JPS TARIFF APPLICATION
2014 – 2019
ANNEX

April 7, 2014

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Annex A: Cost of Capital Study

The Cost of Capital Study will be submitted as a separate document

Annex B: X Factor Study

Appendix A: X-Factor Study

This report presents Castalia LLC's analysis and conclusions on an appropriate X-Factor to be applied to the Jamaica Public Service Company Ltd. as part of the Performance Based Rate Making for the 2014–2019 tariff period. The report is the independent expert opinion of Castalia LLC. The analysis was carried out by David Ehrhardt and John Miller of Castalia.

Data was sourced from JPS' audited financial statements and, for data on independent power producer (IPP) costs, directly from JPS staff. For comparative efficiency analysis we sourced data on Caribbean and New Zealand utilities from our proprietary data (based on audited financial statements and regulatory reports), and for United States utilities from audited financial statements and FERC Form 1 data.[1] To calculate economy-wide Total Factor Productivity growth (an input to the X-Factor calculation) we used data from the United States Bureau of Labor Statistics and the Penn World Table.

Data was analysed using techniques that have been approved by the Office of Utilities Regulation (OUR) in the past. For comparative efficiency analysis purposes we used the same techniques used by two of the leading price-cap based regulators in the world: Ofgem (the UK's energy regulatory agency) and the Australian Energy Regulator.

In this report, we begin by describing the regulatory basis for the X-Factor, including a discussion of how to translate the language of the Licence into functional equations. This is necessary because the wording of the licence leaves some room for ambiguity. We put down what we believe is the correct interpretation in equation form (Section A.1).

We then explain the fundamental, conceptual basis for the X-Factor, and its role in the regulatory scheme. Conceptually, the X-Factor exists to pass on expected efficiency gains to the consumer in the form of lower tariffs. We explain why the productivity growth of the general economy features in the formula as something that *reduces* the X-Factor. In essence, this is because tariffs are indexed to a general inflation index in an attempt to keep them constant in real terms (the X-Factor then imposes a real tariff reduction). Inflation in the economy already factors in efficiency gains in the economy as a whole, so to keep costs constant in real (that is, inflation-adjusted) terms, JPS will need to increase its efficiency as fast as the average firm in the economy. This means that only efficiency gain *in excess* of the general level of efficiency increase in the economy should be reflected in the X-Factor (Section A.2).

The fundamental question then is "by how much can JPS' productivity growth be expected to exceed the productivity growth of the economy as a whole?" For JPS, "the economy as a whole" is defined by the Licence[2] to mean a weighted average of the United States economy (with a 76 per cent weighting) and the Jamaican economy (with a 24 per cent weighting). In Section A.3 we show that there is no good reason to assume that utilities in general should be able to increase efficiency faster than other firms. Evidence from the United States shows that utilities' rate of productivity growth is slightly slower than the rate of productivity

[1] FERC Form 1 refers to a mandatory annual report of major electric utilities in the United States to the Federal Energy Regulatory Commission. The dataset is publicly available at http://www.ferc.gov.

[2] Government of Jamaica, All-Island Electricity Licence 2011, Schedule 3, Exhibit 1.

growth in the economy as a whole. The electricity regulator in New Zealand has set the X-Factor at zero in its most recent price reset[3], based on this fundamental understanding that there is no reason to expect the average utility to become efficient faster than the average firm in the economy.

Of course, if JPS was below the average efficiency for the industry then it could be expected to catch up to industry standards, and in doing so to increase efficiency faster than the average firm in the economy. However, analysis presented in Section A.4.2 shows that JPS is already on the efficiency frontier with respect to its non-fuel costs. There is therefore no reason to assume JPS can outperform other utilities in increasing productivity (since it is already among the most efficient). The evidence therefore supports the view that, like other utilities, JPS should be expected to increase efficiency at about the same rate as firms in the economy as a whole. It follows that the X-Factor should be set at zero. We call this line of reasoning the "fundamentals approach," since it is based on an understanding of fundamental relationships between economy wide TFP growth and utility TFP growth. In our opinion, this is the best way to think about the X-Factor.

For consistency with past determinations, and to provide an additional perspective, we also repeat the calculations that have been done in the past to estimate individual parameters in the formula used to set the X-Factor. We call this the "calculations approach."

The calculations approach part of the report starts in Section A.4 with the estimation of JPS' historic TFP growth. We present the calculation of a TFP index for JPS, and show that over the five years from 2006–2011, JPS' annual TFP growth has been 0.5340 percent.

The term in the licence is "expected TFP," so we then need to consider the extent to which JPS' TFP growth could be expected to slow or accelerate in the future. Here a key question is how efficient JPS is now compared to other similar utilities. We use three different analytic techniques to answer this question: productivity benchmarking, efficient frontier analysis, and data envelopment analysis. These techniques all show that JPS is better than its peers at constraining non-fuel costs, and indeed is on the efficiency frontier for the industry in this regard. We therefore conclude that there is no reason to assume some efficiency deficit that JPS can "catch up" from. Therefore there is no reason to think that JPS' efficiency growth in the next five years will exceed what it achieved over the last five. The analysis shows that the easy gains following privatisation have already been taken, and also that the low demand growth that has limited efficiency gains over the last period will likely continue in the next tariff period.

To complete the calculations approach, it is then necessary to estimate efficiency gains for the economy as whole over the last five years. We do this in Section A.5, calculating the general economy TFP growth rate. For JPS, this is a weighted average of the historic TFP growth rates of the United States and Jamaican economies. We show that this was 0.1799 percent. Plugging this number into the X-Factor formula then yields an X-Factor of 0.35 percent.

[3] New Zealand Commerce Commission. "Resetting the 2010-15 Default Price-Quality Paths for 16 Electricity Distributors." 30 November 2012, p. 7. http://www.comcom.govt.nz/dmsdocument/9686 (accessed October 30, 2013).

Based on this analysis, our conclusion is that JPS' X-Factor should be set at zero (using a fundamentals approach, which we think is preferable). If the calculations approach is preferred, then an X-Factor of 0.35 percent would result.

A.1 Regulatory Basis of the X-Factor

JPS' tariff is subject to five-year price cap regulation, as defined by the Performance-Based Ratemaking Mechanism (PBRM) in Schedule 3 of the All-Island Electricity Licence 2011 ("Licence"). Under the PBRM, non-fuel base rates increase annually at the rate of inflation, less the X-Factor (and are also subject to adjustments for a Q-Factor and a Z-Factor).

> *The annual Performance-Based Rate-Making (PBRM) filing will follow the general framework where the annual rate of change in non-fuel electricity prices (dPCI) will be determined through the following formula:*
>
> $$dPCI = dI \pm X \pm Q \pm Z$$
>
> *where:*
>
> *dI = the annual growth rate in an inflation and devaluation measure; X = the offset to inflation (annual real price increase or decrease) resulting from productivity changes in the electricity industry.*

The X-Factor is designed as an "annual offset to inflation," and so conceptually X should always be subtracted from ΔI. This means that the X-Factor will be a positive value if non-fuel base rates are to *decrease* in real terms, and conversely the X-Factor will be a negative value if non-fuel base rates are to *increase* in real terms.

The Licence defines the X-Factor as:

> *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'.*

Castalia has interpreted this language to mean that the X-Factor is calculated as:

$$X = \Delta TFP_{JPS}^{Expected} - \Delta TFP_{General}$$

We have also interpreted the language of the Licence to mean that $\Delta TFP_{General}$ is calculated as the weighted average of the TFP growth rates of the United States and Jamaican economies.

$$\Delta TFP_{General} = (0.76 \times \Delta TFP_{US}) + (0.24 \times \Delta TFP_{Jamaica})$$

This weighted average, with 76 percent weight given to TFP growth in the United States and 24 percent weight given to TFP growth in Jamaica, is derived from the formula used to calculate ΔI.[4]

[4] Per the Licence, $dI = ((EX_n - EX_b)/EX_b)(1+0.92INF_{us})+(\mathbf{0.76})(0.92)1+\mathbf{0.24}INF_j$

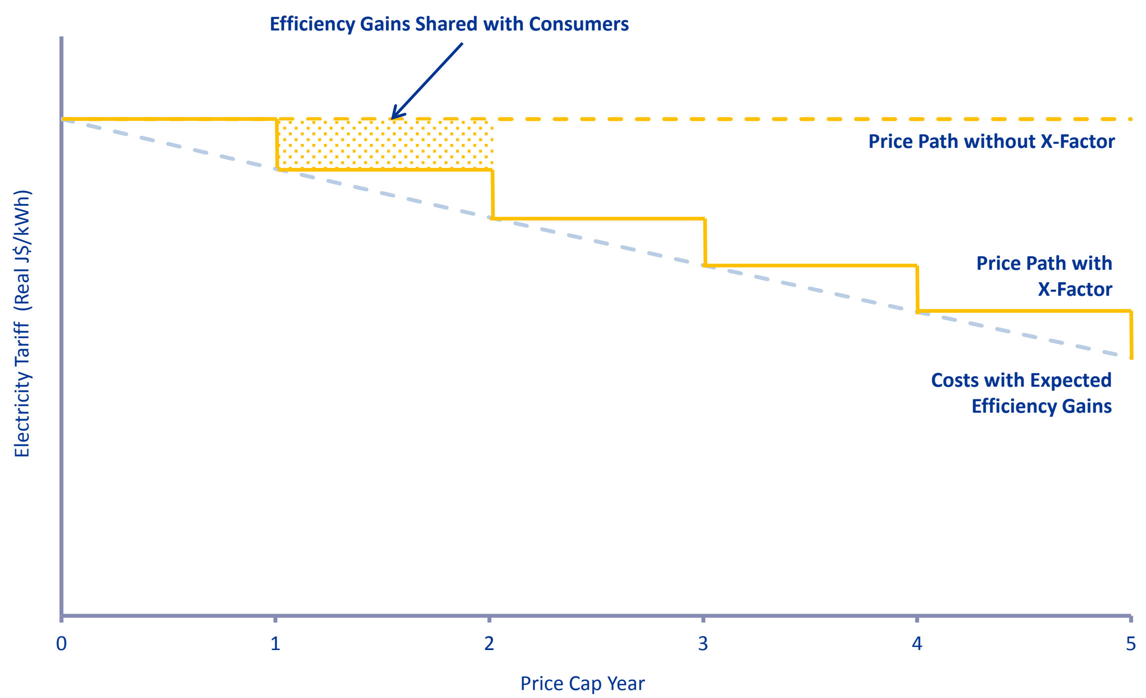
A.2 Conceptual Basis of the X-Factor

Price cap regulation (also referred to as CPI−X) is appealing to policymakers and regulators because it gives the utility a strong incentive to achieve productivity gains. These productivity gains are achieved through two related components:

- First, a price path is set for the duration of the tariff period. This price restriction induces the utility to control its costs over this period
- Second, an X-Factor is applied to the price path. The application of this X-Factor is based on the insight that the utility's cost controlling initiatives will yield efficiency gains—and that these should be shared with consumers in the form of lower prices

Figure A.1 illustrates how a price cap with a X-Factor shares efficiency gains with consumers. In the first rate year of a price cap regime, no X-Factor is applied, and so any productivity gains achieved in that year purely benefit the utility. In subsequent years, however, the price cap (in real terms) "ratchets" down based on the X-Factor prescribed at the beginning of the tariff period. In this way, efficiencies achieved up to the end of the prior year are now captured by consumers, and the utility must continue to achieve cost efficiencies in order to remain ahead of these real tariff reductions.

Figure A.1: Stylised Diagram of a Price Cap with X-Factor



A.3 Fundamentals Approach to Setting the X-Factor

In this section we explain why the Licence sets the X-Factor equal to the difference between TFP growth expected in the economy as a whole, and that expected of JPS. We then provide evidence that this difference should be *expected* to be zero. It follows that the X-Factor for JPS in the 2014–2019 tariff period *should* be set to zero. We call this the "fundamentals approach" because it is based on an understanding of fundamental academic relationships and contexts.

The X-Factor is the difference between the rate of productivity growth a utility can achieve, and the rate of productivity growth in the economy as a whole

The X-Factor is clearly defined in the Licence:[5]

> *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'.*

If the X-Factor is positive, then JPS is expected to improve its productivity faster than the general rate of productivity gains across the general economy.

$$X = \Delta TFP_{JPS}^{Expected} - \Delta TFP_{General}$$

The X-Factor is predicated on the assumption that the expected efficiency gains the utility can make should be passed on to benefit ratepayers. In addition, the efficiency gains of other firms in the economy help keep their output prices lower than they would otherwise be—that is to say, there is already an efficiency target embedded in the inflation adjustment. Under the X-Factor definition, then, JPS must increase efficiency as fast as the average firm in the economy *just to maintain profits* under a pure inflation cap approach. So, in order to be able to earn a reasonable return on capital while reducing prices in real terms, JPS would have to be able to increase productivity *faster* than firms in the general economy generally are increasing their productivity.[6]

This insight implies that if JPS' expected productivity growth was simply equal to the productivity growth achieved by other firms in the economy, the X-Factor would be zero.

The average productivity growth of United States utilities is equal to that of other firms in the economy

Makholm et al. conducted a TFP study of 72 electric utilities in the United States using data from 1972–2009.[7] The authors found that the average annual growth rate of TFP among these United States electric utilities was 0.85 percent. During that same time, United States TFP grew at an average annual rate of 0.91 percent. That is, average productivity of United States utilities grew at a slightly lower rate than that of other firms in the economy.

This finding should not be particularly surprising. What drives productivity growth is technological progress. Rates of technological progress differ between sectors of the economy: telecommunications and IT have had very high rates of innovation, while other parts of the economy have experienced slower rates of progress. Because the electricity

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[5] Government of Jamaica, All-Island Electricity Licence 2011, Schedule 3, Exhibit 1.

[6] Jamison, Mark A. "Regulation: Price Cap and Revenue Cap." 2007, p. 7. http://warrington.ufl.edu/centers/purc/purcdocs/papers/0527_jamison_regulation_price_cap.pdf (accessed October 28, 2013).

[7] Makholm, Jeff D., Agustin J. Ros, and Meredith A. Case. "Total Factor Productivity and Performance-Based Ratemaking for Electricity and Gas Distribution." 2010. http://www.nera.com/nera-files/PUB_TFP_Makholm_Ros.pdf (accessed October 28, 2013).

utility industry now uses mostly mature technologies, there is no *a priori* reason to think that electricity utilities should be able to increase productivity faster than the economy as a whole.

The assumption that utilities could improve faster than the economy as a whole is a product of the particular context in which CPI−X (price cap) regulation was introduced: the privatisation of UK public utilities. When the British government privatised its telecommunications, electricity, and water utilities in the 1980s, the government was convinced that decades of government ownership had made the utilities inefficient compared to their private sector counterparts. For this reason, it expected the newly privatised companies to boost productivity faster than firms in the economy generally. Under the circumstances, this was a reasonable assumption. The firms were able to rapidly improve productivity. However, there is no reason to take a condition that existed in Great Britain in the 1980s, and assume that it is equally applicable in the current Jamaican context.

The evidence from the United States shows that, over the long run, utilities increase productivity at the same rate as the economy as a whole, reflecting common underlying drivers of productivity in mature industries: innovation in technology and in managerial practices. Notably, the regulator in New Zealand arrived at the same conclusion in 2012 for its electricity distributors, and set the X-Factor to zero percent.[8]

Growth in economy-wide and utility TFP is influenced by economic growth

TFP in the economy as a whole is driven in large part by rising demand. Rising demand ensures full capacity utilization, allows for economies of scale, and brings forward the deployment of new technologies by increasing spending on capital items which embody those new technologies.[9]

Likewise, public utility TFP is also driven by economic growth. This is because economic growth drives demand, and increasing demand boosts utility productivity—particularly because of the largely fixed cost nature of the business. Demand growth leads to a need to invest in new fixed assets, which in turn drives productivity growth because new technology is embodied in new capital equipment.[10]

JPS' future TFP growth should be expected to be equal to economy wide TFP growth

The historical pattern that the TFP of United States utilities grows at the same rate as the TFP of the economy generally should be expected to apply to JPS going forward. This is because:

- The equipment and management technologies available to JPS are similar to those available to United States utilities generally. This is acknowledged by the 76 percent weighting given to the United States foreign exchange rate (and TFP growth rate) in the Licence

[8] New Zealand Commerce Commission. "Resetting the 2010-15 Default Price-Quality Paths for 16 Electricity Distributors." 30 November 2012, p. 7. http://www.comcom.govt.nz/dmsdocument/9686 (accessed October 30, 2013).

[9] Syverson, Chad. 2011. "What Determines Productivity?" Journal of Economic Literature, 49(2): 357. http://home.uchicago.edu/syverson/productivitysurvey.pdf (accessed October 31, 2013).

[10] Coelli, Tim. "Choice of Methodology." In *Primer on Efficiency Measurement for Utilities and Transport Regulators*, p. 113. Washington, DC: World Bank Publications, 2003.

- As we will show in Section A.4.2, JPS is now at the *frontier* of efficiency for electricity utilities, and so it cannot be expected to do *better* than electricity utilities do generally

For these reasons—and even though it is difficult to predict TFP growth of the economy generally—we can safely assume that the historical United States pattern will apply in our current context, and so JPS' TFP growth will not exceed that of a weighted average of the United States and Jamaican economies. Accordingly, the X-Factor should be no more than zero percent.

A.4 JPS' Expected TFP Growth

Fundamentally, the X-Factor should be equal to the difference between JPS' expected TFP growth and the expected TFP growth of the economy as a whole. This relationship can be estimated directly, as we did in the last section, or alternatively each component can be calculated. We call this the "calculations approach." While conceptually inferior, it is the approach used in JPS' 2009–2014 tariff review application and was accepted by the OUR. So, here we estimate the values for each of the components in the calculation.

The first component of this "calculations approach" is calculating JPS' expected TFP growth. We find that JPS' expected TFP growth is approximately 0.5340 percent over the tariff period 2014–2019.

Past TFP growth is one indicator of likely future performance. Therefore, we first calculate JPS' historic TFP growth. This approach is consistent with JPS' 2009–2014 tariff review application, and was generally accepted by the OUR in its 2009 determination notice.[11] We then examine the basis for applying a "stretch factor" to this growth rate, to account for any expected changes over the 2014–2019 tariff period.

A.4.1 Historic TFP Growth

In this section, we focus on calculating JPS' historic TFP growth. We find that from 2006–2011, JPS' TFP has grown at 0.5340 percent per year. We arrive at this calculation by constructing a TFP index for JPS, using indexes of their production inputs and outputs. We first present the TFP index, and then discuss the methodology used to construct it. We conclude with a discussion on the choice of time period used in our results.

Table A.1 presents the two TFP indexes we produced for JPS: a TFP index including IPP capacity payments, and an index excluding them. Conceptually, we believe a TFP index excluding IPP capacity payments is most appropriate (see our discussion of this issue in the Capital Sub-Index section below). However, our recommended historic TFP growth rate for JPS uses the TFP index *including* IPP capacity payments, because this is the approach proposed by JPS in its 2009–2014 tariff review application and accepted by the OUR.

[11] Office of Utilities Regulation. "Jamaica Public Service Company Limited, Tariff Review for Period 2009–2014, Determination Notice." October 2009, pp. 64-67. http://www.our.org.jm/ourweb/sites/default/files/documents/sector_documents/jps_tariffreview_2009-2014__determination_0.pdf (accessed October 23, 2013).

Table A.1: JPS' TFP Index (1991 = 1.000)

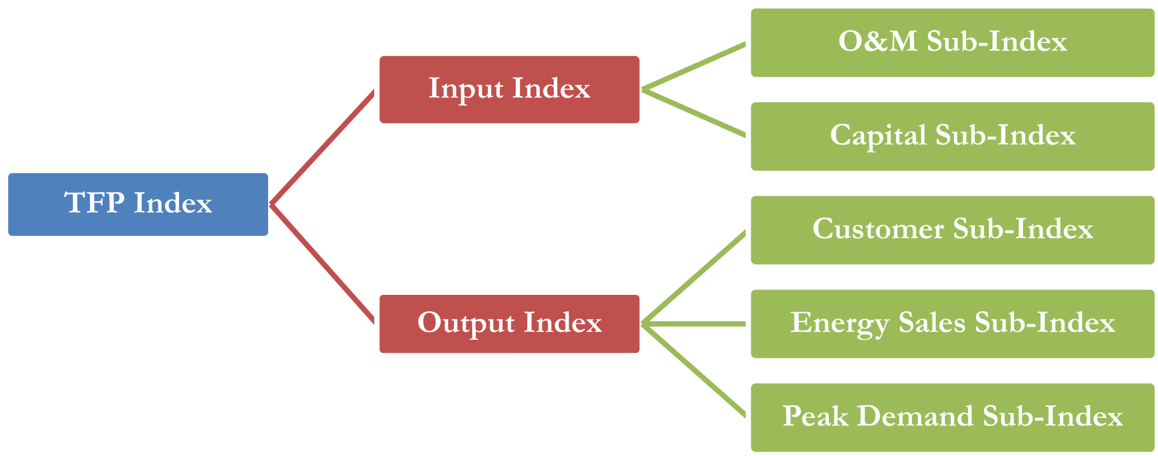
Year	w/ IPP Capacity Payments	w/o IPP Capacity Payments
1991	1.0000	1.0000
1992	0.9320	1.0247
1993	0.8280	0.7753
1994	0.9000	0.8657
1995	0.7640	0.7612
1996	0.8340	0.7656
1997	0.8340	0.7159
1998	0.8330	0.8202
1999	0.9070	0.9496
2000	0.9090	0.9945
2001	1.0010	1.0735
2002	1.0130	1.0967
2003	0.9980	1.1261
2004	1.0220	1.1441
2005	1.0960	1.1320
2006	1.1050	1.1306
2007	1.1320	1.0867
2008	1.1549	1.0798
2009	1.2844	1.2379
2010	1.1823	1.1099
2011	1.1348	1.0546
2012	1.2094	1.1353

In addition, we encountered difficulties replicating the exact TFP index results for the years 1991–2007, as submitted in JPS' last tariff review application. This is because JPS did not have, and was not able to obtain, the exact data set used by its prior consultants. Our solution to this problem was to "splice" the TFP index submitted in the last tariff review application with our own TFP index (including IPP capacity payments). We did this by taking the 2007 TFP index from the last tariff review application and using annual growth rates from our own TFP index to estimate the TFP index for the years 2008–2012.

An Overview of Total Factor Productivity

Total Factor Productivity is a measure of how efficiently a firm converts production inputs to outputs. It is measured as an index, and calculated as the ratio of an output quantity index to an input quantity index. Each of the output and input quantity indexes, in turn, are composed of several quantity sub-indexes. Figure A.2 illustrates how these sub-indexes and indexes combine to arrive at a TFP index for JPS.

Figure A.2: Composition of the TFP Index



The input quantity index is composed of two sub-indexes: an operating & maintenance (O&M) sub-index, and a capital sub-index.

Input quantities were estimated by examining costs from JPS' audited financial statements, converted to a common currency (United States Dollars) and adjusted to real terms (using the relevant inflation measure, as described below). The O&M sub-index was developed using non-fuel operating expenses, defined as excluding all fuel costs, purchased power costs, and depreciation expense. O&M expenses were expressed in real terms using the United States Consumer Price Index. The capital sub-index was developed using a service price approach, which estimates the cost of consuming capital in a given year. The calculation takes into account depreciation expense, opportunity cost of capital, and capacity payments made to Independent Power Producers (IPPs).

The output quantity index is composed of three sub-indexes: a customer index, an energy sales index, and a peak demand index.

All indexes used a base year of 1991, and were constructed using a Törnqvist form (see Box A.1), which is common in the TFP literature because it is a chain-weighted approach with desirable indexing properties. The Törnqvist approach was also used in the calculation of JPS' TFP growth in the prior tariff submission and was accepted by the OUR.

Box A.1: Törnqvist Index Formula

$$\ln\left({Input\ Quantities_t}/{Input\ Quantities_{t-1}} \right) = \sum_t \frac{1}{2} \cdot \left(S_{j,t} + S_{j,t-1}\right) \cdot \ln\left({X_{j,t}}/{X_{j,t-1}} \right)$$

In each year *t*,

$Input\ Quantities_t$	= Input quantity index
$X_{j,t}$	= Quantity sub-index for input *j*
$S_{j,t}$	= Share of input category *j*

To produce the input quantity index, the share assigned to each category *j* was based on its contribution to JPS' total cost. For the purposes of share weighting, JPS' total cost was defined as the sum of its O&M and estimated capital costs in a given year. The section on the Capital Sub-Index below describes how we estimated annual capital costs.

To produce the output quantity index, the share assigned to each category *j* was based on best estimates of the relative importance of each output in driving JPS' non-fuel costs. We assigned a zero percent weight to energy sales, based on evidence from New Zealand and Australia that energy sales do not drive non-fuel costs.[12] We then assigned a 44 percent weight to peak demand, to reflect the approximate share of JPS' asset base that is dedicated to generation. Data on JPS' asset base by function was obtained from its 2009–2014 tariff review application.[13] The remaining 56 percent weight was given to the customer index.

Calculating the O&M Sub-Index

To calculate the O&M sub-index, Castalia calculated real non-fuel operating expenses and indexed these O&M inputs to the base year (1991). For the purposes of this calculation, we defined non-fuel operating expense as operating expenses in JPS' income statement, less any fuel expenses, purchased power costs, and depreciation expense. We then deflated non-fuel operating expenses using the United States Consumer Price Index to obtain real non-fuel operating expenses. Table A.2 provides the results of the O&M sub-index calculation.

Table A.2: O&M Sub-Index (1991 = 1.0000)

Year	O&M Sub-Index
1991	1.000
1992	0.991
1993	1.299
1994	1.368
1995	1.819
1996	1.895
1997	2.192
1998	2.996
1999	2.443
2000	2.358
2001	2.327
2002	2.306
2003	2.351

[12] Benchmark Economics. "Electricity Distribution Networks: Cost structure analysis—Volume II: Technical appendix." October 2005, p. 9. www.comcom.govt.nz/dmsdocument/2885 (accessed October 28, 2013).

[13] Jamaica Public Service Company Ltd. "2009–2014 Tariff Review Application." March 2009, p. 134. http://www.our.org.jm/ourweb/sites/default/files/documents/sector_documents/jps_rate_case_submission_-_march_9_final_-_for_publication.pdf (accessed October 28, 2013).

Year	O&M Sub-Index
2004	2.335
2005	2.462
2006	2.572
2007	2.802
2008	3.077
2009	2.446
2010	2.875
2011	3.081
2012	2.854

Calculating the Capital Sub-Index

To calculate the capital sub-index, Castalia first produced a "roll-forward" estimate of real capital stock. To do so, we set capital stock at the beginning of 1991 equal to the net book value of property, plant, and equipment. We then subtracted depreciation expense, and added real capital additions, to arrive at real capital stock at the end of 1991. In each subsequent year, capital stock was set equal to real capital stock at the end of the prior year. Real capital additions in each year were calculated by deflating capital additions, as reported in the notes to JPS' financial statements, using a composite Handy-Whitman Index.[14]

We then calculated annual capital consumption. In a given year, this was equal to the depreciation expense plus the return on capital stock. For the period 1991–2008, the rate of return was assumed to be fixed at 12.00 percent, which was the authorised rate of return (that is, WACC) through 2008. From 2009–2012, we assumed 11.68 percent, which was the authorised rate of return in the most recent tariff determination.

Next, we calculated an average capital stock for the year, by averaging the estimated capital stock at the beginning and end of each year. The return on capital stock was calculated as the rate of return times the average capital stock in a given year.

After producing an estimate of annual capital consumption, we then produced two capital sub-indexes: one which includes IPP capacity payments as a JPS capital input, and a sub-index which excludes these payments. Table A.3 provides the results of the capital sub-index calculations.

Conceptually, JPS capital inputs should not include IPP capacity payments, since they are not an input under the control of JPS management, but rather are fixed payments set during contract negotiation. However, we have calculated a capital input index including IPP capacity payments because JPS included these costs in its TFP calculation in the 2009–2014 tariff review application, and the OUR accepted this approach.

[14] The Handy-Whitman Index is a proprietary index of public utility construction costs, published by Whitman, Requardt and Associates. It is the *de facto* standard for revaluing public utility capital assets over time. It is also commonly used by foreign electric utilities, such as JPS, whose fixed asset costs closely follow those in the United States.

For the capital sub-index including IPP capacity payments, we simply added real capital consumption to real IPP capacity payments, and then indexed this value to the base year (1991). We obtained data on IPP capacity payments directly from JPS, since these payments are not separately identified in the financial statements. IPP capacity payments were deflated to real terms using the United States Consumer Price Index, to reflect the fact that the power purchase agreements with IPPs are executed in United States dollars.

For the capital sub-index which excluded IPP capacity payments, the index was calculated as annual capital consumption, indexed to the base year (1991).

