make optimal choices by focusing on the costs and benefits at the margin. On the other hand, it is the average tariff that allows the full recovery of the costs the firm faces. Therefore to narrowly insist on applying either the marginal cost tariff or the average tariff can lead to sub-optimal results in an economy. A combination of both these approaches in the rate design exercise may be necessary to ensure that the utility remains viable and price signals sent to enhance consumer welfare.

The PPA/Frontier study commissioned by the OUR concluded among other things that:

- The OUR is obliged to ensure that JPS recovers its embedded cost revenue requirement because these cost were incurred in the past in order to meet its responsibility to produce and deliver electricity.

- JPS' marginal cost tariff is lower than its embedded cost tariff, "because the cost of new capacity to meet incremental demand is lower than the embedded costs incurred to meet existing demand". Marginal cost pricing would therefore not lead to cost-reflective tariffs

- While the Ramsey pricing methodology is a possible approach to reconcile marginal cost tariff with embedded cost tariff, JPS should be allowed the latitude to take advantage of its comprehensive knowledge of the demand profile of its customers and set individual tariffs within the framework of the total allowed revenue requirement.

Applying the Ramsey pricing methodology suggested by PPA/Frontier[40] requires that rate design be predicated on the marginal tariffs, with any revenue difference between the marginal cost and embedded cost approaches being redistributed by an inverse price elasticity method. According to the Ramsey pricing principle, it is economically efficient to recover a relatively larger part of common costs from those customers whose demand is relatively more inelastic (i.e., less sensitive to price changes). In other words, under Ramsey pricing, costs would be allocated according to the customers' willingness to pay.[41] Strict application of this method is discriminatory and excludes social considerations that are very important in rate design. In addition, the Ramsey approach is not exactly straightforward and depends on the availability and accuracy of the elasticity estimates.

Another approach, which can be used to allocate the embedded costs across the different rate groups, is the equi-proportional mark-up (EPMU) method. Under this method, the embedded cost revenue is divided among rate classes in the same proportion as derived from the marginal cost tariff. The application of this method is simpler to apply than Ramsey pricing and may be considered a more equitable approach to the distribution of revenue.

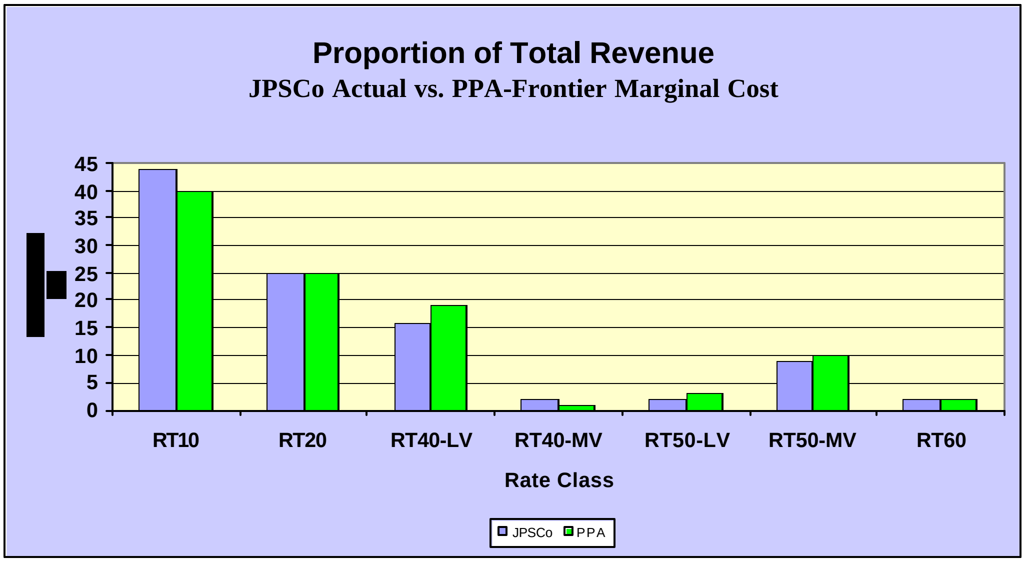
In fact, JPS' current tariffs mimic a marginal cost-plus pricing based on the EPMU method. This is reflected in the comparison of the current actual proportion of revenue versus the PPA marginal cost allocation, which indicates that, apart from the RT10 and the RT40-LV group, there is close correlation in the relative rates (see Figure 16.2).

[40] See PPA (2002) op. cit.

[41] Put differently, the amount of revenue difference assigned to a rate class depends on its price elasticity. Consequently, the more price-inelastic a rate class is, the higher the proportion of the revenue difference it bears.

JPS therefore proposes retention of the current structure of its tariffs, which is reflective of marginal cost pricing. Annual adjustments will be made over the five-year term to move these tariffs in line with the Cost of Service study results. In addition, under the global price cap system (see Section 11) some latitude should be given to JPS to fine tune the rates to minimise rate shocks. The application of this approach in setting the tariffs proposed for 2004 is detailed in Section 17.

Figure 16.2: Proportion of Revenue and Marginal Cost across Rate Classes



As mentioned previously, the current tariffs closely reflect the PPA/Frontier Marginal Cost revenue proportions. However, comparison of the results of the Hagler-Bailly and PPA/Frontier Marginal Cost studies shows that the relative marginal costs for residential consumers (RT10) and streetlight (RT60) in the PPA/Frontier study[42] is lower than those in the Hagler-Bailly study (see Table 16.4). The opposite holds true for commercial and industrial consumers (RT20, RT40 and RT50). The reason for this difference is however not associated with any fundamental change in the consumption pattern or the structure of future costs, but it arises as a result of the assumptions made in the two studies.

[42] See PPA (2002) op. cit

Table 16.4: Comparison of Marginal Cost Tariffs

	Hagler-Bailly Study			PPA/Frontier Study		
	Marginal cost	Relative Rate	Share of Revenue	Marginal Cost	Relative Rate	Share of Revenue
	US c/kWh	**%**	**%**	**US c/kWh**	**%**	**%**
RT10	15.30	121	40	11.95	102	40
RT20	12.00	95	22	13.56	116	25
RT40-LV	11.50	91	22	11.23	96	19
RT40-MV	9.60	76	2	10.14	87	1
RT50-LV	10.50	83	2	10.18	87	3
RT50-MV	8.90	71	9	9.23	79	10
RT60	15.50	123	3	12.79	109	2
System average	**12.60**	**100**	**100**	**11.72**	**100**	**100**

In the Hagler-Bailly Study, the demand costs were allocated using the contribution to the coincident peak for the respective rate classes. This peak occurs between 7:00 pm–8:00 pm and residential consumers have the largest share of the peak. The PPA/Frontier took a different approach.[43] They argued that since the difference between the near peak (2:00 pm – 3:00 pm) and the coincident peak is not significant, the demand costs should not be assigned entirely on the basis of demand during the coincident peak. Instead, demand allocation was weighted as 20% on the near peak and 80% on the peak. Consequently, residential consumers in the PPA/Frontier study bear less of the demand cost. Also streetlights with zero demand during the near peak have a reduction in their marginal cost. The commercial and industrial classes, whose contribution to the near-peak are more substantial, experience the opposite effect, as the relative marginal tariffs are higher in the PPA/Frontier study.

16.8 Design of the Customer Charge

The customer charge is designed to recover costs other than those related to the production and transportation of electricity to the point of use. As such, it includes costs related to metering, billing, collecting and providing service information, to name a few. Of course, these costs will vary between rate categories and as a result customer charges are different depending on customer group.

From time to time JPS has been called upon to explain why customer charges differ between customer groups. The classical example cited by the PPA/Frontier consultants, in

[43] See PPA (2002) op. cit.

their Jamaica OUR Electricity Tariff Study 2002, is that Rate 20 customers with very low levels of consumption (e.g. farmers with only lighting in barns) experience higher bills than Rate 10 customers with significantly larger loads.

To remedy this PPA/Frontier[44] suggested that a possible option would be to apply a uniform customer charge across all classes mirroring the fact that apart from metering charges the difference in customer charges is immaterial.

The application of a uniform customer charge runs counter to the principle of cost reflective tariffs, since customer related charges vary significantly from one rate category to the next. For instance a simple residential meter costs approximately US$40 while at the other end of the scale a demand meter for an industrial customer costs about US$540. Additionally, the larger customers face a more severe maintenance regime, which includes monthly readings and annual inspection.

The uniform approach is also likely to create a negative impact (i.e.: higher cost) on Lifeline tariffs. Presently, the Lifeline customer benefits from the customer charge that is set well below their real cost in order to ensure that low-end users pay bills that are socially bearable. Table 16.5 shows that this would lead to a 471% increase in the residential customer charge. The situation would be further exacerbated by the fact that the customer charge in all other categories would be reduced.

Table 16.5: Impact of Uniform and Differential Customer Charge

	Existing Charge ($/Month)	**Uniform Approach**	
		Charge ($/Month)	Increase
Rate 10	58	331	471%
Rate 20	552	331	-40%
Rate 40	1642	331	-80%
Rate 50	2124	331	-84%
Rate 60	413	331	-20%

The existing differentiated approach used to derive the customer charges is therefore more cost reflective, with the exception of the residential class. It is therefore being proposed that this method be maintained.

[44] See PPA (2002) op. cit.

Section 17: Proposed Non-Fuel Tariffs for 2004/05

17.1 Proposed Tariffs for 2004/05

Table 4 shows the non-fuel base tariffs that JPS proposes, for the year starting June 1, 2004. These tariffs imply a system level ABNF of $6.47/kWh.

Table 17.1: Proposed Rates for 2004 (J$/kWh)

Rate Class		Rate Option	Customer Charge (J$/Month)	Energy Charge (J$/kWh)	Demand-J$/KVA Standard	Off-Peak	Part Peak	On-Peak
Rate 10	LV	Lifeline	87	6.127	-	-	-	-
Rate 10	LV	Non Lifeline	87	8.656	-	-	-	-
Rate 20	LV		816	6.433	-	-	-	-
Rate 40A	LV	Standard	2,497	3.882	417	-	-	-
Rate 40	LV	Standard	2,497	0.926	1,083	-	-	-
Rate 40	LV	TOU	2,497	0.926	-	45	469	600
Rate 50	MV	Standard	2,497	0.731	1,167	-	-	-
Rate 50	MV	TOU	2,497	0.731	-	49	513	664
Rate 60	LV		611	9.110	-	-	-	-
Standby Tariff (Reserve Capacity Charge):					60			

These rates have been set to recover the revenue requirement for test year period of $19.5 billion (see Section 6), based on the following factors:

- Forecasted 2004 billing determinants for each rate class for the test year period. The 2004 forecast is based on an expected annual average growth rate of 4%. See Appendix A4 for details of forecasted sales growth.

- The merging of the RT40 LV with the RT50 LV classes and the RT40 MV with the RT50 MV classes, as discussed in Section 16;

- Correction of the TOU rates for RT 40 and RT50, as discussed in Section 16;

- Slight rebalancing of tariffs between rate classes in accordance with the cost of service study (see Section 15 and Volume IV of this submission). Specifically, the study indicated some rate classes were contributing a lower return on equity than other classes, thus requiring tariff increases if the tariffs are to move gradually towards cost reflectiveness. In setting the tariffs in Table 17.1:

  – the Rate 20 (Small Commercial) and Rate 40A classes both incurred a decrease of 1 percentage point relative to the system average;
  – within the new Rate 40 (power service low voltage), the existing 50LV Standard customers incurred a 1 percentage point decrease, while the existing 40LV Standard customers incurred a 1 percentage point increase

relative to the system average. The existing TOU LV classes remained at the system average;

- within the new Rate 50 (power service medium voltage), all existing MV classes, except 40MV TOU, earned an additional 1 percentage point increase relative to the system average; 40MV TOU remained at the system average;
- rate 60 (street lighting) acquired a decrease of 1 percentage point, relative to the system average;
- the additional revenue to be recovered was allocated to the Rate 10 class as a 0.23 percentage point increase relative to the system average.

• The exclusion of sales to, and revenue from Carib Cement from both the forecasted sales and revenue requirement. This is because Carib Cement enjoys a special tariff and is JPS' largest single customer. The exclusion of Carib Cement from both the sales and revenue requirement is consistent with its treatment in the 2001 rate application.

The correction of the TOU rates and the rebalancing are discussed in the following.

17.2 Proposed Tariff Increase Relative to Current Tariff

The base gazetted tariffs set in April 2003 do not reflect the effects inflation and currency movements that have taken place since then. Rates are normally adjusted annually, using the inflation escalation factor as defined in the Licence, i.e.:

$$dI = \lfloor 0.6\Delta e(1 + 0.6 i_{us}) + 0.4 i_j \rfloor$$ [45]

Where,

$\Delta e \equiv$ Change in the Base Exchange rate

$i_{us} \equiv$ US inflation rate (as defined in the licence)

$i_j \equiv$ Jamaican inflation rate (as defined in the licence)

Based on the escalation factor above, JPS estimates that an escalation of 21.35% on the April 2003 base rates is required to reflect inflation levels and devaluation of the Jamaican currency since then. Table 17.2 shows the derivation of the inflation escalation factor. The tariffs proposed in Table 17.1 therefore reflect a 23% real increase over the inflation adjusted 2003 base rates.

[45] Note that the current Escalation Factor is used. See section 10 for a proposed revision of the Escalation Factor

Table 17.2: Adjusting current tariffs to reflect inflationary and devaluation effects

	2002	2003	2004 (estimated)
JA inflation[1] (%)	7.7%	5.8%	13.9%
US inflation[1] (%)	2.1%	2.0%	2.0%
Present Base Exchange Rate[2] (J$:US$)	44	47	50
Proposed Base Exchange Rate[3] (J$:US$)	47	50	63
Escalation Factor[4] (%)	7.2%	6.2%	21.3%

Note: [1] Point-to-point inflation as from October the previous year; [2] This is the exchange rate used prior to the annual submission; [3] This is the exchange rate implemented upon submission; [4] This is calculated based on the formula in the licence, using the Jamaican and US inflation and the foreign exchange.

17.3 Analysis of Proposed Tariff: Key Drivers of Tariff Increase

Table 17.3 shows, by cost category the allowed non-fuel revenue requirement in 2001:

- at historical prices and sales levels (column 2); and
- adjusted for inflation—using the inflation adjustment factors shown in Table 17.2—and sales growth between 2001 up to the test year period (column 3).

Table 17.3: Allowed 2001 Revenue Requirement

Components of allowed revenue requirement (column 1)	2001 allowed revenue (J$'000s)	
	Historical price and sales levels (column 2)	Adjusted for inflation and sales growth (column 3)
Return on Investment[1]	3,458,559	5,102,257
Depreciation	1,685,460	2,486,484
Operations & Maintenance	6,940,482	10,238,981
JPS O&M Cost (Less OUR Licence Fees)	4,045,692	5,968,428
IPP's Capacity Payments	2,403,145	3,545,251
IPP's Power Energy Payments	457,545	674,996
Street Light Acceleration Cost	-	-
OUR Licence Fees	34,100	50,306
Miscellaneous adjustments	(614,255)	(906,183)
-Taxes	-	-
-Other Operating Revenue	(428,751)	(632,517)
-Carib Cement Revenue	(185,504)	(273,666)
Non Fuel Revenue Requirement	11,470,246	16,921,539

[1] The return on investment in 2001 was calculated on the basis of a rate base of $17,437 million and an ROE of 19.83% (the rate base was 100% equity-financed then).

Table 17.4 compares the 2001 inflation and sales-adjusted allowed revenue requirement (from column 3 in Table 17.3) with the components of JPS' revenue requirement for the test year period.

Table 17.4: Comparison of 2001 allowed revenue requirement and test year revenue requirement

	2001 allowed revenue adjusted for inflation and sales growth. (a)	Test year revenue requirement (b)	Change (c = b – a)
Bogue	-	1,767,040	1,767,040
GT11	-	193,029	193,029
Return on investment (excluding Bogue and GT11)	5,102,257	3,968,232	(1,134,025)
Depreciation (excluding Bogue and GT11)	2,486,484	1,978,842	(507,642)
Operations & maintenance	10,238,980.97	10,443,790.64	204,810
JPS O&M cost (excluding OUR fees, Bogue and GT11)	5,968,428	6,730,801	762,373
IPP's Energy & Capacity payments	4,220,247	3,666,489	(553,757)
street light acceleration cost	-	-	-
OUR licence fees	50,306	46,500	(3,806)
miscellaneous adjustments	(632,517)	1,361,771	1,994,288
Taxes	-	1,483,368	1,483,368
Other operating revenue[1]	(632,517)	(121,597)	510,920
Total non-fuel revenue requirement	17,195,204	19,712,704	2,517,500
Carib Cement revenue	(273,666)	(210,467)	63,199
Non-fuel revenue requirement (excluding Carib Cement)	16,921,539	19,502,237	2,580,699
Sales (including sales to Carib Cement) (MWh)		3,102,602	
Sales (excluding sales to Carib Cement) (MWh)		3,013,591	

Note: [1] The items included in other operating revenue may differ between the 2001 and the current test year revenue requirement.

As shown in the Table 17.4, the real rate increase applied for in the submission is primarily to:

- Increased costs associated with JPS' investment in additional generation capacity (Bogue and GT11); and
- Increased tax burden.

The effect of the Bogue expansion and GT11 investment is calculated as shown in Tables 17.5 and 17.6 respectively.

Table 17.5: Impact of Bogue investment on revenue requirement

Pre-Tax Cost of Debt (%)	**A**	12.56	
Return on Equity (%)	**B**	18.95	
Tax Rate (%)	**C**	33 1/3	
Gearing Ratio (%)	**D**	43.31	
Depreciation Rate (%)	**E**	4.00	
Return on investment			
Bogue Investment ($'000) (Cost @ December 31,2003)	**F**	7,200,000	
Bogue Investment ($'000) (NBV @ December 31,2003)	**G**	6,768,000	
Debt Portion ($'000) based on gearing ratio	**H=D*G**	2,931,221	
Equity Portion ($'000) based on gearing ratio	**I=(1-D)*G**	3,836,779	
WACC Effect ($'000)	**J=K+L**		**972,511**
Cost of Debt ($'000)	**K=H*(1-C)*A**	245,441	
Return of Equity ($'000)	**L=I*B**	727,070	
Tax Effect ($'000)	**M=0.5*L**		**363,535**
Depreciation Effect ($'000)	**N=F*E**		**288,000**
O&M costs effect ($'000)	**O**		**142,995**
Total Effect ($'000)	**P=O+N+M+J**		**1,767,040**

Table 17.6: Impact of GT 11 investment on revenue requirement

Pre-Tax Cost of Debt (%)	A	12.56	
Return on Equity (%)	B	18.95	
Tax Rate (%)	C	33 1/3	
Gearing Ratio (%)	D	43.31	
Depreciation Rate (%)	E	4.00	
Return on investment			
GT 11 Investment ($'000) (Cost @ December 31,2003)	F	815,029	
GT 11 Investment ($'000) (NBV @ December 31,2003)	G	721,247	
Debt Portion ($'000) based on gearing ratio	H=D*G	312,372	
Equity Portion ($'000) based on gearing ratio	I=(1-D)*G	408,875	
WACC Effect ($'000)	J=K+L		**103,638**
Cost of Debt ($'000)	K=H*(1-C)*A	26,156	
Return of Equity ($'000)	L=I*B	77,482	
Tax Effect ($'000)	M=0.5*L		**38,741**
Depreciation Effect ($'000)	N=F*E		**32,601**
O&M costs effect ($'000)	O		**18,049**
Total Effect ($'000)	P=O+N+M+J		**193,029**

17.4 Estimated Impact on Customer Bills

Table 17.7 provides estimates of the impact of the new proposed non-fuel tariffs on monthly customer bills. The results are based on the estimated change between the (expected) May 2004 and June 2004 bills. Details of the analyses are provided in Appendix A14.

Table 17.7: Estimated impact of proposed non-fuel tariffs on customer bills

Rate class	Estimated increase in monthly bills due to: inflation and currency movements	Estimated increase in monthly bills due to: real increase in rates	Total estimated increase in monthly bill
Rate 10 Life Line customer (99kWh/month)	3.27%	13.04%	16.32%
Rate 10 typical customer (250kWh/month)	3.15%	13.80%	16.95%
Rate 20 typical customer (1000kWh/month)	3.23%	12.60%	15.83%
Rate 40A average customer (10,933 kWh/month and 85 kVA/month)	3.22%	12.73%	15.95%
Rate 40 Standard average customer			
-40 LV (35,128 kWh/month and 114kVA/month)	3.71%	11.15%	14.87%
-50 LV (264,172kWh/month and 795 kVA/month)	3.72%	7.54%	11.26%
Rate 40 TOU average customer			
-40 LV (76,336 kWh/month and 189 kVA/month)	3.91%	10.77%	14.68%
-50 LV (181,811kWh/month and 498 kVA/month)	3.80%	8.55%	12.35%
Rate 50 Standard average customer			
-40 MV (91,778 kWh/month and 322 kVA/month)	3.69%	14.12%	17.81%
-50 MV (493,323kWh/month and 1,359kVA/month)	3.81%	9.05%	12.86%
Rate 50 TOU average customer			
-40 MV (124,077kWh/month and 365kVA/month)	3.84%	14.49%	18.33%
-50 MV (462,001kWh/month and 1,302kVA/month)	3.84%	10.85%	14.69%

Note: [1] The TOU consumption is based on the sum of the energy (kWh) used in each time period and the average of the demand (kVA) used in each period.

Section 18: Reconnection Fees

JPS is required to reconnect a customer after full payment of the outstanding amounts and payment of the reconnection fee. A reconnection fee is applicable to all rate categories. The company currently charges a reconnection fee of $1,325 to reinstate service to customers, whose electricity supply had been disconnected because of non-payment of bills. This fee was based on a cost review carried out in 2002.

According to the Rate Schedule 2003:

> "The reconnection fee shall be determined by June 30 each year and which shall be based on the actual cost of undertaking reconnection in the preceding year plus a 10 percent service charge PROVIDED THAT the said actual cost was incurred in the most cost efficient and cost effective manner".

The total cost associated with disconnection and reconnection in 2003 is estimated to be $94,829,709, based on the sum of the O&M costs, administrative costs and audit fees. The total number of reconnections in 2003 is 72,366. The cost per reconnection is estimated as follows:

Actual reconnection cost = Total cost / Total number of reconnections

As per Rate Schedule, a 10% of the actual reconnection cost is added as a service charge. Based on analysis the reconnection fee per activity should be set at $1,441. The derivation of this fee is summarized in Table 18.1 and is fully explained in Appendix 15.

Table 18.1: Reconnection Cost Summary

Description	Costs ($)
Total Reconnections for 2003 (a)	72,366
Contractor Cost for 2003 (b)	75,672,591
Administrative Cost for 2003 (c)	18,907,118
Audit Fees (d)	250,000
Total Cost (e =b+c+d)	94,829,709
Actual reconnection unit cost for 2003 (f=e/a)	1,310
Plus 10% service charge (g = f X 0%)	131
Derived Reconnection fee (f+g)	1,441

Section 19: Proposed Revision of Penalties on Guaranteed Standards

Under the Licence (Schedule 1), JPS is subject to certain guaranteed standards. Where JPS fails to meet these standards, customers are currently entitled, under the Licence, to the following compensation for each breach:

- Residential: $150;
- Industrial/Commercial: $750.

Further, for each period that the compensatory payment remains outstanding, JPS is liable for additional payments of the same amount for each succeeding period provided that maximum exposure of JPS for such payments does not exceed four periods. However, guaranteed standards will not be in effect during a period of *force majeure*.

JPS proposes that, as of June 1, 2004, the penalties be increased by 100% to the following:

- Residential: $300;
- Industrial/Commercial: $1500.

JPS proposes the exemption of the guaranteed standards during periods of *force majeure* be retained.

Part D: Appendices

Appendix A1: Delivering on our commitments

A1.1 Maintenance on Generating Units

A1.1.1 Major Maintenance upgrades – by plant

- Oil fired steam plants—rehabilitation work carried out included:
  - Chemistry improvement programme—including the water chemistry programme as well as improving combustion control. The focus on water quality was aimed at improving boiler reliability.
  - Improvement and rehabilitation of combustion systems and combustion management programmes to improve boiler reliability.
  - Elimination of the bottleneck of critical pumping systems—in 2001, the steam pumps had two 60% capacity pumps, which had to be de-rated whenever routine maintenance was carried out. The pumping systems were increased to two 110% units to eliminate the problem. This is 50% complete, as three of the larger plants need to be done. Other measures have been taken to improve the reliability of the pumping systems.
  - Rehabilitation and modernization of critical electrical and mechanical protection systems.
  - Turbine generator rehabilitation has been effected on three of the five units. The remaining two units are to be completed by the end of 2005.
  - Isolation and correction of steam leaks.
- Gas turbines—the major problem that JPS faced with regard to the gas turbines was the reliability of the starts. To overcome this problem, JPS has invested into the improvement of the fuel atomisation system on the Frame 5 combustion turbines. The hydraulic systems on the Frame Machines were also rehabilitated, while the starting package on the Frame 5 machines were renovated.
- Diesel plants—while the diesel plants have been operating reliably, JPS is undertaking rehabilitation work on the excitation system and the cooling water system to ensure continued reliable operations. Substantial expenditures are being made to replace cylinder liners that are nearing the end of their useful lives.
- Hydroelectric plants – these units were rehabilitated at a cost of US$27 million. As a result, the hydro units are showing the best level of reliability and production in years.

Table A1.1 shows the major rehabilitation and maintenance work that JPS has carried out in various plants between 2001 and 2003.

Table A1.1: Major rehabilitation and maintenance expenditures 2001 – 2003 (J$ million)

Location	Year	O&M	Capital	Notes
Old Harbour				
Unit No.1	2002	50	62	Major overhaul and replacement of Forced draft fan, feedwater heater and superheater tubes.
Unit No.2	2001	80		Turbine over haul and auxilliary overhaul
Unit No.3	2001	38		Generator cleaning and repairs
Unit No.3	2003	130	80	Major overhaul and replacement of boiler bank and superheater tubes (work in progress)
Unit No.4	2002	33		Burner replacement, superheater bends replacement and chemical clean boiler
Unit Nos.1 and 2 pumps	2003		150	Installation of 100% capacity pumps
Hunts Bay				
Gas Turbine No. 5	2002	58		Hot Gas Path overhaul
Gas Turbine No.10	2002	20	43	Hot Gas Path overhaul
Bogue				
Gas Turbine No. 3	2002	35	11	Hot Gas Path overhaul
Gas Turbine No.7	2002 – 03	47		Gas Generator and Free Turbine
Gas Turbine No.8	2003 – 03	37		Gas Generator and Free Turbine
Gas Turbine No. 9	2001 – 02	41		Gas Generator and Free Turbine
Gas Turbine No.11	2003	25	38	Hot Gas Path Repairs and upgrading
Hydro Units	2001 - 03		766	Rehabilitation of units
Total		**594**	**1150**	

In addition to the specific maintenance and rehabilitation work that has been and continues to be undertaken, JPS has also improved the general physical infrastructure of the generation assets. Poor housekeeping in prior years had led to the progressive deterioration of the physical assets. Since the privatisation of JPS, efforts have been and continue to be undertaken towards the renovation and protection of the assets. Provision of the requisite tools and equipment has also been improved.

The maintenance and operating practices are in the process of being reviewed and updated so as to establish a sustainable preventative maintenance programme and the implementation of a work management system. In line with this, staff is also being retrained to ensure that they keep abreast with the updated and improved work practices.

A1.2 Guaranteed Standards Of Service

Table A1.2 Percentage Compliance on Guaranteed Standards (2001—2003)

Guaranteed standard	2001	2002	Oct 2003
New Service Installations (GS1a)	86	82	78
Simple Connections (GS1b)	92	83	78
Complex Connections (GS2a)			
- Work Estimates	40	60	78
- Construction	62	66	75
Complex Connections (GS2b)			
- Work Estimates	57	62	74
- Construction	61	72	70
Response to Service Calls (GS3)	76	82	83
Billing New Accounts (GS4)	87	76	85
Reconnections (GS6)	81	84	93
Average	**83**	**81**	**86**

Table A1.3 Potential Compensation Payable on Guaranteed Standards (2002—2003)

Guaranteed Standards	2002	October 2003
Simple Connections (GS1)		
New Service Installation	428,700	235,950
Connection	205,650	163,350
Complex Connections (GS2a)	295,200	122,400
Complex Connections (GS2b)	65,700	36,900
Response to Service Calls (GS3)	807,300	555,300
Billing New Accounts (GS4)	3,787,200	1,283,100
Reconnec tions (GS6)	1,164,478	445,500
Total	**6,754,228**	**2,842,500**

Figure A1.1 New Installations from (January 2001–September 2003)

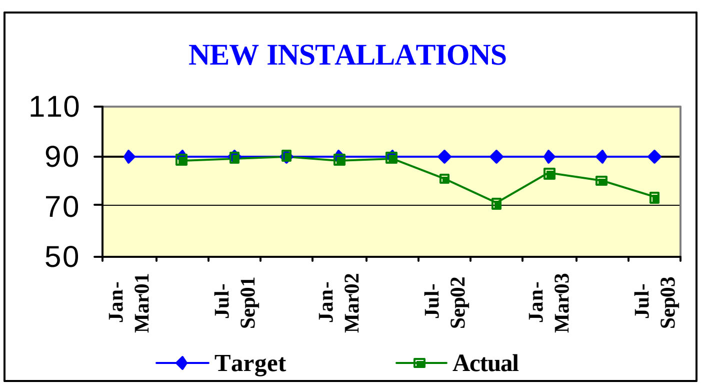


Figure A1.2 Simple Connections (January 2001-September 2003)

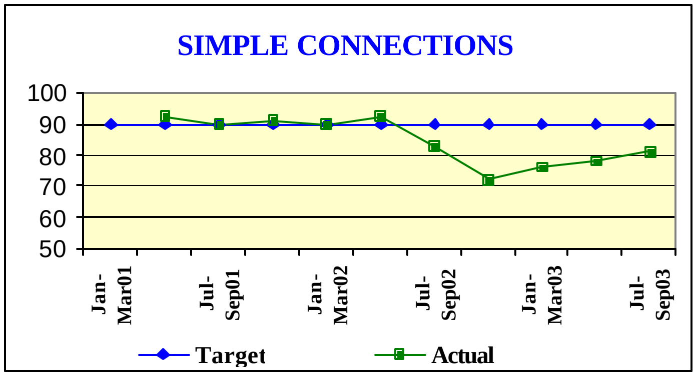


Figure A1.3 Work Estimates (1-10 working days) (January 2001-September 2003)

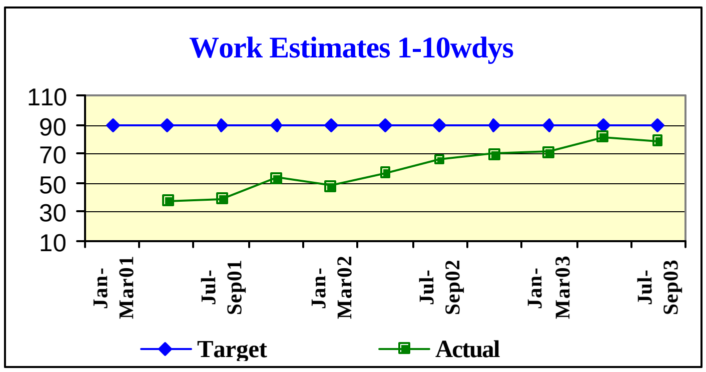


Figure A1.4 Construction (1-30 working days) (January 2001-September 2003)

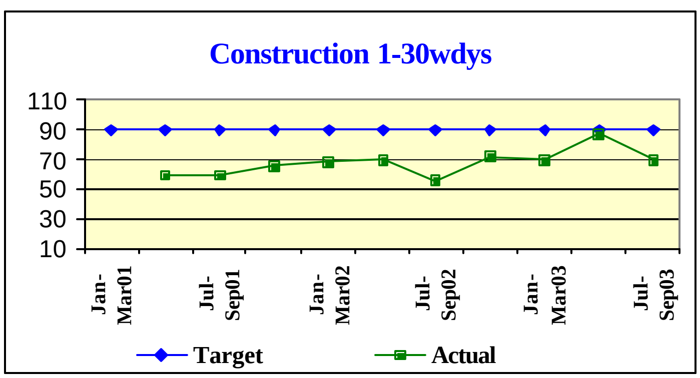


Figure A1.5 Work Estimates (1-15 working days) (January 2001-September 2003)

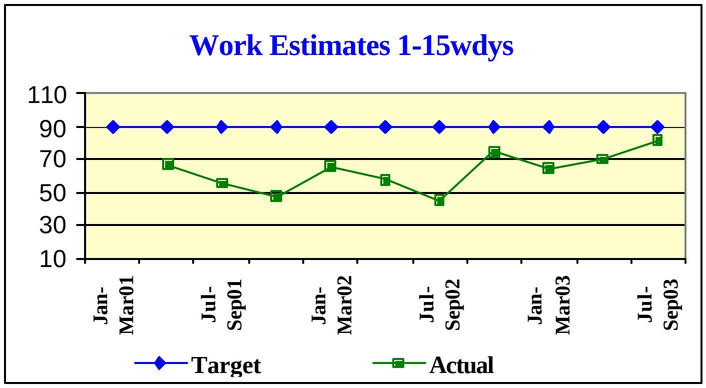


Figure A1.6 Construction (1-40 working days) (January 2001-September 2003)

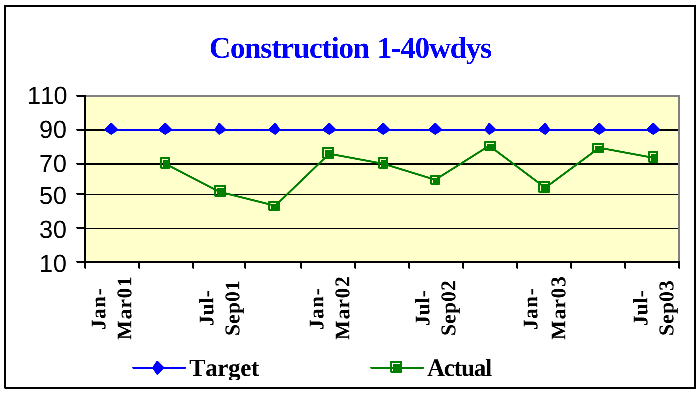


Figure A1.7 Billing of New Accounts (January 2001-September 2003)

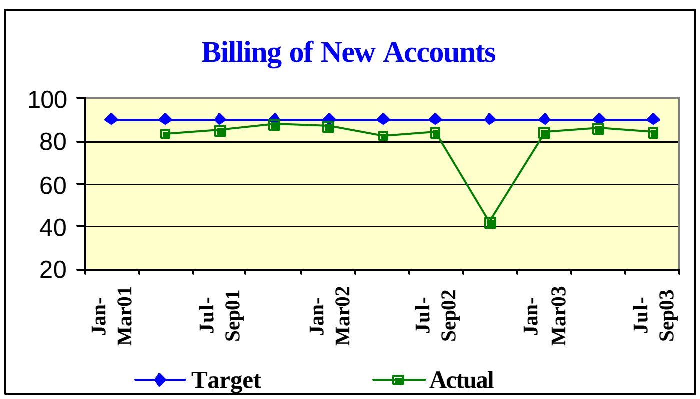


Figure A1.8 Response to emergency calls (January 2001-September 2003)

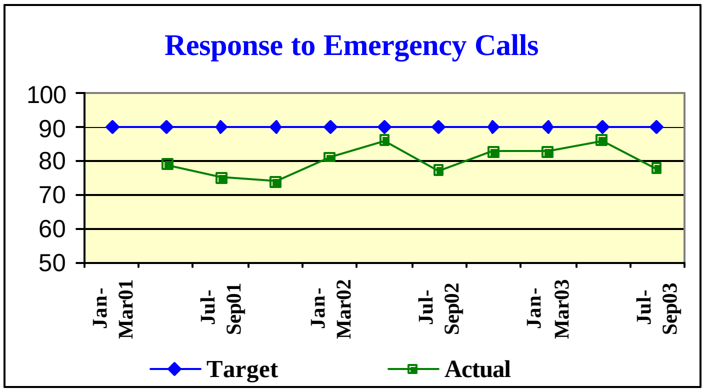
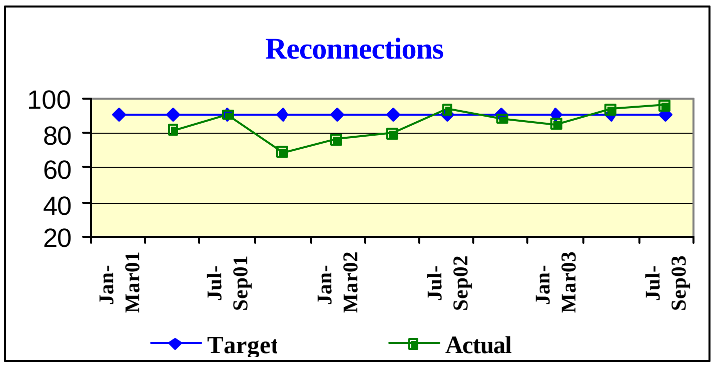


Figure A1.9 Reconnections (January 2001-September 2003)



Appendix A2: Earnings Statement, Balance Sheet and FERC Accounts for 2003

Table A2.1: JPS Jamaica GAAP Statement of Earnings (J$000s)[1]

	Mar-02	Dec-02	Dec-03
Operating revenue	18,809,578	16,356,833	26,463,097
Cost of sales:			
Fuel	7,856,575	7,144,753	12,570,818
Purchased power (excluding fuel)	2,513,117	2,344,485	3,477,385
	10,369,692	9,489,238	16,048,203
Gross profit	8,439,886	6,867,595	10,414,894
Operating expenses:			
Payroll, benefits & training	2,944,266	2,208,922	3,476,293
Third party services	659,812	583,852	909,778
Materials & equipment	295,374	256,344	432,635
Office & Other expenses	692,938	516,159	924,274
Insurance expense	257,580	272,801	384,697
Bad debt write-off	64,690	53,468	62,003
	4,914,660	3,891,546	6,189,680
Selling, general & administrative	2,555,884	2,310,543	4,609,157
Maintenance	2,358,776	1,581,003	1,580,523
	4,914,660	3,891,546	6,189,680
Profit before interest tax & dep'n (EBITDA)	3,525,226	2,976,049	4,225,214
Depreciation	1,692,468	1,333,869	1,960,574
Operating profit	1,832,758	1,642,180	2,264,640
Net Financing costs:			
Interest Income	78,313	142,700	260,116
Allowance for funds used in construction	242,559	247,869	230,846
	320,872	390,569	490,962
Interest expense	966,839	879,713	1,678,588
Loan financing fees	76,970	28,800	58,457
Foreign exchage loss/(gain)	285,345	629,865	1,993,796
	1,329,154	1,538,378	3,730,841
Total Net Financing costs/(income)	1,008,282	1,147,809	3,239,879
Operating profit after net financing costs	824,476	494,371	(975,239)

Note: [1]Figures are based on unaudited accounts, as on February 15th 2004. At time of submission of this report, audited accounts are not available. They will be available in March 2004.