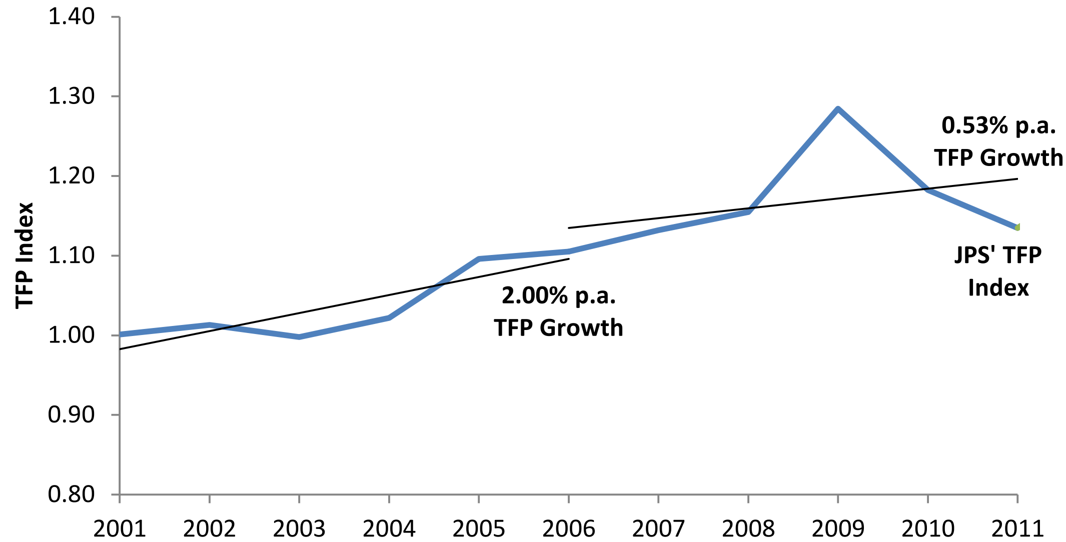
Table A.3: Capital Sub-Index

Year	w/ IPP Capacity Payments	w/o IPP Capacity Payments
1991	1.000	1.000
1992	1.027	1.027
1993	1.442	1.442
1994	1.310	1.310
1995	1.459	1.459
1996	1.798	1.559
1997	2.184	1.663
1998	1.746	1.121
1999	1.698	1.153
2000	1.780	1.173
2001	1.562	1.110
2002	1.707	1.127
2003	1.664	1.152
2004	1.679	1.197
2005	1.679	1.221
2006	1.702	1.232
2007	1.759	1.256
2008	1.576	1.149
2009	1.596	1.138
2010	1.583	1.159
2011	1.580	1.168
2012	1.591	1.167

Understanding JPS' Historic TFP Trend

JPS has demonstrated consistent gains in TFP since privatisation. From 2002–2011, JPS' TFP has grown at an average annual growth rate of 1.27 percent. Figure A.3 shows the change in the TFP index over this time.

Figure A.3: JPS' Historic TFP Growth (2001–2011)



Note: JPS' TFP index as shown includes IPP capacity payments

However, as the OUR has rightly indicated,[15] TFP growth can also be volatile from year to year.

> *A TFP growth [rate for JPS from 1990–2001] of 0.12% appears very low when compared with other electricity utilities….In the last seven years [2001–2007] JPS has shown growth of 1.94%. This highlights the fact that the choice of period for the study can introduce biases in the prediction of the expected TFP.*

Examining JPS' TFP growth in five-year windows in Figure A.3, we see that TFP grew by an average annual rate of 2.00 percent from 2001–2006. While, from 2006–2011, TFP grew at an average annual rate of 0.53 percent. This variation over time emphasises the point that the choice of time period matters.

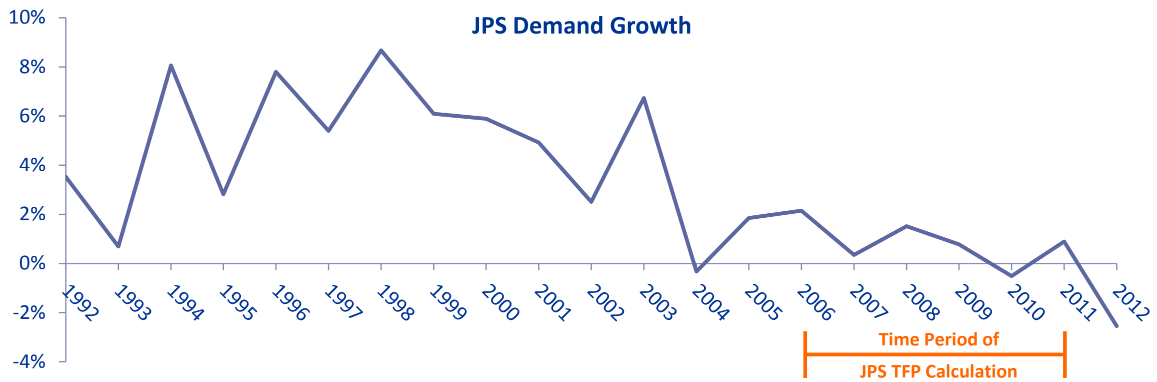
Accordingly, we have chosen the 2006–2011 time period as most appropriate to measure JPS' average annual TFP growth, for two reasons:

- The five-year duration matches the length of a tariff period
- It uses the most recent data available, which is most likely to be indicative of the future[16]

[15] Office of Utilities Regulation. "Jamaica Public Service Company Limited, Tariff Review for Period 2009–2014, Determination Notice." October 2009, p. 62. http://www.our.org.jm/ourweb/sites/default/files/documents/sector_documents/jps_tariffreview_2009-2014__determination_0.pdf (accessed October 23, 2013).

Moreover, going forward we do not expect JPS' TFP growth rates to maintain the same high growth levels as observed in the early 2000s, because JPS' demand growth has slowed in recent years (see Figure A.4). As the index values in Table A.1 confirm, JPS' TFP growth began to slow in 2010 because of slowing (and even declining) demand growth over the past three years.

Figure A.4: JPS' Demand Growth is Stalling



A.4.2 Expected TFP Growth

As we discussed in the previous section, for the period 2006–2011, JPS' TFP growth was approximately 0.53 percent per year. However, the Licence requires that the X-Factor consider the "*expected* productivity gains" of JPS.[17] In practice, the OUR has interpreted this to mean a measure of historic TFP growth, plus a stretch factor to account for additional expected productivity gains over the tariff period. The OUR's past interpretation of expected productivity gains has been predicated on the assumption that JPS is "a below average performer" within the electric utility industry.[18]

To test this assumption, Castalia used three efficiency analysis techniques to measure JPS' relative performance:

- Productivity benchmarking
- Efficient frontier analysis (EFA), and
- Data envelopment analysis (DEA).

To enable these comparisons, we compiled a data set containing observations for 49 utilities in the Caribbean, United States, and New Zealand, from 2005–2011. Our data set contained variables relating to operating expenses, capital expenses, scale, and operating environment.

[16] We had sufficient data to calculate JPS' TFP growth through 2012, but we were limited in using it because TFP data was only available through 2011 for the Jamaican economy.

[17] Government of Jamaica, All-Island Electricity Licence 2011, Schedule 3, Exhibit 1.

[18] Office of Utilities Regulation. "Jamaica Public Service Company Limited: Tariff Review for Period 2009–2014—Determination Notice." September 2009, p. 65. http://www.our.org.jm/ourweb/sectors/electricity/determination-notices/jps-ltds-tariff-review-2009-2014-determination-notice-sept (accessed October 28, 2013).

Table A.4 details the various components of our benchmarking data set. All of the data collected were gathered from audited financial statements or regulatory reports.

Table A.4: Benchmarking Data Set (2005–2011)

Utilities			
ANGLEC (Anguilla)	Florida Power & Light (US)	Ashburton (NZ)	Scanpower (NZ)
BEL (Belize)	Georgia Power (US)	Invercargill (NZ)	TLC (NZ)
BL&P (Barbados)	Gulf Power (US)	Horizon (NZ)	TPCL (NZ)
DOMLEC (Dominica)	Hawaii Electric Light (US)	Mainpower (NZ)	Top (NZ)
EDEESTE (Dominican Republic)	Hawaiian Electric (US)	Marlborough (NZ)	Unison (NZ)
GPL (Guyana)	Maui Electric (US)	Nelson (NZ)	Auckland (NZ)
GRENLEC (Grenada)	Alpine (NZ)	Tasman (NZ)	Waipa (NZ)
JPS (Jamaica)	Dunedin (NZ)	Waitaki (NZ)	Hamilton (NZ)
LUCELEC (St. Lucia)	Buller (NZ)	Northpower (NZ)	Wellington (NZ)
T&TEC (Trinidad & Tobago)	Centralines (NZ)	Christchurch (NZ)	Westpower (NZ)
VINLEC (St. Vincent)	Counties (NZ)	Otago (NZ)	
	Eastland (NZ)	Powerco (NZ)	
	Electra (NZ)		

Cost Variables		**Outputs**
Operating Revenue (US$)	Fuel Expense (US$)	Customers
Total Assets (US$)	Non-Fuel OPEX (US$)	MWh Sold
Current Assets (US$)	Staff Cost (US$)	MW Peak Load
Current Liabilities (US$)	Non-Fuel, Non-Staff OPEX (US$)	Network Length (km)
Working Capital (US$)	Capital Expenditure (US$)	
PP&E Gross Book Value (US$)	Capital Consumption (US$)	
PP&E Net Book Value (US$)	IPP Capacity Payments (US$)	
Depreciation Expense (US$)	Capital Consumption + IPP (US$)	
Operating Expense (US$)	Employees	

The results of our three efficiency analysis techniques generally support the conclusion that JPS is, in fact, an efficient cost performer relative to its peers. As a result, we recommend that no stretch factor should apply in the 2014–2019 tariff period.

While this contrasts with the OUR's assumption in the prior tariff determination, it is still consistent with its prior rationale, since the OUR set a stretch factor with the expectation that JPS would catch up to the industry frontier. Now that JPS is operating at the efficiency frontier, a stretch factor should not apply in the current X-Factor calculation.

The remainder of this section describes the methodologies used in the three efficiency analysis techniques, including a discussion of our data choices, assumptions, and key findings.

Productivity Benchmarking

Productivity benchmarking takes specific outputs, such as customers served and energy sold, and shows the inputs, often expressed as costs, required to produce the outputs. It is an intuitive way to compare the productivity of the electric utilities[19] in our data set, because it relies on data collected from audited financial statements and annual reports. In this way, it is the most straightforward of the three efficiency analysis techniques.

We believe that number of customers is the most important output in productivity benchmarking, and our discussion will focus on various inputs per customer. This is because the X-Factor is applied to the Non-Fuel Base Rate, and the primary driver of non-fuel costs is the number of connections to the grid, not energy sales. However, because energy sales are frequently used as the primary output in productivity benchmarking of electric utilities, we also include those results.

The figures in this section show the results of the productivity benchmarking exercise. Each figure is annotated with JPS' ranking in yellow, its corresponding calculated value clearly labelled, and an average (arithmetic mean) line inserted for perspective. Each figure below is paired with a discussion of the data, including important details on our interpretation of the results.

Labour Productivity

First, we examined the productivity of labour inputs to the provision of electricity. This was measured as the number of employees per 1,000 customers. As Figure A.5 shows, JPS outperforms all of the United States and Caribbean utilities in the data set, except for Florida Power & Light Company. Notably, this result is consistent with JPS' relative performance in the 2012 CARILEC benchmarking study.[20]

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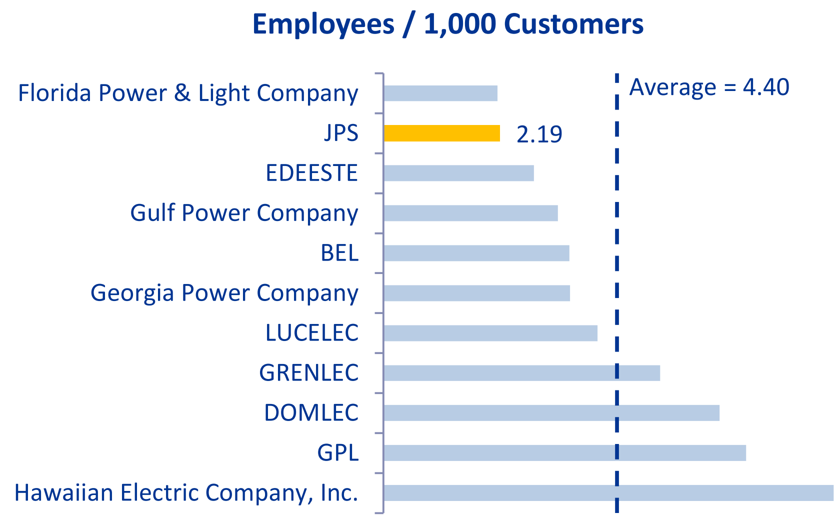
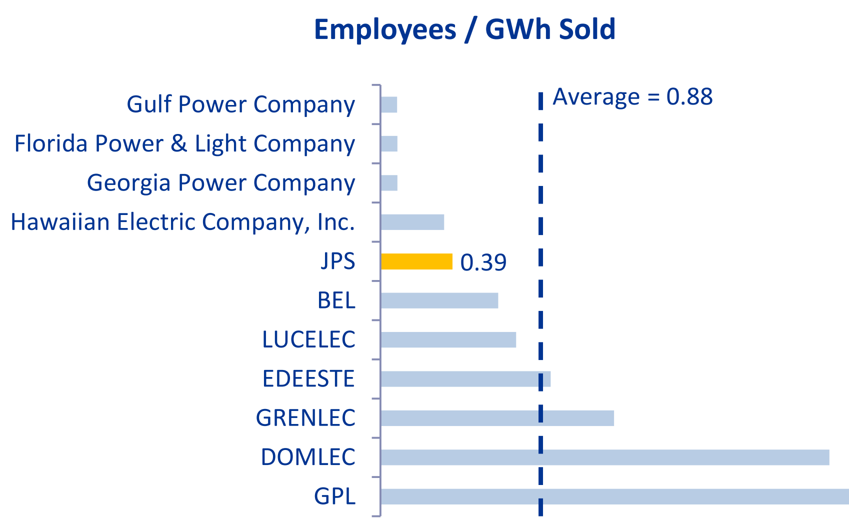
[19] We excluded New Zealand utilities from the productivity benchmarking primarily because of a lack of available, comparable data

[20] CARILEC. "Benchmark Study of Caribbean Utilities: Ninth Update—Year 2012." 2013.

Figure A.5: Productivity Benchmarking—Staff Numbers

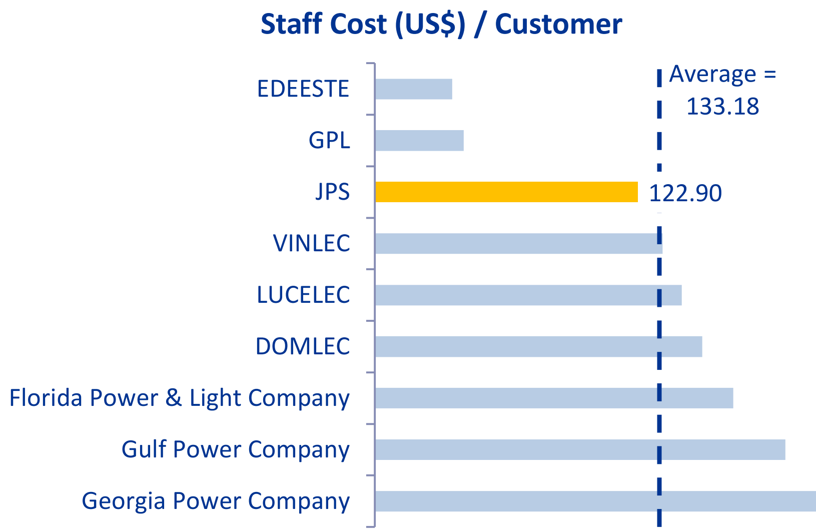


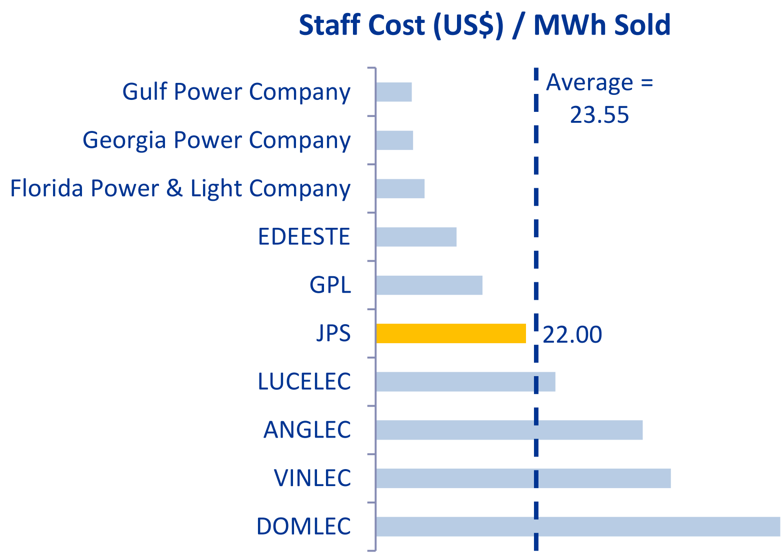


If we measure labour productivity as number of employees per GWh sold, JPS is outperformed by only four utilities—all of which are in the United States. Not surprisingly, this is because all of the United States utilities in the data set have significantly higher average energy consumption, presumably driven by higher per capita income and higher levels of industrial and commercial electricity demand.

As an alternative to measuring staff numbers, we also examined staff costs per customer. By this measure (shown in Figure A.6), JPS is again among the best performers. Although it ranks third-best, JPS' staff cost per customer are still better than average. The two utilities that outrank JPS—EDEESTE, a distribution utility in the Dominican Republic, and Guyana Power & Light in Guyana—likely face lower wage rates than JPS.

Figure A.6: Productivity Benchmarking—Staff Cost



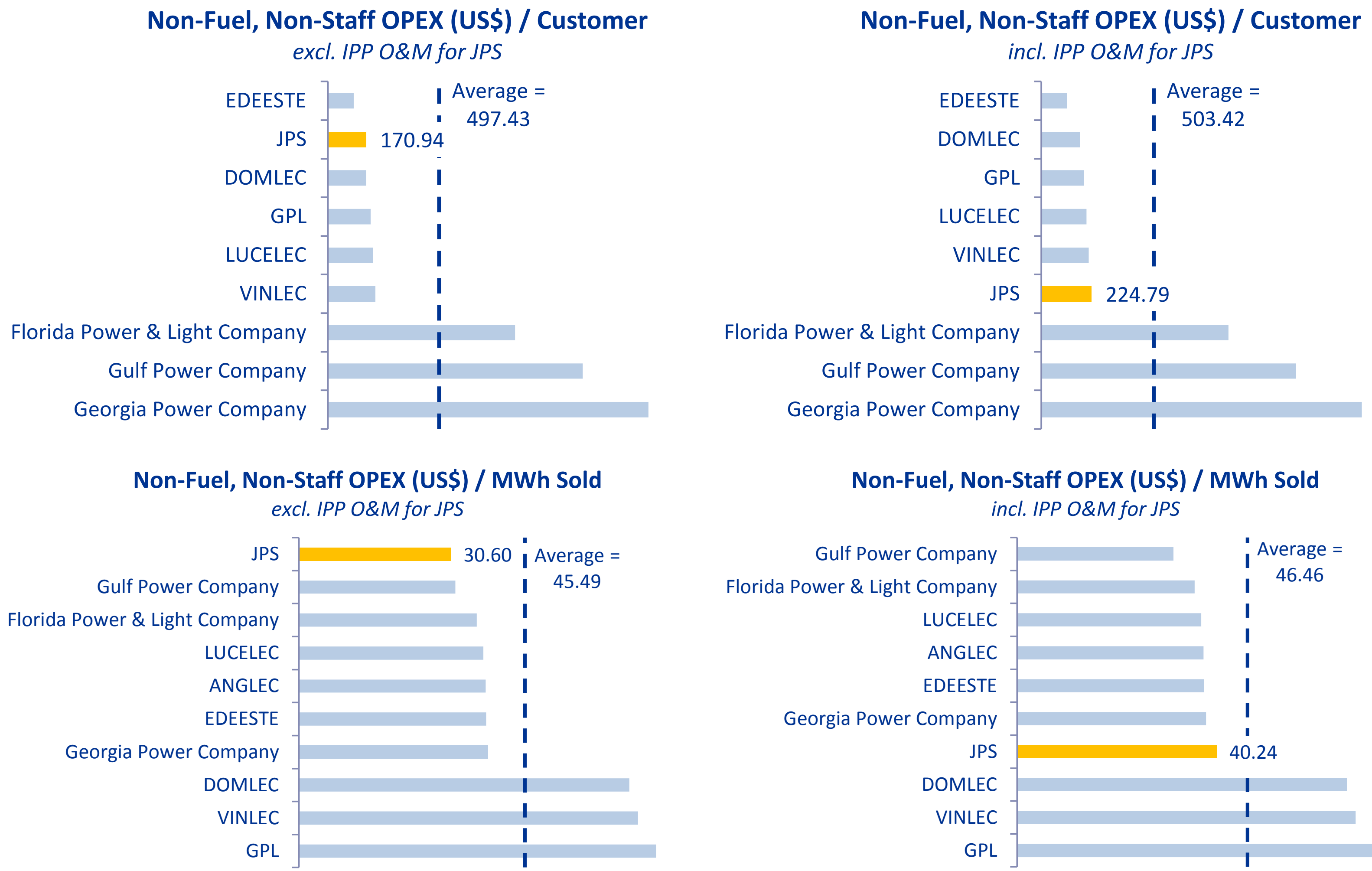


When we measure labour productivity as staff cost per MWh sold, the United States utilities again outperform JPS. Again, this is explained by higher energy demand per customer in the United States. However, JPS still remains more efficient than average—and considerably better than its Caribbean peers with comparable wage levels.

Productivity of Non-Fuel, Non-Labour Operating Expense

Turning to non-fuel, non-labour costs, in Figure A.7, we present two sets of benchmarking graphs: (1) non-fuel operating expense excluding operation & maintenance (O&M) costs for independent power producers (IPPs) in Jamaica, and (2) non-fuel operating expense including these IPP O&M costs.

Figure A.7: Productivity Benchmarking—Non-Fuel, Non-Staff Operating Expense



We provide both sets of benchmarking graphs because IPP O&M costs were unavailable for the other utilities in the data set. We know this is a significant limitation of the data, because some utilities (such as EDEESTE) purchase a significant amount of power from IPPs, but those avoided O&M costs are not reflected in their productivity ranking.

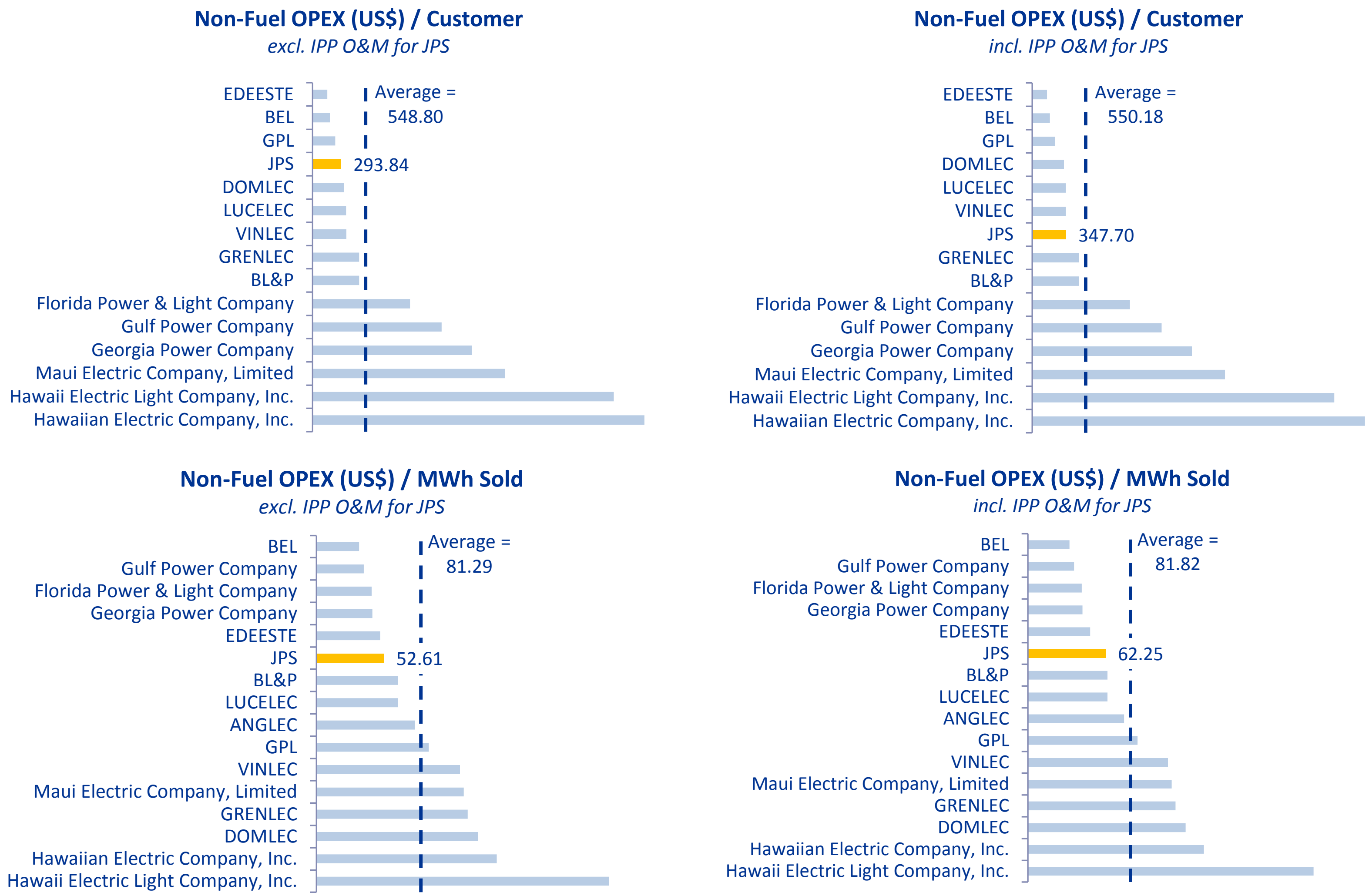
Our solution to this data availability problem was to show JPS' relative performance both excluding, and including, these costs. JPS' productivity when IPP O&M costs are *excluded* will be *overstated*, while our productivity when IPP O&M costs are *included* will be *understated*. In this way, we can place JPS' ranking within a "bracket" of high and low performance. Put another way, we know that JPS' true productivity must be somewhere between our performance when we exclude these IPP O&M costs and when we include them.

Considering this "bracket" of performance, JPS still outperforms its peers—and in all cases, JPS is better than average in non-fuel, non-labour operating expense.

Productivity of Total Non-Fuel Operating Expense

We then combine the labour and non-labour components of non-fuel operating expense into a measure of *total* non-fuel operating expense. As with the non-fuel, non-labour operating expense measure (see Figure A.7), we provide a set of graphs including IPP O&M costs, as well as a set of graphs excluding IPP O&M costs. Figure A.8, on the next page, shows that JPS is again a strong performer when it comes to non-fuel operating expense.

Figure A.8: Productivity Benchmarking—Non-Fuel Operating Expense



Whether we consider non-fuel operating expense per customer, or per MWh sold, JPS performs far better than average—and outperforms most of its Caribbean peers. Even if we consider JPS' performance "bracket," produced by excluding and including IPP O&M costs from non-fuel operating expense, JPS remains a strong performer.

In addition to providing a broad measure of operating cost productivity, using total non-fuel operating expense as a productivity benchmark has the added benefit of allowing us to accurately rank as many utilities as possible. This benefit is particularly relevant because we lacked sufficient disaggregated data to otherwise separate labour and non-labour costs for many utilities in our data set. In these cases, we were forced to exclude those utilities from the separate labour and non-labour cost benchmarking.

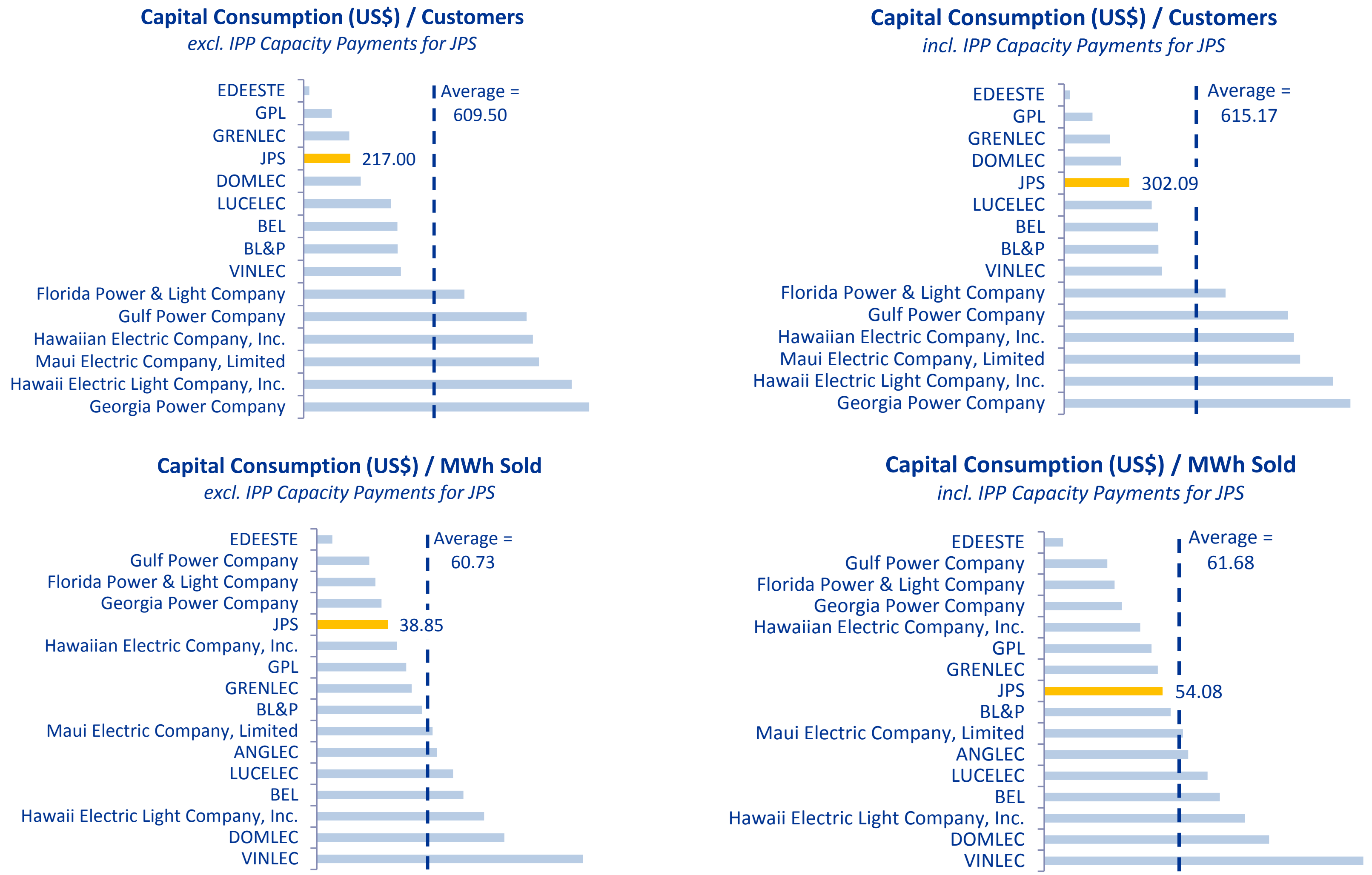
In a related issue, we lacked sufficient detail for JPS' own IPP O&M costs to be able to separate them into labour and non-labour components. Because of this data availability problem, we assumed all IPP O&M costs were non-labour in nature. This had the unintended effect of overstating JPS' staff cost performance (see Figure A.6) and understating its non-fuel, non-labour cost performance (see Figure A.7).