Table A2.1: JPS Jamaica GAAP Statement of Earnings (cont'd.) [1]

Other income	38,725	158,384	275,896
Net Profit before tax & extra-ordinary item	863,201	652,755	(699,343)
Taxation	-	(229,211)	38,329
Net Profit after tax but before extra-ordinary item	863,201	423,544	(661,014)
Extraordinary items	-	-	576,430
Net profit attributable to stockholders	863,201	423,544	(84,584)
Transfer to profit and loss	630,550	657,251	328,626
Dividends – Preference and Ordinary	(169)	(127)	(1,215,960)
	1,493,582	1,080,668	(971,918)
Retained earnings at beginning of year	2,033,424	3,897,085	6,057,885
Prior year adjustment	(111,071)	(481,150)	(1,561,282)
Retained earnings B/F (restated)	1,922,353	3,415,935	4,496,603
Retained earnings at end of year	3,415,935	4,496,603	3,524,685

Note: [1]Figures are based on unaudited accounts, as on February 15th 2004. At time of submission of this report, audited accounts are not available. They will be available in March 2004.

Table A2.2: JPS Jamaica GAAP Balance Sheets (J$'000)[1]

	Mar-02	Dec-02	Dec-03
CURRENT ASSETS			Restated
Cash and short-term deposits	1,676,486	2,508,428	1,575,543
Receivables, net of provisions	1,914,344	3,770,676	4,342,551
Other receivables	15,581	50,012	509,229
Unbilled revenue	589,260	886,647	1,527,862
Prepaid expenses and deposits	167,026	353,527	487,743
Fuel inventory	261,921	276,827	472,667
Materials and supplies	979,459	1,001,104	1,000,286
	5,604,077	8,847,221	9,915,881
CURRENT LIABILITIES			
Payables	2,264,520	2,706,946	3,113,427
Payroll taxes payable	162,765	235,082	245,545
Bank overdraft	-	-	-
Short-term loans	1,066,955	2,654,874	1,012,036
Current maturity of long-term debt	23,012	227,755	557,164
Interest accrued	218,779	266,288	530,060
Due to parent company	62,628	1,277,042	143,228
	3,798,659	7,367,987	5,601,460
NET CURR. ASSETS/(LIABILITIES)	1,805,418	1,479,234	4,314,421
Land	780,740	802,551	800,438
Production	19,683,182	24,114,367	31,637,629
Transmission and distribution	34,648,992	36,327,349	41,537,249
General	8,575,901	9,054,004	5,816,922
Total Fixed assets at cost	63,688,815	70,298,271	79,792,238
Accumulated depreciation	43,586,629	46,446,070	49,169,075
	20,102,186	23,852,201	30,623,163
Construction work-in-progress	3,674,188	3,193,239	1,791,458
Total Fixed assets NBV	23,776,374	27,045,440	32,414,621
Long-term investment	1,748	1,748	
Pension Asset	881,000	937,000	1,069,798
Deferred tax asset	-	-	-
Deferred Expenditure	76,645	52,072	-
	26,541,185	29,515,494	37,798,840

Note: [1]Figures are based on unaudited accounts, as on February 15th 2004. At time of submission of this report, audited accounts are not available. They will be available in March 2004.

Table A2.2: JPS Jamaica GAAP Balance Sheets (cont'd.) [1]

Financed by:			
SHAREHOLDERS' EQUITY			
Share capital	10,917,300	10,917,300	10,917,300
Capital reserve	3,139,704	3,183,522	5,469,057
Retained earnings	3,415,935	4,496,603	3,524,685
	17,472,939	18,597,425	19,911,042
Long-term debt	6,410,083	7,555,562	13,034,737
Customer deposits & advances	1,634,783	1,759,381	2,060,285
Employee benefit obligations	844,650	844,650	1,074,300
Deferred tax liability	178,730	758,476	1,718,476
	26,541,185	29,515,494	37,798,840

Note: [1]Figures are based on unaudited accounts, as on February 15th 2004. At time of submission of this report, audited accounts are not available. They will be available in March 2004.

Table A2.3: JPS Balance Sheet Details (J$'000)

[Figures omitted. See note on page iii.]

Table A2.4: JPS Trial Balance by FERC Accounts (closing balance on December 31, 2003)

[Figures omitted. See note on page iii.]

Appendix A3: Details of Test Year O&M and Capital Expenditure

Table A3.1 : Non-payroll O&M Costs for Test Year by Activity (J$)

[Figures omitted. See note on page iii.]

Table A3.2: JPS Planned Capital Expenditures during Test Year period (US$'000s)

[Figures omitted. See note on page iii.]

Appendix A4: Sales Forecast Analysis

This appendix describes the methods used to forecast sales and numbers of customers by rate class over the five-year price cap period. Two models were developed for each rate class:

- the first model forecasts sales per customer (or sales for Rate 60); and
- the second model forecasts the number of customers.

This separation allows us 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 Rate 60, sales are forecast directly because of the uncertainty surrounding the meaning of a "customer" in the context of street lights. A separate forecast of Rate 60 customers is produced as well.

A4.1 Sales per Customer Models

Table A4.1 below summarizes the sales per customer models (sales model for Rate 60), including the variables that are included, the estimated coefficients and standard errors for each variable, and the R-squared values for the models. In each case, the natural log of sales per customer (sales for Rate 60) is used as the dependent variable.

Table A4.1: Sales per Customer Regressions by Rate Class

Explanatory Variable	Rate 10	Rate 20	Rate 40	Rate 50	Rate 60
ln (real price)	-0.272	-0.085	-0.168	-0.175	--
	(0.073)	(0.064)	(0.033)	(0.108)	
ln (real disposable income)	0.362	--	--	--	--
	(0.056)				
ln (real GDP)	--	1.550	0.273	3.272	--
		(0.806)	(0.093)	(1.295)	
ln (real GDP) * time trend	--	-0.0006	--	-0.0011	--
		(0.0003)		(0.0004)	
Gilbert	-0.108	--	-0.068	--	--
	(0.065)		(0.030)		
CIS 40	--	--	-0.162	--	--
			(0.021)		
Time trend	--	--	--	--	0.040
					(0.005)
Constant	3.672	5.148	10.003	3.066	-69.223
	(0.781)	(2.079)	(1.155)	(6.837)	(9.457)
R-squared	0.887	0.306	0.860	0.523	0.923
Timeframe used	1980-2003	1986-2003	1986-2003	1993-2003	1996-2003

Notes: standard errors in parentheses. Rate 10, 20, 40, and 50 dependent variable is the natural log of sales per customer. Rate 60 dependent variable is the natural log of sales.

The variables are defined as follows:

- **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.

- **ln (real disposable income)**: Data on nominal national disposable income were obtained from the Statistical Institute (STATIN).[46] This was converted to real disposable income using CPI data. Real disposable income is 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, and customers are expected to use more electricity as income rises.

- **ln (real GDP)**: Data on nominal GDP were obtained from STATIN.[47] 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.

- **Time trend**: 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.

- **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.

- **Gilbert**: This is equal to 1 in 1988 and zero in all other years, and it reflects the changes in sales per customer that occurred because of Hurricane Gilbert.

- **CIS 40**: This is equal to 0 prior to 1991 and 1 from 1991 through the end of the forecast period. It reflects the changes that occurred in reported Rate 40 sales due to changes in the CIS and rate classifications.

A4.2 Number of Customer Models

Table A4.2 below summarizes the number of customer models, including the variables that are included, the estimated coefficients and standard errors for each variable, and the

[46] See STATIN (1985), National Income and Product, Table 2.1; STATIN (1992), National Income and Product, Table 2.1; STATIN (2002), National Income and Product, Table 2.1.

[47] See STATIN (1988), National Income and Product, Table 2.1; STATIN (2001), National Income and Product, Table 2.1.

R-squared values for the models. In each case, the natural log of the number of customers is used as the dependent variable.

Table A4.2: Number of Customer Regressions by Rate Class

Explanatory Variable	Rate 10	Rate 20	Rate 40	Rate 50	Rate 60
ln (population) * time trend	0.0012 (0.00004)	--	--	--	--
Gilbert	-0.144 (0.050)	-0.117 (0.051)	--	--	--
Time trend	--	0.050 (0.002)	0.025 (0.0008)	0.035 (0.003)	0.029 (0.009)
Constant	-22.360 (1.315)	-89.325 (4.501)	-43.374 (1.581)	-65.346 (6.595)	-52.777 (17.318)
R-squared	0.972	0.975	0.985	0.926	0.651
Timeframe used	1980-2003	1986-2003	1986-2003	1993-2003	1996-2003

Notes: standard errors in parentheses. In all cases, the dependent variable is the natural log of the number of customers.

The variables are defined as follows:

- **Time trend**: 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.

- **ln (population) * time trend**: 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. The positive estimated coefficient for Rate 10 indicates that the effect of population growth on customer growth has increased over time.

- **Gilbert**: This is equal to 1 in 1988 and zero in all other years, and it reflects the changes in the customer count that occurred because of Hurricane Gilbert.

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 data through 2003 so that the results reflect the most recent conditions. The Rate 10 model uses data beginning in 1980, as an examination of the data indicated that conditions prior to 1980 may not be relevant to the current conditions. The regression data for Rates 20 and 40 begin in 1986 because the nominal GDP data were not available prior to that date.

For Rate 50, we began the analysis in 1993 based on the fact that large changes (i.e., reductions in usage per customer and increases in the number of customers) that had occurred from 1991 to 1992 seemed to have ended by that time, making the 1993 to 2003 time period the most relevant for forecasting purposes. For similar reasons, we selected 1996 as the start year for the Rate 60 sales model. The period from 1989 through 1995 displayed no growth, but steady growth was observed continuously beginning in 1996.

This time period therefore seemed more relevant for determining the near-term forecast growth rate.

A4.3 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.

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 price cap period are as shown in Table A4.3.

Table A4.3: Projections 2004—2008

	Real Price Change	Real GDP Growth	Population Growth	Inflation
2004	8.00%	2.50%	0.50%	10.00%
2005	8.00%	3.00%	0.50%	8.50%
2006	0.00%	3.00%	0.50%	7.50%
2007	0.00%	3.00%	0.50%	7.50%
2008	0.00%	3.00%	0.50%	7.50%

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 except Rate 60, 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 number of customers are as shown in Tables A4.4 and A4.5.

Table A4.4: Forecasted sales growth rates: 2004—2008

	Rate 10	Rate 20	Rate 40	Rate 50 excl. CCC	CCC Sales	Rate 60	Total
2004	1.8%	4.6%	3.6%	3.3%	0.0%	4.1%	3.0%
2005	2.0%	4.7%	3.5%	3.8%	0.0%	4.1%	3.2%
2006	4.1%	5.4%	4.7%	5.2%	0.0%	4.1%	4.6%
2007	4.1%	5.4%	4.7%	5.2%	0.0%	4.1%	4.6%
2008	4.1%	5.4%	4.7%	5.1%	0.0%	4.1%	4.6%
Average	**3.2%**	**5.1%**	**4.2%**	**4.5%**	**0.0%**	**4.1%**	**3.97%**

Note: CCC = Carib Cement.

Table A4.5: Forecasted number of customers' growth rates: 2004—2008

	Rate 10	Rate 20	Rate 40	Rate 50	Rate 60	Total
2004	3.0%	5.1%	2.6%	3.6%	2.9%	3.2%
2005	3.0%	5.1%	2.6%	3.6%	2.9%	3.2%
2006	3.0%	5.1%	2.6%	3.6%	2.9%	3.2%
2007	3.0%	5.1%	2.6%	3.6%	2.9%	3.2%
2008	3.0%	5.1%	2.6%	3.6%	2.9%	3.2%
5-year average	**3.0%**	**5.1%**	**2.6%**	**3.6%**	**2.9%**	**3.2%**

Appendix A5: Algebraic Decomposition of Unit Cost Trends into Input Prices and TFP Trends in setting the X-factor

According to the Licence:

> "The X-factor is based on the expected productivity gains of the Licensed Business. 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 reflect the price escalation measure "dI"."

The X-factor can therefore be defined as follows:

$$X_y = (JPS\_TFP_{y-1} - JPS\_TFP_{y-2}) - (IF\_TFP_{y-1} - IF\_TFP_{y-2}) \qquad \text{Equation A5.1}$$

where

JPS_TFP_{y-1} = TFP of JPS as at 60 days prior to the adjustment date;

JPS_TFP_{y-2} = TFP of JPS one year prior to the date used for JPS_TFP_{y-1};

IF_TFP_{y-1} = TFP of the indexed firms (whose price index of output make up the measure "dI") as at 60 days prior to the adjustment date;

IF_TFP_{y-2} = TFP of the indexed firms one year prior to the date used for JPS_TFP_{y-1}

The rationale behind X is as follows. In a competitive market, price changes in response to:

- *Cost inflation of inputs*—which, all else held constant, will cause an increase in the price of the final product.
- *Increases in productivity*—which, all else held constant, will cause a decrease in the price of the final product.

Specifically, the change in output prices (ΔP) in any industry is the difference between the change in input prices (ΔIP) and TFP growth (ΔTFP):

$$\Delta P_{industry} = \Delta IP_{industry} - \Delta TFP_{industry} \qquad \text{Equation A5.2}$$

Given that an objective of price regulation is to mimic the outcomes of competitive markets, the regulatory framework would impose equation (A5.2) onto the regulated company, in this case JPS, i.e.:

$$\Delta P_{JPS} = \Delta IP_{JPS} - \Delta TFP_{JPS} \qquad \text{Equation A5.3}$$

Similarly, the price trend of the output of the indexed firms can be expected to be as follows:

$$\Delta P_{IF} = \Delta IP_{IF} - \Delta TFP_{IF} \qquad \text{Equation A5.4}$$

If the input price inflation faced by JPS is the same as the input price inflation of the indexed firms—i.e., ΔIP_{JPS} equals ΔIP_{IF}— then the difference between the price change of

JPS' output and the overall price inflation of the indexed firms must solely be due differences in productivity growth. This can be seen by subtracting equation (A5.4) from equation (A5.3):

$$\Delta P_{JPS} - \Delta P_{IF} = -(\Delta TFP_{JPS} - \Delta TFP_{IF})$$

$$\Delta P_{JPS} = \Delta P_{IF} - (\Delta TFP_{JPS} - \Delta TFP_{IF}) \qquad \text{Equation A5.5}$$

A comparison of equations (A5.1) and (A5.5) show that the terms in the parenthesis on the right-hand side of the equation is the X-factor as defined in the Licence Agreement. In other words, the price-cap formulation in equation (A5.1) seeks to ensure that any anticipated productivity gains JPS makes, above that of the economy as a whole, is passed onto consumers.

Appendix A6: Benchmarking Approaches in Determining Relative Efficiency of Companies

A6.1 Parametric Benchmarking Approaches

A6.1.1 Econometric Cost functions

A cost function is a mathematical relationship designed to capture the relationship between the cost of service and business conditions. Business conditions are aspects of a company's operating environment that may influence its activities but cannot be controlled. Economic theory can guide the selection of business condition variables in cost function models. According to theory, the total cost of an enterprise depends on the amount of work it performs - the scale of its output - and the prices it pays for capital goods, labour services, and other inputs to its production process.[48] Theory also provides some guidance regarding the nature of the relationship between outputs, input prices, and cost. For example, cost is likely to rise if there is inflation in input prices or more work is performed.

In addition to output quantities and input prices, electric utilities confront other operating conditions due to their special circumstances. Unlike firms in competitive industries, utilities are obligated to provide service to designated customers within a given service territory. Many utility services are also delivered directly into the homes, offices and businesses of end-users. Utility cost is therefore sensitive to the circumstances of the territories in which they provide delivery service. Some key factors affecting cost are as follows:

- *Customer location*—this follows from the fact that utility services are delivered over networks that are linked directly to customers. The location of customers throughout the territory therefore directly affects the assets that utilities must put in place to provide service. Different spatial distributions for customers can have different implications for electric utility cost.

- *Mix of customers served*—the assets needed to provide delivery service will differ somewhat for residential, commercial, and industrial customers. Even more importantly, different types of customers have different levels and temporal patterns of demand and different load factors.

- *Physical environment of the service territory*—the cost of constructing, operating and maintaining a given network will depend on the terrain over which that network extends. These costs will also be influenced by weather and related factors. For example, costs will likely be higher in areas with high winds or other severe weather that can damage equipment and disrupt service. Operating costs

[48] Labour prices are usually determined in local markets, while prices for capital goods and materials are often determined in national or even international markets.

will also influenced by the type and density of vegetation in the territory, which will be at least partly correlated with precipitation and other weather variables. To a great extent, these conditions accompany the particular territory that the utility is required to serve and are therefore beyond management control.

Econometric cost functions require that a functional form be specified that relates cost to outputs, input prices, and other business conditions. Parameters are associated with the variables specified in this cost function. Econometric methods are then used to estimate the parameters of cost function models. Econometric estimates of cost function parameters are obtained using historical data on the costs incurred by utilities and measurable business condition variables that are included in the cost model. Performance is measured by comparing a company's actual cost with the cost predicted by the model. The following comparison makes use of the point prediction of cost.

$$Estimated\ Cost\ Performance = C_{DB,t} - \hat{C}_{DB,t}$$

Here $C_{DB,\ t}$ refers to a distribution business's (DB's) actual cost in period t, while $\hat{C}_{DB,t}$ is the estimated DB cost in that period. Econometric cost functions reflect the cost that would be expected for that firm given an average efficiency standard.

A6.1.2 Stochastic frontier analysis

Stochastic frontier analysis (SFA) is similar in many respects to other econometric cost models. SFA also specifies a functional form that relates cost to outputs, input prices, and other business conditions. The same business condition variables would be used in SFA as in econometric cost functions. Parameters of SFA models are estimated using historic data on the variables used in the cost function.

However, SFA differs in that it also estimates an inefficiency factor for each firm. SFA is specifically focused on estimating the *minimum* cost of production, or minimum cost frontier.[49] The actual total cost (C_i) incurred by company, i, in providing service is assumed to be the sum of the minimum achievable cost (C_i^*) and an inefficiency factor.

$$C_i = C_i^* + inefficiency_i$$

SFA uses econometric methods to isolate and measure this inefficiency factor. While not estimating firm inefficiency directly, it should be noted that econometric cost functions can also be specified that distinguish between inefficiency and other random factors that are not reflected in the business condition variables. An average inefficiency can then be calculated for the sample. The utility in question's inefficiency would then be benchmarked against the average inefficiency. Such an approach would be consistent with economic paradigm described in Section 7 where prices is set with reference to the average, not the most efficient, firm in the industry.

[49] Alternatively, SFA can be focused on estimating maximum production frontiers.

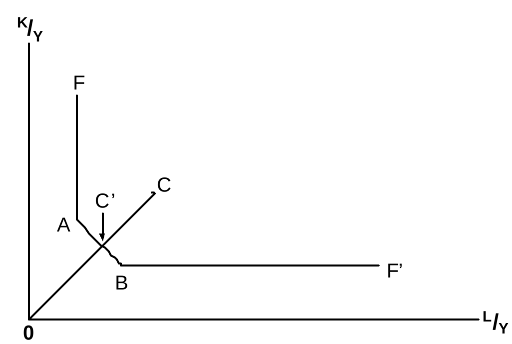
A6.2 Non-parametric benchmarking approaches: Data Envelope Analysis

Data envelope analysis (DEA) represents a much different approach towards estimating efficiency. It does not estimate the parameters of a cost function and is therefore often described as "non-parametric." Instead, DEA uses linear programming techniques to "envelope" data on sample firms that relate outputs to inputs. DEA is therefore essentially a technique for identifying what are known in economics as isoquant or isocost curves and in measuring the distance of individual firms from the efficient cost (production) frontier reflected in that isocost (isoquant).

In a basic input-oriented DEA model, the relative efficiency of a firm is determined by assigning weights to firm inputs and outputs such that the ratio of aggregated outputs to aggregated inputs is maximized. This linear programming problem is subject to the constraint that the efficiency score cannot exceed a value of one for a firm using the same set of weights. The result of this process will be an efficiency measure for each firm that takes a value between zero and one. These efficiency scores are relative to "peers" identified through the analysis and which set the efficiency "frontier." The DEA efficiency score has the intuitive interpretation that, relative to the peers, it measures the amount by which a firm can radially contract all of its inputs while still producing the same level of output.

This can perhaps be clarified through a visual example. In Figure One, there are two inputs, capital (K) and labour (L). The X-axis in this figure is labour per unit of output (L/Y) while the Y-axis is capital per unit of output (K/Y).

Figure A6.1



In this example, the points A, B and C refer to specific firms that are identified as peers. It can be seen that firms A and B are using fewer capital and labour inputs per unit of output than firm C. The DEA technique would construct a piece-wise linear frontier through points A and B, which is identified by the line FABF'. This line is the production frontier. The efficiency of firm C is measured relative to this frontier, and the efficiency measure is equal to OC'/OC. Suppose this value turns out to be 0.6. This implies that firm C is 40% below the production frontier, and it can reach the frontier by reducing both its capital and labour inputs by 40%. Under input-oriented DEA, the firm's measured inefficiency is therefore equal to the entire difference between its position and the constructed efficiency frontier.

It is important to point out that DEA can be conducted using only physical input and output measures. It is not necessary to compute the financial costs or input prices associated with various inputs.[50] This is sometimes considered to be a significant advantage, for these measures are often not readily available and can require significant data to calculate. This is particularly true for capital inputs, which account for the largest share of electric utilities' (non-fuel) cost.[51]

[50] However, input prices are required to calculate allocative efficiency, for this measures the extent to which the input mix is optimal given the relative input prices facing the firm.

[51] JPS' fuel costs are currently subject to separate regulation from the non-fuel costs that are covered by the PBRM.

Appendix A7: Disadvantages of Date Envelope Analysis (DEA)

When applied to electric utilities, many of DEA's potential advantages are illusory. There are also numerous problems with this technique. Some of these problems have been noted generally, but few have examined the particular problems that arise when applying DEA to electric utilities. The disadvantages with DEA can be divided into four categories:

- data requirements and related problems;
- the ability to deal with uncertainty;
- assumptions regarding the production process; and
- problems with controlling for utilities' business conditions.

Some of these issues are interrelated so the problems will overlap somewhat between categories.

A7.1 Data Measures and Requirements

Capital accounts for the dominant share of electric utility costs, so its treatment in benchmarking models is critical. DEA typically uses physical rather than financial capital measures as inputs in electric utility benchmarking studies. Examples include MVA of transformer capacity and km of distribution line. We believe that this approach is problematic in several respects.

One reason is that utility capital is in fact extremely varied. For example, SCADA and related computer systems are increasingly important for monitoring and controlling distribution systems, but these cannot be measured in simple quantitative units.[52] Similarly, utilities have sophisticated telephone call centres, customer information service systems for maintaining metering and billing databases, networks that link customer service and field service representatives, and many other types of equipment. These items account for sizeable shares of capital stock, but they can only be measured in financial terms. It is therefore not possible to measure the scope of electric utility capital accurately with a few simple physical measures.

In addition, physical capital units will not capture the age profile of assets. This can be an important consideration, since older assets will typically entail greater maintenance expenses. If DEA inputs include higher O&M costs but do not reflect the age profile of the capital stock, results may be biased against firms with an older asset profile. In contrast, there are rigorous methods for constructing financial capital measures that appropriately reflect the age and effective services provided by a firm's capital assets. This should lead to more reliable benchmarking assessments.

[52] SCADA stands for system control and data acquisition and refers to computer-based systems that are used for a variety of operations, including monitoring and controlling network components.

A more subtle point is that power distribution systems are also designed differently in different countries, and this can affect the relative amounts of physical assets. For example, the US delivers electricity to most end-users at 110V, while in Australia power is delivered to most end-users at 220/250V. This difference has implications for the design of distribution systems for most urban and suburban residential customers. In the US, there is usually one transformer per residential customer (usually 10 or 16 kVA) with little low voltage line. In Australia, there is usually one larger transformer for each 100 customers or so (usually a three phase 315 kVA) with an extensive low voltage network.

These design differences can affect the results from DEA benchmarking models. DEA usually deals with physical quantities of inputs, so differences in relative amounts of inputs can affect DEA results. In general, US utilities will have more MVA of transformer capacity and fewer km of line, while Australian DBs will have more km of line and fewer MVA of transformer capacity.[53] Different input proportions can distort which firms are selected as peers, since this choice depends on relative input proportions among sampled companies. Comparing an Australian DB to an inappropriate peer leads directly to inappropriate benchmarking results.[54] In contrast, distortions do not arise with econometric cost models that focus on total cost and financial capital measures. Differences in network design do not distort these measures since, given each system's history, the differences in design are most cost effective. Therefore total cost comparisons (as in econometric models) remain valid between US and Australian DBs, while DEA results are distorted by differences in system design and the proportions of physical inputs.

Difficulties also arise in accounting for the transportation nature of energy delivery networks. Measures of energy transportation, such as km of distribution line, are sometimes treated as inputs in DEA studies. However, this is flawed in at least two ways. The first is that purely physical measures like km of line do not reflect the efficiency with which firms construct delivery networks. There is evidence that these differences can be substantial, particularly because of differences in work rules and other factors that affect the productivity of construction labour in different countries.[55] These factors will not be manifested in the physical km of line measure, but they will be reflected in the financial cost (and efficiency) of constructing distribution lines.

[53] For example, if there is one 16kVA transformer for each US customer, there will be 1600 kVA for each 100 customers, compared with 315 kVA for each 100 Australian customers. But consistent with using a higher voltage transformer, Australian DBs have a greater reticulated low-voltage network compared with US firms.

[54] Put another way, differences in system design between US and Australian DBs would lead to expected differences in the proportions of MVA capacity and km of line for two firms in the same countries that served the same customer mix. If an Australian and US firm were selected as peers because they used similar proportions of MVA capacity and km of line, this would imply that these firms actually served a different mix of customers.

[55] The *Richardson International Construction Cost Location Factors* provide evidence on the cost of constructing utility plant in different countries, as well as evidence on the factors that account for differences in construction costs. This data source estimates significant differences in labour productivity across countries.

In addition, it is difficult to capture the transportation nature of power distribution services if km of line is treated as an input. Direct delivery of power to customers is an essential electric utility *output*. This output can be proxied by the total km of distribution line, since this is related to the physical location of customers in the utility's territory. But it is not possible to include km of line as an output in DEA models if it is already used as an input. However, if km of line is used as a DEA output rather than an input, then the model will not reflect the costs associated with the "lines and poles" needed to deliver power to customers.

In short, it is not possible to capture utilities' essential service of delivering power directly to customers and the costs associated with this service by using a single variable such as km of line. The only sensible model must also include the financial costs associated with constructing these lines.

A similar problem is likely to arise when attempting to measure power generation efficiency using DEA. The main power generation output can be measured straightforwardly as kWh generated. A physical measure of the generation capital input could be installed kW. But in this formulation, the "efficiency" measure that is generated for a given company will naturally depend greatly on that company's load factor. Companies have some control over their load factors, but these also are also determined to a great extent by the characteristics of their customer base, which of course vary greatly among utilities. This is another example of the pitfalls of attempting to measure efficiency using only physical input quantities in DEA studies. For these reasons, it does not appear to be practical to benchmark utilities using only physical capital measures.

A7.2 Data Issues and Uncertainty

DEA is not a statistical method, so it much less conducive to dealing with uncertainties regarding benchmarking measures. It is generally not possible to test the statistical precision of benchmarks that are estimated through DEA. DEA also does not naturally lend itself to the construction of confidence intervals around benchmarks.[56]

In fact, since DEA is not a statistical approach, the data themselves establish the cost and/or production frontier. This means that the constructed frontier, and therefore any firm's estimated inefficiency, is extremely sensitive to the quality of the sample data themselves. While it is important to use high quality data in any benchmarking study, the quality of the data becomes a paramount issue under DEA.

Data problems can directly affect efficiency measures. For example, estimated frontiers can result from sample "outliers." Firms may be outliers because of data errors, business condition variables that are omitted from the analysis, and a host of other reasons.

[56] However, "bootstrapping" techniques can be applied in DEA models as a means of generating confidence intervals, but this is a fairly advanced empirical technique that is rarely, if ever, applied in regulatory applications of DEA.

In its report to the OUR, frontier disputes this particular point and claims that outliers will be less of an issue in DEA than in other benchmarking studies. Their reasoning is that if a firm is truly an "outlier" it will not have many identified peers, and its DEA-based efficiency score must increase as a result. It therefore becomes unlikely that such a firm will be identified as inefficient because it is an outlier – indeed, the opposite is likely to be true.

While this will likely be viewed as an acceptable outcome for the outlying firm, it will be much less appropriate for other firms for which this is not the case (*i.e.* the majority of firms that are not "outliers"). In a cross section of computed DEA scores, some of scores at the top may reflect inappropriate inference due to the inability of the DEA model to reflect the business conditions that made these firms outliers. Even if these firms are not identified as "peers" of firms with lower DEA scores, those firms could still be penalized, in a relative sense, since their DEA scores are still low relative to the entire cross section of computed DEA scores. Again, this is not necessarily a valid inference but rather results from the way in which DEA handles "outlier" observations. We believe econometric methods handle such observations more appropriately since, all else equal; there are wider confidence intervals for cost predictions on firms that are more dissimilar than the "mean" sample firm. Wider confidence intervals imply that the econometric benchmarking method is not able to detect any statistically significant difference between the performance of that firm and its expected cost, which is an appropriately cautious conclusion for any "outlier" observation.

DEA measures are also sensitive to the size of the sample. All else equal, larger samples will reduce a firm's efficiency score. The reason is that as the sample size increases, it becomes more likely that a firm will dominate the firm in question.[57] Again, this demonstrates that DEA benchmark measures can be affected by the performance of a single firm.

Data-related problems and the uncertainty of benchmark measures are likely to be greater with international samples. With international data, there is a higher probability that variables will be defined and measured differently across countries. Researchers must take great care to ensure that data are comparable in international benchmarking. Even the most conscientious researcher may have difficulty making data series entirely comparable between countries. Because of its nonparametric nature, non-comparable or otherwise erroneous data are likely to have a much bigger impact in DEA than in econometric studies. This issue is also indisputably relevant in Jamaica, since there is only a single electric utility in the country, so benchmarking by definition must rely on international samples.

[57] This result has been demonstrated by Zhang and Bartels; see Y. Zhang and R. Bartels (1998), "The Effect of Sample Size on the Mean Efficiency in DEA with an Application to Electricity Distribution in Australia, Sweden and New Zealand", *Journal of Productivity Analysis*, 9: 1877-204.

In this regard, the recent decision by the Netherlands energy regulator to use DEA rather than statistical methods for benchmarking in that country is noteworthy. The regulator based this decision on the fact that there were limited data in the country (20 data points), and statistical methods are not precise with such small sample sizes. However, it is *possible* to obtain point estimates of cost function parameters using as few as 20 data points, but statistical analysis is also likely to show that these estimates are very imprecise.[58] DEA will not present information on the confidence associated with DEA-based benchmarks, but there is no *a priori* reason to believe that DEA uses a small number of data points to generate more precise benchmarks. Indeed, it is fair to say that with econometrics, the imprecision with small sample sizes is made plain, while this imprecision simply remains unknown under DEA.

The regulatory implications of data errors and uncertainty are also worth noting. With DEA, problematic data are more likely to lead to outliers that directly affect efficiency measures. Bad data can therefore be translated directly into incorrect inferences on efficiency and, ultimately, bad regulatory policy. With econometrics, "noise" in the data will likely lead to less precise estimated benchmarks. This will be reflected in wider confidence intervals around the benchmarks, which should make regulators less confident about adopting this benchmark as the basis for public policy. Hence, another disadvantage of DEA relative to econometric benchmarking is that its diminished ability to deal with uncertainty can lead to unfortunate policy decisions.

A7.3 Restrictions on Production Process

While DEA does not directly restrict the relationship between electric utility cost and business condition variables, it can involve other problems in terms of correctly specifying the production process. One is that you need *a priori* knowledge to categorize a variable as an input or an output in DEA models. This may be straightforward in many businesses, but it is not always the case for power distribution. One example of this, whether km of line is treated as an input or an output, has already been discussed. Such incomplete specifications necessarily reduce the quality of DEA results.

In addition, DEA results depend on the *number* as well as the choices for inputs and outputs. Increasing the number of variables in DEA studies generally makes it more difficult to identify peers for any individual firm. This can lead to artificially high efficiency measures.

DEA can overcome this problem through second stage regressions that relate DEA efficiency scores to other business conditions variables. These are typically Tobit regressions.[59] However, it is known that second stage Tobit regressions will lead to

[58] However, even to estimate cost function parameters with such small sample sizes, it may be necessary to limit either the number of independent variables and/or restrict the form of the cost function.

[59] The assumptions needed to implement simpler regression methods, such as generalized least squares, are not satisfied when DEA scores are used as the dependent variable in a regression.

biased estimates for business condition parameters if these variables are correlated with the inputs used in DEA. Careful modelling may be able to reduce this problem, but there can still be significant correlations between inputs used in DEA models and business conditions used in Tobit regressions. Two possible examples are km of line (input) and population density (business condition), and O&M costs (input) and percent of kWh sales to residential customers (business condition).

A second stage Tobit will also impose a functional relationship between the efficiency measure and the business conditions. This appears to undercut one of DEA's advantages, that there is no need to specify a functional form for the cost or production relationship. A functional relationship appears to be implicit when a function is specified that relates efficiency to business condition variables, since the efficiency measure is itself derived from DEA's input-output analysis. This relationship may be even more ad hoc than flexible form cost functions, which are disciplined by economic theory and place a minimum of restrictions on the underlying production relation.

A7.4 Problems with Controlling for Differences in Business Conditions

DEA may not control for differences in business conditions as well as econometric methods. Some reasons are suggested above. DEA must often limit the number of business conditions considered, and second stage regressions may yield biased estimates of business condition parameters. Also, because DEA is a non-statistical approach, it may be more difficult to select the right set of business conditions. With econometric methods, one can test the statistical significance of different business conditions on electric utility cost. This provides a straightforward criterion for judging whether a given business condition should be included in the analysis.

The treatment of service quality represents a particularly nettlesome business condition for electric utilities. There are clear cost-quality tradeoffs in the electric power industry. Managers make inter-related decisions about optimising cost and reliability. This optimization process is influenced by other business conditions that the utility faces. In other words, the cost-quality trade-off confronting a utility will vary depending on its other business conditions. Rural utilities, in particular, face circumstances that tend both to raise the cost and reduce the quality of their service.

It is not clear that DEA is a subtle enough benchmarking tool to model these relationships. Indeed, simply adding a service quality output to a DEA model may further bias results. For example, suppose a rural utility has a low DEA efficiency score relative to urban utilities because it requires more inputs to provide the same level of output. If service quality is added as an output, the rural company's performance is likely to look even worse. The DEA model will now show the rural utility is providing fewer units of the quality "output" relative to urban utilities. All else equal, this further reduces the DEA score. This is not a reasonable result, since rural operating conditions *per se* will tend both to raise costs and reduce quality (at a given level of cost).

In principle, econometric cost functions may be able to capture this inter-relationship. For example, econometrics can model utility behaviour so that it involves simultaneous decisions on cost and quality levels. Higher quality can only be obtained at higher cost, with the cost-quality trade-off itself influenced by other business condition variables. This optimization problem can be solved for equilibrium cost and quality levels as a function of exogenous business conditions, and these equations can then be estimated simultaneously. While this is a complex problem, it reflects utility's real behaviour and thus should be explored in benchmarking analysis. To be honest, this has not been the case to date, and econometric benchmarking studies have relied on much simpler models of utility behaviour. Nevertheless, it is possible to see how econometric models can reflect these complexities, but it is not clear how it can be done in DEA. This is an important issue, since managing the complex relationships between cost and service quality is central to the electric power business and thus should be reflected in benchmarking.