To summarise, non-fuel operating expense provides the most accurate and comprehensive measure of operating expense productivity—and, it shows that JPS is a strong performer.

Capital Productivity

We also attempt to measure the relative productivity of JPS' fixed assets—something which is generally difficult to do. We use a service price approach to estimate annual capital consumption, which effectively annuitizes the cost of capital ownership. Figure A.9 shows that JPS again performs better than average, and also outperforms most of its Caribbean peers. An intuitive way to interpret this benchmark is that in 2011, JPS spent US$217.00 per customer on capital assets (excluding IPP capacity payments), or US$302.09 per customer (including IPP capacity payments).

Figure A.9: Productivity Benchmarking—Capital Consumption



To develop this benchmark, we defined capital consumption as the sum of depreciation expense, rate of return on assets, and IPP capacity payments (for JPS only). Because regulatory rate base is not reported in audited financial statements, we instead used net book value of property, plant, and equipment. We also assumed the rate of return on assets for all the utilities in the data set was equal to JPS' authorised rate of return in the current tariff period (11.68 percent).

As with the treatment of IPP O&M costs, JPS' ranking can only be interpreted as a performance "bracket." This is because we only had data on JPS' IPP capacity payments, and not for the other utilities in the data set. Despite this caveat, JPS still performs better than average by this measure. In fact, if we consider capital productivity per customer, JPS' performance "bracket" only varies between fourth and fifth-best.

Efficient Frontier Analysis

As we have discussed, productivity benchmarking is a simple and easy-to-understand efficiency analysis technique. However, it does not consider the relationship between total inputs (costs) and total outputs, but rather relates specific costs with specific outputs. Additionally, we cannot correct for variations in operating environment, business structure, and scale. For this reason, we also look to efficient frontier analysis (EFA) to provide a more comprehensive and sophisticated evaluation of JPS' productivity.

EFA is an efficiency analysis technique that relies on econometric regression of total expenditure ("totex") on multiple independent variables. It is a technique used by the Office of Gas and Electricity Markets (Ofgem) in the UK for its distribution utility price resets.[21] The regression produces a linear function that models "expected" (that is, average) totex given a set of inputs to the independent variables. The regression line is then shifted to the 75th percentile of efficient cost performers, in order to generate an efficiency frontier. Using actual observations from the data set, a utility's direction and distance from its expected value on the efficiency frontier determines its level of efficiency (or inefficiency).

We carried out the EFA technique using a data set comprising 49 utilities throughout the Caribbean, New Zealand, and the United States, over a five-year time period (2005–2011). Figure A.10 illustrates the results of the EFA, with JPS highlighted as a yellow dot, the efficiency frontier also marked in yellow, and expected totex marked by a blue dashed line. We see that in 2011, JPS was both above average, and above even the efficiency frontier. Put another way, JPS' totex was less than what the model expected—and even less than what is considered the efficiency frontier. JPS is clearly an efficient cost performer.

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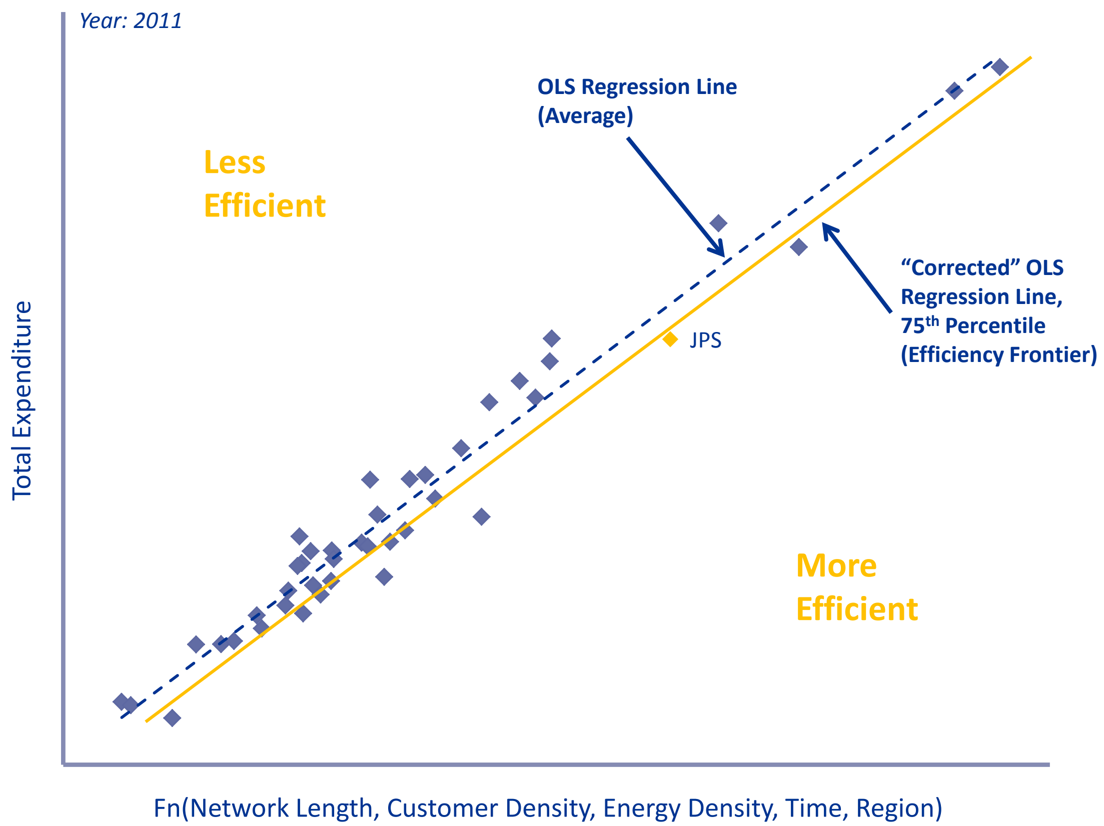
[21] Cambridge Economic Policy Associates. "Background to Work on Assessing Efficiency for the 2005 Distribution Price Control Review." September 2003, p. 31. http://regulationbodyofknowledge.org/wp-content/uploads/2013/03/CEPA_Background_to_Work.pdf (accessed October 28, 2013).

Figure A.10: Efficient Frontier Analysis with Corrected OLS



In determining a preferred econometric model, we used sound economic theory to predict a series of models *a priori*. The models we considered included variations of key cost drivers, such as network length, number of customers, peak demand, customer density, energy density, and asset age (measured as the ratio of capital expenditure to depreciation expense).

In total, we considered nine models, three of which were selected for further analysis. Our initial screening of the models examined goodness of fit (Adjusted R^2), as well as the statistical significance of independent variables, and the joint significance of the variables in each of the three short-listed model. We then conducted additional tests for heteroskedasticity, multicollinearity, and serial correlation.

Table A.5 summarises the characteristics of the various models we considered. Columns indicate the various independent variables used in the models we tested, and the coefficients and t statistics of each variable are reported in the appropriate cells. Model 1.9, highlighted in dark blue, was selected as our preferred model. Models 1.2 and 1.8 (highlighted in light blue) were short-listed, but not ultimately selected.

To improve the transparency of our regression analysis, we initially ran the models using the Data Analysis toolpak of Microsoft Excel 2010. We also validated the regression results using Stata, an industry-standard statistical analysis package.

Table A.5: Summary of Econometric Models Considered

Model	$D_{DistOnly}$	$D_{Caribbean}$	D_{NZ}	log Customer	logMWh Sold	logPeak Load	logNtwrk Length	Capex/ Deprec.	Customer Density	Energy Density	Notes
1.1	-1.65 (3.85)[22]			-0.17 (-1.72)	0.60 (2.66)	0.03 (0.11)	0.45 (4.55)	0.05 (1.92)	0.01 (3.15)	0.00 (0.82)	**Rejected;** illogical coefficient signs, weak coefficient magnitudes, poor p-values
1.2		-1.23 (-10.90)	-2.27 (-21.22)				0.97 (36.17)		0.02 (10.50)		**Short-listed;** meaningful coefficients, Adjusted R^2 = 0.952, Significance F = 0.000
1.3		-0.48 (-4.20)	-1.86 (-19.71)		0.55 (10.38)		0.33 (5.08)		0.01 (2.81)		**Rejected;** coefficients weakly related to network cost theory, despite good Adjusted R^2 = 0.969 and Significance F = 0.000
1.4		-0.54 (-3.64)	-1.92 (-18.75)	0.23 (2.31)		0.59 (6.91)			0.00 (-1.89)		**Rejected;** poor p-values and coefficients weakly related to network cost theory
1.5		-0.61 (-4.12)	-1.97 (-17.38)	0.14 (1.39)		0.68 (7.46)				0.00 (-1.78)	**Rejected;** poor p-values and illogical coefficient signs
1.6		-1.23 (-10.94)	-2.29 (-21.29)				0.98 (36.21)	-0.05 (-1.50)	0.02 (10.43)		**Rejected;** poor p-values and illogical coefficient signs
1.7		-0.49 (-4.24)	-1.88 (-19.61)		0.55 (10.26)			-0.02 (-0.95)	0.01 (2.83)		**Rejected;** poor p-values and illogical coefficient signs
1.8		-0.54 (-4.05)	-1.88 (-17.57)				0.91 (36.20)		0.01 (4.85)	0.00 (7.61)	**Short-listed;** meaningful coefficients, Adjusted R^2 = 0.963, Significance F = 0.000
1.9	**-1.59 (-19.72)**						**0.95 (38.53)**		**0.01 (4.99)**	**0.00 (12.75)**	**Selected;** meaningful coefficients, Adjusted R^2 = 0.963, Significance F = 0.000

[22] Coefficients of each of the independent variables are provided in the table cells, with t-statistics in brackets. T statistics are useful in conducting significance tests for each of the independent variables considered. We conducted a one-sample, two-tailed t test for each independent variable, where degrees of freedom = 207. Since all models included dummy variables for time, they were not reported in this table.

Our preferred model (see Box A.2) suggests that that total expenditure of an electric utility is primarily driven by network length, with slight cost additions for increasing customer density and energy density.

Box A.2: Our Preferred Econometric Model

Our preferred econometric model is a log-linear, time fixed-effects model. The model accounts for variation due to network scale and operating environment, in addition to time and business structure.

$$\begin{aligned}\log(Totex) = 9.9914 &+ 0.9475\log(NetworkLength)\\ &+ 0.0078(CustomerDensity) + 0.0015(EnergyDensity)\\ &+ 0.1303(D_{2006}) + 0.0632(D_{2007}) + 0.1883(D_{2008})\\ &+ 0.1563(D_{2009}) + 0.2401(D_{2010}) + 0.3418(D_{2011})\\ &- 1.5851(D_{DistributionOnly})\end{aligned}$$

Where:

D_{2006}, D_{2007}, D_{2008}, D_{2009}, D_{2010}, D_{2011} = time fixed-effects dummy variables

$D_{DistributionOnly}$ = a business structure dummy variable

This model exhibits highly desirable statistical properties, such as:

- **A strong goodness-of-fit coefficient (Adjusted R^2 = 0.9626).** In general, the closer to 1 the Adjusted R^2, the higher the ability of the model to explain observed variation from the predicted value.
- **Statistically significant independent variables, with no multicollinearity.** Multicollinearity exists when independent variables in the model are strongly correlated with one another, and it suggests that the predictive power of the model could be improved by removing one or more the affected variables.
- **No omitted variables.** If omitted variables exist, the predictive power of the model is weakened.
- **No heteroskedasticity.** This condition exists when the error terms are not dispersed homogenously, and its presence can suggest that certain significance tests may be biased.
- **No serial correlation.** This condition exists when error terms from different time periods are correlated with one another, and its presence can bias the results of the model.

After producing a conceptually and statistically valid model, we adjusted the ordinary least square residuals from the regression to "shift" the regression line to produce an efficiency frontier. An examination of JPS' performance relative to this constructed efficiency frontier shows that it achieved a 119 percent efficiency score in 2011.[23] This supports our initial conclusion from the productivity benchmarking that JPS is an efficient cost performer.

[23] JPS also was at or above the efficiency frontier during each of the other years contained in the data set.

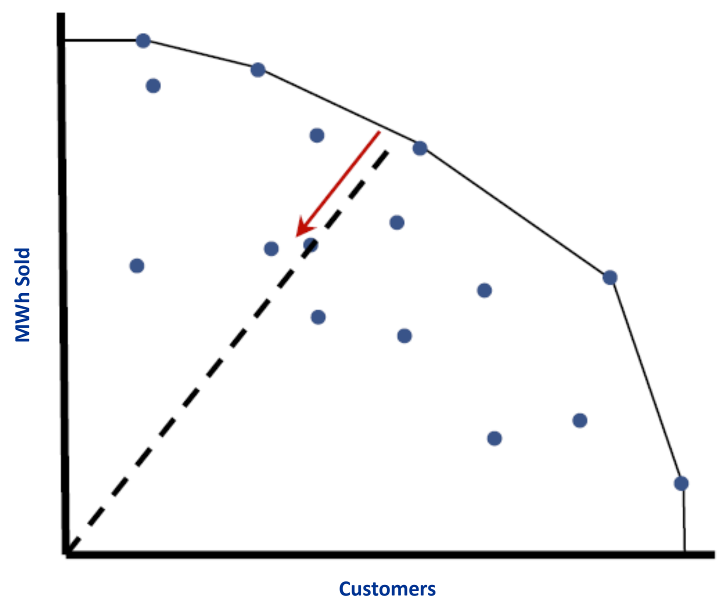
Data Envelopment Analysis

Having shown that JPS is efficient using two efficiency analysis techniques, we sought to check these results using data envelopment analysis (DEA).

DEA is a non-parametric method for assessing operational performance. It is particularly relevant for measuring the performance of electric utilities because unlike the other two techniques we used, it takes data on inputs and outputs directly and produces an efficiency frontier. In doing so, it avoids the problems associated with examining specific costs relative to specific outputs (as in the case of productivity benchmarking), or with defining a production cost model *a priori* (as is required with efficient frontier analysis).

Figure A.11 illustrates the concept of constructing a DEA efficiency frontier. In this stylised diagram, the efficiency frontier is constructed using the available data on utilities in the data set. Any utilities not on this frontier are inefficient, and the degree of inefficiency is equal to the distance of that utility from the frontier (as shown by the red arrow).

Figure A.11: A Stylised Concept of Data Envelopment Analysis



We ran the DEA analysis in Microsoft Excel 2010, using *DEA-Solver* software from Cooper et al.[24] We chose an input-oriented BCC model, which attempts to minimise inputs (total expenditure) given a fixed vector of outputs (MWh, sold, MW peak demand, and number of customers). Our choice of model was guided by Cooper et al., and from documentation of the DEA analysis conducted by Ofgem and the Australian Energy Regulator.[25]

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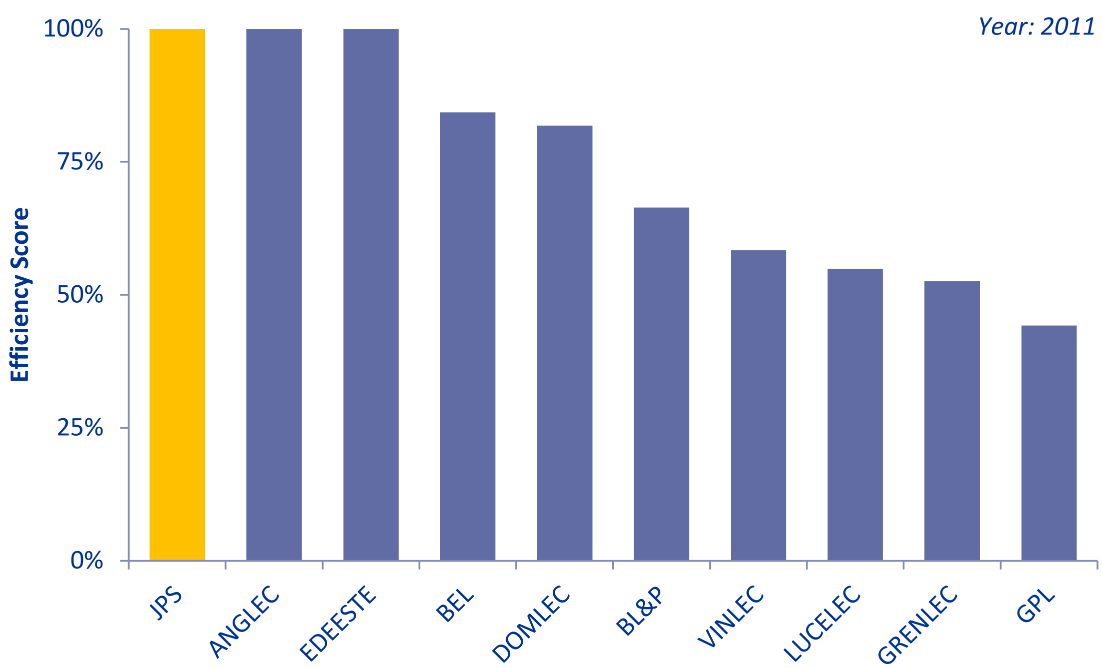
[24] Cooper, William W., Lawrence M. Seiford, and Kaoru Tone. *Data Envelopment Analysis: A Comprehensive Text with Models, Applications, References, and DEA-Solver Software.* New York: Springer, 2007.

[25] Cambridge Economic Policy Associates. "Background to Work on Assessing Efficiency for the 2005 Distribution Price Control Review." September 2003, pp. 16-23. http://regulationbodyofknowledge.org/wp-content/uploads/2013/03/CEPA_Background_to_Work.pdf (accessed October 28, 2013).

Because it was not simple to account for variation in time, business structure, and operating environment (as we did using the EFA technique), we restricted our model to the year 2011, and to the subset of Caribbean utilities in our broader benchmarking data set.

The results of our DEA analysis are illustrated in Figure A.12, and they validate our conclusion thus far: JPS is an efficient cost performer. This is plainly shown by JPS' efficiency score of 100 percent, which suggests that it—along with ANGLEC and EDEESTE—forms the efficiency frontier for the utilities in this analysis.

Figure A.12: DEA Results



Conclusion from the Efficiency Analysis

To summarise our approach, we assessed JPS' efficiency relative to comparators using three recognized techniques: productivity benchmarking, efficient frontier analysis, and data envelopment analysis. The results of each technique suggest that JPS is operating on, or near, the efficiency frontier for electric utilities. Therefore, there should be no stretch factor applied in order to arrive at JPS' expected TFP growth rate in the 2009–2014 tariff period.

A.5 General TFP Growth

The second component of the "calculations approach" to estimating the X-Factor is the calculation of the general economy TFP growth rate. We find that the general economy TFP growth rate to be used over the tariff period 2014–2019 is approximately 0.1799 percent.

To recall Section A.1, the language of the Licence states that $\Delta TFP_{General}$ is calculated as the weighted average of the TFP growth rates of the United States and Jamaican economies.

$$\Delta TFP_{General} = (0.76 \times \Delta TFP_{US}) + (0.24 \times \Delta TFP_{Jamaica})$$

This weighted average, with 76 percent weight given to TFP growth in the United States and 24 percent weight given to TFP growth in Jamaica, is derived from the formula used to calculate ΔI (also prescribed in the Licence). In this section, we calculate the TFP growth rate for the United States. We then calculate the TFP growth rate for the Jamaican economy, and combine the two results to calculate the general economy TFP growth rate for the 2014–2019 tariff period.

A.5.1 TFP Growth in the United States

To calculate a TFP growth rate for the United States, we used Nonfarm, Private Multifactor Productivity (MFP) as calculated by the United States Bureau of Labor Statistics. MFP is the most commonly used measure of TFP in the United States. Additionally, it was used to estimate the United States TFP growth rate in JPS' last tariff review application, and was accepted by the OUR.

Table A.6 shows the MFP index from 1991–2012. Based on the data, from 2006–2011, TFP in the United States grew at an average annual rate of 0.4207 percent.

Table A.6: TFP in the United States (2005 = 1.0000)

Year	Multifactor Productivity
1991	82.6530
1992	84.5920
1993	84.8400
1994	85.4710
1995	85.4920
1996	86.6680
1997	87.1790
1998	88.4460
1999	89.9090
2000	91.3540
2001	92.0320
2002	94.2290
2003	96.6270
2004	98.9260
2005	100.0000
2006	100.3620
2007	100.7070
2008	99.3050
2009	98.9120
2010	101.4650

Year	Multifactor Productivity
2011	102.4910
2012	103.4170

Source: United States Bureau of Labor Statistics

A.5.2 TFP Growth in Jamaica

Our TFP growth rate calculations for the Jamaican economy are based on the most recent data available from the Penn World Table.[26] Obtaining a suitable input to represent TFP growth in the Jamaican economy is inherently difficult because, unlike in the United States, the Jamaican government does not publish economy-wide TFP estimates. In its place, we rely on the Penn World Table, a data set compiled by a group of international economists who specialize in macroeconomic growth accounting. The Penn World Table is considered the international gold standard for comparative country productivity data, and we believe it represents a marked improvement over the consultant's calculations used to estimate Jamaican TFP growth in JPS' last tariff review application.[27]

Table A.7 shows the TFP index for Jamaica from 1991-2011. For the period 2006–2011, TFP in Jamaica grew at an average annual rate of -0.5827 percent.

Table A.7: TFP in Jamaica (2005 = 1.0000)

Year	Total Factor Productivity
1991	1.0894
1992	1.1725
1993	1.1699
1994	1.1460
1995	1.1144
1996	1.1050
1997	1.0818
1998	1.0592
1999	1.0711
2000	1.0669
2001	1.0645

[26] University of Groningen. Penn World Table Version 8.0. 2011. http://www.rug.nl/research/ggdc/data/penn-world-table (accessed October 28, 2013).

[27] The only limitation of the Penn World Tables is that data are only available through 2011. For this reason—and because we preferred consistency of time periods used to measure average annual growth in JPS and economy-wide TFP—all growth rates in this analysis use 2011 as the ending year.

Year	Total Factor Productivity
2002	1.0105
2003	1.0189
2004	1.0194
2005	1.0000
2006	0.9989
2007	0.9856
2008	0.9742
2009	0.9630
2010	0.9644
2011	0.9701
2012	1.0105

Source: Penn World Table 8.0

Notably, a negative TFP growth rate in Jamaica has troubling implications and, in the long run, is unsustainable. However, the last 20 years of Penn World Table data suggest that a negative TFP growth rate for the general TFP calculation is indeed appropriate.

Calculating the General TFP Growth Rate

We can now combine our calculations in this section to obtain a general TFP growth rate. As we just showed, the growth rate for the United States economy is 0.4207 percent, and the TFP growth rate for the Jamaican economy is -0.5827 percent.

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

$$\Delta TFP_{General} = (0.76 \times 0.004207) + (0.24 \times -0.005827) = 0.1799\%$$

Therefore, the general TFP growth rate for the 2014–2019 tariff period is 0.1799 percent.

A.6 Conclusions

To summarise our analysis, we are able to tell a story of JPS' productivity that is consistent with the OUR's past characterisations. JPS is a utility that *was* inefficient at privatisation, as acknowledged by the OUR in its 2009 tariff determination notice: "Given the recent change in ownership of JPS and the regulatory regime change in Jamaica to a performance based regime, it is likely that JPS' TFP growth will accelerate."[28]

[28] Office of Utilities Regulation. "Jamaica Public Service Company Limited, Tariff Review for Period 2009–2014, Determination Notice." October 2009. http://www.our.org.jm/ourweb/sites/default/files/documents/sector_documents/jps_tariffreview_2009-2014__determination_0.pdf (accessed October 23, 2013).

However, in response to the PBRM, JPS' efficiency has increased significantly, at approximately 1.27 percent annually from 2002–2011. In fact, this TFP growth rate is roughly 50 percent higher that achieved by United States utilities from 1972–2009.[29]

If we consider the "fundamentals approach" to setting JPS' X-Factor (see Section A.3), we would expect JPS' TFP to grow at the same rate as the general economy TFP, and thus the X-Factor should be no more than zero percent.

If we consider the "calculations approach" to setting JPS' X-Factor (see Sections A.4 and A.5), we find that the X-Factor for the tariff period 2014–2019 should be approximately 0.35 percent. This is given by $X = \Delta TFP_{JPS} - \Delta TFP_{General} = 0.5340\% - 0.1799\% = 0.3541\%$. We also find that is no justification for a "stretch factor," as we have no reason to believe future growth in JPS' TFP will be faster than in the past. Rather, the opposite is more likely. JPS' TFP growth has slowed, and will continue to slow in the future because (1) JPS is now at the efficiency frontier for non-fuel costs, as demonstrated by our efficiency analysis techniques, and (2) low demand growth will continue to depress opportunities for productivity gains.

Therefore, we believe the X-Factor for the tariff period 2014–2019 should be between zero percent and 0.35 percent.

[29] Makholm, Jeff D., Agustin J. Ros, and Meredith A. Case. "Total Factor Productivity and Performance-Based Ratemaking for Electricity and Gas Distribution." 2010. http://www.nera.com/nera-files/PUB_TFP_Makholm_Ros.pdf (accessed October 28, 2013).

Annex C: Depreciation Study

1 Context to this report

1.1 Background

The Office for Utility Regulation (the “OUR”) is responsible for determining the pricing regime for JPSCo. The current JPSCo tariff was set in 2009 and runs through to 2014, at which point the terms for the next tariff period will be determined.

The OUR regulates JPSCo and other utility companies in Jamaica. JPSCo is regulated by the OUR through the Amended and Restated All-Island Electric Licence, 2011. The OUR uses economic asset lives to set depreciation allowances. The economic life takes into consideration both the technical life of the assets and the estimated period over which the assets will be usefully employed.

In setting the terms for the next licence period, starting 2014, there are a number of key regulatory decisions required for determining prices.

1.2 The use of depreciation in regulation

Determining asset values, and annual depreciation charges is a key building block of economic regulation. The concept of regulatory asset value is often used to determine how prices are calculated over the period of a price control regime.

Depreciation, for the purposes of economic regulation and for accounting purposes represents a measure of consumption in the useful economic life of an asset, due to the regular use, passage of time, inadequacy, or obsolescence.

From a regulatory economics perspective, it is important to recognise that the rate of depreciation is an important factor in determining the level of prices that a company is able to charge. In some regulatory regimes the methodology and lives for deprecation for regulatory purposes diverges from the accounting depreciation because regulators need to manage the trade off between investor requirements to be reimbursed for investments and consumer requirements to have affordable bills. A regulator may change the period over which an asset is depreciated if it thinks that the consumer would not be able to pay for it over its useful life.

There are different approaches to determining depreciation. For regulatory purposes this usually takes into consideration a number of objectives, including:

- Efficient pricing: regulated prices should provide a signal to the customers in relation to the scarcity of the resources used to provide electricity.
- Efficient investment: the regulated charges should be those which provide the investors the incentive to invest in efficient long-lived assets that will be required to ensure the continuity and quality of service.
- Efficient production: the regulatory regime should provide incentives to invest and operate in an efficient way, therefore operation, maintenance and construction should be provided at the least possible cost.
- Price stability and intergenerational equity: the regulatory depreciation should generate relatively stable charges and cost allocation between customers over the useful life of the asset.
- Administrative simplicity: regulatory depreciation should be as simple, from the administrative point of view, as possible.
- Certainty and consistency: as much as possible, the approaches adopted from one regulatory period to the next, should be the same.

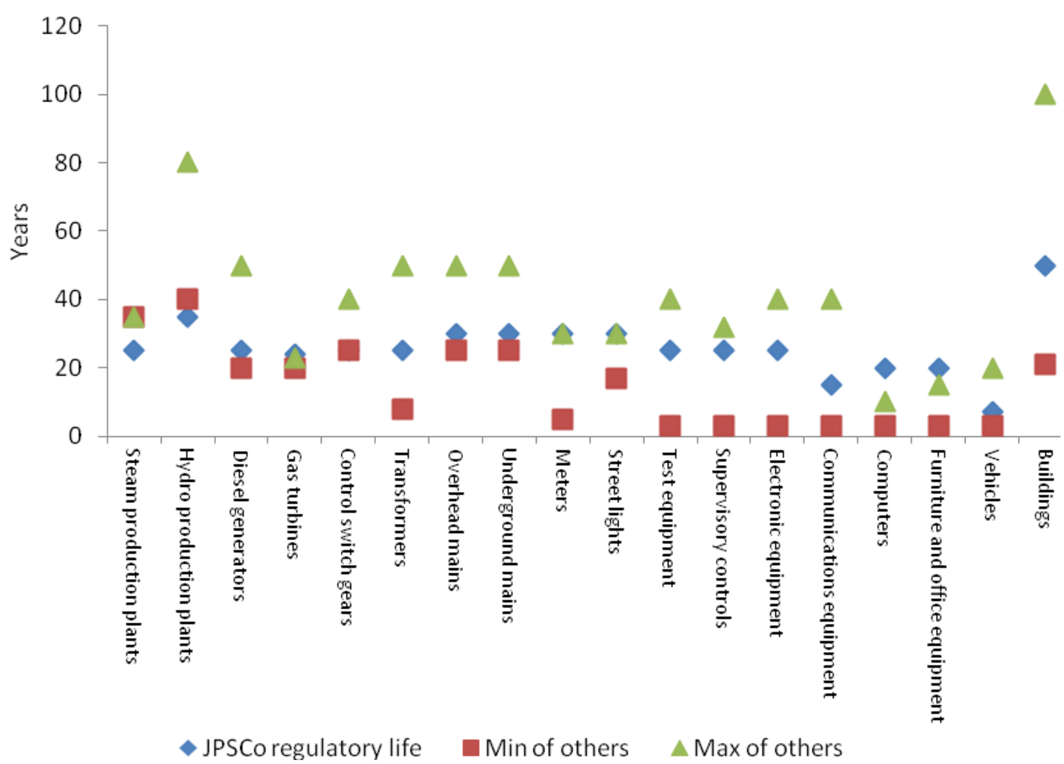
It is possible that some of these objectives may be in conflict with each other, in which case the regulator needs to determine its overriding policy objectives.