Appendix A8: Customer Count List 2003

Table A8.1: JPS Customer Count List 2003

Sub-station	Feeder name	Feeder no.	No. of customers	kW/customer
EASTERN REGION				
KSAN				
Duhaney	Pembrooke Hall	020 / 6-310	10,788	0.53
W/ Kings Hse	New Kingston	241 / 6-210	279	34.92
W/Kings Hse	Kings Way	241 / 6-310	2,155	1.65
W/Kings Hse	Half-way-Tree	241 / 6-410	1,143	3.82
Up Pk Camp	Lady Musgrave Rd	245 / 6-410	1,133	5.35
Washington Blvd	Const. Spring Rd	104 / 6-510	2,428	3.75
Washington Blvd	Half Way Tree	104 / 6-410	3,182	2.96
Washington Blvd	Red Hills Road	104 / 6-810	3,274	1.73
Constant Spring	Red Hills	191 / 6-210	6,896	0.91
Constant Spring	Stony Hill	191 / 6-410	13,882	0.61
Washington Blvd	Shortwood Rd.	104 / 6-610	4,806	1.14
Hope	East	041 / 6-510	13,623	0.58
Hope	West	041 / 6-410	3,617	2.18
Hope	University	041 / 5-310	141	23.92
Constant Spring	Long lane	191 / 6-310	1,599	1.49
Subtotal			*68,946*	
KSAS				
Up Pk Camp	Oxford Rd	245/6-310	1,051	5.36
Hunts Bay - B	Cross Rd/Camp Rd	265 / 6-310	2,652	0.00
Hunts Bay - B	Darling Street	265 / 6-510	1,951	0.00
Hunts Bay - B	Orange Street	265 / 6-410	494	0.93
Greenwich Rd.	Beechwood Ave.	223 / 6-510	1,378	6.70
Greenwich Rd.	Cross Rd/Mt View	223 / 6-410	1,211	7.95
Greenwich Rd.	Lyndhurst Rd.	223 / 6-310	737	10.45
Greenwich Rd.	West New Kgn.	223 / 6-710	1,253	7.44
Gorden Cay		169/5-210	1	2,674.32
Gorden Cay		169/5-110		1,686.08
Up Pk Camp	Mountain View	245 / 6-510	5,430	1.09
Hunts Bay - B	Pt. Royal St.	265 / 6-110	267	19.39
Hunts Bay - B	New Port East	265 / 6-210	525	32.20
Rockfort	Dow n Tow n	243 / 6-410	3,773	1.64
Rockfort	Flour Mills	243 / 6-310	1	3,072.96
Rockfort	Rollington Twn	243 / 6-210	737	0.44
Cement Co			1	0.00
Cane River	Airport	200 / 6-610	1,844	1.35
Cane River	Harbour View	200 / 6-410	1,762	2.10
Cane River	St. Thomas	200 / 6-310	6,838	0.21

Table A8.1: JPS Customer Count List 2003 (cont'd.)

Sub-station	Feeder name	Feeder no.	No. of customers	kW/customer
Wash/ Blvd.	Molynes Road	104 / 6-710	5,565	0.73
Wash/ Blvd.	Waltham Pk Rd.	104 / 6-310	4,448	1.21
D & G	D & G	281/5-210	1	4,606.80
D & G	Y. Wray & Nephew	281 / 5-310	535	3.74
Hunts Bay - B	Esso Refinery	265 / 5-610	1	2,370.72
Hunts Bay - B	New Port West	265 / 5-810	2,111	1.34
Hunts Bay - B	Spanish Town Rd.	265 / 5-710	1,610	6.96
Duhaney	Spanish Town Rd.	020 / 6-410	2,019	1.27
Three Miles	Free Zone	289 / 5-310	749	8.59
Three Miles	Seaview	289 / 5-410	2,019	3.08
Three Miles	Industrial Estate	289 / 5-510	286	17.09
Subtotal			*51,250*	
St. Thomas				
Good Year	Factory	186 / 6-110	1	0.00
Good Year	Morant Bay	186 / 6-210	8,547	0.50
Lyssons	Morant Bay	238 / 6-410	9,572	0.27
Subtotal			*18,120*	
Portland				
Port Antonio	San San	297 / 6-310	7,887	0.34
Port Antonio	Town	297 / 6-410	9,475	0.59
Subtotal			*17,362*	0.00
St. Mary				
U. White River	Lucky Hill/Gayle	010 / 4-210	4,830	0.52
Blackstoneage	Guys Hill	199/4-110	1,193	1.02
Oracabessa	Port Maria	126 / 4-110	1,723	1.02
Oracabessa	Rio Nuevo/Stew Twn	126 / 4-210	3,310	0.94
Annotto Bay	Annotto Bay	218 / 6-310	1,298	1.31
Annotto Bay	Port Antonio	218 / 6-210	1,115	4.88
Highgate	Highgate	011 / 4-110	3,784	0.57
Highgate	Port Maria	011 / 4-210	7,017	0.48
Subtotal			*24,270*	

Table A8.1: JPS Customer Count List 2003 (cont'd.)

Sub-station	Feeder name	Feeder no.	No. of customers	kW/customer
SOUTHERN REGION				
Manchester, St. Elizabeth				
Kendal	Christiana	237/6-210	9,764	0.37
Kendal	Mile Gully	237/6-310	7,477	1.23
Porus	Comfort	014/6-210	3,425	0.33
Porus	Porus	014/6-310	5,052	0.76
Spur Tree	Santa Cruz	064/6-210	13,095	0.57
Spur Tree	Newport	064/6-310	11,926	0.47
Maggotty	Maggotty	031/6-110	11,998	0.16
Maggotty	Black River	031/6-210	7,443	1.16
Subtotal			*70,180*	
Clarendon				
May Pen	Eastern (Chapelton, Frankfield)	201/6-110	9,113	0.31
May Pen	West (Town)	201/6-210	12,084	0.29
Monymusk	Lionel Town,	194/4-210	1,752	0.78
Monymusk	Factory	194/4-310	10	441.81
Monymusk	Monymusk	194/4-410	7,835	0.48
Parnassus	York Town	026/6-210	5,760	0.77
Parnassus	Hayes	026/6-310	5,448	0.88
Subtotal			*42,002*	
St. Catherine				
Duhaney	Ferry	020/6-210	3,692	2.99
Michelton Halt	Bog Walk	013/4-110	6,869	0.95
Michelton Halt	Linstead	013/4-210	4,774	1.22
Naggo's Head	Braton, Edgewater	239/6-210	6,756	0.00
Naggo's Head	Bernard Lodge	239/6-510	11,404	0.78
Naggo's Head	Hellshire, Greater Portmore	239/6-610	6,227	0.82
Rhoden's Pen	Spring Village	092/4-210	3,769	0.52
Rhoden's Pen	Factory, Salt River	092/4-310	3,138	1.07
Rhoden's Pen	Browns Hall	092/4-410	5,716	0.48
Tredegar	Old Harbour Rd./ St Johns	197/6-210	5,570	0.43
Tredegar	Eltham Park	197/6-310	3,286	1.08
Tredegar	Spanish Town	197/6-410	10,130	0.99
Twichenham	Central Village / Waterford	298/6-210	13,562	0.85
Twichenham	Twickham / Greendale	298/6-410	13,813	1.00
Subtotal			*98,706*	

Table A8.1: JPS Customer Count List 2003 (cont'd.)

Sub-station	Feeder name	Feeder no.	No. of customers	kW/customer
NORTHERN REGION				
Trelawny				
Greenwood	Trelawny	006/4-110	3,689	1.08
Martha Brae	Trelawny	007/4-110	4,240	0.65
Duncans	Trelawny	161/4-110	5,572	0.88
Subtotal			*13,501*	0.00
St. Ann				
Cardiff Hall	St. Ann	053/6-210	3,968	0.77
Cardiff Hall	St. Ann	053/6-310	11,635	0.85
Ocho Rios	St. Ann	167/4-310	1,764	3.26
Ocho Rios	St. Ann	167/4-410	3,581	1.52
Ocho Rios	St. Ann	167/4-510	1,547	2.23
Roaring River	St. Ann	009/4-210	8,576	0.45
Roaring River	St. Ann	009/4-310	305	2.15
Roaring River	St. Ann	009/4-410	3,581	1.21
Subtotal			*34,957*	
St. James				
Bogue	Montego Bay	001/6-210	8,703	1.19
Bogue	Montego Bay	001/6-310	11,159	0.83
Bogue	Montego Bay	001/6-410	174	26.35
Queen's Drive	Montego Bay	004/6-310	3,206	0.87
Queen's Drive	Montego Bay	004/6-410	1	3,560.48
Queen's Drive	Montego Bay	004/6-710	14,613	0.61
Queen's Drive	Montego Bay	004/6-810	3,460	2.85
Rose Hall	Montego Bay	005/4-210	1,284	5.43
Subtotal			*42,600*	
Hanover				
Orange Bay	Lucea	017/6-210	2,159	4.59
Orange Bay	Lucea	017/6-310	12,004	0.91
Subtotal			*14,163*	
Westmoreland				
Paradise	Sav-la-Mar	019/6-110	12,616	0.41
Paradise	Sav-la-Mar	019/6-210	11,495	0.44
Paradise	Sav-la-Mar	019/6-310	8,778	0.57
Subtotal			*32,889*	

Appendix A9: Foreign Exchange Adjustment Factor: Details of JPS' Cost Analyses

Table A9.1 shows how JPS originally derived the 75% foreign exchange factor that has been implemented since the 2001 Tariff Submission. Subsequent reviews of the company's cost structure have revealed however, that the relative proportions of fuel and non-fuel costs are no longer as reflected in table A1. The details of these analyses are given in tables A9.2 – A9.5.

Tables A9.2, A9.3 and A9.4 show the cost analyses for JPS for the financial years ended March 2001, March 2002 and December 2002 respectively. These costs were extracted from the audited financial statements for the corresponding periods. Table A9.5 was derived from the financial statements for the twelve months ended December 2003 (unaudited and updated as of February 15th, 2004). It should be noted that both fuel and non-fuel expenses include IPP costs.

Table A9.1: Analysis of Local and US-Dollar Costs for financial year ended March 2000

	Actual Costs		US component of Actual Costs (J$ Equivalent)	
	J$'000	% of Total Expense	%	J$'000
Purchased Power (non fuel)	**2,413,480**	**16%**	**100%**	**2,413,480**
O&M Expenses	**4,270,641**	**29%**	**27%**	**1,153,073**
Other Expenses	**2,720,194**	**18%**	**85%**	**2,312,165**
Depreciation	*1,631,478*	*11%*	*85%*	*1,386,756*
Net Operating Profit	*1,088,716*	*7%*	*85%*	*925,409*
TOTAL NON FUEL EXPENSES	**9,404,315**	**64%**	**63%**	**5,878,718**
TOTAL FUEL EXPENSE (incl. IPP)	**5,354,338**	**36%**	**100%**	**5,354,338**
TOTAL EXPENSES	**14,758,653**	**100%**	**76%**	**11,233,056**

Table A9.2: Analysis of Local and US-Dollar Costs for financial year ended March 2001

	Actual Costs		US component of Actual Costs (J$ Equivalent)	
	J$'000	% of Total Expense	%	J$'000
Purchased Power (non fuel)	**2,671,518**	**12%**	**100%**	**2,671,518**
O&M Expenses	**4,601,236**	**21%**	**27%**	**1,262,694**
Payroll, benefits & training	*2,683,738*	*12%*	*2%*	*53,675*
Third party services	*815,800*	*4%*	*35%*	*285,530*
Materials & equipment	*305,924*	*1%*	*100%*	*305,924*
Office & Other expenses	*658,526*	*3%*	*80%*	*526,821*
Insurance expense	*100,827*	*0%*	*90%*	*90,744*
Bad debt write-off	*36,421*	*0%*	*0.00%*	*0*
Other Expenses	**6,794,145**	**31%**	**100%**	**6,794,145**
Depreciation	*1,598,767*	*7%*	*100%*	*1,598,767*
Financing costs	*1,353,477*	*6%*	*100%*	*1,353,477*
Return on Equity	*3,841,901*	*18%*	*100%*	*3,841,901*
TOTAL NON FUEL EXPENSES	**14,066,899**	**64%**	**76%**	**10,728,357**
TOTAL FUEL EXPENSE (incl. IPP)	**7,767,225**	**36%**	**100%**	**7,767,225**
TOTAL EXPENSES	**21,834,124**	**100%**	**85%**	**18,495,582**

Table A9.3: Analysis of Local and US-Dollar Costs for financial year ended March 2002

	Actual Costs		US component of Actual Costs (J$ Equivalent)	
	J$'000	% of Total Expense	%	J$'000
Purchased Power (non fuel)	**2,513,117**	**12%**	**100%**	**2,513,117**
O&M Expenses	**4,914,660**	**23%**	**28%**	**1,371,366**
Payroll, benefits & training	*2,944,266*	*14%*	*2%*	*58,885*
Third party services	*659,812*	*3%*	*35%*	*230,934*
Materials & equipment	*295,374*	*1%*	*100%*	*295,374*
Office & Other expenses	*692,938*	*3%*	*80%*	*554,350*
Insurance expense	*257,580*	*1%*	*90%*	*231,822*
Bad debt write-off	*64,690*	*0%*	*0.00%*	*0*
Other Expenses	**6,261,560**	**29%**	**100%**	**6,261,560**
Depreciation	*1,692,468*	*8%*	*100%*	*1,692,468*
Financing costs	*1,043,809*	*5%*	*100%*	*1,043,809*
Return on Equity	*3,525,283*	*16%*	*100%*	*3,525,283*
TOTAL NON FUEL EXPENSES	**13,689,337**	**64%**	**74%**	**10,146,043**
TOTAL FUEL EXPENSE (incl. IPP)	**7,856,575**	**36%**	**100%**	**7,856,575**
TOTAL EXPENSES	**21,545,912**	**100%**	**84%**	**18,002,618**

Table A9.4: Analysis of Local and US-Dollar Costs for 9-month financial year ended December 2002

	Actual Costs		US component of Actual Costs (J$ Equivalent)	
	J$'000	% of Total Expense	%	J$'000
Purchased Power (non fuel)	**2,344,485**	**13%**	**100%**	**2,344,485**
O&M Expenses	**3,891,546**	**21%**	**30%**	**1,163,319**
Payroll, benefits & training	*2,208,922*	*12%*	*2%*	*44,178*
Third party services	*583,852*	*3%*	*35%*	*204,348*
Materials & equipment	*256,344*	*1%*	*100%*	*256,344*
Office & Other expenses	*516,159*	*3%*	*80%*	*412,927*
Insurance expense	*272,801*	*1%*	*90%*	*245,521*
Bad debt write-off	*53,468*	*0%*	*0.00%*	*0*
Other Expenses	**5,255,827**	**28%**	**100%**	**5,255,827**
Depreciation	*1,333,869*	*7%*	*100%*	*1,333,869*
Financing costs	*908,513*	*5%*	*100%*	*908,513*
Return on Equity	*3,013,445*	*16%*	*100%*	*3,013,445*
TOTAL NON FUEL EXPENSES	**11,491,858**	**62%**	**76%**	**8,763,631**
TOTAL FUEL EXPENSE (incl. IPP)	**7,144,753**	**38%**	**100%**	**7,144,753**
TOTAL EXPENSES	**18,636,611**	**100%**	**85%**	**15,908,384**

Table A9.5: Analysis of Local and US-Dollar Costs for financial year ended December 2003[1]

	Actual Costs		US component of Actual Costs	
	J$'000	% of Total Expense	%	J$
Purchased Power (non fuel)	**3,477,385**	**11%**	**100%**	**3,477,385**
O&M Expenses	**6,189,680**	**20%**	**31%**	**1,925,465**
Payroll, benefits & training	*3,476,293*	*11%*	*2%*	*69,526*
Third party services	*909,778*	*3%*	*35%*	*318,422*
Materials & equipment	*432,635*	*1%*	*100%*	*432,635*
Office & Other expenses	*924,274*	*3%*	*80%*	*739,419*
Insurance expense	*384,697*	*1%*	*95%*	*365,462*
Bad debt write-off	*62,003*	*0%*	*0.00%*	*0*
Other Expenses	**1,975,613**	**6%**	**92%**	**1,823,843**
Depreciation	*1,960,574*	*6%*	*100%*	*1,960,574*
Interest on Customer Deposits	*151,770*	*0%*	*0%*	*0*
Net Financing costs[2]	*-262,731*	*-1%*	*100%*	*-262,731*
Sinking (self-insurance) fund contribution[3]	*126,000*	*0%*	*100%*	*126,000*
Return on Rate Base (WACC)	**6,722,998**	**22%**	**100%**	**6,722,998**
Cost of Debt	*1,091,442*	*4%*	*100%*	*1,091,442*
Pre-Tax Return on Equity	*5,631,556*	*18%*	*100%*	*5,631,556*
TOTAL NON FUEL EXPENSES	**18,365,676**	**59%**	**76%**	**13,949,690**
TOTAL FUEL EXPENSE (incl. IPP)	**12,570,818**	**41%**	**100%**	**12,570,818**
TOTAL EXPENSES	**30,936,494**	**100%**	**86%**	**26,520,508**

Notes: [1]Figures are based on unaudited accounts, as on February 15th 2004. At time of submission of this report, audited accounts are not available. They will be available in March 2004; [2] Net Financing Costs excludes Interest on Long Term Debt, which is captured in the WACC; [3] Self-Insurance Fund Contribution taken from the Revenue Requirement for the Test Year Period (see Table 6.1);

Appendix A10: Modelling of Heat Rate Performance

The JPS Generating System is fairly small and reasonably predictable in terms of the operating regime over a short timeframe. Hence, a spreadsheet model was developed to estimate the effect of system dispatch and new plant addition on heat rate performance over the five-year period. The critical parameters that affect the system heat rate were identified for use in the model. They are:

- availability;
- capacity factor or utilization level; and
- average generating unit heat rate.

The system heat rate is primarily affected by the individual unit's capacity factors. Each generator's utilization level is likewise determined by its availability and its dispatch regime. The prior five-year historic averages for these metrics were calculated and used as a baseline performance for the system going forward.

In looking at the future five years, the following assumptions were made:

- The existing generating units perform at an average availability and average heat rate that is consistent with the previous five years.

- The projected demand and energy growth rates were adjusted to reflect the trends of the last three years. Average 3.5% growth assumed for both going forward.

- To serve the projected energy (MWh) requirements, the capacity factor of the plants is first assumed to be at least equivalent to the prior five-year averages. This assumption is held for the baseload plants, which if available at the same levels as the previous five years, will be utilized at similar capacity factors. The levels of utilization of Intermediate Plants and GTs are then adjusted until the composite energy output of all plants matches the projected energy requirements. (see Table A10.2 for historical and projected capacity factors).

- Capacity additions required within the five-year horizon were determined from the least cost expansion planning optimization process. The plan going forward assumes that a 40MW Bridge-Capacity is added in 2005 followed by another 40MW in 2006. These Bridge-Capacity additions are needed to give sufficient time for the addition of the main base-load plant in 2008. This major 115MW addition is assumed to be a Coal Fired Steam Plant.

- The MW output of individual generating units are kept within ranges consistent with their historical five-year maximums and minimums. This ensures that the assumption of Average Heat Rates going forward is a reasonable one. In the early years before the Bridge-Capacity additions, GT utilization levels are closer to 2001 operating levels. In future years with new capacity added, GT utilization levels will fall at or just below the five-year average levels. Each Bridge-Capacity Plant is assumed to have projected utilization (Capacity Factor) growing from 15% in their first year (added in last quarter of each year) to 40 to 65% in the years preceding the Coal Plant addition in 2008. These utilization levels then fall off to 40 to 45% in 2008-2009.

The average performance for the steam baseload plants is a reasonable basis for the projections with assumed availabilities and forced outage rates going forward which are similar to the previous five years. The gas turbines however may have different heat rates depending on the performance of the baseload units, demand growth rates, etc. Given the relative sizes of the plants and their rank in the merit order, baseload plants will however have the most significant effect on System Heat Rate due to their share of the total energy requirements.

The basic formulae used in the model are:

> Average System Heat Rate (KJ/kWh) = Sum of (Unit Energy (kWh) x Average Unit Heat Rate (KJ/kWh) / (Total kWh)

Where:

- Unit Energy (kWh) = capacity factor x MCR^{c} (kW) x 8760
- MCR^{c} = maximum continuous rating

System heat rate is calculated as the weighted average generating unit heat rate including hydro energy and IPP's (see Tables A10.1—A10.4 for JPS' system historical and projected MCR, capacity factor. unit energy and average unit heat rate respectively).

Table A10.1 JPS' System Historical and Projected MCR (MW)

[Figures omitted. See note on page iii.]

Table A10.2 JPS' System Historical and Projected Capacity Factor (%)

[Figures omitted. See note on page iii.]

Table A10.3 JPS' System Historical and Projected Unit Energy (MWh)

[Figures omitted. See note on page iii.]

Table A10.4 JPS' System Historical and Projected Average Unit Heat Rate (kJ/kWh)

[Figures omitted. See note on page iii.]

Appendix A11: Liquidated Damages under Purchase Power Agreements

[Text omitted. See note on page iii.]

Appendix A12: Load Research Analysis

In an effort to better understand demand profile of customers, JPS in 2003 injected additional resources into its load research programme. This involved the acquisition and installation of 300 mass memory meters; the purchase of new meter reading devices as well as software upgrades to facilitate data analysis. The result is that since September 2003, the electricity consumption of approximately 600 customers is constantly being recorded to provide a meaningful insight into the behaviour of the company's entire customer base.

This report presents important elements of the results of load research analyses for the month of December 2003. More specifically, it addresses customer load characteristics and rate class contribution to system peak.

A12.1 Contribution to the Peak Demand

Over the last ten years the annual system peak has occurred between 6:00-8:00 p.m. There is also a day peak, which generally occurs between 10:00 am – 2:00 p.m. However over time the difference between these peaks have diverged, moving from 4% (i.e. the extent to which the evening peak exceeds the day peak) in 1994 to 17% in 2002. For the year 2003 the difference was 15% (see Table A12.1).

Table A12.1: Day and Evening Peak (1994 – 2003)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	**2003**
Evening Peak (MW)	380	391	431	468	489	520.9	546.7	554.8	581.3	**592.8**
Day Peak (MW)	366	371	415	444	453	470.5	473.7	516.9	496.5	**505.6**
Difference (MW)	14	20	16	24	36	50.4	73.0	37.9	84.8	**87.2**
% Difference	4%	5%	4%	5%	7%	11%	15%	7%	17%	**15%**

Based on the average demand on the day of peak for the three months period October to December 2003, the evening peak occurs at 7:00 p.m., with the Residential (Rate 10) class accounting for the greatest share (42%, excluding losses) of the system demand (see Table A12.2). The average demand for the three months also indicates that the day peak occurs at 12:30 p.m. with the General Service (Rate 20) class responsible for (33% excluding losses) most to the system demand (see Table A12.3).

Table A12.2: Average Contribution to Evening Peak (October- December 2003)

Rate Class	No. of Customers	Contribution to EVENING PEAK - 7:00 PM		
		MW	Relative Share	Relative Share (excl. Losses)
Rate 10 - Residential	470,856	184.83	32%	42%
Rate 20 - General Service	53,598	82.36	14%	19%
Rate 40 LV - Power Service	1,348	70.17	12%	16%
Rate 40 MV - Power Service	46	6.49	1%	1%
Rate 50 LV - Large Power	37	13.08	2%	3%
Rate 50 MV - Large Power	64	52.64	9%	12%
Denoes & Geddes	1	4.73	1%	1%
Carib Cement	1	9.32	2%	2%
Port Authority	1	1.90	0%	0%
Rate 60	190	11.00	2%	3%
Losses & Unaccounted For	-	145.48	25%	
System Total	526,143	582.01	100%	100%

Table A12.3: Average Contribution to Day Peak (October - December 2003)

Rate Class	No. of Customers	Contribution to DAY PEAK - 12:30 PM		
		MW	Relative Share	Relative Share (excl. Losses)
Rate 10 - Residential	470,856	112.90	22%	26%
Rate 20 - General Service	53,598	139.98	28%	33%
Rate 40 LV - Power Service	1,348	78.31	16%	18%
Rate 40 MV - Power Service	46	9.40	2%	2%
Rate 50 LV - Large Power	37	15.63	3%	4%
Rate 50 MV - Large Power	64	57.45	11%	13%
Denoes & Geddes	1	5.21	1%	1%
Carib Cement	1	10.04	2%	2%
Port Authority	1	1.56	0%	0%
Rate 60	190	0.00	0%	0%
Losses & Unaccounted For	-	72.54	14%	
System Total	526,143	503.03	100%	100%

A12.2 December 2003 Results

The gross peak demand for month of December 2003 was 592.8 MW (559.6MW net). This was the highest gross peak demand recorded for the year and it occurred at 7.00pm on Thursday, December 18, 2003. The evening peak in December exceeded the day peak by 87.2 MW or 15% (See Table A12.1). The day peak registered was 505.6 MW and it occurred at 12:30 p.m.

The Rate 20 group dominates demand during the day, 25% of the daytime peak on December 18 was attributable to the demand from that class and residential customers accounted for 22%. (See table A12.5.) In contrast, the Rate 10 group dominates the demand during the evening accounting for 31% of the evening peak (see Table A12.4) while the Rate 20 class was only responsible for 13%. From this it is evident that the evening peak is driven by residential demand and the daytime peak is largely explained by commercial activities (see Figure A12.1)

Table A12.4: Contribution to Evening Peak – December 2003

Rate Class	No. of Customers	Contribution to EVENING PEAK -7:00 PM		
		MW	Relative Share	Relative Share (excl. Losses)
Rate 10 - Residential	473,370	180.82	31%	42%
Rate 20 - General Service	53,884	74.85	13%	17%
Rate 40 LV - Power Service	1,349	69.30	12%	16%
Rate 40 MV - Power Service	49	6.51	1%	2%
Rate 50 LV - Large Power	36	13.67	2%	3%
Rate 50 MV - Large Power	62	54.89	9%	13%
Denoes & Geddes	1	5.15	1%	1%
Carib Cement	1	12.80	2%	3%
Port Authority	1	2.05	0%	0%
Rate 60	190	11.00	2%	3%
Losses & Unaccounted For	-	161.76	27%	
System Total	528,943	592.80	100%	100%

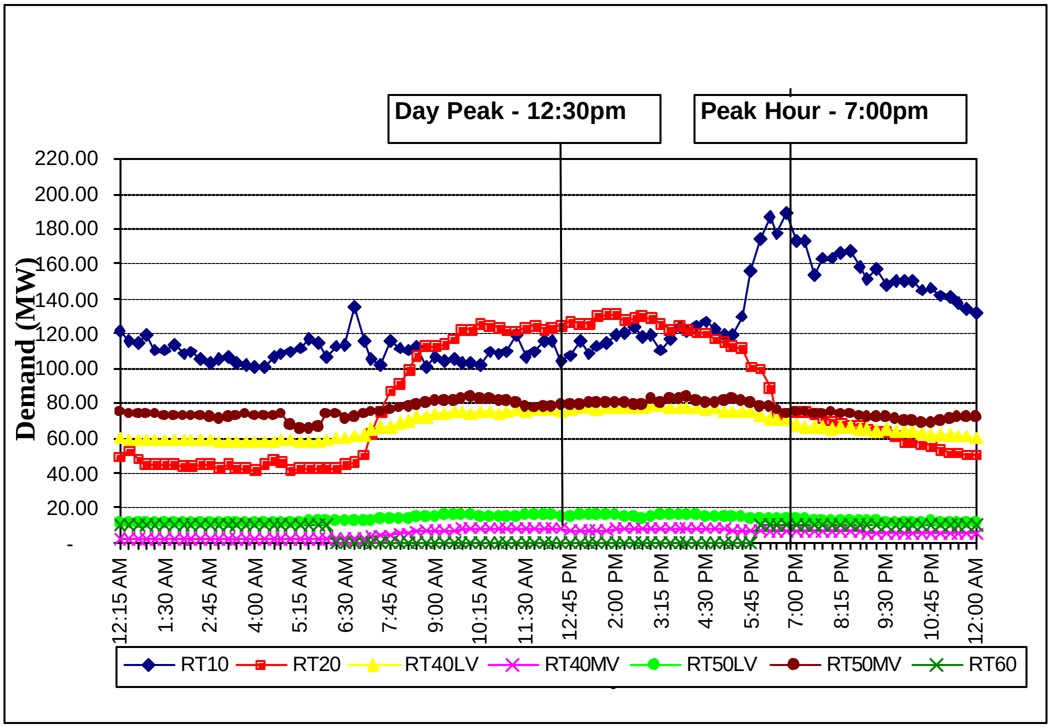
Table A12.5: Contribution to Day Peak – December 2003

Rate Class	No. of Customers	Contribution to DAY PEAK - 12:30 PM		
		MW	Relative Share	Relative Share (excl. Losses)
Rate 10 - Residential	473,370	109.72	22%	27%
Rate 20 - General Service	53,884	124.14	25%	30%
Rate 40 LV - Power Service	1,349	75.94	15%	18%
Rate 40 MV - Power Service	49	8.28	2%	2%
Rate 50 LV - Large Power	36	15.56	3%	4%
Rate 50 MV - Large Power	62	57.60	11%	14%
Denoes & Geddes	1	5.75	1%	1%
Carib Cement	1	13.65	3%	3%
Port Authority	1	1.75	0%	0%
Rate 60	190	0.00	0%	0%
Losses & Unaccounted For	-	93.22	18%	
System Total	528,943	505.6	100%	100%

A12.3 Demand Profile

From the perspective of generating economics, the flatter the daily system demand is the lower the cost of generation. The opposite is also true – peaky demand profiles lead to relatively higher generation. This is because of two reasons, with peaky demand profiles the utility has to invest more in (peaking) plants that are only required for short periods during the day to ensure that supply is adequate to meet the highest demand. Secondly, these peaking plants are generally gas turbines and use more expensive fuel; consequently they are more costly to operate.

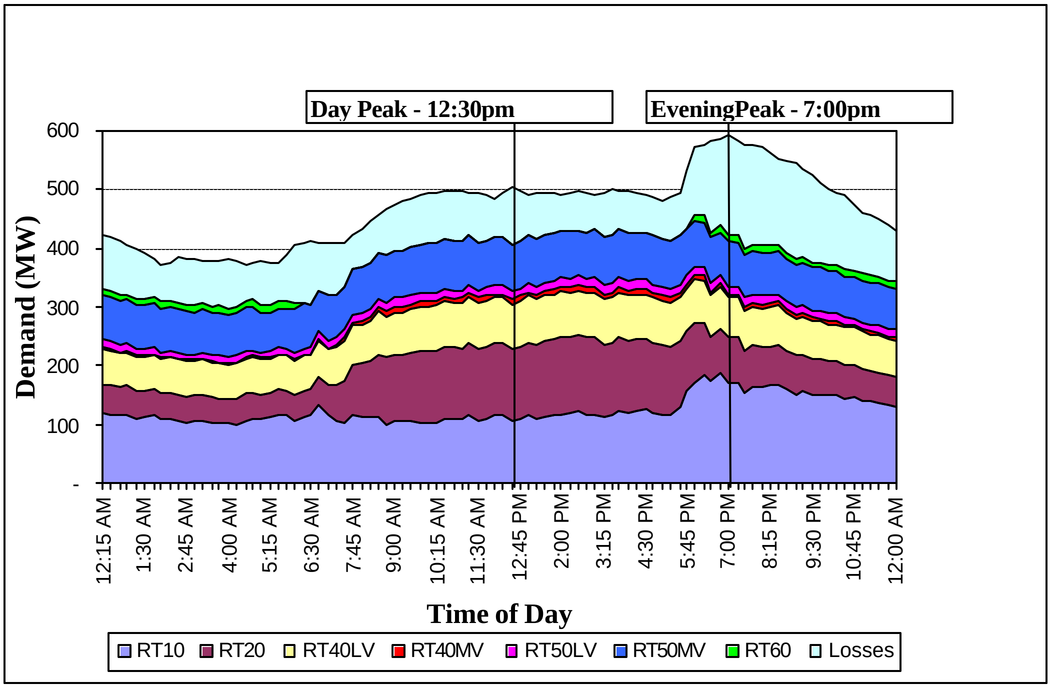
Figure A12.1: Rate Class Demand Profile for Peak Day (Thursday December 18th, 2003)



An examination of JPS' system demand profile (excluding losses) reveals that between 10:00 pm and 8:00 am the total demand is less than 350 MW while at the peak it is over 500 MW (see Figure A12.2). However, it is the Rate 10 and the Rate 20 classes that have the biggest impact on the variability in the daily demand since the profile for all the other groups tend to have less variability between the peaks and troughs.

If it is generally accepted that residential demand tend to be inelastic because it is primarily determined by convenience, then it is clear that the Rate 20 group should be given greater consideration in any attempt to flatten the demand profile.

Figure: A12.2: System Profile on Peak Day (Thursday December 12th, 2003)



Appendix A13: JPS 2003 Billing Determinants

The billing determinants for 2003 are used as the basis for deriving the proposed rates. Forecasted growth rates are applied to these determinants to derive forecasted 2004 billing determinants. In arriving at the billing determinants used in the tariff design, the actual set of billing determinants for 2003 was modified in two ways. Both are discussed in the following.

A13.1 Reclassification of customers

Reclassification of customers into the appropriate rate classes—commercial and industrial customers are currently differentiated according to their demand profile, i.e., a commercial customer is classified as a Rate 20 customer if its demand is consistently under 25kVA. Similarly, a customer is placed in Rate 40 if it has consistently consumed over 25kVA but below 500kVA. Currently, a Rate 50 customer should have a demand in excess of the 500kVA threshold.

In reviewing the historical demand profile of some customers, the JPS has determined that there are some customers that should no longer be assigned to a particular class as they have not met the criteria highlighted above. For instance, a customer that was originally classed as Rate 20 may have expanded to a demand in excess of 25kVA. This customer should therefore be billed as a rate 40 or 50 depending on its current load. JPS has therefore modified the 2003 billing determinants to reflect the reclassification of customers, as appropriate. The intention is that these customers will be moved into the new rate classes soon after the implementation date of the new rates. This exercise, however, has only been undertaken for customers who, once moved, will see a reduction in their bills.

A summary of the number of customers moved across classes is outlined in Table A13.2 below. Of particular note is the migration of Rate 40A to either Rate 20 or Rate 40, the result of which has been a reduction of the 40A class by approximately 50%.

Table A13.2: Summary of Customers Moved Across Classes

	Original Total Number of Customers	Number of Customers moved to			
		Rate 20	Rate 40	Rate 50	New Total Number of Customers
Number of Rate 20	52,885	-	253	-	52,681
Number of Rate 40A	455	23	126	-	306
Number of Rate 40[1]	972	26	-	-	1,334
Number of Rate 50[2]	100		9		91

Note: [1] Rate 40 includes 40LV and 40MV; [2] Rate 50 includes 50LV and 50MV;

A13.2 Adjustments to the billing demand of current Rate 50 customers

Another proposal by the JPS is the removal of the 500kVA minimum demand threshold for customers in the current Rate 50 class. This is a direct result of the rate class rationalization exercise outlined in Section 16.1, in which Low Voltage customers (Rates 40LV and 50LV) will be merged together, with Medium Voltage customers (Rates 40MV and 50MV) being placed in a separate group. This union of the current rate classes effectively puts two classes together that originally had different threshold levels. Specifically, the current Rate 40LV will be merged with Rate 50LV although each class has a different minimum demand of 25kVA and 500kVA respectively. A similar problem occurs with the MV class, which merges the current Rate 40MV with the Rate 50MV classes together. JPS proposes to eliminate these inconsistencies by choosing the lower threshold of 25kVA as the minimum demand required for both the Low Voltage and Medium Voltage classes.

In light of this change, JPS recommends that, for any Rate 50LV and Rate 50MV customer that consumed less than 500kVA for any month during 2003, the actual kVA readings be used as an estimate of the billing kVA levels going forward. This is because current billed readings would have imposes a minimum demand of 500kVA that is also ratcheted. With the removal of the 500kVA threshold, this would no longer be appropriate going forward. Using actual readings for these customers will therefore ensure that the billing determinants for these customers are not being overstated.

The billed readings will however be used for all other Rate 50LV and Rate 50MV customers that consistently consume in excess of 500kVA. Similarly, billed readings will be used for all current Rate 40LV and Rate 40MV classes since the minimum demand of 25kVA already corresponds to that being proposed under the new rate structure.

A13.3 Billing determinants for 2003

Table A13.2 summarizes the billing determinants for 2003 that was derived according to the methods outlined above.