Depreciation can be set using: a straight line basis, where by the annual depreciation is the same in each year of an assets life; or through a declining balance basis, whereby a greater proportion of its value is depreciated in the early years of the assets life and the annual depreciation is based on the residual value of the asset in a particular year.

It is important to note that the relationship between depreciation charges and prices is not necessarily direct. The faster an asset is depreciated, the faster its carrying value reduces. Another important cost input into the determination of regulated prices is the return on capital employed in the business and the largest element of capital employed is the carrying value of the underlying assets. So whereas accelerating the rate of depreciation of an asset leads to a higher deprecation charge (until the asset is fully depreciated), it also accelerates the decline in the carrying value of the asset and thus a reduction in the allowance for a return on capital. This effect may be more than sufficient to counteract the effect of the higher depreciation charge.

Figure 1

JPSCo depreciation lives by asset class compared with range of results from comparator countries



The comparison with other countries indicated:

- The current depreciation lives used by JPSCo for major items of plant and equipment (gas turbines, control switchgear, transformers and mains) were generally comparable with the experience of other countries;

- Steam production and hydro generation plant depreciation lives for JPSCo were marginally below the international experience;

- The asset lives for diesel generation assets were in the range of international comparators however towards the lower end of that range;

- For meter assets the regulatory life allowed for JPSCo was at the top of the range of expected range from our sample of countries. Generally longer asset lives are used for existing non-smart or “dumb” meters. At present there is little useful data about the useful economic lives of smart meters, they are a relatively new asset class. A number of companies are considering and using a maximum life of 15 years, consistent with the expected meter technical lives. However, this will be kept under review based on the rate of technical progress, which could potentially reduce the useful economic life of meters.

- For electronic equipment and computers, etc. JPSCo’s depreciation lives are either towards the top end of the range of international comparators or outside of that range suggesting that there may be scope to review these asset lives for regulatory depreciation purposes.

1.2.1 Evidence from analysis of JPSCo’s retired assets

- For distribution plant the range of lives allowed for in the Licence (25 to 30 years) was higher than the weighted life of assets on the date of retirement, which was 20 years.

- The General property and equipment asset class, which includes a significant proportion of technology related assets, we found retired assets tended to have an average life of 10 years (on a weighted average basis) compared with a depreciation life of 15 years for regulatory purposes. This difference may justify a potential change to the allowed life of the assets for regulatory purposes.

- For steam production, other production, and transmission asset classes their asset data capture for long lived assets did not form a reliable basis on which to draw any conclusions on the actual economic lives of these asset classes.

- For long lived assets, asset life is extended through asset overhauls and major maintenance, however, JPSCo’s asset management systems do not link the maintenance/overhaul projects to the specific assets to provide a lifetime cost/depreciation analysis resulting in a lack of data with which to perform an analysis.

Figure 2

Comparison of JPSCo asset lives on retirement compared with allowed regulatory asset lives

Summary of useful life of retired assets							
			Useful life (years)				
	Sample size	Depreciation life (years)	Minimum	Maximum	Simple average	Weighted average	Mode
Distribution Plant	686	25 to 30	-	38	15	20	14
General property-Equipment	390	15	-	22	9	8	9
General property - structures	15	50	-	42	11	29	7

Source: 1) Asset_Retirements-Jan 2005-Aug 2013.xlsx
2) JPS Depreciation Rate Categories.docx

Figure 3

Recommended regulatory asset lives

Activity	Asset	Current Life	Recommended Life
Generators	Steam production plant	25	25
	Hydro production plant	35	35
	Diesel generations	25	25
	Gas turbine	24	24
Transmission	Control gear/Switchgear	25	25
	Transformers	25	25
Distribution	Overhead mains	30	30
	Underground mains	30	30
	Meter	30	15
	Street lights	30	20
	Test equipment	25	15
	Supervisory control systems	25	25
General Plant	Electronic equipment	25	10
	Communication equipment	15	5
	Computer equipment	20	6
	Furniture and office equipment	20	10
	Vehicles	7	4
	Land-leasehold	50	50
	Buildings	50	50

1.2.2 Assessing the historical useful life of JPSCo's assets

In assessing the appropriateness of the regulatory asset lives that JPSCo utilises, assessing actual useful lives of assets can be informative.

This type of analysis requires reviewing the asset register to identify assets that JPSCo has retired over time. In doing this analysis we reviewed the asset register of JPSCo as at August 31, 2013 and a list of all JPSCo assets retired between January 2005 and August 2013.

For those assets that were retired we were able to determine the actual useful life of the assets. For those assets that were in service but for which significant maintenance or renewal had been performed we were unable to determine the length of time between the significant maintenance or renewal dates, and as such were unable to determine the average actual economic life of this class of assets.

Figure 4 below shows a selection of countries for the comparison which have similar attributes to Jamaica. These characteristics, which are relevant to Jamaica, include:

Figure 4

List of comparator electricity systems for JPSCo depreciation study

	Island	Variety of generation sources	Market size	Population	GDP per capita (US$)
Jamaica	Y	Steam (Oil fired) Gas, turbines, combined cycle, diesel, hydropower and wind	Net generation: 4,132 GWh Consumption: 3,314 GWh Installed capacity: 930 MW	2.7 million	$5,391
New Zealand	Y	75% comes from renewable sources namely hydropower, geothermal and wind. The remaining comes from oil, gas and coal.	Generation: 45,000 GWh (approx) Consumption: 39,128 GWh	4.4 million	$36,687
Barbados	Y	Approximately 50% is Diesel generated. The rest is from Steam and Gas Turbine.	Consumption:1,024.3 GWh Capacity: 239.1 MW 33% - Domestic 67% - Commercial	283,221	$15,554
Trinidad and Tobago	Y	Primarily from Natural Gas	Net generation: 9,100GWh Total capacity: 2,064 MW	1.3 million	$17,822
Singapore	N	80.4% Natural Gas 15.4% Petroleum products 4.2% Others	Consumption: 47,000 GWh Installed capacity: 11,615 MW	5 million	$50,000
Jersey	Y	90% of electricity imported from France via two undersea cables known as EdF1 and EdF2. The oil fired La Collette power station is used as a backup.	Consumption: 650 GWh	100,000	NA
Dominican Republic	Y	Dominated by thermal generation fired up by fuel oil, coal or gas	Installed capacity: 3,394.1 MW Consumption: 13,356 GWh	10 million	$5,532
Guatemala	N	40% from Hydroelectric 18% Reciprocating	Demand: 5,180.9 GWh Installed Capacity: 2,795	15 million	$3,188

	Island	Variety of generation sources	Market size	Population	GDP per capita (US$)
		Engines 18% - Steam Turbines The rest is from Gas turbines, biomass and geothermal	MW		
Bolivia	N	33.5% from Hydroelectric 66.5% from Thermoelectric	Gross Generation: 6,940.6 GWh Consumption: 6604.3 GWh Installed capacity: 1,384.8 MW	10.5 million	$2,269

1.2.3 Comparable country profiles

In New Zealand, Electricity generation is not subject to ex ante regulation, generation pricing is determined by wholesale electricity market arrangements, and the depreciation lives are the lives used for statutory reporting purposes.

The regulatory authority, The Commerce Commission of New Zealand, has oversight of the generation market through its usual market powers. Ex ante regulation exists for transmission and distribution activities. As part of the price setting process asset lives are reviewed and assessed. For transmission the asset lives were last reviewed in June 2012 and for distribution the asset lives were reviewed in November 2012.

In Singapore and Guatemala as the regulatory authorities have more of an ex post oversight role. It is less clear the point at which depreciation lives were last reviewed for the key assets and as they are not explicitly set by the regulator the asset lives for statutory reporting purposes are used in assessing the overall performance of the business.

In Barbados the last major rate setting decision was in 2009/10 with a formal decision concerning the Barbados Power and Light company depreciation policy in 2009. The electricity supply industry in Barbados and Trinidad and Tobago have not started a programme of investment in smart technologies for their networks to the same scale as JPSCo and may as a result face less of a challenge in terms of their approach to depreciation thus far.

1.3 Undertaking analysis of comparables

Figure 5

Comparison of regulatory asset lives in years by country1

Activity	Asset	Jamaica	Trinidad & Tobago	New Zealand	Singapore	Barbados	Guatemala
Generators	Steam production plant	25	NA		Varies by company typically	35	
	Hydro production plant	35	NA			n.a.	

[1] We have been unable to access comparable electricity generation asset lives for Guatemala.

	Diesel generations	25	20		up to 40 to 50 years	30	
	Gas turbine	24	NA			23	
Transmission	Control gear/Switchgear	25	25	40	30	32	30
	Transformers	25	25	8 to 50	30	23	30
Distribution	Overhead mains	30	30		30	30	25
	Underground mains	30	40	Average of 50 years	30	33	25
	Meter	30	15	5 to 30 years	3 to 30 years	20	na
	Street lights	30	20	na	n.a.	17	na
	Test equipment	25	15	3 to 40 years	3 to 15 years	15	15
	Supervisory control systems	25	25	3 to 40 years	3 to 15 years	32	15
General Plant	Electronic equipment	25	10	3 to 40 years	3 to 15 years	15	15
	Communication equipment	15	5	3 to 40 years	3 to 15 years	15	15
	Computer equipment	20	6	Software 2-4 years	3 to 15 years	6	7
	Furniture and office equipment	20	10	5 to 20 years	3 to 15 years	15	na
	Vehicles	7	4	5 to 20 years	3 to 15 years	12	na
	Land-leasehold	50	50	Not depreciated	n.a.	n.a.	na
	Buildings	50	30	40 to 100 years	21 to 30 years (leasehold)	45	na

The comparison with other countries indicated:

- The current depreciation lives used by JPSCo for major items of plant and equipment (gas turbines, control switchgear, transformers and mains) were generally comparable with the experience of other countries;

- Steam production and hydro generation plant depreciation lives for JPSCo were marginally below the international experience;

- The asset lives for diesel generation assets were in the range of international comparators however towards the lower end of that range;

- For meter assets the regulatory life allowed for JPSCo was at the top of the range of expected range from our sample of countries. Generally longer asset lives are used for existing non-smart or "dumb" meters.

- For electronic equipment and computers etc JPSCo's depreciation lives are either towards the top end of the range of international comparators or outside of that range suggesting that there may be scope to review these asset lives for regulatory depreciation purposes. Of note was that in New Zealand software was depreciated over 2 to 4 years and generally the range of asset lives for computers and technology was generally at a maximum of 10 years for the other countries any typically more in the range of 5 to 7 years.

2 The historical useful life of JPSCo's assets

An analysis of the assets that JPSCo retired between January 2005 to August 2013 was compared to the age of the asset at retirement with the regulatory depreciation life. The actual useful lives of assets retired were broadly consistent with the regulatory asset lives.

The average age at retirement for the general property equipment assets of 10 years, which consist mainly of information technology related assets, was lower than the 15 years regulatory depreciation life. The average age of life at retirement for these assets was approximately 10 years.

Figure 6

Summary of retired asset lives analysis

Summary of useful life of retired assets							
			Useful life (years)				
	Sample size	Depreciation life (years)	Minimum	Maximum	Simple average	Weighted average	Mode
Distribution Plant	686	25 to 30	-	38	15	20	14
General property-Equipment	390	15	-	22	9	8	9
General property - structures	15	50	-	42	11	29	7

Source: *1) Asset_Retirements - Jan 2005 - Dec 2009.xlsx*
2) Asset_Retirements-Jan 2010-Aug 2013.xlsx
3) JPS Depreciation Rate Categories.docx

Further analysis is presented below.

2.1 Ages of distribution plant assets at retirement

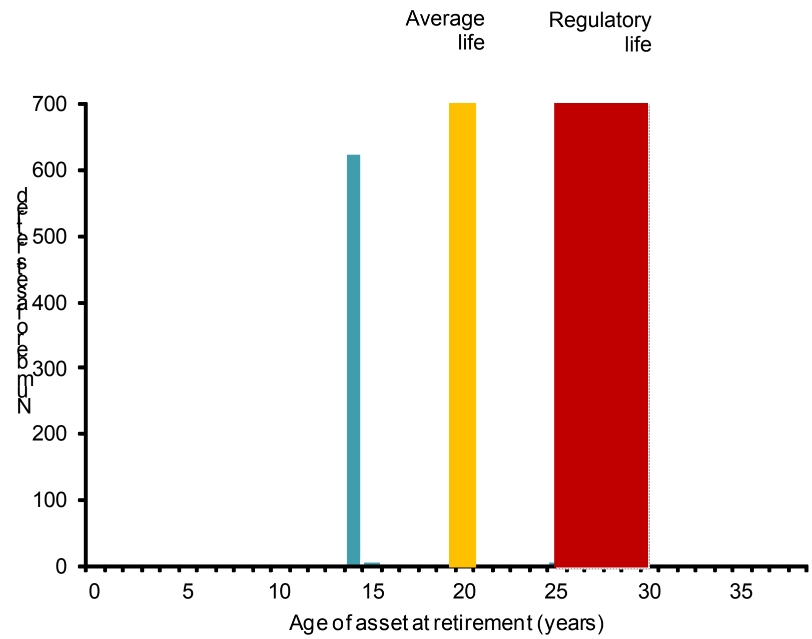
686 distribution plant assets were retired between 2005 and 2013. The average useful life of the 686 distribution plant assets was approximately 20 years. The majority of the distribution plant assets had useful lives below the current regulatory depreciation life of 25 to 30 years.

- The oldest distribution plant asset was a low voltage grounding transformer with a useful life of 38 years.
- Three assets, AMI anti-theft networks, had useful lives of 6 months.
- 627 of the 686 retired assets had a useful life of approximately 14 years. These 627 assets consisted mainly of primary lateral and secondary distribution systems.

The full distribution is shown below with asset age at time of retirement on the horizontal axis and the number of assets in the sample retired at that age.

Figure 7

Distribution of ages of distribution plant assets upon retirement
2005 to 2013



Source: *1) Asset_Retirements - Jan 2005 - Dec 2009.xlsx*
2) Asset_Retirements-Jan 2010-Aug 2013.xlsx
3) JPS Depreciation Rate Categories.docx

2.2 Ages of general plant – structures at retirement

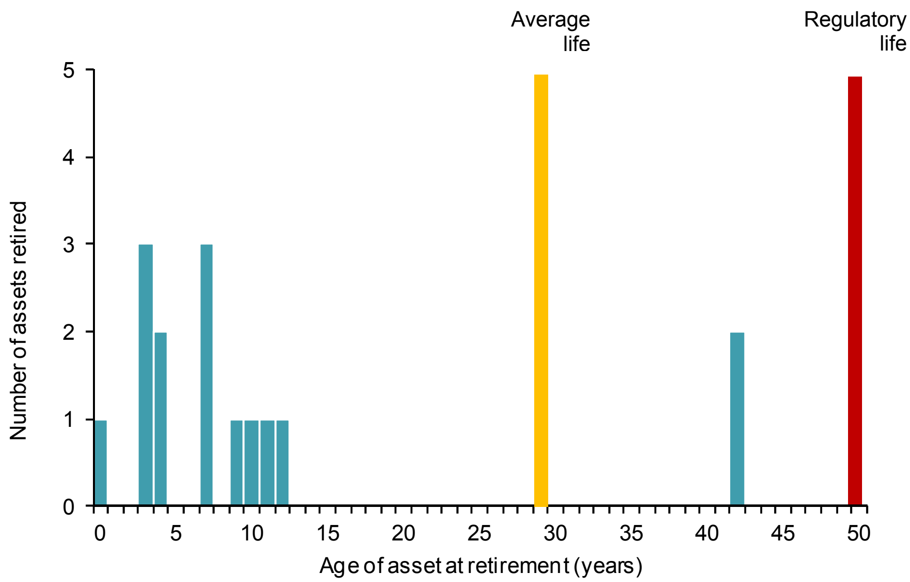
15 general plant – structures were retired between 2005 and 2013. The average useful life of the general plant – structures was approximately 29 years. The majority of the distribution plant assets had useful lives below the current regulatory depreciation life of 50 years.

- The two oldest general plant – structures assets that were retired during the period was land at the Knutsford Boulevard Head Office Complex and Building - Head Office which had useful lives of 42 years each (this retirement represents a sale of the building).
- One asset, Head Office parking lot re-pavement, had a useful life of 7 months (this retirement represents a sale of the asset).
- Most of the general plant – structures assets retired were building improvements.

The full distribution is shown below with asset age at time of retirement on the horizontal axis and the number of assets in the sample retired at that age.

Figure 8

Distribution of ages of general plant – structures assets upon retirement
2005 to 2013



Source: *1) Asset_Retirements - Jan 2005 - Dec 2009.xlsx*
2) Asset_Retirements-Jan 2010-Aug 2013.xlsx
3) JPS Depreciation Rate Categories.docx

2.3 Ages of general plant - communications and other equipment assets at retirement

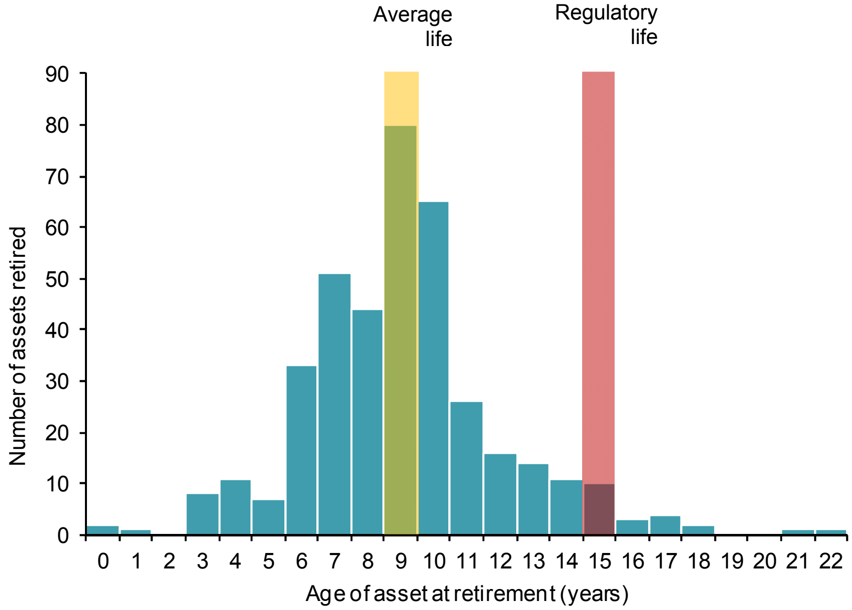
390 general plant – communications and other equipment assets were retired between 2005 and 2013. Most of the general plant – communications and other equipment assets were computers. The average useful life of the communications and other equipment assets was approximately 8 years. The majority of the distribution plant assets had useful lives below the current regulatory depreciation life of 15 years.

- The oldest asset that was retired during the period was a calculator that had a useful life of 22 years.
- The youngest asset at time of retirement was a hand held computer that had a useful life of 1 year.
- 80 retired assets had a useful life of approximately 9 years. All of these assets were computers.

The full distribution is shown below with asset age at time of retirement on the horizontal axis and the number of assets in the sample retired at that age.

Figure 9

Distribution of ages of general plant - communications and other equipment upon retirement 2005 to 2013



Source: *1) Asset_Retirements - Jan 2005 - Dec 2009.xlsx*
2) Asset_Retirements-Jan 2010-Aug 2013.xlsx
3) JPS Depreciation Rate Categories.docx

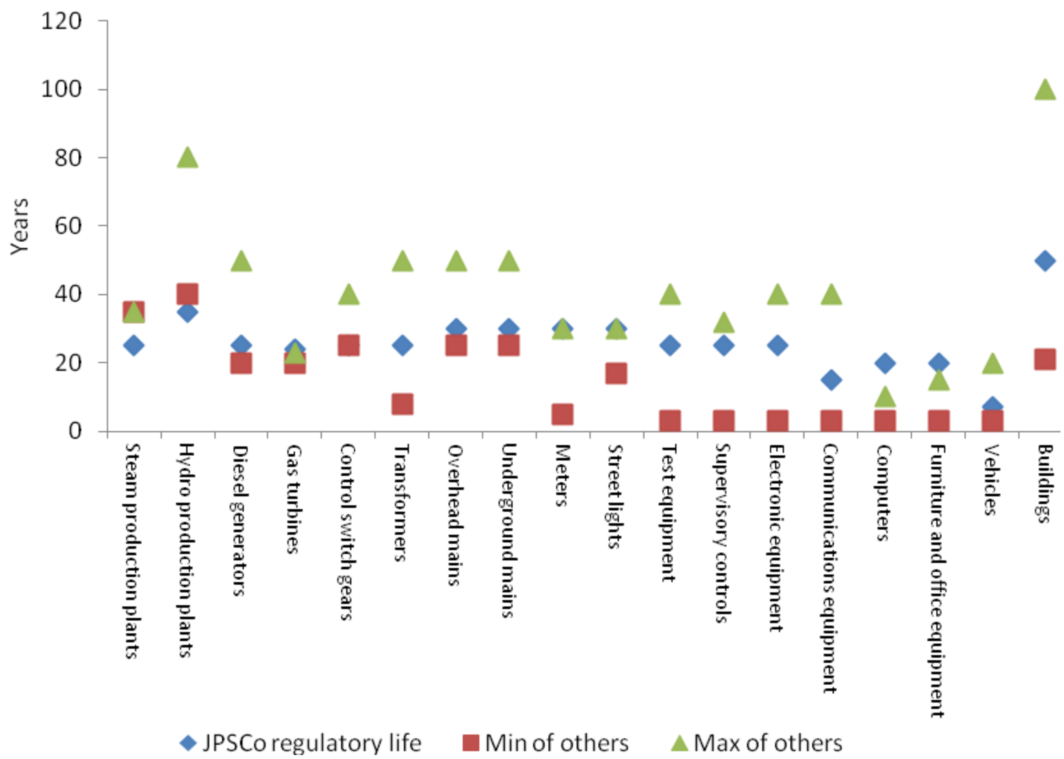
2.4 Ages of production and transmission plant assets

For distribution plant, steam production, other production, and transmission asset classes the asset data capture for long lived assets did not form a reliable basis on which to draw any conclusions on the actual economic lives of these asset classes. For long lived assets, asset life is extended through asset overhauls and major maintenance, however, JPSCo's asset management systems do not link the maintenance/overhaul projects to the specific assets to provide a lifetime cost/depreciation analysis resulting in a lack of data with which to perform an analysis.

The comparison of depreciation lives by asset class for JPSCo versus the minimum and maximum of the sample of comparator countries is shown below.

Figure 10

JPSCo asset deprecation lives compared with range of results from other countries 2005 to 2013

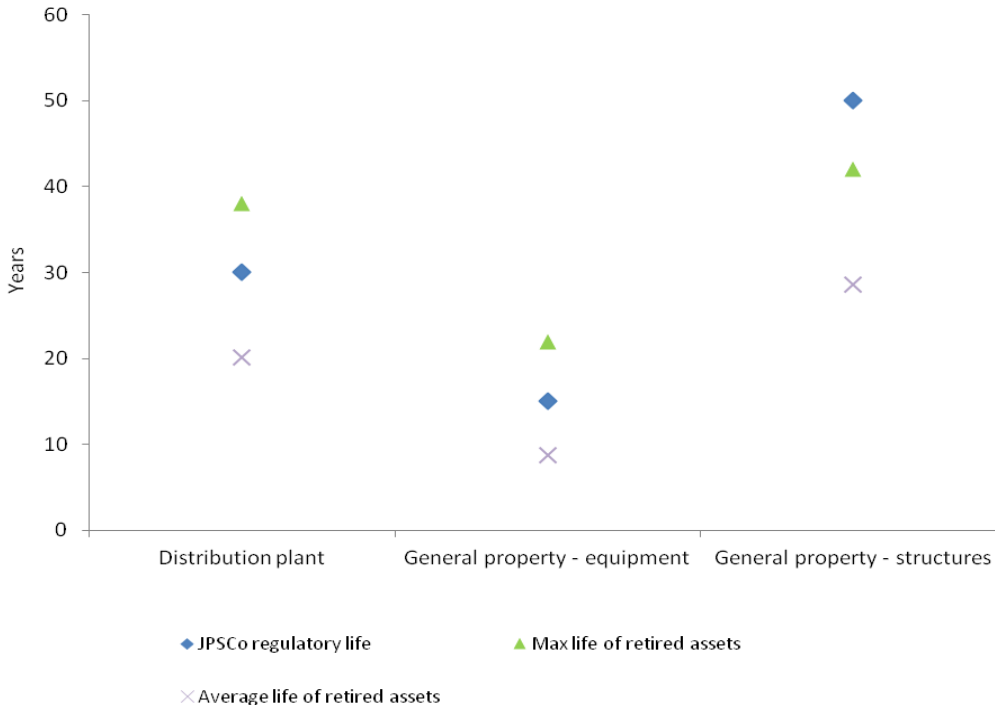


Source: 1) JPSCo

The analysis of asset lives versus the age of assets on retirement show a varying picture for the operational assets (see Figure 11 overleaf). For distribution plant and general equipment the regulatory lives lie in the middle of the ages of the asset at retirement. For general property – communications and other equipment assets the regulatory life for the assets is significantly higher than average age of retirement for these assets.

Figure 11

JPSCo retired asset lives compared with asset depreciation life
2005 to 2013



Source: *1) Asset_Retirements - Jan 2005 - Dec 2009.xlsx*
2) Asset_Retirements-Jan 2010-Aug 2013.xlsx
3) JPS Depreciation Rate Categories.docx

2.5 Recommendations

Fig 12

Recommended regulatory asset lives

Activity	Asset	Current Life	Recommended Life
Generators	Steam production plant	25	25
	Hydro production plant	35	35
	Diesel generations	25	25
	Gas turbine	24	24
Transmission	Control gear/Switchgear	25	25
	Transformers	25	25
Distribution	Overhead mains	30	30
	Underground mains	30	30
	Meter	30	15
	Street lights	30	20
	Test equipment	25	15
	Supervisory control systems	25	25
General Plant	Electronic equipment	25	10
	Communication equipment	15	5
	Computer equipment	20	6
	Furniture and office equipment	20	10
	Vehicles	7	4
	Land-leasehold	50	50
	Buildings	50	50

3 Qualifications and limitations

There can be significant differences between regulatory useful lives in the comparators countries and the actual useful lives of the assets of operators in those countries.

Rounding errors may occur.

The useful lives of the retired assets are based on the assets retired for the period January 2005 to August 2013; as such, sampling errors are unavoidable as with any analysis that does not test the entire population of retired assets. Sampling errors can be caused by:

- Sampling bias where the sample of the retired assets may not be representative of the population; and

- Sample size where the number of observations for some of the retired asset classes may not be large enough to arrive at an acceptable margin of error.