Table A13.2: Billing Determinants (Adjusted): January - December 2003

Rate Class	No. of Customers	Energy (MWh) Standard	Energy (MWh) Off Peak	Energy (MWh) Part Peak	Energy (MWh) On Peak	Demand (kVA) Standard	Demand (kVA) Off Peak	Demand (kVA) Part Peak[1]	Demand (kVA) On Peak
Rate 10	462,107	1,106,691							
Rate 20	52,681	597,378							
Rate 40A LV	306	40,144				312,592			
Rate 40 LV Standard	1,161	492,040				1,597,337			
Rate 40 LV TOU	123		57,536	42,516	12,734		303,260	301,988	265,377
Rate 50 LV Standard	26	86,631				264,917			
Rate 50 LV TOU	10		11,439	8,245	2,133		97,612	88,837	47,445
Rate 40 MV Standard	42	46,256				162,085			
Rate 40 MV TOU	8		5,883	4,716	1,312		37,798	39,654	31,620
Rate 50 MV Standard	29	178,464				491,273			
Rate 50 MV TOU[2]	26		71,020	56,575	16,549		461,952	432,059	347,650
Rate 60	462,107	1,106,691							
ALCAN interchange	52,681	597,378							
TOTAL	**516,714**	**2,620,594**	**145,877**	**112,053**	**32,730**	**2,828,203**	**900,622**	**862,538**	**692,092**

Note: [1] Partial Peak ratcheted as the maximum of the on peak and the partial peak as proposed in Section 16.5.1; [2] Rate 50 MV excludes Caribbean Cement Company

Appendix A14: Analysis on impact proposed tariff on customer bills

The following tables present the analysis of the impact of the proposed tariff on customer bills. Specifically, they compare the expected bills for the month of June 2004, relative to the expected bills for the month of May. The impact analysis is disaggregated into two components:

- The impact of adjusting the current rates to reflect inflation, based on the current inflation escalation factor, and the implementation of the proposed foreign exchange adjustment factor, i.e.:
  - calculating the fuel charge using the billing exchange rate, implementing the foreign exchange adjustment factor on the non-fuel charges only; and
  - updating the adjustment factor to reflect the current proportion of US-related costs of 76%).
- The incremental impact of the proposed rates.

For comparison purposes, the fuel charge is assumed to be constant at J$3.739/kWh for the months of May and June.

Table A14.1: Impact of Proposed Rates on the Monthly bill a Typical Lifeline Rate 10 Customer

Description		Current rates	Inflation escalated rates and new foreign exchange adjustment mechanism	Proposed rates
Assumptions				
Usage (kWh)	a	99	99	99
Base Exchange Rate	b	50	63	63
Billing Exchange Rate	c	63	63	63
Foreign exchange adjustment factor	d	75%	76%	76%
Charges				
Energy First 100 kwh	e	4.102	4.978	6.127
Fuel Charge	f	3.739	4.711	4.711
Customer Charge	g	58	70.38	86.63
Monthly bill components				
Energy First 100 kwh	h=a x e	406	493	607
Customer Charge	i=g	58	70	87
Sub Total	j=h+i	464	563	693
F/E Adjust	k = (c-b)/b) x d x j	90	-	-
Non-Fuel After F/E Adj.	l=j+k	555	563	693
Fuel Charge	m=f x a	370	466	466
F/E Adjust	n = (c-b)/b) x d x m)	72	-	-
Fuel After F/E Adj.	o = m+n	442	466	466
Total Charges Before F/E Adj.	p = j + m	834	1,030	1,160
Total F/E Adj.	q = k+o	163	-	-
Total Bill	r=p+q	997	1,030	1,160
Impact on bill relative to current rates (%)			3.27%	13.0%
Total impact on bill (%)				16.3%

Table A14.2: Impact of Proposed Rates on the Monthly bill a Typical 10 Customer

Description		Current rates	Inflation escalated rates and new foreign exchange adjustment mechanism	Proposed rates
Assumptions				
Usage (kWh)	a	250	250	250
Base Exchange Rate	b	50	63	63
Billing Exchange Rate	c	63	63	63
Foreign exchange adjustment factor	d	75%	76%	76%
Charges				
Energy First 100 kwh	e	4.102	4.978	6.127
Energy charge (> 100kWh)	f	5.795	7.032	8.656
Fuel Charge	g	3.739	4.711	4.711
Customer Charge	h	58	70	87
Monthly bill components				
Energy First 100 kwh	i=100 x e	410	498	613
Energy (>100kWh)	j = (a-100) x e	869	1,055	1,298
Customer Charge	k = h	58	70	87
Sub Total	l=i+j+k	1,337	1,623	1,998
F/E Adjust	m=((c-b)/b) x d x i	261	-	-
Non-Fuel After F/E Adj.	n=l+m	1,598	1,623	1,998
Fuel Charge	o=a x g	935	1,178	1,178
F/E Adjust	p = ((c-b)/b) x d x o	182	-	-
Fuel After F/E Adj.	q = o+p	1,117	1,178	1,178
Total Charges Before F/E Adj.	r = i+o	2,272	2,801	3,176
Total F/E Adj.	s=m+p	443	-	-
Total Bill	t=r+s	2,715	2,801	3,176
Impact on bill relative to current rates (%)			3.15%	13.8%
Total impact on bill (%)				16.9%

Table A14.3: Impact of Proposed Rates on the Monthly bill a Typical 20 Customer

Description		Current rates	Inflation escalated rates and new foreign exchange adjustment mechanism	Proposed rates
Assumptions				
Usage (kWh)	a	1000	1000	1000
Base Exchange Rate	b	50	63	63
Billing Exchange Rate	c	63	63	63
Foreign exchange adjustment factor	d	75%	76%	76%
Charges				
Energy charge	f	4.350	5.279	6.433
Fuel Charge	g	3.739	4.711	4.711
Customer Charge	h	552	670	816
Monthly bill components				
Energy	i=a x f	4,350	5,279	6,433
Customer Charge	j = h	552	670	816
Sub Total	k = i + j	4,902	5,948	7,249
F/E Adjust	l = ((c-b)/b) x d x k	956	-	-
Non-Fuel After F/E Adj.	m = k + l	5,858	5,948	7,249
Fuel Charge	n = a x g	3,739	4,711	4,711
F/E Adjust	o = ((c-b)/b) x d x n	729	-	-
Fuel After F/E Adj.	p = n + o	4,468	4,711	4,711
Total Charges Before F/E Adj.	q = k + n	8,641	10,660	11,960
Total F/E Adj.	r = l + o	1,685	-	-
Total Bill	s = q+r	10,326	10,660	11,960
Impact on bill relative to current rates (%)			3.23%	12.6%
Total impact on bill (%)				15.8%

Table A14.4: Impact of Proposed Rates on the Monthly bill a Typical 40A Customer

Description		Current rates	Inflation escalated rates and new foreign exchange adjustment mechanism	Proposed rates
Assumptions				
Usage (kWh)	a	10,933	10,933	10,933
Demand usage (kVA)	b	85	85	85
Base Exchange Rate	c	50	63	63
Billing Exchange Rate	d	63	63	63
Foreign exchange adjustment factor	e	75%	76%	76%
Charges				
Energy charge	f	2.625	3.185	3.882
Demand charge	g	282	342	417
Fuel Charge	h	3.739	4.711	4.711
Customer Charge	i	1,642	1,993	2,497
Monthly bill components				
Energy	j=a x f	28,698	34,824	42,439
Demand	k = b x g	24,006	29,131	35,501
Customer Charge	l = i	1,642	1,993	2,497
Sub Total	m = j+k+l	54,346	65,947	80,437
F/E Adjust	n=((d-c)/c) x e x m	10,597	-	-
Non-Fuel After F/E Adj.	o=m+n	64,944	65,947	80,437
Fuel Charge	p=a x h	40,877	51,505	51,505
F/E Adjust	q = ((d-c)/c) x e x p	7,971	-	-
Fuel After F/E Adj.	r = p + q	48,848	51,505	51,505
Total Charges Before F/E Adj.	s = m+p	95,223	117,452	131,942
Total F/E Adj.	t = n+q	18,568	-	-
Total Bill	u = s + t	113,791	117,452	131,942
Impact on bill relative to current rates (%)			3.22%	12.7%
Total impact on bill (%)				16.0%

Table A14.5: Impact of Proposed Rates on the Monthly bill a Typical 40 Customer (from 40LV)

Description		Current rates	Inflation escalated rates and new foreign exchange adjustment mechanism	Proposed rates
Assumptions				
Usage (kWh)	a	35,128	35,128	35,128
Demand usage (kVA)	b	114	114	114
Base Exchange Rate	c	50	63	63
Billing Exchange Rate	d	63	63	63
Foreign exchange adjustment factor	e	75%	76%	76%
Charges				
Energy charge	f	0.642	0.779	0.926
Demand charge	g	706	857	1,083
Fuel Charge	h	3.739	4.711	4.711
Customer Charge	i	1,642	1,993	2,497
Monthly bill components				
Energy	j=a x f	22,552	27,366	32,514
Demand	k = b x g	80,662	97,881	123,713
Customer Charge	l = i	1,642	1,993	2,497
Sub Total	m = j+k+l	104,856	127,240	158,724
F/E Adjust	n=((d-c)/c) x e x m	20,447	-	-
Non-Fuel After F/E Adj.	o=m+n	125,303	127,240	158,724
Fuel Charge	p=a x h	131,342	165,491	165,491
F/E Adjust	q = ((d-c)/c) x e x p	25,612	-	-
Fuel After F/E Adj.	r = p + q	156,954	165,491	165,491
Total Charges Before F/E Adj.	s = m+p	236,198	292,731	324,215
Total F/E Adj.	t = n+q	46,059	-	-
Total Bill	u = s + t	282,257	292,731	324,215
Impact on bill relative to current rates (%)			3.71%	11.2%
Total impact on bill (%)				14.9%

Table A14.6: Impact of Proposed Rates on the Monthly bill a Typical 40 Customer (from 50LV)

Description		Current rates	Inflation escalated rates and new foreign exchange adjustment mechanism	Proposed rates
Assumptions				
Usage (kWh)	a	264,172	264,172	264,172
Demand usage (kVA)	b	795	795	795
Base Exchange Rate	c	50	63	63
Billing Exchange Rate	d	63	63	63
Foreign exchange adjustment factor	e	75%	76%	76%
Charges				
Energy charge	f	0.483	0.586	0.926
Demand charge	g	820	995	1,083
Fuel Charge	h	3.739	4.711	4.711
Customer Charge	i	2,124	2,577	2,497
Monthly bill components				
Energy	j=a x f	127,595	154,833	244,517
Demand	k = b x g	651,723	790,848	860,600
Customer Charge	l = i	2,124	2,577	2,497
Sub Total	m = j+k+l	781,442	948,259	1,107,615
F/E Adjust	n=((d-c)/c) x e x m	152,381	-	-
Non-Fuel After F/E Adj.	o=m+n	933,824	948,259	1,107,615
Fuel Charge	p=a x h	987,739	1,244,551	1,244,551
F/E Adjust	q = ((d-c)/c) x e x p	192,609	-	-
Fuel After F/E Adj.	r = p + q	1,180,348	1,244,551	1,244,551
Total Charges Before F/E Adj.	s = m+p	1,769,181	2,192,810	2,352,166
Total F/E Adj.	t = n+q	344,990	-	-
Total Bill	u = s + t	2,114,172	2,192,810	2,352,166
Impact on bill relative to current rates (%)			3.72%	7.5%
Total impact on bill (%)				11.3%

Table A14.7: Impact of Proposed Rates on the Monthly bill a Typical 50 Customer (from 40MV)

Description		Current rates	Inflation escalated rates and new foreign exchange adjustment mechanism	Proposed rates
Assumptions				
Usage (kWh)	a	91,778	91,778	91,778
Demand usage (kVA)	b	322	322	322
Base Exchange Rate	c	50	63	63
Billing Exchange Rate	d	63	63	63
Foreign exchange adjustment factor	e	75%	76%	76%
Charges				
Energy charge	f	0.597	0.724	0.731
Demand charge	g	695	843	1,167
Fuel Charge	h	3.739	4.711	4.711
Customer Charge	i	1,642	1,993	2,497
Monthly bill components				
Energy	j=a x f	54,792	66,488	67,133
Demand	k = b x g	223,510	271,223	375,246
Customer Charge	l = i	1,642	1,993	2,497
Sub Total	m = j+k+l	279,943	339,703	444,876
F/E Adjust	n=((d-c)/c) x e x m	54,589	-	-
Non-Fuel After F/E Adj.	o=m+n	334,532	339,703	444,876
Fuel Charge	p=a x h	343,159	432,380	432,380
F/E Adjust	q = ((d-c)/c) x e x p	66,916	-	-
Fuel After F/E Adj.	r = p + q	410,075	432,380	432,380
Total Charges Before F/E Adj.	s = m+p	623,102	772,083	877,256
Total F/E Adj.	t = n+q	121,505	-	-
Total Bill	u = s + t	744,607	772,083	877,256
Impact on bill relative to current rates (%)			3.69%	14.1%
Total impact on bill (%)				17.8%

Table A14.8: Impact of Proposed Rates on the Monthly bill a Typical 50 Customer (from 50MV)

Description		Current rates	Inflation escalated rates and new foreign exchange adjustment mechanism	Proposed rates
Assumptions				
Usage (kWh)	a	493,323	493,323	493,323
Demand usage (kVA)	b	1359	1359	1359
Base Exchange Rate	c	50	63	63
Billing Exchange Rate	d	63	63	63
Foreign exchange adjustment factor	e	75%	76%	76%
Charges				
Energy charge	f	0.467	0.567	0.731
Demand charge	g	803	974	1,167
Fuel Charge	h	3.739	4.711	4.711
Customer Charge	i	2,124	2,577	2,497
Monthly bill components				
Energy	j=a x f	230,382	279,562	360,853
Demand	k = b x g	1,091,045	1,323,952	1,585,374
Customer Charge	l = i	2,124	2,577	2,497
Sub Total	m = j+k+l	1,323,551	1,606,092	1,948,724
F/E Adjust	n=((d-c)/c) x e x m	258,092	-	-
Non-Fuel After F/E Adj.	o=m+n	1,581,643	1,606,092	1,948,724
Fuel Charge	p=a x h	1,844,533	2,324,111	2,324,111
F/E Adjust	q = ((d-c)/c) x e x p	359,684	-	-
Fuel After F/E Adj.	r = p + q	2,204,217	2,324,111	2,324,111
Total Charges Before F/E Adj.	s = m+p	3,168,083	3,930,203	4,272,835
Total F/E Adj.	t = n+q	617,776	-	-
Total Bill	u = s + t	3,785,860	3,930,203	4,272,835
Impact on bill relative to current rates (%)			3.81%	9.1%
Total impact on bill (%)				12.9%

Table A14.9: Impact of Proposed Rates on the Monthly bill a Typical Rate 40 TOU Customer (from 40LV)

Description		Current rates	Inflation escalated rates and new foreign exchange adjustment mechanism	Proposed rates
Assumptions				
Energy usage (kWh) - off-peak	a1	38,967	38,967	38,967
Energy usage (kWh) - part-peak	a2	28,746	28,746	28,746
Energy usage (kWh) - on-peak	a3	8,622	8,622	8,622
Demand usage (kVA) - off-peak	b1	205	205	205
Demand usage (kVA) - part-peak	b2	194	194	194
Demand usage (kVA) - on-peak	b3	180	180	180
Base Exchange Rate	c	50	63	63
Billing Exchange Rate	d	63	63	63
Foreign exchange adjustment factor	e	75%	76%	76%
Charges				
Energy charge	f	0.642	0.779	0.926
Demand charge (off-peak)	g1	29	35	45
Demand charge (part-peak)	g2	304	369	469
Demand charge (on-peak)	g3	373	453	600
Fuel charge (off-peak)	h1	3.247	4.091	4.091
Fuel charge (part-peak)	h2	3.905	4.920	4.920
Fuel charge (on-peak)	h3	4.866	6.131	6.131
Customer Charge	i	1,642	1,993	2,497
Monthly bill components				
Energy	j=(a1+a2+a3) x f	49,008	59,469	70,656
Demand	k = (b1 x g1)+(b2 x g2)+(b3 x g3)	131,906	160,064	208,018
Customer Charge	l = i	1,642	1,993	2,497
Sub Total	m = j+k+l	182,555	221,526	281,171
F/E Adjust	n=((d-c)/c) x e x m	35,598	-	-
Non-Fuel After F/E Adj	o=m+n	218,154	221,526	281,171
Fuel Charge	p=(a1xh1)+(a2xh2)+(a3xh3)	280,737	353,729	353,729
F/E Adjust	q = ((d-c)/c) x e x p	54,744	-	-
Fuel After F/E Adj.	r = p + q	335,481	353,729	353,729
Total Charges Before F/E Adj.	s = m+p	463,293	575,255	634,900
Total F/E Adj.	t = n+q	90,342	-	-
Total Bill	u = s + t	553,635	575,255	634,900
Impact on bill relative to current rates			3.91%	10.8%
Total impact on bill				14.7%

Table A14.10: Impact of Proposed Rates on the Monthly bill a Typical Rate 40 TOU Customer (from 50LV)

Description		Current rates	Inflation escalated rates and new foreign exchange adjustment mechanism	Proposed rates
Assumptions				
Energy usage (kWh) - off-peak	a1	95,321	95,321	95,321
Energy usage (kWh) - part-peak	a2	68,711	68,711	68,711
Energy usage (kWh) - on-peak	a3	17,778	17,778	17,778
Demand usage (kVA) - off-peak	b1	813	813	813
Demand usage (kVA) - part-peak	b2	549	549	549
Demand usage (kVA) - on-peak	b3	395	395	395
Base Exchange Rate	c	50	63	63
Billing Exchange Rate	d	63	63	63
Foreign exchange adjustment factor	e	75%	76%	76%
Charges				
Energy charge	f	0.483	0.586	0.926
Demand charge (off-peak)	g1	34	41	45
Demand charge (part-peak)	g2	350	425	469
Demand charge (on-peak)	g3	436	529	600
Fuel charge (off-peak)	h1	3.247	4.091	4.091
Fuel charge (part-peak)	h2	3.905	4.920	4.920
Fuel charge (on-peak)	h3	4.866	6.131	6.131
Customer Charge	i	2,124	2,577	2,497
Monthly bill components				
Energy	j=(a1+a2+a3) x f	87,815	106,560	168,284
Demand	k = (b1 x g1)+(b2 x g2)+(b3 x g3)	392,139	475,849	531,351
Customer Charge	l = i	2,124	2,577	2,497
Sub Total	m = j+k+l	482,077	584,987	702,131
F/E Adjust	n=((d-c)/c) x e x m	94,005	-	-
Non-Fuel After F/E Adj	o=m+n	576,082	584,987	702,131
Fuel Charge	p=(a1xh1)+(a2xh2)+(a3xh3)	664,334	837,061	837,061
F/E Adjust	q = ((d-c)/c) x e x p	129,545	-	-
Fuel After F/E Adj.	r = p + q	793,879	837,061	837,061
Total Charges Before F/E Adj.	s = m+p	1,146,411	1,422,048	1,539,192
Total F/E Adj.	t = n+q	223,550	-	-
Total Bill	u = s + t	1,369,962	1,422,048	1,539,192
Impact on bill relative to current rates			3.80%	8.6%
Total impact on bill				12.4%

Table A14.11: Impact of Proposed Rates on the Monthly bill a Typical Rate 50 TOU Customer (from 40MV)