Appendix 1

	Separation of Generation, Transmission, Wholesale and Retail?	Availability of data in English	Total size Electricity Market and Main source of fuel generation	Country population/Size of market
Jamaica	No	Yes	4,132 GWh (Generation) 3,134 GWh (Consumption) 930 MW (Capacity) Mainly Steam (Oil-fired) and slow speed diesel. Others include gas turbines, combined cycle, diesel, hydropower and wind[2]	Population - 2.7 million 33% Residential 44% Small Commercial 20% Large Commercial 3% Other[3]
Singapore	Yes	Yes	47,000 GWh[4] (Consumption) 11,615 MW (Capacity) 80.4% Natural Gas 15.4% Petroleum products 4.2% Others[5]	Population - 5 million Industry 40% Commerce and services 38% Households 16% Transport related 5% Others 1%
New Zealand	Yes	Yes	45,000 GWh (Generation - approx) 39,128 GWh (Consumption) 75% comes from renewable sources namely hydropower, geothermal and wind. The remaining comes from oil, gas and coal.	Population - 4.4 million 5% - Agriculture 38% - Industrial 33% - Residential 24% - Commercial
Portugal	Yes	Limited	52,500 GWh >50% fossil fuels 20% Hydro	Population – 10 million

[2] http://www.myjpsco.com/wp-content/uploads/JPS-Annual-Report-2012.pdf

[3] http://www.myjpsco.com/wp-content/uploads/JPS-Annual-Report-2012.pdf

[4] http://www.ema.gov.sg/reports/id:72/

[5] http://www.ema.gov.sg/reports/id:72/

	Separation of Generation, Transmission, Wholesale and Retail?	Availability of data in English	Total size Electricity Market and Main source of fuel generation	Country population/Size of market
Trinidad and Tobago	Yes[6]	Yes[7]	9,100 GWh (Generation) 2064 MW [8](Capacity) Primarily from Natural Gas	Population - 1.3 million[9] Breakdown – not available
Dominican Republic	Yes[10]	No	13,356 GWh[11](Consumption) 3,394.1 MW[12] (Capacity) Dominated by thermal generation fired up by fuel oil, coal or gas	Population - 10 million 90% households 8% Commercial 1% Industrial 1% States departments (need to confirm this, as it was in Spanish)
Jersey	No	Yes	650 GWh[13] (Consumption) 90% of electricity imported from France via two undersea cables known as EdF1 and EdF2. The oil fired La Collette power station is used as a backup.	Population - 100,000 45% Households 44% Commercial & industrial customers 11% States departments [14]

[6] http://www.energy.gov.tt/resources.php?mid=9

[7] http://www.energy.gov.tt/resources.php?mid=9

[8] http://www.energy.gov.tt/resources.php?mid=9

[9] http://www.cso.gov.tt/sites/default/files/content/images/census/TRINIDAD%20AND%20TOBAGO%202011%20Demographic%20Report.pdf

[10] http://www.bcpsecurities.com/textos/update3/BCP_Securities_Report_on_Dominican_Electricity_Sector_Egehai_and_Aesdom_and_Itabo_September_15_2010.pdf

[11] http://www.sie.gob.do/index.php?option=com_phocadownload&view=file&id=3286:rep.-op.-30-07-2013-9-00-am&Itemid=122

[12] http://www.sie.gob.do/index.php?option=com_phocadownload&view=file&id=72:energia-instalada&Itemid=122

[13] http://www.cicra.gg/_files/121211%20-%20Review%20of%20Jersey%20Electricity%20Sector%20-%20public.pdf

[14] http://www.cicra.gg/_files/121211%20-%20Review%20of%20Jersey%20Electricity%20Sector%20-%20public.pdf

	Separation of Generation, Transmission, Wholesale and Retail?	Availability of data in English	Total size Electricity Market and Main source of fuel generation	Country population/Size of market
Options Australia (Victoria)	Yes[15]	Yes	46,871 GWh (estimate)[16] 12,000 MW[17] (Capacity) Mainly generated by Brown coal and Oil	Population - 5.6 million
Bolivia	No -	No	6,940.6 GWh[18] (Gross Generation) 6,604.3 GWh[19] (Consumption) 1,384.8 MW (Installed capacity) 33.5% from Hydroelectric 66.5% from Thermoelectric	Population – 10.5 million
Guatemala	Yes	No	5,180.9 GWh[20] (Demand) 2,795 MW[21] (Installed Capacity) 40% from Hydroelectric 18% Reciprocating Engines 18% - Steam Turbines[22] The rest is from Gas turbines, biomass and geothermal.[23]	Population – 15 million
Barbados	No	Yes	1,024.3 GWh (Consumption) 239.1 MW (Capacity) Approximately 50% is Diesel generated. The rest is from Steam and Gas Turbine.[24]	Population - 283,221 33% - Domestic 67% - Commercial

15 http://www.efa.com.au/Page.aspx?intPageID=6

16 www.aemo.com.au/Electricity - 2012 NATIONAL ELECTRICITY FORECASTING REPORT

17 http://www.aer.gov.au/sites/default/files/20130811-20130817%20electricity%20weekly%20report.pdf

18 http://www.cndc.bo/media/archivos/boletines/memyres_2012.pdf

19 http://www.cndc.bo/media/archivos/boletines/memyres_2012.pdf

20 http://www.amm.org.gt/ (click on Generacion)

21 http://www.amm.org.gt/pdfs/capacidad_instalada.pdf

22 http://www.amm.org.gt/ (click on Generacion)

23 http://www.internationalrivers.org/files/attached-files/energia_ingles_072412.pdf

24 http://www.blpc.com.bb/photos/LPH2013AnnualRep.pdf

Annex D: JPSCo Wheeling Proposal

Confidential

Designing an Appropriate Wheeling Tariff in Jamaica

Report to Jamaica Public Service Co. Ltd.

December 2013

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1 Introduction

Electricity wheeling in Jamaica is specified by Condition 12 of the 2011 All-Island Electricity Licence ("Licence").[1] The Licence requires that the Jamaica Public Service Company Ltd. (JPS) must prepare charges for system access, top-up service, and standby service. These charges must be "cost reflective and consistent with tariffs and the Price Controls" as approved by the Jamaica Office of Utilities Regulation (OUR). This licence condition is designed to allow customers who can generate electricity at a lower cost than JPS to do so. These customers can pay JPS a fee to carry ("wheel") the power from where it is generated to where it is consumed.

In July 2013, the OUR issued a determination notice specifying a framework for electricity wheeling for large customers. The wheeling tariff is intended to enable large commercial and industrial customers (in rate classes 40 and 50) to self-supply electricity using off-site generation. JPS engaged Castalia to assess the framework, because it was concerned that the wheeling tariff would send incorrect price signals to potential wheeling customers.

In this report, we begin in Section 2 by briefly characterising the wheeling tariff set in the OUR determination, including a discussion of the intent of the wheeling tariff, and how charges are set. We also identify problems with the tariff. In Section 3, we describe various wheeling frameworks that have been adopted by regulators in countries with power sectors comparable to that in Jamaica. This international comparison allows us to better understand what approaches are considered best practice, and what may be a better way forward for wheeling in Jamaica. Having discussed Jamaica's wheeling tariff, and compared it to international experience, we conclude in Section 4 that a postage stamp methodology based on the Efficient Component Pricing Rule (ECPR) is the most appropriate framework for wheeling in Jamaica.

As we will show, our conclusion is consistent with the policy goals of lowering the total cost of electricity supply in Jamaica. The proposed approach ensures that when a customer generates power for itself, JPS' revenue falls by an amount equal to the cost JPS avoids by no longer having to supply power to that customer. This is the only way to send price signals that encourage efficient generation while discouraging inefficient generation. This rule also means that wheeling becomes financially neutral for JPS. As a result, JPS can work with its customers to help them reduce costs through wheeling, without suffering financially as a result.

2 Will the Wheeling Regime Achieve its Objectives?

Wheeling is economically desirable when it promotes cost efficiency of generation—and so reduces power costs for customers. In this section, we first discuss the primary objectives of a wheeling framework, followed by a brief introduction to the tariff in the determination. We then compare the wheeling tariff to the objectives, and conclude that in many respects, the wheeling tariff misses the mark.

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[1] Government of Jamaica, All-Island Electricity Licence 2011, Condition 12.

2.1 Objectives of Jamaica's Wheeling Regime

Wheeling regimes are implemented to reduce the cost of power for customers by increasing generation choices. In Jamaica, wheeling allows customers to choose to generate power for themselves at one location, and consume it at another location (or locations). In other jurisdictions, wheeling is used to trade power between utilities, or to allow customers to choose which of a number of competitive generators to buy power from (also called "retail competition"). In all cases, the aim is to allow customers to source power from cheaper generation sources.

To guide its thinking, the OUR specified several key principles of the wheeling tariff design.[2] In short, these suggest that wheeling should:

- Reduce the cost of electricity by enabling greater choice in generation,
- Enable the utility to recover the costs of providing power delivery services, and
- Send price signals that promote efficiency in generation and consumption decisions.

2.2 Overview of the Wheeling Tariff Determination

As specified in the wheeling determination, wheeling charges are determined separately for use of the distribution network and for use of the transmission network. The distribution network includes all lines with voltage ratings less than 69kV, while the transmission network includes all lines rated at 69kV or greater.

For transactions that make use of the distribution network, charges are calculated on a postage stamp basis. This metaphor refers to the fact that, much like a postage stamp, one charge applies to all customers, regardless of distance. Under the postage stamp approach, then, JPS' annual cost of providing distribution services is divided by the system peak demand (in MW). This per-MW charge is multiplied by the capacity of the proposed wheeling transaction to determine each customer's annual wheeling charge.

For transactions that make use of the transmission network, charges are calculated in a more complicated manner, using a flow-based MW-km charge. Using this approach, wheeling customers pay for transmission service based on two defining characteristics: how much capacity is required, and how far the power must flow to complete the transaction. Each wheeling customer pays a customised annual charge, which is calculated using a load flow model which estimates the physical route over which the wheeling transaction occurs. The charge is equal to the annual cost of the line, times a utilisation ratio that reflects the share of total power flows along the line attributable to the wheeling transaction. Where the load flow modelling shows that a wheeling transaction reduces flow on a certain line (because the direction of flow is running "against traffic"), the wheeling charge is set to zero.

In instances where a wheeling transaction traverses both the distribution and transmission networks, the wheeling charge is equal to the sum of the applicable transmission and distribution charges.

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[2] Office of Utilities Regulation. 2013. Electricity Wheeling Determination Framework. Document No. 2013/ELE/009/DET.002. http://www.our.org.jm/ourweb/sites/default/files/documents/sector_documents/wheeling_framework_determination_notice.pdf (accessed December 20, 2013).

2.3 Assessing the Wheeling Framework against Wheeling Objectives

Although the wheeling tariff aims to achieve the objectives described in Section 2.1, our analysis finds several flaws in the design which mean those objectives are unlikely to be achieved. In this section, we restate the objectives of wheeling and assess how well the tariff design satisfies each objective.

2.3.1 Enabling Greater Choice in Generation

By allowing large commercial and industrial customers to self-generate and wheel power, the wheeling tariff succeeds in achieving the objective of enabling greater choice in generation.

However, greater choice may not lead to lower power costs. The current wheeling tariff does not reflect JPS' full cost of providing transmission and distribution service. As a result, wheeling charges provide distorted price signals for potential wheeling customers to invest in generation assets that may not be cost competitive with the existing generation fleet. This would have the unintended consequence of investment in uneconomic generation assets, and uneconomic system dispatch.

Furthermore, because the wheeling tariff sends incorrect price signals for generators, it could spur additional knock-on effects which may *further* increase the cost of power for Jamaican electricity consumers. For example, in the short run, JPS' creditworthiness could suffer. If more large customers switch to wheeling than is economically justified, JPS would suffer greater lost revenues than it would otherwise if wheeling charges were truly cost reflective. Because JPS would be unable to recover its cost of transmission and distribution service for wheeling customers, its creditworthiness would decline. This, in turn, would threaten JPS' ability to finance the 360MW liquefied natural gas (LNG) plant. Without this plant, it is highly likely that power prices would remain at their elevated levels—rather than decline, as was intended by the wheeling framework.

2.3.2 Enabling the Utility to Recover the Cost of Power Delivery

In order to successfully implement wheeling, the utility must be able to recover its cost of providing power delivery service—regardless of whether the power being delivered is intended for wheeling customers or traditional retail customers. However, the wheeling tariff in the determination notice is, on average, less than the charges retail (non-wheeling) customers currently pay for transmission and distribution service. Therefore, the current tariff design does not satisfy this key objective of the wheeling framework.

As an additional knock-on effect, in the medium run, the non-fuel base rate would increase. Under the wheeling tariff, wheeling customers may not always pay a charge that reflects the true cost of service. This would mean that in order for JPS to recover its cost of power delivery, at the next rate reset, JPS would need to seek an increase in the non-fuel base rate component of the tariffs paid by all non-wheeling customers. This is an undesirable consequence, since it would run counter to the objective of implementing wheeling to lower the cost of power for Jamaican electricity consumers.

2.3.3 Sending Price Signals that Promote Efficiency Creating

The wheeling tariff in the determination notice is designed to send good locational signals to potential wheeling customer, in the interest of promoting efficiency. If market participants are to act efficiently, they must be given price signals that reflect the cost "caused" by wheeling. However, in practice the signals sent by the wheeling tariff may not be efficient.

In the short run, wheeling transactions have no impact on the cost of providing transmission and distribution service. That is, the same wires as before still carry the power and no new utility staff are employed. Therefore, the short-run marginal cost of wheeling is zero. In the long run, wheeling can cause significant costs, by requiring investments in the transmission and distribution networks to accommodate additional capacity. Therefore, an efficient wheeling tariff should reflect the cost of bringing forward necessary investments due to wheeling transactions. However, these costs are not signalled in the wheeling tariff.

In addition, if the locational signals are to promote efficiency, they should be sent to all customers (load)—not just those that wheel. Likewise, these locational signals should be sent to all generators, including new IPPs, and not just wheeling customers seeking to site self-generation. That these locational signals are not uniformly applied misses an opportunity for broader efficiency in the Jamaican power sector, as it risks sending distortionary price signals for load and generation.

To summarise, these three factors mean that the wheeling regime is not likely to achieve the objective of lowering the total cost of power supply in Jamaica. Worse yet, it threatens to increase the tariffs of all customers beyond what would occur without the wheeling tariff. We can therefore conclude that the wheeling tariff fails to achieve its objectives in some important respects. This makes it worth looking for other options that would more fully achieve the objectives.

3 Review of International Practice

Because the wheeling tariff in Jamaica may not satisfy all of the objectives set by the OUR, we look next to international experience for examples of alternative wheeling methodologies. This helps us better understand what may be a better way forward for Jamaica.

We first introduce and briefly describe a range of wheeling pricing methodologies. We then discuss the experience of several relevant comparators, all of which have introduced transmission access pricing to enable competitive generation.

In our international comparison, we find that New Zealand and Ireland are the most relevant comparators, because they are islands with smaller electricity market sizes—although both still dwarf the peak demand of the Jamaican power system. Both countries rely on a mix of postage stamp and zonal pricing to recover the cost of transmission assets. We also discuss transmission access pricing in the United States, Great Britain, Australia, and Japan. While many of these jurisdictions have implemented nodal pricing, it has only applied to energy dispatch and congestion management—not for recovery of investment costs.

Notably, none of the regimes reviewed use the MW-km method adopted in the determination notice. Rather, international experience suggests that for the Jamaican context, a wheeling charge based on postage stamp methodology is most appropriate for both the transmission and distribution networks—and not just for use of the distribution network, as was adopted in the determination notice.

3.1 Alternative Wheeling Pricing Methodologies

Jurisdictions around the world have implemented a wide range of wheeling pricing methodologies. In this section, we discuss the primary methods considered by regulators:

- Contract path pricing

- MW-km pricing
- Postage stamp pricing
- Nodal pricing, and
- Zonal ("license plate") pricing.

3.1.1 Contract Path Pricing

Contract path pricing is the first of two "route" methods for setting the price of network access. The contract path approach specifies a "route" over which the wheeling transaction will occur. Although this path does not reflect the physical reality of power flows (because AC flows cannot be directed), it is useful for accounting for wheeling transactions.

Under the contract path approach, transactions are priced individually. While implementations vary, contract path pricing typically is based on the annual cost of service for each transmission line segment. The charge for a given segment is equal to the annual cost of service (capital and operating costs) divided by the system peak demand on that segment.

Therefore, a wheeling customer would specify the path over which power would be transmitted. The customer's total wheeling charge, then, would be the sum of the individual segment charges, which are each equal to the MW of reserved capacity times the segment per-MW charge.[3]

The contract path pricing method assumes that the exact location of, and route to, the transaction counterparty matters. That is, if loads are responsible for transmission costs, the precise transmission route to the generators from which they purchase power directly influences the price paid for transmission. Likewise, if generators are responsible for transmission costs, the location of the loads served matters.

3.1.2 MW-km Pricing

Just as with the contract path approach, MW-km pricing assumes that the transmission route to the transaction counterparty matters. However, MW-km pricing models attempt to better reflect reality by charging on the basis of the actual power flows that occur, rather than using an arbitrary contract path.[4] Put another way, contract path pricing and MW-km pricing are similar in that they are based on the notion that transmission customers should pay for the share of transmission assets utilised by a given transaction. Where these two methodologies differ, though, is in how the transmission route is determined: determined contractually, or in the case of MW-km pricing, calculated.

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[3] Camfield, Robert. 2008. "Contract Path and TLR." Presentation to the Edison Electric Institute Transmission and Market Design School. http://www3.eei.org/meetings/Meeting%20Documents/2008-0811Camfield_presentation.pdf (accessed December 21, 2013).

[4] We note that there is a simpler variation on MW-km pricing that relies purely on physical distance between load and generation, similar to the contract path approach. To avoid confusion, we do not describe this methodology in greater detail. However, more information on this approach can be found in the OUR's first wheeling consultation paper.

See Office of Utilities Regulation. 2012. "Electricity Wheeling Methodologies: Consultation Document." Document No. ELE2012004_CON001. http://www.our.org.jm/ourweb/sites/default/files/documents/sector_documents/electricity_wheeling_methodologies_-_consultation_document.pdf (accessed December 21, 2013).

MW-km pricing works by modelling power flows using a software tool to estimate the actual route that would be traversed by a wheeling transaction. The calculated MW-km value is then used to determine the appropriate charges for the transaction. The important point to emphasise is that under the MW-km method adopted by the OUR, DC power flow analyses are performed for **each** wheeling transaction. That is, the price for **each** wheeling customer is set on the basis of customised power flow modelling.

3.1.3 Postage Stamp Pricing

The simplest wheeling pricing methodology is the postage stamp method. It does not include locational signals for load and generation. Rather, much like a postage stamp allows a letter to be mailed to any address in the country, postage stamp pricing applies one price for access to the entire transmission and distribution network.

A key assumption of the postage stamp methodology is that the location of both parties to the transaction is irrelevant. That is, where loads are located relative to the generators from which they purchase power does not matter.

Postage stamp pricing is often implemented *because* of its simplicity. On an annual basis, the total cost of operating the transmission and distribution network is divided by the system peak demand. This yields an average cost per MW-year, which is applied to the reserved MW capacity under wheeling contracts to determine a wheeling customer's charge.

3.1.4 Nodal Pricing

Conceptually, nodal pricing is the most economically efficient of the transmission pricing methodologies. When properly implemented, it provides precise locational signals for generation or consumption of electricity at the margin.

Nodal pricing works by specifying defined points on the network ("nodes") where energy is either injected by generators or withdrawn by load. Because energy prices match actual power flows on the network, when a transmission line is congested, energy prices at nodes on either side of the congested line diverge to reflect the cost of congestion. The price at the "sending" node will be lower than at the "receiving" node, because physical capacity constraints prevent the "receiving" node from receiving all of the energy that could otherwise be transmitted.

A key issue with nodal pricing is *how* transmission owners are compensated for competitive use of the grid. The system operator cannot simply keep the congestion rents generated by the differences in nodal pricing, because this would incentivize sustained congestion, and hence inefficient dispatch. Rather, nodal pricing must be combined with a mechanism for redistributing these rents through long-term congestion contracts. These contracts are known as Financial Transmission Rights (FTRs).[5]

In effect, FTRs provide two features: (1) they provide the owners of the FTRs a hedge against uncertainty in transmission congestion, and (2) they remove the adverse dispatch incentive for system operators. The contracts are initially allocated to the incumbent transmission owners, who can then either keep the contracts (and the congestion rents associated with the FTRs), or sell them to other market participants. In this way, FTRs provide a source of fixed cost recovery for transmission owners. However, FTRs have only

[5] Hogan, William. 1998. "Competitive Electricity Market Design: A Wholesale Primer." http://www.hks.harvard.edu/fs/whogan/empr1298.pdf (accessed December 22, 2013).

been implemented in limited cases—and in these few cases, they have not been successful in ensuring cost recovery, or signalling the need for new, efficient transmission investment.[6]

In a perfectly functioning nodal energy market with FTRs, then, nodal pricing *theoretically* gives efficient signals for both dispatch and investment. Actual practice is that nodal pricing is often used to provide short-run price signals (that is, manage network congestion). In nearly all cases, transmission revenue requirements are largely recovered using a complementary access charge set using postage stamp pricing, or zonal pricing (which we discuss next).

3.1.5 Zonal Pricing

Zonal pricing, also referred to as "license plate" pricing, represents a hybrid approach between the precise locational signalling of nodal pricing and the cost-sharing design of postage stamp pricing. In some implementations, a zonal price is determined using an aggregated measure of nodal prices, while in others, it is based on power flow modelling (similar to what is used to determine MW-km pricing). It has emerged as a favoured approach in instances where complementary access charges are necessary to ensure cost recovery, but pure postage stamp pricing is rejected.

The key distinction of zonal pricing (compared to MW-km pricing) is that the location of, and route to, the transaction counterparty does not matter, while the customer's location is still taken into account. For example, if load is responsible for transmission costs, the load pays a charge that accounts for the transmission costs of the zone in which it is located, regardless of the location of the generators from which it buys power. Likewise, if generators are responsible for transmission costs, they pay a transmission charge that reflects the general cost of transmission at the injection point, regardless of where the loads they serve are located.

Like the postage stamp rate, every transmission customer pays a single rate for any transmission transaction. Unlike the postage stamp rate, however, customers pay a different transmission rate depending on the zone in which the transaction originates (or terminates, if load pays the transmission cost). Put another way, each customer's rate reflects the cost of transmission facilities within that customer's zone. A customer residing in a high-transmission-cost zone will pay a higher rate than a customer in a low-cost zone. But having paid that single rate, the customer is entitled to "drive," or have power transmitted, throughout all zones in the region.

3.2 Wheeling in International Jurisdictions

We examined six international jurisdictions that have implemented transmission access pricing to enable wheeling. Our analysis focused on countries with robust, competitive power sectors, because this is one of the stated goals of the Government of Jamaica's implementation of a wheeling tariff.

We begin with a discussion of those jurisdictions most comparable to Jamaica, such as New Zealand and Ireland. We find that in New Zealand, zonal pricing is preferred, while in Ireland, a hybrid postage stamp and zonal pricing methodology is used. Even in the United States, Great Britain, and Australia, where the markets are larger and more complex, postage

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6 Joskow, Paul and Jean Tirole. 2000. "Transmission Rights and Market Power on Electric Power Networks." *The RAND Journal of Economics*, 31:3, pp. 450-487. http://www.jstor.org/stable/2600996 (accessed December 9, 2013).

stamp or zonal pricing is preferred for access pricing because it recovers investment costs Moreover, while load flow modelling is used to set the zonal prices in several of these jurisdictions, in none of them is the MW-km approach used to set charges on a transaction-specific basis.

3.2.1 New Zealand

New Zealand is a relevant comparator to Jamaica because it is a small island nation, has no interconnections other than the link between the North and South Islands, and has adopted transmission pricing rules designed to enable wheeling and competitive generation. Despite these characteristics, the system peak demand in New Zealand of 6,218MW is roughly ten times that of Jamaica, which was 635MW in 2012.[7]

We mention the New Zealand approach to transmission pricing because it is often regarded as a model of economic efficiency, as its energy market operates under full nodal pricing. However, we find that even in this case, transmission investment costs are recovered through zonal pricing—and not through nodal pricing.

Under the New Zealand model, the transmission provider, Transpower, determines its revenue requirement for operating high voltage AC (HVAC) transmission service on the North and South Islands, and its revenue requirement for operating the high voltage DC (HVDC) transmission link between the islands. Load pays a zonal interconnection charge, set equal to the HVAC revenue requirement divided by the regional coincident system peak demand. In this way, customers pay for their individual share of transmission capacity to meet system peak demand. South Island generators that inject into the transmission system pay the full cost of the HVDC link, which is allocated based on each generator's share of maximum injection level.[8]

Notably, under the nodal pricing framework for system dispatch, revenue from transmission congestion charges is rebated back to the users of the transmission network. That is, congestion revenues are not available to Transpower for reinvestment in the grid.[9]

3.2.2 Republic of Ireland

The Republic of Ireland is another relevant comparator to Jamaica, again because it is an island nation, with open access transmission pricing rules. It has limited interconnections to Northern Ireland, as well as a link to Great Britain's transmission system via undersea cable to Wales. Like New Zealand, its annual peak demand is relatively small—although even then, the Republic of Ireland's system peak demand in 2012 was 4,589MW, or approximately seven times that of Jamaica.[10]

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7 New Zealand Electricity Authority. "Peak Electricity Demand." http://www.ea.govt.nz/industry/monitoring/cds/centralised-dataset-web-interface/peak-electricity-demand-nationally/ (accessed December 11, 2013).

8 Transpower Limited. 2013. "Year Specific Pricing Data 2013/14." https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/year-specific-data-april-2013.pdf (accessed November 26, 2013).

9 Electricity Authority. 2012. "Information Paper: Allocation of residual loss and constraint excess post introduction of financial transmission rights." www.ea.govt.nz/dmsdocument/13357 (accessed December 17, 2013).

10 EirGrid. "Weekly Peak Demand." http://www.eirgrid.com/operations/systemperformancedata/weeklypeakdemand/ (accessed December 11, 2013).

Under the Irish transmission pricing regime, the transmission system operator sets a use of system charge, with costs allocated approximately 25 percent to generators, and the remaining 75 percent to load. Generators pay a zonal transmission charge, while load pays a pure postage stamp charge.[11]

Therefore, although the capacity of the Irish electric grid dwarfs that of JPS, it is instructive that even in this case, a combination of zonal and postage stamp charges are preferred to other methodologies for transmission pricing.

3.2.3 United States

We next turn to examples from the United States, where each transmission provider is free to set its own transmission pricing mechanism, subject to approval by the federal regulator (FERC). While it is true that major Regional Transmission Organizations (RTOs) such as PJM Interconnection (PJM), Midcontinent Independent System Operator (MISO), and California ISO (CAISO) use nodal pricing, this only applies to energy markets and transmission congestion. Charges for firm point-to-point transmission service (wheeling) are set on a fixed demand charge basis, according to the requirements of the Open Access Transmission Tariff that each transmission provider must file with FERC.

How this demand charge for wheeling transactions is set varies among transmission providers, but generally follows a variation on the postage stamp methodology. Within PJM, for example, firm point-to-point transactions are billed using a postage stamp rate. Within the MISO territory, wheeling into and within MISO is billed using a zonal rate, while wheeling out and through MISO is billed using a postage stamp rate. Meanwhile, in CAISO, the wheeling charge comprises a postage stamp access charge, plus a zonal charge for access to the local delivery network at a specific node. Within the Southwest Power Pool, another RTO, firm point-to-point transactions are billed using a zonal rate.[12]

Outside of the major RTOs, transmission pricing methodologies tend to diverge. For example, in Texas, transmission wheeling charges are assessed on a zonal basis (based on delivery point). In most Western states outside California, utilities are vertically integrated, and so rarely trade power on the wholesale market. To the extent that wholesale transactions are needed (or occur), bilateral contracts using a contract path methodology are executed.[13]

For completeness, we also briefly reviewed wheeling charges for distribution in the US. In the 17 states (plus the District of Columbia) with retail choice, or "retail wheeling," utilities recover distribution costs for wheeled power on a postage stamp basis. Likewise, under Texas' retail choice regime, utilities recover distribution costs for wheeled power on a postage stamp basis.

We conclude with a brief note on the comparability of the United States transmission pricing regimes to the adopted regime in Jamaica. While the United States, and particularly PJM, is sometimes preferred as a model for designing wheeling access arrangements, the unique

[11] EirGrid. 2013. "Statement of Charges: Applicable from 1st October 2013." http://www.eirgrid.com/media/2013-2014StatementofChargesCERApproved(180913)v20.pdf (accessed December 9, 2013).

[12] Southwest Power Pool. Open Access Transmission Tariff. Attachment T. http://www.spp.org/publications/spp_tariff.pdf (accessed December 21, 2013).

[13] Barmack, Matthew et al. October 2006. "A Regional Approach to Market Monitoring in the West." http://emp.lbl.gov/sites/all/files/REPORT%20lbnl%20-%2061313.pdf (accessed November 26, 2013).

market characteristics make a direct comparison difficult. For example, in 2012, the system peak demand in PJM was 152,405MW[14], while in CAISO it was 46,846MW[15], and in MISO it was 98,556MW.[16] Therefore, we emphasise that because of the interconnectedness of the United States grid, and the sheer size of system peak demand, it is inappropriate to transplant a framework designed for these markets onto a market like Jamaica's.

3.2.4 Great Britain

Great Britain is also often mentioned as a good model for transmission access pricing. Like the United States, however, the size of its system peak demand (55,761MW[17] in 2012) limits its usefulness as a comparator for Jamaica. Despite this limitation, we briefly describe the British approach to transmission pricing, which is recovered through the Transmission Network Use of System (TNUoS) charge.

Under the TNUoS framework, costs are allocated to two tariffs: 27 percent of cost responsibility is borne by generators, and the remaining 73 percent borne by demand. Both the generator and demand tariffs use a zonal charge, levied in £/kW. The zonal charges comprise a locational component and a postage stamp component.

The locational component is determined using a MW-km DC flow-based model to determine incremental investment needs based on estimated power flows. The costs of these incremental investments are determined using standard assumptions of transmission capital asset costs. The postage stamp component is the "residual" amount of the system revenue requirement not recovered through locational components, and is applied equally to all customers.[18] Notably, approximately 25 percent of TNUoS revenues have been recovered through locational charges, with the remaining 75 percent through residual charges.[19]

In addition to the TNUoS charge, a Balancing Services Use of System (BSUoS) charge recovers the cost of day-to-day operation of the transmission system, and is applied as a postage stamp charge to all transmission customers. National Grid, the transmission provider, recovers BSUoS revenue up to the maximum allowable revenue for balancing services (as limited by its revenue cap).[20]

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[14] PJM Interconnection. 2012. "Summer 2012 Weather Normalized RTO Coincident Peaks (MW)." http://www.pjm.com/~/media/planning/res-adeq/load-forecast/summer-2012-pjm-5cps-and-w-n-zonal-peaks.ashx (accessed December 11, 2013).

[15] California ISO. 2013. "California ISO Peak Load History: 1998 through 2012." http://www.caiso.com/Documents/CaliforniaISOPeakLoadHistory.pdf (accessed December 11, 2013).

[16] Potomac Economics (MISO Independent Market Monitor). 2013. "2012 State of the Market Report for the MISO Electricity Markets." p. 6. http://www.potomaceconomics.com/uploads/reports/2012_SOM_Report_final_6-10-13.pdf (accessed December 11, 2013).

[17] National Grid plc. 2013. "Demand_Jan 2010 to Dec 2012." http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=28567 (accessed December 11, 2013).

[18] National Grid Electricity Transmission plc. "Final TNUoS tariffs for 2013–14." http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=13694 (accessed November 26, 2013).

[19] Commission for Energy Regulation. 2004. "Electricity Tariff Structure Review: International Comparisons." http://www.cer.ie/CERDocs/cer04101.pdf (accessed November 26, 2013).

[20] National Grid Electricity Transmission plc. *Connection and Use of System Code.* Section 14.30. http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=21523 (accessed November 26, 2013).

We conclude that although the load flow modelling used to determine the locational charge is similar to the approach adopted in Jamaica, it results in a zonal charge—and not a unique per-customer customised wheeling charge.[21]

3.2.5 Australia

We also examined transmission pricing arrangements in Australia, where an open access regime has been adopted to facilitate wheeling and wholesale power trading. Although we find that the system capacities of the National Electricity Market (NEM) and the Western Australia grid—at 32,538MW[22] and 3,694MW[23], respectively—both dwarf that of Jamaica, we nonetheless describe them here to be thorough. We first discuss the wheeling regime in NEM, which interconnects eastern and southern Australia, and then briefly describe the regime in Western Australia.

In the NEM, transmission tariffs are set according to the National Electricity Rules, which set maximum allowed revenue under a revenue cap framework. Transmission costs are then allocated according to the Cost Reflective Network Pricing (CRNP) method. The CRNP method uses load flow modelling to calculate the utilization of assets on the network, and to allocate costs accordingly to zones. The tariff, then, combines postage stamp and zonal pricing to recover the following transmission service costs:

- Exit price ($/day)
- Transmission use of system, locational component ($/MW/day)
- Transmission use of system, non-locational (either $/MW/day or $/MWh)
- Common service (either $/MW/day or $/MWh)

In Western Australia, which is governed by a separate regulatory regime, the transmission tariffs are derived using a CRNP cost allocation method very similar to that in the NEM. This approach also relies on load flow modelling to calculate the utilization of assets on the network, and to allocate costs accordingly to zones (designated at the substation level). The tariff relies on a combination of postage stamp and zonal pricing to recover the following transmission service costs:[24,25]

- Use of system, differentiated by substation (c/kW/day)
- Common service (c/kW/day)

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[21] Perekhodtsev and Cervigni 2010. "UK Transmission Congestion Problem: Causes and solutions." http://idei.fr/doc/conf/eem/perekhodtsev.pdf (accessed November 26, 2013).

[22] Australian Energy Regulator. 2013. "Seasonal Peak Demand (NEM)." http://www.aer.gov.au/node/9766 (accessed December 11, 2013).

[23] Western Power. 2013. "Reducing Peak Demand." http://www.westernpower.com.au/aboutus/save_electricity/Reducing_peak_demand.html (accessed December 11, 2013).

[24] Western Power. 2013. "2013/14 Price List." http://www.erawa.com.au/cproot_download/11473/2/20130626%20D108124%20-%20Western%20Power%20-%202013-14%20Price%20List%20-submitted%2014%20June%202013.PDF (accessed November 26, 2013).

[25] Western Power. 2013. "2013/14 Price List Information." http://www.erawa.com.au/cproot_download/11472/2/20130626%20D108122%20-%20Western%20Power%20-%202013-14%20-%20Price%20List%20Information%20-submitted%2014%20June%202013.PDF (accessed November 26, 2013).

- Control system services (c/kW/day)

3.2.6 Japan

Japan is not a directly relevant comparator to Jamaica, both in relation to the size of its system (peak demand in 2012 was 154,522MW[26]) and its overall approach to electricity sector regulation. However, it is instructive that until 2003, Japan used a MW-km approach to allocating transmission charges. Notably, this method was abandoned in favour of a postage stamp approach because of the significant modelling complexity required to maintain the MW-km approach.[27]

3.3 Conclusions from International Experience

To summarise these brief descriptions of international experience, we can draw four key conclusions:

- Wheeling charges should not be set based on MW-km power flow modelling of individual transactions. International practice does not support this approach.
- Locational signals are important in promoting efficiency, and should figure in network pricing whenever practical.
- The charges for transmission and distribution service should be the same whether or not a customer purchases power from the incumbent utility.
- The most relevant comparators are the Republic of Ireland and New Zealand, which use zonal pricing.

As we have shown, the MW-km approach adopted in the determination notice is not modelled after international jurisdictions which are generally considered to have competitive, robust power sectors. This is an important conclusion, because it implies that the wheeling pricing methodology as adopted may not succeed in promoting the objectives of competition and efficiency in the Jamaican power sector.

However, this does not discount the importance of locational signalling, which is a hallmark of efficient network pricing. International experience shows that locational signals are integrated into pricing mechanisms whenever possible. For example, nodal pricing is used to signal efficient energy dispatch and manage network congestion, while zonal pricing is commonly used to recover investment costs from zones with varying congestion levels. Therefore, we agree that locational signalling should remain an important goal of the Jamaican wheeling framework.

Our international research also shows that, among jurisdictions with competitive electricity markets, in no instance are the charges for wheeling customers determined using a separate methodology than that used to set network pricing for non-wheeling customers. That is, wheeling customers and non-wheeling customers pay for network access using the same pricing methodology. This is an important requirement, because network access must be provided on a non-discriminatory basis in order for wheeling to be economically justified.

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[26] The Federation of Electric Power Companies of Japan. 2013. "Electricity Statistics Information: Maximum Peak Load." http://www5.fepc.or.jp/tok-bin-eng/kensaku.cgi (accessed December 11, 2013).

[27] Hamada, Hiromu and Ryuichi Yokoyama. 2011. "Wheeling Charge Reflecting the Transmission Conditions based on the Embedded Cost Method." *Journal of International Council on Electrical Engineering,* Vol. 1, No. 1, pp. 74-78.

Lastly, we conclude that of all the jurisdictions studied, the most relevant comparators are the Republic of Ireland and New Zealand. Like Jamaica, both are island countries with relatively small service territories, and relatively small system peak demands. To provide an approximate comparison, we overlay the land area of Jamaica onto maps of both countries. As Figure 3.1 shows, the entirety of Jamaica is smaller than the Republic of Ireland (on the left), or even the North Island of New Zealand (on the right).

Figure 3.1: Comparing the JPS Service Territory to Ireland and New Zealand

This comparison is relevant because it suggests what might be an appropriate pricing methodology for wheeling in Jamaica. Specifically, given that both the Republic of Ireland and New Zealand have imposed forms of zonal pricing to recover embedded transmission costs, it stands to reason that zonal pricing might also make sense in Jamaica. This example, though, shows that Jamaica is likely smaller than any single zone in countries with zonal pricing. For example, the entire North Island of New Zealand comprises a zone, and yet all of Jamaica fits within that zone. This suggests that, ultimately, defining multiple zones may not be a reasonable approach for Jamaica.

4 Setting the Wheeling Charge using Efficient Component Pricing

As we have shown, international practice is that wheeling transactions are not priced using the MW-km method in the Determination. Rather, those systems most comparable to Jamaica—such as the Republic of Ireland and New Zealand—rely on zonal pricing, and in some cases postage stamp pricing, to charge for access to the network.

If we apply this international experience to the Jamaican context, a zonal pricing regime in Jamaica should only consist of one zone—effectively, a postage stamp method. This is based on the reasonable assumption[28] that locational prices in Jamaica, should they be calculated,

[28] For simplicity, we make this assumption. However, a study of transmission congestion and locational power prices in Jamaica should be conducted to validate this assumption.

would not vary significantly enough to justify multiple zones, as exist in the larger markets we studied. In effect, a single zonal rate means the charges for both the distribution network and the transmission network would be uniform for all wheeling customers, regardless of where they or their generators are located.

From our international comparison, we emphasise one more important point: transmission and distribution charges in competitive markets do not differ based on who generates the power. This is consistent with the principles of network open access, which is required for fair competition in the power sector. To illustrate this point, consider a hypothetical wheeling customer located in Ocho Rios, who self-generates at a site adjacent to the JPS generation plant in Hunts Bay. Presumably, there is no logical basis for the wheeling customer to pay a different rate for transmitting power produced by its own generator than what it would pay to transmit power as a retail customer from JPS' own generation plant.

The intuition presented here is also supported by economic reasoning. That is, if two separate pricing regimes apply for the same service (transmission and distribution of power), it creates inefficient incentives for customers to self-generate. In particular, a customer may be able to arbitrage the system by choosing to wheel power because it pays a lower charge for transmission and distribution service than it otherwise would as a retail customer, regardless of whether the generation costs it faces as a wheeling customer are economically justified. This represents a "second best" problem,[29] and it illustrates how inconsistent pricing for wheeling and non-wheeling customers could lead to overall inefficiency relative to the status quo.

How can these insights that emerge from international experience and economic theory, then, be applied to the Jamaican context? The clear answer is what is called "retail-minus" pricing. This approach effectively unbundles the JPS retail rate into generation, transmission and distribution components. Wheeling customers, then, pay the transmission and distribution components, while avoiding the generation component.

If the OUR does not wish to unbundle rates for all customers, the same effect can be achieved by estimating the avoided cost of generation, and subtracting that from the retail rate. This approach has a solid foundation in economic theory, and is referred to in the economic literature as the Baumol-Willig rule, or the Efficient Component Pricing Rule (ECPR). Below, we briefly describe the ECPR and how it could be implemented to set JPS' wheeling tariff. We then identify some key considerations for implementing the rule in Jamaica, including how to treat system losses in the wheeling charge, and how to address the potential for stranded generation assets. We next describe the key benefits of the ECPR approach, and conclude with a simple illustration of how the wheeling tariff might be set.

4.1 An Overview of Efficient Component Pricing

The ECPR stipulates that the charge for using the monopoly network should be set equal to the retail price of the bundled service minus the avoided costs of the services that are not being purchased. This approach is also commonly referred to as "retail-minus" pricing.

Regulators across various network monopoly sectors have adopted the ECPR as the basis for access pricing. This is because it eliminates the perverse incentive for customers to self-

[29] Viscusi, W. Kip, Joseph E. Harrington, Jr., and John M. Vernon. *Economics of Regulation and Antitrust*. 4th ed. Cambridge, MA: MIT Press, 2005. 559-560.

supply services at a cost greater than is available from the network incumbent, if the access charge is set too low to be cost reflective.[30]

In the case of setting a wheeling tariff for JPS, retail-minus pricing would mean that wheeling tariffs would be set by taking the current "bundled" industrial and large commercial rates, and subtracting from those rates the avoided cost of generation.

$$Wheeling\ Tariff_R = Bundled\ Retail\ Tariff_R - Avoided\ Cost_R$$

This concept of a "bundled retail tariff" reflects the full cost of power paid by customers, including the Non-Fuel Base Rate, plus the applicable Fuel and IPP Charge.

This calculation of avoided cost based on the bundled retail tariff means that customers who choose to wheel receive a discount equal to the actual costs that JPS avoids from not supplying electrical energy to the customer. These avoided costs comprise avoided generation capacity costs, plus avoided fuel costs.

Avoided generation capacity costs would represent those costs which are avoided or deferred because of self-generation by wheeling customers. For example, when a large customer elects to wheel power, the utility can avoid incremental O&M costs associated with the decreased generator output. Additionally, avoided cost can account for generation capacity expansion that is deferred because of lowered utilisation of existing generation capacity. There is a robust body of literature on the various approaches accepted by regulators to determine avoided cost, and we do not attempt to describe them in detail here.[31] The key point is that these costs would be calculated on a per kWh or kW basis, and subtracted from the appropriate energy or demand component of the customer's retail tariff to arrive at the retail-minus value.

Avoided fuel costs simply represent the pass-through fuel costs which are avoided by burning less fuel to satisfy lower demand. As applied in a retail-minus approach, the avoided cost of fuel burn on a per kWh basis would be subtracted from the energy charge of a customer's retail tariff to arrive at the retail-minus value.

4.2 Applying Efficient Component Pricing in Jamaica

While the ECPR approach is conceptually simple, its application in Jamaica raises two special considerations:

- How are transmission and distribution losses accounted for in the wheeling charge?
- How would the problem of stranded generation assets be mitigated, when wheeling customers switch to self-generation?

We attempt to address both questions in the sections below.

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30 Baumol, William J. and J. Gregory Sidak. 1994. "The Pricing of Inputs Sold to Competitors." *Yale Journal on Regulation*, 11, p. 171.

31 Graves, Frank, Phillip Hanser, and Greg Basheda. 2006. "PURPA: Making the Sequel Better than the Original." Prepared for the Edison Electric Institute. http://www.eei.org/whatwedo/PublicPolicyAdvocacy/StateRegulation/Documents/purpa.pdf (accessed December 22, 2013).

4.2.1 Accounting for Transmission and Distribution Losses

When a customer wheels power, system losses are not avoided. Therefore, wheeling customers should not make a lower contribution to the cost of system losses than other customers do.

Customers as a whole cover the cost of system losses (up to the system loss cap) as part of the total cost of service. The biggest cost from system losses is in fuel and IPP costs. These costs are driven by total generation, which exceeds total consumption by the amount of system losses. These costs are recovered through the Fuel and IPP pass-through charge.

Since the costs of system losses are not avoided by wheeling, the wheeling customer should continue to contribute to these costs. Fortunately, this can be achieved through a simple application of the retail minus methodology. The retail tariff obviously includes a charge for Fuel and IPP costs. Wheeling customers should receive a discount on this charge equal to the Fuel and IPP costs that they avoid by wheeling.

To be consistent with Efficient Component Pricing and the avoided cost principle, then, the wheeling tariff must also recover the cost of losses. Even for wheeling customers, the applicable losses rate (for the purposes of calculating the cost of losses) is equal to the allowed system wide loss rate. This is fully consistent with the physical properties of AC electricity networks, which do not allow for energy to *only* flow over the transmission network, or *only* over a specific, low-losses route.

Therefore, a wheeling customer should not be granted a privileged charging arrangement for losses, where it is only responsible for losses along a contracted or modelled power flow path. Allocating a smaller share of system losses to wheeling customers creates a distortionary subsidy that will drive an inefficient number of customers to wheel. This, in turn, will drive up the total cost of power for Jamaica—and negate the key objective of implementing wheeling.

The advantage of the avoided cost concept is that, by design, it passes on tariff discounts to wheeling customers commensurate only with the costs that are actually avoided. Since wheeling transactions do not reduce the total amount or cost of system losses, wheeling customers should contribute as much to covering the cost of system losses as non-wheeling customers do.

4.2.2 Avoided Generation Capacity Costs and Stranded Assets

As previously described, a key guiding principle of the retail-minus approach is that wheeling customers should not pay for costs which the utility avoids by those customers self-generating power. As it applies to the utility's generation capacity, we can say that if a wheeling customer no longer depends on the utility's capacity, then it does not pay (and is not responsible) for that capacity.

However, for those wheeling customers that choose to rely on the utility's generation capacity on a standby basis, whether for planned outages (maintenance) or unplanned outages (backup), separate tariffs would be developed to reflect the cost of those contingent capacity services. Similarly, wheeling customers that do not satisfy their entire demand from self-generation may choose to regularly purchase "top-up" service from the utility, at a price equal to the cost of providing that service.

Another important consideration is how the existing generation assets and PPA obligations in force at the time of wheeling implementation will not be unrecoverable, or "stranded." This situation could arise when large customers shift load to self-generation under the wheeling tariff. This would reduce demand on JPS' generation fleet, as well as demand on IPP generation, even though these assets were built to serve total system load.

Under the existing price cap regime, these generation assets and PPA obligations can become stranded between rate reviews. That is, tariffs are set for the duration of the regulatory period, subject to annual adjustments under the PBRM. If customers shift to wheeling during the regulatory period, JPS is no longer able to recover the generation component embedded in the non-fuel base rates that those wheeling customers would have otherwise paid under the retail tariff. The only way to eliminate the stranded asset problem is to wait for a rate review, at which point tariffs can be rebalanced to recover generation costs from the remaining retail customers.

However, this stranded asset problem disappears under a revenue cap regime. Under a revenue cap, JPS demonstrates its (non-fuel) cost of service—including the cost of generation capacity—at the start of a regulatory period. The tariffs are set to recover this revenue requirement. In the next year of the regulatory period, if the wheeling tariff has attracted customers away from the retail tariffs, the generation costs that would have been paid by wheeling customers are now reallocated into the tariffs paid by all customers. In this way, the revenue cap can work well to eliminate the stranded asset problem—and so eliminates a potential financial penalty for JPS implementing wheeling. For more information on the revenue cap concept, please see the companion Castalia report, titled "Revenue Cap: A Regulatory Approach to Support the Next Phase of Jamaica's Electricity Sector Evolution."

4.3 Benefits of Efficient Component Pricing

A postage stamp wheeling charge, set using the ECPR, is beneficial for both wheeling customers and for JPS. In particular, it means that wheeling charges are predictable and easy to understand for customers, while also ensuring that JPS is made whole for its cost of transmission and distribution service to these customers.

For wheeling customers, the postage stamp approach is desirable because it is simple to understand. In addition to lower administrative costs for wheeling customers, the retail-minus approach ensures that JPS will recover its reasonable cost of transmission and distribution service to wheeling customers—no more, and no less. This is because under the existing Performance Based Ratemaking Mechanism (PBRM), JPS' costs are already subject to regulatory scrutiny and are controlled for the duration of the five-year regulatory period. By using the approved retail tariff, less avoided cost, the wheeling tariff would be fully consistent with other tariffs, and with the price control regime. Moreover, because the PBRM addresses the problem of monopoly power, the common critique that retail-minus protects monopoly rents embedded in the retail tariff does not hold.

The end result is that a postage stamp charge set using the ECPR ensures a simple tariff structure for wheeling customers, produces a cost reflective tariff for JPS, and avoids any incentive for inefficient network access by wheeling customers.

4.4 Illustrating Efficient Component Pricing for JPS

Given the simplicity of the ECPR approach, and the benefits we have described in the previous sections, we now illustrate the mechanics of the retail-minus approach, using JPS' current retail tariffs. In Table 4.1, we show how the ECPR could be applied to rates 40 and 50 to derive the appropriate wheeling charges.

Table 4.1: Efficient Component Pricing for Rate Classes 40 and 50

	Customer Charge (US$)		
Rate Class	**Bundled Tariff**	**- Avoided Cost =**	**Wheeling Tariff**
R40 - LV Standard Service	$ 58.97	$ -	$ 58.97
R50 - MV Standard Service	$ 58.97	$ -	$ 58.97

	Energy Charge (US$/kWh)		
Rate Class	**Bundled Tariff**	**- Avoided Cost =**	**Wheeling Tariff**
R40 - LV Standard Service	$ 0.34	$ 0.26	$ 0.08
R50 - MV Standard Service	$ 0.34	$ 0.26	$ 0.08

	Demand Charge (US$/kW)		
Rate Class	**Bundled Tariff**	**- Avoided Cost =**	**Wheeling Tariff**
R40 - LV Standard Service	$ 15.23	$ 7.64	$ 7.59
R50 - MV Standard Service	$ 13.71	$ 7.67	$ 6.04

Source: JPS 2012 Cost of Service Study and Wheeling Rates. Adapted by Castalia. Bundled Tariff includes the December 2013 Fuel & IPP Charge.

This example is based on the cost of service study and wheeling rates prepared on behalf of JPS by Quantum. To arrive at an accurate bundled tariff for the energy charge, we have included the Fuel and IPP charge calculated for December 2013. As discussed in Section 4.2.1, the avoided cost calculation only includes costs which JPS is truly able to avoid due to wheeling transactions. Therefore, the avoided cost discount on the bundled tariff does not include system losses.

As we show, under the ECPR approach, potential wheeling customers can save on power costs in two ways: through a 76 percent discount on the variable energy charge, and through a 50 to 55 percent discount on the demand charge (depending on rate class). Therefore, if customers can self-generate electricity at a cost lower than JPS' avoided cost, wheeling is economically justified. If not, the ECPR approach provides the correct price signals for these customers to continue to purchase power as a bundled service.

5 Conclusion

To conclude, we reemphasise that the retail-minus approach to setting a postage stamp charge for wheeling transactions is more likely to achieve the objective for the wheeling tariff of lowering the cost of power for customers. This is because the postage stamp charge—effectively, a single-zone case of a zonal charging regime—exhibits the desirability of locational signalling, while also ensuring cost recovery for the provision of transmission and distribution services. This means that it will provide accurate incentives for customers to participate in wheeling, if and only if their cost of self-generation is lower than the cost of generation under their existing retail tariff.

Notably, the proposed approach is consistent with international practice for jurisdictions similar to Jamaica. That is, in countries like the Republic of Ireland and New Zealand, where the electric service territories are relatively small island systems with low system peak demand, zonal pricing has been successfully implemented for wheeling transactions (with *some* postage stamp pricing, in the case of Ireland). Even in larger markets, such as the major RTOs in the United States and the NEM in Australia, zonal pricing has been part of the wheeling pricing design.

The proposed approach is also supported by sound economic reasoning. The retail-minus approach was developed by some of the most respected economists in the world, and has enjoyed wide discussion in the economic literature. In addition, by applying a consistent pricing methodology to both wheeling and non-wheeling customers, the proposed approach avoids the "second best" problem that would otherwise arise under the methodology adopted in the determination notice.

As a concluding note, we recognise the importance of defining charges for top-up and standby service, as required in Condition 12 of the JPS Licence.[32] Consider a case where a wheeling customer's generator does not operate as scheduled, and the customer relies on JPS to supply electricity during these unplanned (forced) outages. In this instance, JPS is providing a backup standby service. Likewise, if a wheeling customer's generator is out of service for scheduled maintenance, the customer must offtake power from JPS as part of a "maintenance standby service." These are tangible services JPS provides to the wheeling customer, and it must be fairly compensated for them. In setting these charges, then, the same economic principles underlying the ECPR hold. That is, the charges should be set to be cost reflective and consistent with JPS' retail tariffs.

[32] Although the determination notice does not propose charges for these services, it does provide *pro forma* contracts for standby and top-up services.

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Annex E: Decommissioning Study 1: Old Harbour

Final Report Nov 30, 2013

Jamaica Public Service Company Limited

POWER ON

OLD HARBOUR POWER STATION

DECOMMISSIONING & CLOSURE PLAN

November 30, 2013

Jamaica Public Service Co. Ltd.
New Generation
6 Knutsford Boulevard
Kingston 5

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1 EXECUTIVE SUMMARY

In recognition of the Office of Utilities Regulation (OUR) proposal to construct a new generation facility and retire the existing Old Harbour Power Plant in 2016, JPS will be required to retire Old Harbour Power Plant and as such to prepare a decommissioning and closure plan for submission to the environmental agency. JPS will also be required to include this cost in the next OUR rate case submission.

"Closure" of a facility refers to the process by which the facility is secured, at the end of its use to prevent or minimize future impacts to human health and/or the environment. The facility may either be completely decontaminated or treated so that exposure to the remaining contamination is minimized. ***(Source: RCRA)***.

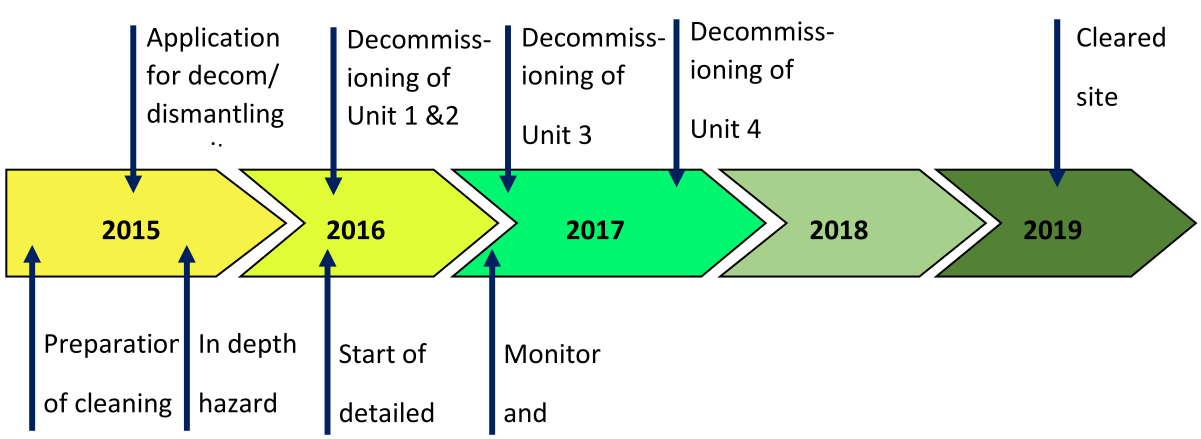
Decommissioning Strategy

The closure of Old Harbour Power plant is required in accordance with the OUR Generation Expansion Plan of October 2010. The OUR, has now selected a preferred bidder for the generation expansion of 360 MW for implementation by June 2016. This will include the introduction of natural gas. As such Old Harbour Power Plant will have to be closed based on the current load growth and age of the plant. The proposed timetable for shut down will be as follows. (This will be subject to final approval by the OUR)

OH Units	Shutting Down at Latest Date	Decommissioning Start Proposed at latest
Unit 1	Before Dec 2010	June 2016
Unit 2	Before June 2016	June 2016
Unit 3	Before Dec 2016	Mar 2017
Unit 4	Before June 2017	Sep 2017

The decommissioning process itself consists of various phases, comprising a strategic preparation phase first, followed by a decision-making and engineering planning phase, defining steps of decommissioning and demolition work with an agreed time schedule and coordination with the remaining share of generation capacity to ensure a continued safely balanced national power supply.

Figure 1-1 - Decommissioning Chart



The demolition process itself starts with in-depth planning to obtain the necessary permission from the OUR and clarification and the necessary budget to be prepared for the continued operation in the event the new generation is delayed. Decommissioning shall be performed by an external Demolition contractor with the support of external consultants.

Decommissioning Plan

This Decommissioning and Closure Plan (DCP) will document the process the Jamaica Public Service Company will undertake to decommission equipment when it becomes necessary at the end-life of the plant and or equipment. Consideration will be given to the applicable regulations, guidelines, and the disposal options on the island at the time, in addition to economic feasibility and more importantly, due consideration to the health of workers and the surrounding community and environment.

This conceptual DCP outlines the general process and consideration that will be employed to decommission any equipment or facility and Closure of the plant at the appropriate time.

The Decommissioning and/or Closure Plan should be finalized and submitted to the National Environment Planning Agency, Kingston and St. Andrew Corporation and any other relevant authorities for approval at least six (6) months prior to decommissioning and closure respectively of any facility on site or the entire site.

Environmental Clean-up Plan & Implementation

The team identified some areas at the Old Harbour Power Plant site which are most likely to contain asbestos, mineral fibres and mineral oils which will require special attention during dismantling and special treatment for disposal

Time Schedule

A total period of five (5) years starting from January 2015 is estimated to be needed for all the technical measures for decommissioning and dismantling of Old Harbour Power Plant, subdivided as follows:

Figure 1-2 - OH Decommissioning Schedule

		Start	2015		2016				2017				2018				2019			
No.	Activity	Date	J	S	J	M	J	S	J	M	J	S	J	M	J	S	J	M	J	S
1	Preparation of Cleaning Works	Jan-15																		
2	Application for Deccommissioning / Dismantling Permit	Sep-15																		
3	Site Clearence of abandon facilities	Mar-16																		
4	Impliment Safety Measures	Mar-16																		
5	Engineering Planning & Updates	Mar-16																		
6	In Depth Hazard Appraisal	Mar-16																		
7	Start of Detailed Engineering	Mar-16																		
8	Start of dismantling Supervision	Jun-16																		
9	Decommissioning of Unit 1	Jun-16																		
10	Decommissioning of Unit 2	Jun-16																		
11	Decommissioning of Unit 3	Mar-17																		
12	Decommissioning of Unit 4	Sep-17																		
13	Site Remediation Works	Mar-18																		
14	Hand-over Site	Jun-19																		

Cost Estimate of Decommissioning & Dismantling

The total **cost of decommissioning** and dismantling for Old Harbour Power plant to reach a brown field level of decontamination has been estimated at roughly US$7,651,360.

This estimate includes the cost for dismantling and demolition works at the site, the preparation of the demolished materials, their transportation and disposal, as well as a preliminary estimate for asbestos removal and revitalization cost for contaminated soils. However early soil test are recommended to reduce risk and enable appropriate plans to be implemented.

Based on capital expenditures to keep the life of the **assets running**, in addition to the dismantling cost, it is important to include for a known and measurable adjustment to the depreciation rates contemplated in the tariff submission. This would allow the Company to recover the carrying values of these assets over their remaining useful lives.

An overall social impact study was not included in this proposal, however two mitigations were identified, namely, the potential new generation construction within the area and appropriate management action for planning of staff severance payments.

The **severance payments**, out placement cost and or early retirement options were reviewed and the estimated costs range from US$$6.0 M to US 7.4 M. The JPS existing workforce has many of the skills needed to undertake much of the decommissioning and dismantling activities which have been outlined to facilitate the staged decommissioning.

Conclusion and Recommendations

The Old Harbor Power Plant units have exceeded their lifetime and large investment would be needed to bring them close to the required environmental standards and efficiency levels. This is not economically feasible.

The most economical solution is an orderly decommissioning of Old Harbor Power Plant implemented to synchronize with the coming on line of the new 360 MW generation planned by the OUR. It is important that once a PPA is signed and financial closure is reached for the new generation expansion that the detailed planning process for decommissioning is further reviewed and the activities outlined.

The planning process for the decommissioning should start ideally three (3) years before dismantling commences with the control of inventory and inventory management. The dismantling planning process would formally start by January 2015.

Further studies of the Old Harbour site is recommended to arrive at more realistic cost estimates for environmental clean-up, dismantling of equipment and site clearance. As such early soils investigation and asbestos identification are recommended in mid-2014. In this regard it is recommended that an independent demolition consultant be engaged approximately 12 - 18 months before decommissioning to prepare the detail RFP for construction works and environmental remediation.

2 BACKGROUND

This study has been prepared by Jamaica Public Service Company, the Generation Expansion team and other support departments in fulfillment of the OUR requirements to meet the generation expansion plans and facilitate closure of older and less efficient plants.

2.1 Terms of Reference (TOR)

The terms of reference comprise the following main tasks:

- To guide the Power Plant closure process in compliance with OUR, NEPA and international lending agencies requirements
- Prepare an overall decommissioning draft report for OH by Oct 30, 2013
- To estimate the cost, technical and manpower requirements for decommissioning and closure of the Old Harbor Power Plant by Oct 30 for submission to the OUR rate case
- To ensure cost is include in the JPS rate case in Nov 2013 and in the 5 year Plan

2.2 Purpose

The purpose of this report is to support the OUR strategy for the closure of older and less efficient plants in an effort to meet the GOJ overall energy strategy for fuel diversification. The report assumes that the new generation expansion awarded by the OUR for 360MW will be commissioned by June 2016.

The planned decommissioning of all five units at Old Harbour and Hunts Bay within the next 5 years follows the OUR generation expansion plan to create an environment for more efficient power generation throughout the country.

2.3 Project Team

The study was prepared from September 2013 to November 2013. The team comprised a local integrated group from various departments of the power utility. The areas represented were: New Generation, Generation Operations, Transmission, Environment, Health, Security & Safety, Material Management, Financial Control, HR and Legal. Team meetings were held bi-monthly and several site visits were made.