Description		Current rates	Inflation escalated rates and new foreign exchange adjustment mechanism	Proposed rates
Assumptions				
Energy usage (kWh) - off-peak	a1	61,284	61,284	61,284
Energy usage (kWh) - part-peak	a2	49,123	49,123	49,123
Energy usage (kWh) - on-peak	a3	13,671	13,671	13,671
Demand usage (kVA) - off-peak	b1	394	394	394
Demand usage (kVA) - part-peak	b2	371	371	371
Demand usage (kVA) - on-peak	b3	329	329	329
Base Exchange Rate	c	50	63	63
Billing Exchange Rate	d	63	63	63
Forex adjustment factor	e	75%	76%	76%
Charges				
Energy charge	f	0.597	0.724	0.731
Demand charge (off-peak)	g1	29	35	49
Demand charge (part-peak)	g2	299	363	513
Demand charge (on-peak)	g3	367	445	664
Fuel charge (off-peak)	h1	3.247	4.091	4.091
Fuel charge (part-peak)	h2	3.905	4.920	4.920
Fuel charge (on-peak)	h3	4.866	6.131	6.131
Customer Charge	i	2,124	2,577	2,497
Monthly bill components				
Energy	j=(a1+a2+a3) x f	74,074	89,887	90,760
Demand	k = (b1 x g1)+(b2 x g2)+(b3 x g3)	243,263	295,193	428,240
Customer Charge	l = i	1,642	1,993	2,497
Sub Total	m = j+k+l	318,979	387,072	521,497
F/E Adjust	n=((d-c)/c) x e x m	62,201	-	-
Non-Fuel After F/E Adj	o=m+n	381,180	387,072	521,497
Fuel Charge	p=(a1xh1)+(a2xh2)+(a3xh3)	457,335	576,242	576,242
F/E Adjust	q = ((d-c)/c) x e x p	89,180	-	-
Fuel After F/E Adj.	r = p + q	546,516	576,242	576,242
Total Charges Before F/E Adj.	s = m+p	776,314	963,315	1,097,739
Total F/E Adj.	t = n+q	151,381	-	-
Total Bill	u = s + t	927,696	963,315	1,097,739
Impact on bill relative to current rates			3.84%	14.5%
Total impact on bill				18.3%

Table A14.12: Impact of Proposed Rates on the Monthly bill a Typical Rate 50 TOU Customer (from 50MV)

Description		Current rates	Inflation escalated rates and new foreign exchange adjustment mechanism	Proposed rates
Assumptions				
Energy usage (kWh) - off-peak	a1	227,627	227,627	227,627
Energy usage (kWh) - part-peak	a2	181,332	181,332	181,332
Energy usage (kWh) - on-peak	a3	53,043	53,043	53,043
Demand usage (kVA) - off-peak	b1	1,481	1,481	1,481
Demand usage (kVA) - part-peak	b2	1,313	1,313	1,313
Demand usage (kVA) - on-peak	b3	1,114	1,114	1,114
Base Exchange Rate	c	50	63	63
Billing Exchange Rate	d	63	63	63
Foreign exchange adjustment factor	e	75%	76%	76%
Charges				
Energy charge	f	0.467	0.567	0.731
Demand charge (off-peak)	g1	34	41	49
Demand charge (part-peak)	g2	345	419	513
Demand charge (on-peak)	g3	425	516	664
Fuel charge (off-peak)	h1	3.247	4.091	4.091
Fuel charge (part-peak)	h2	3.905	4.920	4.920
Fuel charge (on-peak)	h3	4.866	6.131	6.131
Customer Charge	i	2,124	2,577	2,497
Monthly bill components				
Energy	j=(a1+a2+a3) x f	215,754	261,812	337,942
Demand	k = (b1 x g1)+(b2 x g2)+(b3 x g3)	976,717	1,185,219	1,485,244
Customer Charge	l = i	2,124	2,577	2,497
Sub Total	m = j+k+l	1,194,596	1,449,608	1,825,683
F/E Adjust	n=((d-c)/c) x e x m	232,946	-	-
Non-Fuel After F/E Adj	o=m+n	1,427,542	1,449,608	1,825,683
Fuel Charge	p=(a1xh1)+(a2xh2)+(a3xh3)	1,705,310	2,148,691	2,148,691
F/E Adjust	q = ((d-c)/c) x e x p	332,535	-	-
Fuel After F/E Adj.	r = p + q	2,037,845	2,148,691	2,148,691
Total Charges Before F/E Adj.	s = m+p	2,899,906	3,598,299	3,974,374
Total F/E Adj.	t = n+q	565,482	-	-
Total Bill	u = s + t	3,465,387	3,598,299	3,974,374
Impact on bill relative to current rates			3.84%	10.9%
Total impact on bill				14.7%

Appendix A15: Estimating the Reconnection Fee

This appendix presents JPS analysis of the cost currently incurred to disconnect and reconnect customers.

A15.1 Methodology

To estimate the costs associated with reconnection, information on the number of reconnections and the total cost incurred for reconnection activities are required.

A15.1.1 Total Number of Reconnections

The number of requests for reconnections received by JPS is recorded on a daily basis by the respective locations. This information is extracted by generating a summary report from JPS' CIS. Of the total requests for reconnections received for the month, all cancelled requests are subtracted as cancellations are done to eliminate double-counting of requests (see appendix A15).

A15.1.2 Cost of reconnections

There are three types of costs associated with reconnections. They are as follows:

- operating and maintenance (O&M) costs;
- administrative costs; and
- audit fees.

Operating & Maintenance Costs

O&M costs are stored on the company's Oracle Systems. O&M costs as it relates to disconnections/reconnections are accumulated based on rates paid as per contractual agreement with third party services to disconnect or reconnect customers to the JPS system. The rates charged have been constant since 1999 and it varies based on the type of disconnection or reconnection (see Table A15.5).

Table A15.1: JPS Agreed Labour Rates for Contractors

Details	1997/98	1998/99	2000-2003
a) Discon/Recon. of 4 wire at pole pot/pothead	[✂]	[✂]	[✂]
b) Discon/Recon. of 2&3 wires at pole pot/pothead	[✂]	[✂]	[✂]
c) Discon/Recon. of 4 wire at meter	[✂]	[✂]	[✂]
d) Discon/Recon. of 2&3 wires at meter	[✂]	[✂]	[✂]
e) Visit to location (delivery of letter or where work was not possible)	[✂]	[✂]	[✂]
f) Visit to location (where a cheque was collected instead of disconnection)		[✂]	
g) Transportation Rates	[✂]	[✂]	[✂]
- Motor vehicle upkeep per day	[✂]	[✂]	[✂]
- Mileage	[✂]	[✂]	[✂]

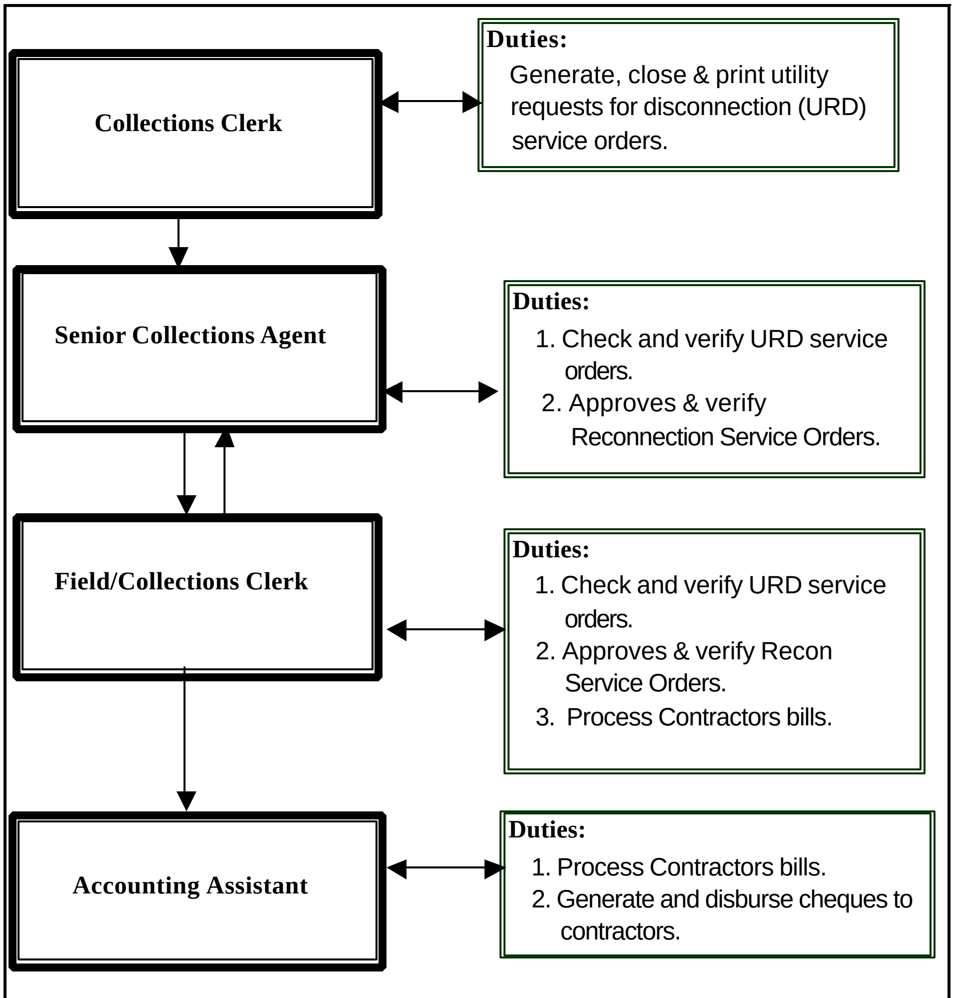
Recon refers to Reconnection; Discon refers to Disconnection

The records do not disaggregate the O&M costs between those incurred for disconnections and those for reconnections. In 2003, the total O&M cost for disconnections and reconnections was $75,672,591(see A15.6).

Administrative Costs

To estimate the Administrative Costs associated with reconnection and disconnection, information from the St. Catherine Customer Service office was used. It is assumed that the work flow of this office – type of personnel, number of personnel, salaries and benefits and time spent by personnel on matters dealing with reconnection and disconnection – is representative of all other JPS offices. The workflow of the St. Catherine Customer Service Office is shown in Figure A15.1.

Figure A15.1: Workflow diagram of Administration of Disconnection and Reconnection Activities



Source - 1. Collections & Field Service Dept. - St. Catherine
2. Computer Operations, Finance & Manpower Dept - New Kingston

As per workflow diagram the costs associated with the salaries and benefits of the following are used as the base in the calculations:

- Collections Clerk Grade 2 Step 2;
- Senior Collections Agent Grade 2 Step 3;
- Field/Collections Clerk Grade 2 Step 3;
- Accounting Assistant Grade 3 Step2.

All benefits are as per the relevant union agreements and the number of employees was extracted from the JPS People Soft Programme (see Table A15.2).

The hourly rates of these personnel is estimated as follows:

Hourly rates (Basic Salary) = annual salary / 52 weeks / 40 hours

Hourly rates (benefits) = annual benefits / 52 weeks / 40 hour

Table A15.2: Estimated hourly rates of administrative personnel involved in reconnection and disconnection activities

Item	Salary and benefits ($)	Hourly Rate ($)
Collections Clerk (16)		
Monthly salary	[✂]	[✂]
Annual benefits	[✂]	[✂]
Transport	[✂]	
Manufacturing	[✂]	
Clothing	[✂]	
Accessories	[✂]	
Vacation	[✂]	
Pension	[✂]	
Senior Collections Clerk (14)		
Monthly salary	[✂]	[✂]
Annual benefits	[✂]	[✂]
Clothing	[✂]	
Vacation	[✂]	
Upkeep	[✂]	
Pension	[✂]	
Field/ Collections Clerk (16)		
Monthly salary	[✂]	[✂]
Annual benefits	[✂]	[✂]
Clothing	[✂]	
Transport	[✂]	
Vacation	[✂]	
Pension	[✂]	
Accounting Assistant (2)		
Monthly salary	[✂]	[✂]
Annual benefits	[✂]	[✂]
Clothing	[✂]	
Vacation	[✂]	
Upkeep	[✂]	
Pension	[✂]	

Note: [*Text omitted. See note on page iii.*]

The annual cost of disconnection and reconnection associated with each employee category is estimated as follows:

> Annual cost = Hourly rates x Number of employees x Approximate time taken to do the job x 5 days x 52 weeks

The total administrative cost associated with reconnections is the sum of the annual cost associated with each employee cost. As shown in Table A15.3, this is estimated to be $18.9 million in 2003.

Table A15.3: Estimated Administrative Costs of Reconnection and Disconnection Activities

Average time taken by each staff per day	Number of Employees	Types	Remuneration	Per Hour ($)	Annual Cost ($)
3 $^{1}/_{2}$ Hours	16	*Basic*	[✂]	[✂]	[✂]
		Benefit		[✂]	[✂]
1 Hour	14	*Basic*	[✂]	[✂]	[✂]
		Benefit		[✂]	[✂]
5 $^{1}/_{2}$ Hours	16	*Basic*	[✂]	[✂]	[✂]
		Benefit		[✂]	[✂]
3 Hours	2	*Basic*	[✂]	[✂]	[✂]
		Benefit		[✂]	[✂]
Annual Administrative Labour Cost					[✂]
Annual Employee Benefit					[✂]
Total cost					[✂]

<u>Audit fees</u>

As per former agreement,[60] audit fees are included in the total cost. At the time of submission the audit had not yet been completed, however, the audit fees are estimated at $250,000.

60 See letter directed to Director General of the OUR from JPS dated July 30th 1998.

A15.2 Estimated cost per reconnection

The total cost associated with disconnection and reconnection is the sum of the O&M costs, administrative costs and Audit fees (see Table A15.4). Total cost is $94,829,709.

The cost per reconnection is estimated as follows:

Actual reconnection cost = Total cost / Total number of reconnections

As per Rate Schedule, a 10% of the actual reconnection cost is added as a service charge. Based on analysis the reconnection fee per activity should be set at $1,441. The derivation of this fee is summarized in Table A15.4.

Table A15.4: Reconnection Cost Summary

Description	Costs ($)
Total Reconnections for 2003 (a)	72,366
Contractor Cost for 2003 (b)	75,672,591
Administrative Cost for 2003 (c)	18,907,118
Audit Fees (d)	250,000
Total Cost (e =b+c+d)	94,829,709
Actual reconnection unit cost for 2003 (f=e/a)	1,310
Plus 10% service charge (g = f X 0%)	131
Derived Reconnection fee (f+g)	1,441

Table A15.5: Total number of reconnections (2003)

	Jan	Feb	March	April	May	June
KSAS Dept	217	143	360	168	167	277
K.S.A.N.	880	316	876	464	980	919
St. Thomas	323	134	248	186	291	307
St. Mary	135	112	254	201	320	376
Portland	151	86	348	200	265	339
St. Catherine	380	816	647	530	1,324	660
Clarendon	471	328	685	409	642	464
Manchester	217	91	318	215	440	536
St. Elizabeth	155	98	238	141	220	223
St. Ann	56	98	320	255	406	397
Trelawny	56	36	69	72	97	158
St. James	418	323	453	356	639	462
Hanover	151	198	174	197	305	190
Westmoreland	508	194	660	425	430	380
Total	4,118	2,973	5,650	3,819	6,526	5,688

Note: Total number of reconnections received for the month excludes cancellations.

Table A15.5 (continued)

	July	Aug	Sept	Oct	Nov	Dec	**Total**
KSAS Dept	574	512	575	774	445	278	4,490
K.S.A.N.	1,205	878	1,153	982	949	834	10,436
St. Thomas	247	197	366	229	233	206	2,967
St. Mary	349	274	350	186	258	269	3,084
Portland	378	383	342	214	185	198	3,089
St. Catherine	1,558	474	1,599	1,419	1,964	1,301	12,672
Clarendon	511	367	806	592	696	592	6,563
Manchester	597	390	451	591	579	326	4,751
St. Elizabeth	474	425	677	533	617	577	4,378
St. Ann	533	405	487	538	547	414	4,456
Trelawny	278	166	207	145	100	129	1,513
St. James	521	499	601	210	386	202	5,070
Hanover	379	324	384	234	322	245	3,103
Westmoreland	562	522	653	697	442	321	5,794
Total	8,166	5,816	8,651	7,344	7,723	5,892	72,366

Note: Total number of reconnections received for the month excludes cancellations.

Table A15.6: Total operating and maintenance costs incurred for disconnections and reconnections (2003)

	Jan	Feb	March	April	May	June
K.S.A.N.	-	1,085,239	324,611	1,230,080	938,019	1,181,110
K.S.A.S	73,371	13,000	618,140	511,351	-	471,846
St. Thomas	-	319,102	207,648	-	254,709	494,081
St. Mary	7,438	139,187	164,888	36,000	433,630	252,866
Portland	5	-	405,882	-	361,866	216,766
St. Catherine	713,724	-	976,535	1,186,232	831,031	1,036,212
Clarendon	137,773	362,052	409,490	664,853	528,479	406,110
Manchester	78,174	208,707	17,064	360,521	48,849	450,565
St. Elizabeth	-	82,156	57,906	425,548	191,030	193,767
St. Ann	-	-	217,975	335,492	142,758	444,796
Trelawny	143,713	72,185	-	169,901	61,417	169,178
St. James	-	-	554,579	561,626	402,318	625,118
Hanover	(287,366)	260,508	419,162	329,655	240,075	344,088
Westmoreland	-	218,546	293,901	716,243	309,895	413,232
Total	866,831	2,760,680	4,667,778	6,527,499	4,744,074	6,699,733

Table A15.6: Total operating and maintenance costs incurred for disconnections and reconnections (2003) (cont'd.)

	July	Aug	Sept	Oct	Nov	Dec	**Total**
K.S.A.N.	1,094,409	854,856	1,426,546	1,263,288	1,093,869	1,949,398	12,441,423
K.S.A.S	390,437	457,733	512,586	867,161	790,782	554,138	5,260,543
St. Thomas	544,775	384,982	286,396	393,986	361,121	407,469	3,654,267
St. Mary	202,427	513,178	223,287	350,961	219,746	502,689	3,046,296
Portland	304,450	661,726	369,937	-	540,119	393,431	3,254,180
St. Catherine	703,183	995,195	972,290	1,739,710	1,628,366	2,706,040	13,488,516
Clarendon	245,587	770,439	401,107	655,425	520,503	716,106	5,817,922
Manchester	218,729	386,250	484,696	184,852	542,868	1,134,703	4,115,978
St. Elizabeth	272,391	339,553	495,358	611,439	609,074	1,134,198	4,412,416
St. Ann	458,103	-	933,809	416,102	446,454	906,044	4,301,533
Trelawny	101,103	72,271	114,351	217,033	-	363,563	1,484,711
St. James	31,756	811,009	711,203	445,932	935,308	1,016,976	6,095,823
Hanover	-	228,638	584,815	551,709	231,324	318,377	3,220,982
Westmoreland	382,702	583,422	122,910	540,081	799,785	697,289	5,078,002
Total	4,950,048	7,059,250	7,639,287	8,237,678	8,719,315	12,800,418	75,672,591