Responsibility Assignment Matrix is provided below:

Figure 2-1 – Project Plan Responsibility Assignment Matrix

No.	AREAS	RESPONSIBILITY							
		D. Cook PM	C. Mantock	M. Dunn/ A. Lawson	L. Higgins/ G. Scarlett	J. Williams. G.Llewellyn	V. McDonald	H. Messado	A. Lee
		New Generation		Environ.	Materials	Operations	HR	Finance	Business
1	Introduction/ Background	R	S	S					
2	Power Plant Facilities	S	S			R			
3	Land Status & Return	R		S					
4	JEP Shared Facilities	S		S		S	R		
5	Permit Requirements	S		R					
6	Environment Health & Security	S		R					
7	Risk Management	R		S		S			
8	Closure Plan Objectives	R		S			S		
9	Decommissioning Plan	R		S		S	S		
10	Decommissioning Strategy	R	S	S		S	S		
11	Social Impact	S					R		
12	Cost Estimating	S	S		R				
13	Book Value Strategy	S						R	
14	Alignment to JPS Strategy	R	S						S
15	Supply Scenarios	S	R						S
16	Cost Analysis	S	R					S	
17	Scheduling	R							S
18	Report Drafting	R	S	S		S			
19	Report Review	R	R	S	S	S	S	S	S
20	Executive Summary	R	S	S					
21	Final Report	R	S	S					

Key

P - Participant, S- Support,	S
R - Responsible	R

2.4 Definitions

The following terms and understandings are agreed:
Decommissioning – refers to in this study as the process of a well-coordinated shutdown of plant systems at the end of their economic life taking into consideration environmental and safety requirements

Dismantling – referred to in this study as the well-coordinated demolition and recycling of decommissioned plants, related buildings and installations for the site clearance and environmental clean-up in order to achieve brown field level enabling the rather flexible further commercial use of the power plant site.

Brown Field - Land previously used for industrial purposes or some commercial uses. The land may be contaminated by low concentrations of hazardous waste but in this case is removed and has the potential to be reused.

2.5 References

The report was prepared with the assistance of the following reference materials:

Guidelines

- Natural Resources Conservation Authority Draft Guidelines For A Closure Plan
- RCRA Closure Handbook April 2010
- Interim Standards for Petroleum in Ground Water and Soil – Pollution Prevention and Control Branch
- OUR Generation Expansion Plan 2010

External Documents

- EVONIK Industries - Study for Decommissioning of Kosovo-A Power Plant - dated March 2010 (EU funded project)
- EUCI Conference – Fossil Fuel Plant Retirement – Oct 14-15, 2013
- Burns & Mc Donnell - Report on Dismantlement Cost Study, Florida Fossil Fuel Plants – (October 2008)
- Fossil Fuel Plant Retirement – EUCI Conference Oct 2013 (Baltimore MD)
- TRC Solutions - Fossil Fuel Plant Retirement & Decommissioning Case Studies & lessons Learnt
- Exelon Generation - Retired Fossil Fuel Fired Power Plants – Philadelphia area Presentation
- DTE Energy - Fossil Decommissioning Activities & lessons learnt
- Dominon Resource Services Inc – Cost to Shut Down Plants mandatory or Optional
- Brandenburg – lessons Learnt
- Exelon – Assets Management Presentation
- NCM Presentation – Inventory Recovery Value Realized.
- Environcon Environmental services – Sample Power plant Coal Feasibility Cost Estimate
- NV Energy – Generation Fleet Retirement decommissioning and Lessons Learnt.

Internal Documents

- JPS Waste Management Policy and Plan
- NHL - Old Harbour Soils Report - 2012
- Old Harbour Spill Management Plan
- Old Harbour Emergency Management Plan
- Hunts Bay Conceptual Decommissioning Plan
- Jentech Consultants Ltd. - Soils Investigations Report Old Harbour Generation Expansion – February 2000.

3 INDRODUCTION

3.1 General

This study was conducted in accordance with the related terms of reference, comprising a review of the current situation at Old Harbour Power Plant and several visits and processing of local plant data obtained from Generation Operations. This proposal provides a very detailed analysis of the shut down and demolition of Old Harbour Power plant, with the following activities: scheduling, cost estimate and impact on the electrical supply in Jamaica.

3.2 Legal

The legal and instructional basis of this study is based on the following:

- The Jamaica Gazette Licence No. 167D – Jamaica Public Service Company Ltd, Amended and restated all Island Electric Licence 2011. (Aug 19 2011)
- The Office Of Utilities Regulation Act (As mended 2000)
- The Electric Lighting Act
- The Regulatory Policy for Addition of New Generating Capacity to the Public Grid.
- The Office of the Utilities Regulation – Generation Expansion Plan 2010 dated August 2010
- The GOJ, Ministry of Mining and Energy document: Jamaica's National Energy Policy 2009-2030 – dated Oct 2009

3.3 Permits/Licences

The principal environmental licences and permits held by Old Harbour Power Station are as follows:

- Water Resources Authority (WRA) Well Licence to Abstract and Use Water - Licence No. **A2006/59 A2006/23 A2006/21**
- NRCA Beach Licence – Licence No. **L3142, L447(a) & (b) & L3142**
- NRCA Air Quality Licence – Licence No. **2008-14017-AQ00013**

3.4 Regulatory Requirements

The National Environment and Planning Agency (NEPA) is the Executive Agency charged with official and legislative responsibilities for environmental management in Jamaica. Currently there are standards and regulations that are in effect and aspects of the NEPA environmental regulations, particularly Trade and Industrial Sewage Sludge that are still being developed. Various agencies and government departments also have regulations that may have relevance to the operations of the power sector. Consequently, there are a number of environmental standards, draft regulations, codes, guidelines and international conventions that are relevant. Current standards, draft regulations, conventions and guideline documents that are or will be applicable (following promulgation) to JPS include:

- Natural Resources Conservation Authority Act, 1991
- Natural Resources Conservation Authority Permit and Licences Regulations 1996
- The Beach Control Act (1956)

- The Natural Resources (Hazardous Waste) (Control of Trans-boundary Movement) Regulations, 2002
- Air Quality Regulations, 2006
- Draft Trade Effluent and Industrial Sludge Regulations
- Noise Guidelines
- World Bank Guidelines
- Draft National EMS Policy
- Basel Convention
- Draft National Implementation Plan for POPs – PCB Management
- Guidelines governing Closure of Tanks or Industrial Facilities

3.5 Study

The study was prepared with the following main working steps:

1. Review and assessment of available inventory and project documents of the power plant
2. Operations staff site visits and review of all plant components.
3. Preparation of all building listing and equipment listings to include materials type, dimensions and weights
4. Preparation of a summary scope of works for dismantling.
5. Discussion with construction groups and demolition companies to obtain budgetary estimates
6. Consultation with operations and materials management staff.
7. Consultation with environmental management staff and NEPA requirements
8. Evaluation of asbestos contamination areas and soil contamination areas.
9. Preparation of a rough time table schedule for dismantling plan
10. Calculation of rough cost estimate

4 OLD HARBOUR EXISTING FACILITIES

4.1 Power Plant Units

Jamaica Public Service Company Limited (JPS) Old Harbour Power Station complex is located in St Catherine along the industrial strip of the Old Harbour Bay Area. The Old Harbour Power Station is the largest power plant in the company's generating system with a total generating capacity of 223.5 MW at maximum continuous rating (MCR).

The plant consists of four (4) oil-fired No. 6 (HFO) fuel boilers, steam generating units, designated as Unit No.1, Unit No.2, Unit No.3 and Unit No.4 respectively.

Unit No. 1

Unit No. 1 was commissioned into service in 1967 with a nameplate rating of 33MW, but is presently unavailable to the system due to a broken turbine shaft since August 2010. Except for the excitation system, the unit was operating with all its originally installed equipment.

Unit No. 2

Unit No. 2 was commissioned into service in 1968 with a nameplate rating of 60MW and is presently available to the system at MCR of 60MW. Except for a new turbine casing and excitation system, the unit is operating with all its originally installed equipment which have undergone rehabilitation works over the life of the plant.

Unit No. 3

Unit No. 3 was commissioned into service in 1970 with a nameplate rating of 68.5MW. This unit was the first of its kind to be manufactured by the supplier (General Electric). Based on operational and maintenance experience during the early operation of the unit, the capacity was de-rated to 55MW in the late 1970s. However, following further evaluation of the unit's performance, the decision was taken in March 1996 to upgrade the capacity to 65MW MCR at which it is presently operating.

The alternator excitation system was upgraded in 1994 to the latest EX2000 static excitation system supplied by General Electric. The controls of the unit were also upgraded with the installation of a modern Power Plant Monitoring System in the 1990s.

Unit No. 4

Unit No. 4 was commissioned into service in 1973 with a nameplate rating of 68.5 MW. This unit was similar in design to Unit No.3, however, based on the company's experience, the furnace area of the boiler was extended by an additional 13 feet which allowed it to operate at MCR of 68.5MW.

On June 4, 1994 the boiler and other associated equipment were completely destroyed as a result of a massive explosion. The boiler and associated equipment (pumps, compressors, heating set, switch gear, etc) were completely replaced by the original manufacturer, Foster Wheeler. The opportunity was also taken to carry out life extension work on the turbine. These include:

a) Replacement of original turbine governor system with a new state-of-the-art Mark V electronic governor system.
b) Taprogge condenser cleaning system
c) Turbine water induction protection system
d) EX2000 static excitation system.

Following the explosion, the unit was returned to service in January 1996.

All the units are equipped with Power Plant Monitoring and Control System (PPMCS). This is a microprocessor system which allows the controllers to have on-line monitoring and control of all the major operating systems of the steam units.

The Station Major Equipment includes:

Figure 4-1 - Units Specifications

	UNIT No. 1	UNIT No. 2	UNIT No. 3	UNIT No. 4
BOILER				
Manufacturer	Franco Tosi	Hitachi	Foster Wheeler	Foster Wheeler
Date	1967	1968	1971	1995
Max Continuous Capacity	330,000 lb/hr	600,000 lb/hr	610,000 lb/hr	610,000 lb/hr
Design Pressure	1100 psig	1150 psig	1525 psig	1525 psig
Press @ Superheater Outlet	900 psig	900 psig	1270 psig	1270 psig
Steam Temp at Outlet	905 ^{o}F	905 ^{o}F	955 ^{o}F	955 ^{o}F
Heating Surface	26,800 ft^2	41,140 ft^2		

TURBINE	UNIT No. 1	UNIT No. 2	UNIT No. 3	UNIT No. 4
Manufacturer	Franco Tosi	Hitachi	General Electric	General Electric
Date	1967	1968	1971	1972
Type	Axial Flow	Axial Flow	Axial Flow	Axial Flow
Rating	33,000 kW	60,000 kW	68,553 kW	68,553 kW
Speed	3,000 rpm	3,000 rpm	3,000 rpm	3,000 rpm
Stages	33	15	18	18
Steam Pressure @ Turbine	850 psig	850 psig	1250 psig	1250 psig
Steam Temp. @ Turbine	900 ^{o}F	900 ^{o}F	950 ^{o}F	950 ^{o}F
Exhaust Pressure	2.1 in Hg abs	2.1 in Hg abs	2.5 in Hg abs	2.5 in Hg abs
Steam Flow to Turbine	274,710 lb/hr	585,340 lb/hr	606,349 lb/hr	606,349 lb/hr

GENERATOR	UNIT No. 1	UNIT No. 2	UNIT No. 3	UNIT No. 4
Manufacturer	Ansaldo Giorgio	Hitachi	General Electric	General Electric
Date	1967	1968	1971	1972
Rating	41.25 MVA	85.93 MVA	80 MVA	80 MVA
Phase	3 Phase	3 Phase	3 Phase	3 Phase
Frequency	50 Hz	50 Hz	50 Hz	50 Hz
Voltage	13.8 kV	13.8 kV	13.8 kV	13.8 kV
Connection	Wye	Wye	Wye	Wye
Power Factor	0.80	0.80	0.85	0.85
RPM	3,000	3,000	3,000	3,000
Exciter Amps	800	693	850	850
Exciter Volts	145	375	250	250

4.2 Fuel Types

The following fuels are utilized / contained at the Old Harbour Power Station:

- No. 6 Fuel oil
- No. 2 / Lubricating oil mixture
- No. 2 / No. 6 Fuel oil mixture
- Transformer oil
- Waste Oil

4.3 Property Description

The Old Harbour Power Plant is located in St Catherine approximately 40 miles from Kingston and consists of a large power plant with stack, above ground water tanks, above ground fuel oil tanks (No. 6), an open storage yard and other attendant facilities. Site soils consist of marl, fill and concrete rubble. Groundwater flow is expected to be southeast towards the adjacent bay.

The following is a list of the major structures at the Old Harbour Power Station site:

- Five reinforced concrete buildings –
  a. Administrative Building
  b. Inventory Warehouse
  c. Canteen
  d. Laboratory
  e. Compressor House
- Units 1 & 2 Generating Plant
- Unit 3 and Unit 4 Generating Plant
- Four operating stacks
- Fuel Oil Storage Tanks with concrete bunds
- Chemical Storage Tanks with concrete bunds
- Water Storage Tanks
- Attendant Pipelines – System water & Fire water pipes
- Demineralizer and Reverse Osmosis Water treatment plant
- Laboratory
- Substation 69kV and 138kV
  - Relay House
  - Transformers
  - Oil and SF6 Circuit Breakers
  - Reclosures
  - Insulators
- Fuel Oil Storage Tanks with concrete bunds
- Fuel Pump Room
- Attendant Pipelines – Fuel Oil Pipes
- Fire System
- Fuel oil containers and dump storage area for soil remediation
- Drainage areas
- Four intake structures
- The flume outfall canal.

Other structures on the facilities are roadways, concrete paved areas and out of service equipment.

4.4 General Description

The main structures of the power plant include: the turbine buildings, generators, smoke stacks, workshops, demineralization building, stores building, boilers, the administration building, a canteen and change rooms as well as social facilities. All the facilities of the power plant are listed in Appendix C.

Administrative Building

Photo 1 – Old Harbour Plant front and Admin. Building

Units 1 and 2 along with their control centers are housed in the same structure alongside the main administrative building. Units 3 and 4 are housed in two separate buildings inclusive of the turbines and generators.

The main buildings are made of concrete and reinforced with steel beams. The administrative building is made of concrete with large glass panels, while the main plant buildings are made of concrete base, zinc sheeting and metal louvre windows.

Main stores and MMD workshop

The main stores building is located south west toward the back of the plant and is made of concrete base, zinc sheeting and reinforced with metal beams. It is adjoined by the mechanical workshop farther south.

Photo 2 – Main Stores Building (Concrete and metal sheeting)

The mechanical workshop is made of concrete and reinforced with steel beams. There are two exits and the area is 545^2m.

Photo 3 – Mechanical workshop

Stacks

There are four boiler stacks each made of reinforced concrete base with brick line interior /metal exterior and are 150 ft. tall. The stacks are located to the south of the unit.

Photo 4 - Southern End of Plant Stack

Steel Structures

The northern end of the power plant showing crane structure and main transformers for the unit in the foreground

Photo 5 - Northern end of plant/crane structure

Western side of boiler

Photo 6 - A section of a boiler

Fuel Oil Storage Systems

HFO is stored at the HFO tank farm located at the southwestern section of the compound where there are three above ground storage tanks (ASTs) TKS1&2&3 each of nominal capacities 25,000 (Tks 1&2)and 50,000 bls respectively.

Photo 7 – HFO Tank #1 and 2

Tank #3 located at tank farm with concrete bund wall. It is located close to JEP barge at the extreme back of the JPSCo. power plant

Photo 8 – HFO Tank #3

Water Storage System

The raw water storage tanks hold 200 gallons and are 32ft. high and made of steel sheeting with steel beam frame. Tank #1 and #3 are located to the right of the administrative building and visible from base up on entrance to the plant. However, tank #2 is located to the left of the administrative block.

Photo 9 - Raw water tanks #1 and 3

Water Treatment House

The water treatment house is made of concrete flooring, steel beams and metal sheeting. There are several agents housed in cylindrical metal tanks and each labelled accordingly.

Photo 10 – Demineralization plant

Waste Storage Area

The waste material holding area is a plot of land located to the west of the transmission switchyard and is approximately 570' x 296 'or 1.57 hectares or 3.39 acres in size. The area is used as a temporary holding area for wastes such as domestic solid waste and industrial waste pending disposal in accordance with NEPA standards.

Photo 11 – Waste material holding area

4.5 Surrounding Area Description

The lands to the west and north-north west of the JPS Old Harbour site have heavy industrial, light industrial, commercial facilities and residential settlements. The southern boundary of the site borders the Old Harbour Bay. The eastern boundary is also along the sea coast.

Lands to the north are mainly light industrial with some livestock farming and open spaces. There is a small private port to the North, North East of the Old Harbour site.

4.6 Hydro-geological Description

The geological setting of the JPS Old Harbour Facilities embraces the southwestern coastal section of the St. Catherine Plains formation. This is a heterogeneous alluvial formation of silt, gravel and clay lenses resulting in limited transmissivity at different locations in the sub layers. Groundwater in the aquifer is limited by the basin recharge potential and the clay substrata act as a natural barrier from the sea.

The Plant Facilities adjoins the shoreline (reclaimed wetland) and the high clay content of the retrieved samples indicates that:

- Transmissivity of the formation would be very low throughout the site
- Yields from the boreholes would be very poor.
- The rate of movement of solutes or pollutants through the formation would be slow, aided by adsorption of organic matter in the formation.

(Excerpt from NHL Soils report - 2012 report of bore holes)

4.7 Wells Description

Four wells are located to the North and North East outside of the facility. These wells are for production of water used in boilers, fire water system and domestic consumption. Water is pumped from the wells to the water storage tanks on the site.

The following is the well licence information:
Licences No. 1 to No. 3 were issued on Jan 2011 valid to Dec 2015 and licence No. 4 was issued on Feb 2012 and valid to Jan 2016.

Figure 4-2 - Well Data

Licence No	Name of Well	Discharge (Cu M/day)	Notes	Licence Expires
R01/2011-A2006/21	Bodles 1R Well	1,635	Chloride < 250mg/l	Dec 2015
R01/2001-A2006/22	Bodles 2R Well	1,635	Chloride < 250mg/l	Dec2015
R01/2011-A2006/23	Vaz 2R Well	1,635	Chloride < 250mg/l	Dec 2015
R01/2012-a2006/59	Vaz 1 Well (Standby)	1,625	Chloride < 250mg/l	Jan 2016

The well water is pumped into a storage tank and distributed to the treatment facility. Well water is used for fire control, boiler make-up and sanitary facilities and piped water, as there is no external utility water available to plant.

Water well licences are to be renewed in Dec 2015 to allow for the planned decommissioning activities up to 2019.

4.8 Waste Disposal

Waste disposal within JPS operations are guided by the JPS Waste Management Policy and Plan – 2009.

4.9 Industrial Solid Waste

Currently there is no local facility for the treatment of industrial waste that is deemed hazardous. Non-hazardous industrial waste, which is salvageable, is typically handled by contractors, who have established markets for such material. The industrial waste handled by contractors is limited to metals, used fuel and lubricating oils (*excerpt JPS Waste Management Policy and Plan – 2009).*

The National Solid Waste Management Authority is responsible for domestic solid and non-hazardous waste collection within the area. The NSWMA or contracted services transport the waste to the Riverton City landfill located in St. Andrew, approximately 8 kilometers (~5 miles) west of the Old Harbour Power Station site.

4.10 Hazardous Waste

Once waste material is deemed hazardous it is disposed of in accordance with the Natural Resources (Hazardous Waste) (Control of Transboundary Movement) Regulations 2002 and any other regulatory guideline.

For the management of asbestos containing materials (ACM), NEPA has guidelines for the management of ACM. Final land disposal for ACM is facilitated through the NSWMA via land disposal within a designated “cell” of their ‘land fill’.

If there is no suitable disposal option on the island the requisite steps are taken to secure the hazardous waste until a disposal option is available.

4.11 Security of Facility

The Old Harbour site presently has a perimeter chain link fence and toe-wall and has a 24 hour contracted security & surveillance system.

5 CLOSURE PLAN OBJECTIVES

5.1 Closure Plan

The closure plan describes the procedures for the removal of all the possible contaminants to air, soil and water; equipment decontamination; sampling and laboratory analysis and closure to the satisfaction of the relevant standards and regulations stipulated by the National Environment and Planning Agency.

(Source: National Environment & Planning Agency guidelines NEPA website)

Two options are currently being considered for the decommissioning and closure of the Old Harbour facility:

1) Clean closure
2) Risk-based closure.

Clean closure occurs when all hazardous wastes and any associated contamination at the facility are removed to the extent that laboratory analysis shows the contaminants remaining are either below the detection limits of the analytical method or below background levels.

(Source: RCRA)

Risk-based closure occurs when a facility leaves any amount of contamination in place at the site, but it is determined to be of no danger to human health or the environment through health-based levels.

(Source: RCRA)

It should be noted that the Old Harbour Power Plant is still in operation and the management systems in place will allow for continuous handling and disposal of materials that can cause or result in impact on the environment. Hazardous materials handling on the site is done according to established plans and procedures – Spill Management, Emergency Management, and Waste Management Plans.

Hazardous wastes generated on the site are handled based on the above Management Plans/Procedures. On an ongoing basis, hazardous materials will be disposed of on a case-by-case basis based on prudent environmental and safety practices as well as options available on the island.

Decommissioning of equipment will occur as practical.

5.2 Closure Plan Scope

The Scope of the DCP document will address:

- Old Harbour Site
- Facility well sites
- All Attendant facilities
- Exclude the Substation

6 CONCEPTUAL DECOMMISSIONING AND CLOSURE PLAN (DCP)

6.1 Purpose

The purpose of the conceptual Decommissioning and Closure Plan (DCP) is to describe the general objectives for the Old Harbour facility, and the planning processes leading to development of a final DCP.

This conceptual DCP includes the following management components:

- Planning to ensure each component of decommissioning of equipment or facilities and the Closure of the facility is done using best practice and to ensure proper management to ensure human health and the environment is protected.
- Decommissioning and removal of plant, infrastructure and other materials
- Retention of specific infrastructure if applicable
- Testing and removal of contaminated material (if relevant)
- Monitoring & reporting

This decommissioning and closure plan will be used to establish the Terms of Reference (TOR) for procedures that will be performed during closure and is required when an industrial facility is to be closed by voluntary means or as a regulatory requirement.

6.2 Planning

JPS will ensure that all wastes generated from the decommissioning and closure of the Old Harbour Facility operations are appropriately managed and disposed of. All waste must be handled, stored, collected, transferred, transported, processed, and disposed of, or reclaimed in a manner consistent with the requirements of a detailed plan. The detailed Decommissioning and Closure Plan will identify and quantify the waste that will be generated from the Closure of the Facility.

The detailed Decommissioning and Closure Plan will address such areas as

- ♦ Scheduling for removal of plant, infrastructure and other materials
- ♦ Retention of specific infrastructure if applicable
- ♦ Site access/fencing and security
- ♦ Environmental monitoring – soil and groundwater
- ♦ Removal of contaminated material (if relevant)
- ♦ Maintenance of equipment retired in place
- ♦ Reporting
- ♦ Facility closure and signoff where required

Industry best practice requires that planning of closure be undertaken progressively throughout the lifetime of an operation. As such the conceptual plan will be reviewed and details added as it becomes available. The Decommissioning and/or Closure Plan will be finalized and submitted to National Environment Planning Agency, Kingston and St. Andrew Corporation and any other relevant authorities for approval at least two (2) to six

(6) months prior to decommissioning and closure respectively of any facility on site or the entire site.

6.3 Decommissioning of Equipment

Decommissioning of equipment or a unit may occur in stages/phases during the life cycle of the Plant as the present units will be retired on a phased basis. In this context 'decommissioning' refers only to the removal (or appropriate retention) of infrastructure and assessment and notification of contaminated materials.

The specific objectives in managing the decommissioning process will be:

- To ensure that decommissioning is carried out in a planned sequential manner, consistent with best practice.
- To avoid any deleterious effects on human health and the environment
- To ensure storage and or disposal of any or all materials are done according to a well-established plan and at a facility that is licensed or approved to dispose of the matter.
- Decommissioning is done according to the relevant regulations and or guidelines established by the Regulatory Agency.

The decommissioning, removal and disposal of fuel and chemical storage tanks will include the following procedures but not limited to:

- Outline technical aspects related to the removal of all residual oil and chemical from storage tanks and associated pipelines
- To outline how the decommissioning process will prevent any further filling of storage tanks with any product
- Ensure the decommissioning of all tanks (fuel and chemical) is executed with strict environmental and safety practices.
- Ensure that the waste produced due to decommissioning of the tanks (fuel and chemical) and other equipment is classified and quantified and disposed of appropriately
- The Plan will include general steps for soil testing for the presence of contamination and soil remediation as required

6.4 Application for Necessary Permits

At the requisite time JPS will apply for the necessary permits, environmental or otherwise required for decommissioning the facilities.

6.5 Infrastructure Removal

Removal of plant, infrastructure and other materials and retention of specific infrastructure if applicable.

Removal of plant, other infrastructure and other materials will depend on the future use of the site, the condition and how well it fits in the plans of the new site. The removal will therefore be selective and will occur under certain engineering requirements.

6.6 Scrap Metal Generated

Scrap Metal generated will be disposed of based on the regulatory and business requirements at the time of decommissioning and/or closure of any area of the facility.

6.7 Other Materials

Other waste generated will also be disposed of based on the disposal requirements and proper location for disposal on island or where necessary off island.

6.8 Site Decontamination

While it is not anticipated that any major contamination of the site will occur, there is always the possibility of contamination occurring via an incident or accident on site. JPS current management systems are designed to minimize the risk of major contamination of the site occurring, by its spill management practices/procedure of reporting spills, clean up and proper disposal. The primary and major risk of contamination is via a hydrocarbon spill.

The basic requirements that will be considered during decontamination of any equipment, materials or the physical environment follows, derived from RCRA Closure Handbook, April 2010:

A complete work plan detailing methods for the decontamination of any contaminated area or equipment (tanks (fuel and chemical), containment areas, concrete pads, etc.) and other areas will be developed based on sampling and analysis to determine if there is contamination, types and the levels of contamination. Based on detailed assessments/analysis decontamination will be undertaken of the different areas where necessary.

Decontamination of equipment and materials depend on the types and levels of contamination. Several means of decontamination are available. The method for decontamination will depend on the materials, equipment or soil and location of the particular contamination.

Decontamination of non-porous surfaces such as tanks and metal piping may be accomplished by washing. Tanks may require entry procedures for a confined space. A detergent may or may not be employed. Steam cleaning is another option. The efficient removal of hazardous waste residues is the goal. *(Excerpts from RCRA Closure Handbook, April 2010)*

Porous surfaces provide a unique problem for decontamination. Decontamination method will be determined based on levels and types and economic feasibility; from complete removal to partial removal, etc. The main goal of the process is to remove the contamination in the most efficient and effective manner possible. *(Excerpt from RCRA Closure Handbook, April 2010)*

6.9 Soil Investigations

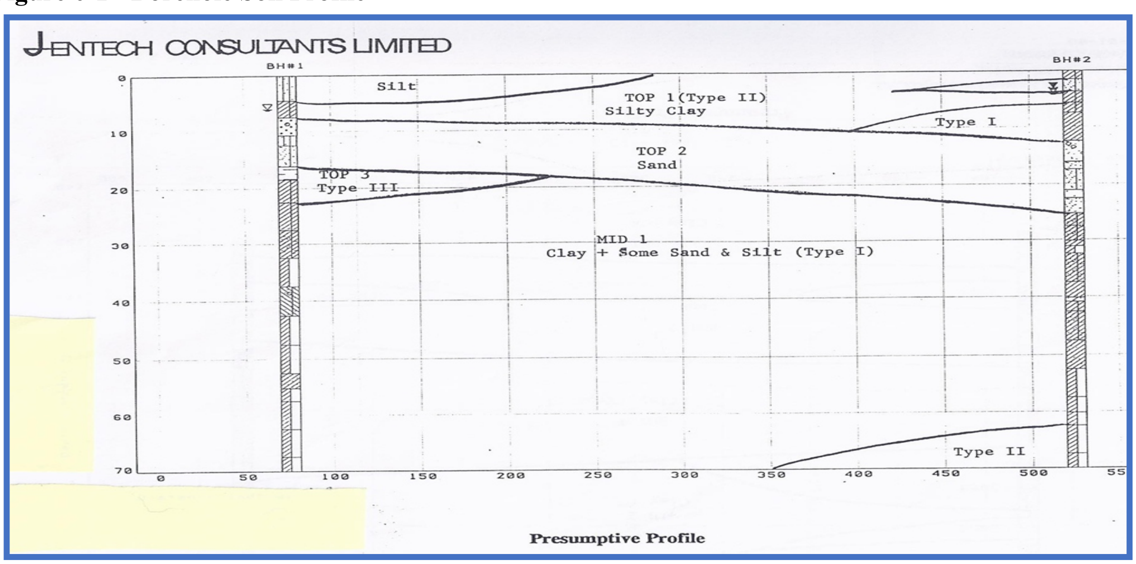
There are a number of ways to decontaminate soil. This too depends on the type of and levels of contamination including, treating soil in-situ. Groundwater will also be considered during the process of soil decontamination and/or treatment. *(Excerpt from RCRA Closure Handbook, April 2010)*

Jentech Consultants Ltd in April 2000 undertook five boreholes for JPS in the Old Harbour Bay Area. Two Bore holes were undertaken on the existing power plant site and three (3) bore holes were undertaken off-shore to explore for a pier facility. The two bore holes on site were located south of the material storage area and the section was north of the administration building. The soil type and stratification was identified. The field on-shore borehole record indicate that the soil penetrated on site are generally fine grained and clayey. The in-situ texture and consistency ranged from soft silty clays to hard clays with little sand (N_{70} =3-59). There were some course-grained sand material encountered in the depth range 2.4 to 4.6m, 23.8-29 m and 33.5-38m in borehole 1. Their in-situ texture and condition ranged from loose to very dense.

In summary it can be reasonably concluded that apart from few bands of sandy material, the sub soils were generally very stiff- hard clays with some silt and sand. Ground water was encountered initially at depth 1.8 and 1.2 meters in boreholes 1 and 2 respectively, rising to a depth of 1.1m in borehole 2. Based on the soil properties it was evident that heavy foundation such as turbine equipment was done using friction bearing piles, in the stiff clay layers. See presumptive profile diagram below.

The two boreholes did not reveal any type of visible contaminations in those areas. Nevertheless, further soil investigations and test will be required to determine the level of any soil contamination within the high risk areas. However, based on the type of soils suspected, one would not forecast any extensive seepage as the clay layers will form an impervious barrier.

Figure 6-1 - Borehole Soil Profile



7 CLOSURE PLAN MONITORING

The performance monitoring programme will be established based on the detailed plans. The final DCP will identify those monitoring requirements and all monitoring records will be collected as per any relevant standards or Monitoring Plan.

7.1 Quality Review

Monitoring results will be reviewed by JPS environmental personnel and Engineering Consultant to enable a response to be implemented if required. The results of the entire monitoring programme will be reviewed internally every quarter as part of the Monitoring Plan that will be established for each component of the decommissioning and closure plan.

7.2 Compliance Audit

The auditing of conformance with this Decommissioning and Closure Plan and any conditions or commitments related to environmental management will be conducted. The auditing will be conducted as per the Project Audit Schedule and will be based on the assigned responsibilities – internal JPS and third party services contractor.

7.3 Reporting

A report describing the performance of the final DCP, based on monitoring results, and the extent to which it has been complied with, will be submitted to the Authority

7.4 Current and Foreseeable Land Uses

Old Harbour Station is an active electricity generating plant located adjacent to the coastline. Based on current future plans for the Old Harbour sites, the facility will remain prime location for generation expansion projects based on the classification of the area as Industrial.

7.5 Management Commitment

The planning and supervision for the decommissioning and dismantling of the power plant must be carried out with trained staff and management. Objectives from the supervision team are:

- To ensure that rehabilitation and decommissioning are carried out in a planned sequential manner according to schedule and consistent with best practice
- To ensure that agreed land-use outcomes are achieved, and
- To avoid ongoing liability
- Prepare Final Decommissioning and Closure Plan at least six months prior to closure of the site. Necessary approvals will be sought where necessary prior to the execution of certain decommissioning and closure operations.

8 RISK MANAGEMENT PLAN – ENVIRONMENT AND SAFETY

8.1 Safety

The required safety equipment and materials will be used during the entire operations. The Contractor and his personnel will be guided by JPS Safety procedures for the duration of operations.

- HSSE orientation of all new personnel is to be performed before the project commences.

- Compliance with the required PPE for the job will be ensured and if there are changes to the planned activity these will also be considered. Contractors will be responsible for providing all the necessary PPE gears for all their employees.
- JPS Job Briefing exercise will be conducted at the job site(s) for all personnel involved in the activities - Contractors, Sub Contractors and their employees and all JPS personnel. This will be conducted at the start of each workday. Any change in work scope will require a job safety analysis (JSA) prior to the start of work.

- Contractors and Sub-Contractors will be trained in areas such as (a) Confined Space Entry Procedure (b) Hazard Communication (c) Personal Protective Equipment (d) Spill Prevention Control and Response Plan.
- Contractors must be knowledgeable about (a) Requirement for safe entry and cleaning of Petroleum tank (b) Factors contributing to confined space fatalities (c) Guidelines and Procedures for entering and cleaning of Petroleum tank. (d) Safe guarding of tanks for entry and cleaning.
- All personnel entering Tank must be equipped with Respirator and adhere to Plants Respiratory Protection and Confined Space Programmes
- Gas monitors must be in good working condition
- Rescue team must be on-site at all times and at least trained as an Entrant.
- Emergency Response Plan Procedures will be in force

Hazard Management processes include:

- Lockout/Tagout programme
- Hot Work management programme
- Confined space entry operation
- Compressed gas handling
- Hazcom programme
- Fall prevention/protection
- Job Briefings
- JHA-as required
- Hearing Conservation
- Respiratory protection
- Asbestos Management
- Illumination/lighting

8.2 Environmental

Environmental considerations which must be reviewed and implemented during the decommissioning exercise will include:

- Mitigation measures: Spill plans, spill mats, spill pallets, plastic sheet, etc. to be in place to avoid/minimize any spill.
- Good housekeeping practices to be observed at all times.
- Waste material (oily rags, gasket material etc) must be properly stored and disposed of at the end of the project.
- All entry to tanks to be governed by established plant Confined Space Entry procedures.
- All recovery, transfer, removal and handling of oil will be guided by established plant spill prevention and control procedures.
- Soil testing and remediation

8.3 Risk Mitigation

A team will establish a risk mitigation plan, through the identification of all associated risk and impact on the closure and probability of occurrence. An expected value will then be calculated and a risk mitigation response plan developed based on identified triggers.

Figure 8-1 - Risk Matrix

No	Risk	Prob. (HML)	Impact (HML)	Expected Valve	Mitigation
1	More soil remediation required than budgeted	M	M	MM	Earlier soils investigations to obtain details of contamination
2	OUR Generation expansion project delayed	M	H	**MH**	Work closely with OUR and preferred bidder to track schedule.
3	Likely-hood of a hurricane and flooding during dismantling	M	M	MM	Weather monitoring and safety procedures
4	Possibility of a major safety Incident during dismantling	L	H	LH	Full safety procedures implemented early
5	Social unrest and objections to dismantling	L	M	LM	Ensure early communication and all stakeholders involved
6	Salvage value of steal and copper falling again	L	L	LL	Allow for contingencies
7	Asbestos contamination larger than expected	M	M	MM	Early assessment and estimation

9 DECOMMISSIONING STRATEGY

The closure of Old Harbour Power plan is required in accordance with the OUR Generation expansion Plan Oct 2010. The OUR has now selected a preferred bidder for the generation expansion of 360 MW for implementation by June 2016. This will include the introduction of natural gas.

As such Old Harbour Power Plant will have to be closed based on the current load growth and the age of the plant. It has therefore been agreed that the timetable for shut down will be as follows. (This will be subject to final approval by the OUR)

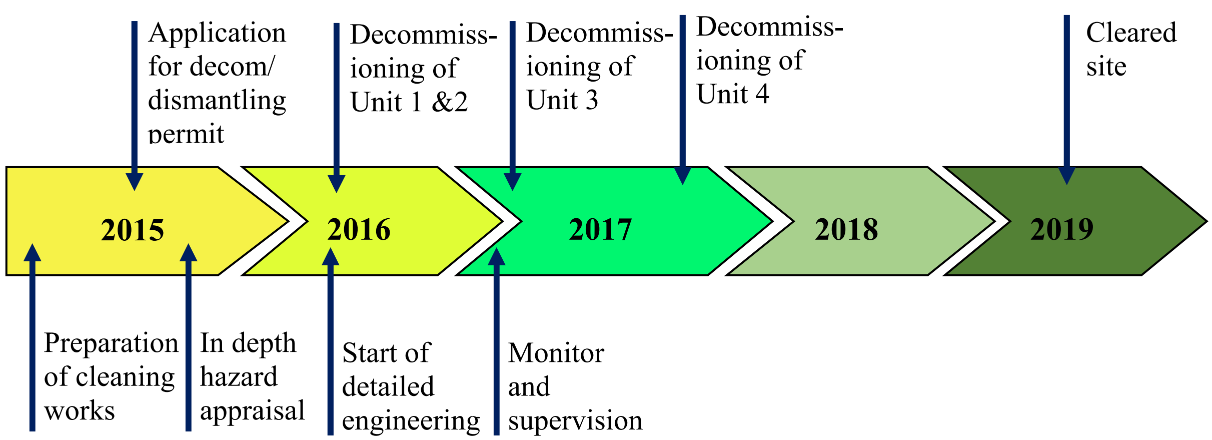
Figure 9-1 - OH Decommissioning Dates

OH Units	Shutting Down at Latest Date	Decommissioning Start Proposed at latest
Unit 1	Before Dec 2010	June 2016
Unit 2	Before June 2016	June 2016
Unit 3	Before Dec 2016	Mar 2017
Unit 4	Before June 2017	Sep 2017

The negative impact on the workforce and external service providers are considered less important if dealt with in a proper way as explained later.

From a purely technical point of view the least cost solution would be to delay the decommissioning and dismantling until the last unit has been shut-down. However the team suggests a different decommissioning strategy in order to alleviate social impacts. This strategy is based on making use of part of the Old Harbour workforce to be involved in the unit by unit planning and implementation of the decommissioning and dismantling.

Figure 9-2 - Timeline of Decommissioning Activities



The decommissioning process itself consists of various political and engineering phases, comprising a strategic preparation phase first, followed by a political decision-making and engineering planning phase, defining steps of decommissioning and demolition work with an agreed time schedule and coordination with the remaining share of generation capacity to enable a continued safe and balanced national power supply. See Figure 9.2.

The demolition process itself starts with an in-depth planning to obtain the necessary permission from the OUR and the necessary budget to be prepared for the continued operation in the event the new generation is delayed. Decommissioning shall be performed by an external demolition contractor with the support of external consultants.

The planning, tendering and award process for the demolition services will be carried out by JPS team to ensure the most cost effective solution is obtained and to ensure that the power supply balance is maintained.

Preparatory measures such as cleaning up the complete power plant site (clearing the scrap yard, the waste heap) can begin as early as June 2015. At the same time, technical safety measures can be planned and carried out for units 1 and 2 mid 2015. This will comprise work to remove any hazardous materials from facility already shut down and securing the facilities from any unauthorized access. Any unused containers and housing can be cleared and demolished in this early phase.

9.1 Decommissioning Permit Procedure

The preparedness of the JPS generation operational team will be checked on the basis of existing local legal regulation and compared with the NRCA closing procedures in appendix B. The general application requirement and form is available from NRCA and NEPA. The following items were outlined by NRCA:

1. The nature of the probable/possible contamination including list of chemicals used on site.
2. Any published or otherwise known information in order to establish whether adjacent property owners are or have been potential sources of contamination
3. Present zoning of the site and details of the zone categories of properties surrounding the site
4. Contour or topographic maps
5. Likely future use of the site
6. Risk Assessment
7. The results of any previous investigations of the site or surrounding land
8. Locations of surface water bodies, particularly where these may be adversely affected by contaminated groundwater or surface drainage from the site
9. Hydrogeological information, which should include:
   - The extent and use of aquifers in the area
   - Estimated depth to groundwater
   - Probable direction of groundwater flow and gradient
   - Soils and soil properties (soil type, porosity and hydraulic conductivity)
   - Location of any springs
   - Sources of local municipal water supply and the location of registered private or industrial wells or bores
10. Solid waste disposal

11. Security of facility/area scheduled for closure. This should include the postage of relevant signs.

NRCA and NEPA serve as the state agencies controlling the country's system balance, making comparative analysis of the inter-systems relations, checking the completeness of the application provided for permit and analyzing the environmental and social impacts of the decommissioning measures according to the Jamaica legislation.

The carefully designed decommissioning procedure represents a complex follow-up of institutional/organizational activities and practical works at the Old Harbour Power Plant site to be performed by an s experienced decommissioning contractor/ expert to coordinate all the actions. The team recommends setting up a dedicated JPS business unit as soon as possible to rationally handle the disaggregation and manage the process with all economic, social and technical consequences.

9.2 Description of the Planning Steps

A detailed decommissioning plan taking into account the legal framework of the Old Harbour Power Plant and respecting JPS supply duties is required to obtain a permit for the decommissioning and demolition of the plants and facilities to ensure orderly and selective dismantling and demolition.

The decommissioning and dismantling plan is divided into eight (8) phases as described below:

Phase 1
Preparatory Measures (Start June 2015)

- Develop terms of reference for planning and engineering of decommissioning and dismantling
- Examination of existing documents and as-built plans
- Definition of those plant systems which are necessary for operation of specific units and definition of plants and facilities which can be dismantled before the last unit is shut down
- Definition of the scope of performance
- Carrying out necessary coordination with the competent technical authority eg. NEPA, OUR and MEM.

Phase 2
Engineering of the decommissioning and dismantling of units and balance of plant.

Phase 3
Preliminary and in-depth exploration of the power plant site to include:

- Soil investigation of any waste areas and potential contaminated areas
- Sampling and analysis of any demolished materials
- Hazard assessment for the demolition materials
- Hazard assessment for the soils; ground water not necessary.

Phase 4
Development of mass balance and disposal concepts

- Examination of structures and buildings
- Study of existing building files, design documents etc.
- Quantity surveying
- Develop a secondary usage or disposal concept
- Asbestos survey
- Develop decommissioning and safety plans (abolition of soil and ground water contamination)
- Mass balance of the demolition materials

Phase 5
Development of a dismantling strategy

- Elaboration of a health and safety plan
- Presentation and description of necessary safety and protection measures
- Planning of necessary measures to guarantee ground stability of adjoining facilities
- Specification of measures to provide utilities, water energy and compression air.

Phase 6
Compilation of tender documents for the dismantling works.

- Presentation of the demolition project
- The development of building descriptions, including specifications and preferable dismantling technologies
- Development of scope of supplies and services.

Phase 7
Cost and time schedule planning

- Ascertainment of the dismantling and disposal cost
- Ascertainment of recoverable proceeds
- Preparation of the dismantling time schedule

Phase 8
Contract award and Planning

- Compilation of the criteria catalogue for bid evaluation
- Issue Request for Proposals
- Bid meetings
- Evaluation of tenders
- Award of contract

Phase 9
Implementation of Dismantling and Disposal

9.3 Dismantling Process

To create a preliminary dismantling time schedule, the decommissioning and dismantling of the Old Harbour Power plant have been divided into separate phases and stages as outlined below.

Stage 1
Before the general shutdown of the power plant:

- Clearance of the complete area of rubbish and waste of any kind
- Cleaning of disaggregated equipment and buildings no longer in use
- Implementation of safety measures in these systems
- Dismantling of technical equipment of unused facilities
- Partial demolition of facilities that are directly assigned to Unit No.1.
- Maintain access roads and access to JEP facilities

Stage 2
After the general shutdown of the power plant:

- Safety measures in OH power plant facilities to be carried out before dismantling of components.

Stage 3

- Dismantling of technical equipment in OH power plant facilities to be carried out before next stages

Stage 4:
Demolition of the following:

- Ancillary buildings
- Workshop
- Pipe bridges, belt conveyors, fuel handling and treatment systems with low dismantling complexity.

Step 5
Dismantling of:

- all ancillary buildings down to ground surface
- Chemical water treatment facilities
- Cooling water systems
- Administrative and social buildings

Stage 6
Structural facilities with high dismantling complexity and requiring heavy lifting equipment.

- Transformers and outdoor installation
- Crane structures

Stage 7
Dismantling of smoke stacks and platforms

Stage 8

- Dismantling and demolition of Main buildings (Turbine house, boilers)

Stage 9

- Dismantling of all buildings down to the lower edge of foundation

- Underground pipelines and cables

Stage 10

- Dismantling of well site No. 1
- Review sale/ hand-over of well site No. 2 and pipe works to JEP

Detailed Procedure will depend on staffing, the number of subcontractors and the availability of the necessary demolition equipment. Demolition is to be carried out using conventional equipment (ball and chain, breaking, cutting or with hand tools) or by explosives, subject to approval. Afterward, the site clearance of the demolition areas as well as removal can be carried out for the treatment, secondary usage or disposal of the demolition masses.

Stage 9 includes the demolition of foundations and undergrounds pipes which are up to 2 ft below grade. This can be followed by backfilling with selected recycled construction materials.

With regard to the Station and Water Resources Authority no additional drainage or water management measures will be required for deep underground work.

The treatment of mineral materials (concrete, masonry) may preferably take place at the site using mobile recycling equipment, assuming quantity and availability.

The mineral recycling material can be used after appropriate treatment for backfilling. The backfilling of pits has to be done in layers followed by compaction. Compaction of at least 97% is to be ensured using proctor compaction test. The length of the edge of the materials should not exceed 63 mm.

No detail investigation of potentially contaminated areas and soil has been made; a simple walk-through audit was done at known places for such a potentially environmental load, (turbine gears, oil storage, holding areas, washing areas) resulting in indicative areas and volumes.

The attached cost estimate for soil contamination works is based on these audits but a more accurate amount has to be accomplished by an in-depth soil investigation before starting the decommissioning works.

10 ASSIGNMENT OF FACILITY TO COMPONENTS

The individual facilities of Old Harbour Power Plant were classified according to the item numbers used in the plant listing at Appendix C. Buildings or plants were further aggregated into components as shown of plant layout at Appendix E.

Based on this list of facilities, assignment was carried out to complete the various dismantling stages using an internal selection system by time and activity.

The assignment of components was carefully done to ensure a coordinated and safe environment and to ensure the work areas are confined.

The Old Harbor site components dismantling assignments include:

- C 1 - Unit 1&2 Turbine & Bldg
- C 2 - Unit 1&2 Boiler & Stack
- C 3 - Unit 1&2 Intake
- C4 - Unit 1&2 Transformers & Compressor
- C5 - Unit 3 Turbine & Bldg
- C6 - Unit 3 Intake
- C7 - Unit 4 Turbine & Bldg
- C8 - Unit 4 Intake
- C9 - Unit 3 & 4 Boiler & Stacks
- C10 - Water Treatment
- C11 - Stores Facility
- C12 - Water Tanks
- C13 – Fuel oil Tanks
- C14 – Front Bulk Storage
- C15 – Waste Storage Area
- C16 – Adm. Building
- C17 - Parking Area
- C18 – Recreation Area
- C19 – Substation (Excluded)
- C20 – Contractor Building
- C21 - Unit 3&4 Transformers & Compressor

11 TIME SCHEDULE FOR DECOMMISSIONING

A period of five (5) years is estimated for all the general measures for the decommissioning and dismantling process.

The sequence of activities will be staggered, according to the progress achieved within the consecutive actions. Some activities will be done in parallel, assuming sufficient resources including staff.

Figure 11-1 - Decommissioning Schedule

		Start	2015		2016				2017				2018				2019			
No.	Activity	Date	J	S	J	M	J	S	J	M	J	S	J	M	J	S	J	M	J	S
1	Preparation of Cleaning Works	Jan-15																		
2	Application for Deccommissioning / Dismantling Permit	Sep-15																		
3	Site Clearence of abandon facilities	Mar-16																		
4	Impliment Safety Measures	Mar-16																		
5	Engineering Planning & Upadtes	Mar-16																		
6	In Depth Hazard Appraisal	Mar-16																		
7	Start of Detailed Engineering	Mar-16																		
8	Start of dismantling Supervision	Jun-16																		
9	Decommissioning of Unit 1	Jun-16																		
10	Decommissioning of Unit 2	Jun-16																		
11	Decommissioning of Unit 3	Mar-17																		
12	Decommissioning of Unit 4	Sep-17																		
13	Site Remediation Works	Mar-18																		
14	Hand-over Site	Jun-19																		
15	Application for HB Unit B6	Sep-16																		
16	Start Engineering	Jan-17																		
17	Decom Hunts Bay Unit B6	Jun-17																		

It is important to observe that the planned activities are slated to start in Jan 2015 and planned demolition of Units 1 and 2 to start in June 2016 with the overall completion of the demolition works and site hand over to be completed in June 2019. This is therefore an estimated five year plan activity to minimize risk and have a smooth transition.

12 ROUGH COST ESTIMATE

The total cost estimate for dismantling of the Old Harbour Power plant is estimated to be US$7.651M

12.1 OH Dismantling Cost

The initial estimate was done using parametric estimating technique. See Table 12.1 . This was done using the Kosova-A Power Plant decommissioning cost and prorating the item cost based on the MW plant ratings. Kosova-A was 600MW while JPS was 230MW.

The JPS preliminary engineer's estimate was done using the Burns & McDonnell Estimates templates for similar sized fossil fuel power plant. The preliminary estimates are summarized below:

Table 12-1 - Decommissioning Cost

No.	Activity	JPS Prorated From Kosovo	JPS Estimate
1	Planning of Dismantling	402,500	150,000
2	Safety Measures	488,750	320,000
3	Supervision of Complete Dismantling	287,500	210,000
4	Dismantling Works All Units & BOP	5,865,000	4,595,000
5	Decontamination for Asbestos	1,437,500	1,300,000
6	Decontamination for Minerals & Oil Hydrocarbons	718,750	1,150,000
	Subtotal	**9,200,000**	**7,725,000**
	Cost per KW	40	34
8	Less Income from Sale of Materials	1,035,000	1,618,640
	Total Estimated for Dismantling Works	8,165,000	6,106,360
	Project Indirects (5%)	408,250	386,250
	Contingencies (15%)	1,224,750	1,158,750
	Total Project Cost	**9,798,000**	**7,651,360**

The Burns McDonnell sample estimates along with the detailed material listing and weight calculations included at Appendix G were compiled and evaluated to arrive at the JPS budgetary engineer's estimated cost of US$7.651M

Costs for asbestos and soil remediation were estimated based on plant size and medium levels of contamination. The summary estimate is presented in Table 12.2 below:

Table 12-2 – OH Summary Decommissioning Estimate

Old Harbour Power Station 230MW

Site Demolition Cost Summary

No.	Description	Unit	Quan.	Labour	Material /Equip	Disposal	Environ.	Total Cost	Salvage
GENERAL									
	Planning Cost	LS	1	150,000				150,000	
	Safety Measures	LS	1	320,000				320,000	
	Supervision of Dismantling	LS	1	210,000				210,000	
	Sub-total			680,000	-	-	-	680,000	-
UNIT 1									
	Mobilize & Demobilization	LS	1	20,000	20,000			40,000	
	Asbestos Remidiation	CF	300				550,000	550,000	
	Boiler & Auxillary & Stack	LS	1	112,000	112,000			224,000	
	Steam Turbine & Building	LS	1	145,000	145,000			290,000	
	Intake	LS	1	30,000	30,000			60,000	
	GSU & Other Transformers	LS	1	40,000	30,000			70,000	
	Onsite Concrete Crushing & Spreading	CY	80	20,000	26,000			46,000	
	Debris Handling, Haulage & Disposal	CY	260			140,000		140,000	
	Scrap Steel ($140/TN)	TN	256					-	(35,840)
	Scrap Non -Ferrous ($3800/TN)	TN	88					-	(246,400)
	Sub-total			367,000	363,000	140,000	550,000	1,420,000	(282,240)
UNIT 2									
	Mobilize & Demobilization	LS	1	20,000	20,000			40,000	
	Asbestos Remidiation	CF	400				750,000	750,000	
	Boiler & Auxillary & Stack	LS	1	112,000	112,000			224,000	
	Steam Turbine & Building	LS	1	145,000	145,000			290,000	
	Intake	LS	1	30,000	30,000			60,000	
	GSU & Other Transformers	LS	1	40,000	30,000			70,000	
	Onsite Concrete Crushing & Spreading	CY	100	30,000	30,000			60,000	
	Debris Handling, Haulage & Disposal	CY	300			180,000		180,000	
	Scrap Steel ($140/TN)	TN	320					-	(44,800)
	Scrap Non -Ferrous ($3800/TN)	TN	110					-	(308,000)
	Sub-total			377,000	367,000	180,000	750,000	1,674,000	(352,800)
UNIT 3									
	Mobilize & Demobilization	LS	1	20,000	20,000			40,000	
	Asbestos Remidiation	CF	0					-	
	Boiler & Auxillary & Stack	LS	1	112,000	112,000			224,000	
	Steam Turbine & Building	LS	1	145,000	145,000			290,000	
	Intake	LS	1	30,000	30,000			60,000	
	GSU & Other Transformers	LS	1	40,000	30,000			70,000	
	Onsite Concrete Crushing & Spreading	CY	100	30,000	30,000			60,000	
	Debris Handling, Haulage & Disposal	CY	300			180,000		180,000	
	Scrap Steel ($140/TN)	TN	420					-	(58,800)
	Scrap Non -Ferrous ($3800/TN)	TN	110					-	(308,000)
	Sub-total			377,000	367,000	180,000	-	924,000	(366,800)
UNIT 4									
	Mobilize & Demobilization	LS	1	20,000	20,000			40,000	
	Asbestos Remidiation	CF	0					-	
	Boiler & Auxillary & Stack	LS	1	112,000	112,000			224,000	
	Steam Turbine & Building	LS	1	145,000	145,000			290,000	
	Intake	LS	1	30,000	30,000			60,000	
	GSU & Other Transformers	LS	1	40,000	30,000			70,000	
	Onsite Concrete Crushing & Spreading	CY	100	30,000	30,000			60,000	
	Debris Handling, Haulage & Disposal	CY	300			180,000		180,000	
	Scrap Steel ($140/TN)	TN	420					-	(58,800)
	Scrap Non -Ferrous ($3800/TN)	TN	110					-	(308,000)
	Sub-total			377,000	367,000	180,000	-	924,000	(366,800)

Site Demolition Cost Summary

No.	Description	Unit	Quan.	Labour	Material /Equip	Disposal	Environ.	Total Cost	Salvage
Fuel Oil Facilities									
	No. 1 Heavy Oil Tank	CF	144218	30,000	30,000			60,000	
	No. 2 Heavy Oil Tank	CF	144218	30,000	30,000			60,000	
	No. 3 Heavy Oil Tank	CF	282289	40,000	40,000			80,000	
	Unit # 3 Day Oil Tank (HFO)	CF	9180	5,000	5,000			10,000	
	Unit # 4 Day Oil Tank (HFO)	CF	9180	5,000	5,000			10,000	
	Unit # 1 Light Oil Tank	CF	1964	1,000	1,000			2,000	
	Unit # 3Light Oil Tank	CF	3928	2,000	2,000			4,000	
	Diesel Oil Tank #1	CF	1559	1,000	1,000			2,000	
	Diesel Oil Tank #2	CF	102			3,000		3,000	
	Oil Room	SF				3,000		3,000	
	Scrap Steel	TN							(220,000)
	Sub-total			114,000	114,000	6,000	-	234,000	(220,000)
Common Plant Facilities									
	Laboratory and Chemistry Building	SF		35,000	25,000			60,000	
	Demineralization Plant	LS		20,000	18,000			38,000	
	Raw Water Storage Tank # 1	CF	28209	20,000	20,000			40,000	
	Raw Water Storage Tank # 2	CF	28209	20,000	20,000			40,000	
	Raw Water Storage Tank # 3	CF	28209	20,000	20,000			40,000	
	Demineralised Water Tank #1	CF	28209	20,000	20,000			40,000	
	Demineralised Water Tank #2	CF	28209	20,000	20,000			40,000	
	Demineralised Water Tank #3	CF	47564	40,000	40,000			80,000	
	Fire System	LS				22,000		22,000	
	Instrumentation	LS				15,000		15,000	
	Maintain Services to JEP	LS		10,000				10,000	
	Scrap Steel	TN							(240,000)
	Sub-total			205,000	183,000	37,000	-	425,000	(240,000)
Common Plant Structures									
	Administration and Workshop Building	SF		65,000	70,000			135,000	
	Canteen and Changeroom	SF		11,000	10,000			21,000	
	Bulk Storage House(Front)	SF		5,000	5,000			10,000	
	First Aid Building	SF		4,000	4,000			8,000	
	Firepump and Emergency Diesel House	SF		5,000	5,000			10,000	
	Main Stores Building	SF		10,000	10,000			20,000	
	Bulk Storage House(Back)	SF		10,000	10,000			20,000	
	Mechanical Workshop	SF		15,000	15,000			30,000	
	Compressor House	SF		5,000	5,000			10,000	
	Inner and Outer Guard House	SF		5,000	5,000			10,000	
	Misc Buildings	SF		10,000	10,000			20,000	
	Scrap Steel	TN							210,000
	Sub-total			145,000	149,000	-	-	294,000	210,000
	Total Demolition Station Cost			2,642,000	1,910,000	723,000	1,300,000	6,575,000	(1,618,640)
SOIL REMEDIATION (EST)									
	Soil Testing	No					50,000	50,000	
	Bulk Storage Area	SF					500,000	500,000	
	Fuel Oil Tank Areas	SF					600,000	600,000	
	Sub-total			-	-	-	1,150,000	1,150,000	
REVISED PROJECT COST								7,725,000	(1,618,640)
PROJECT RESERVES									
	Project Indirects (5%)							386,250	
	Contingencies (15%)							1,158,750	
	LESS TOTAL PROJECT SALVAGE							1,618,640	
TOTAL PROJECT COST								7,651,360	
	See Appendix G - For Detail Plant Listing								

12.2 General Assumptions

1. Cost of Dismantling/ Demolition include:
   - All site facilities prep work, dismantling and demolition works
   - The storage of materials for sale
   - the preparation of demolition materials, transportation & disposal
2. Blasting of stacks and main building allowed based on approval
3. Recyclability of mineral demolition materials (concrete)
4. Overfilling of mineralized material at location
5. Disposal of other demolition materials in a radius of 50km from Site
6. Map of potential Asbestos & Oil Contamination limited to areas shown
   - Asbestos in Unit 1&2 Steam pipe lagging only
   - Soil contamination areas, Tank farm and storage area
7. Transmission and switch yard and substations within the plant boundary are not a part of the demolition scope. Switchyards associated with the power plant facilities ONLY and are not a part of the transmission system are included for demolition
8. Step up transformers, auxiliary transformers and spare transformers are included for demolition in all estimates
9. Abatement of asbestos will precede any other work. After final air quality clearances have been reached, demolition can proceed.
10. All PCB oil will be removed and disposed of properly
11. Only preliminary estimates for soil clean-up have been included and soils investigation will be required to ascertain the final quantities.
12. All structures 2 feet below grade will be abandoned unless deemed hazardous by NEPA.
13. Major equipment and structural steel is included in scrap value. All other demolished materials are considered debris
14. Costs of off-site disposals are included in excess of the onsite inert debris disposal capacity.
15. Valuation and sale of land and all replacement generation costs are excluded from this scope
16. Credit for salvage value are based on scrap value alone. Resale equipment and materials are not included. This is also considered very limited.

17. Labour cost is based on regular 40 hr work week without overtime.
18. Soil testing has not been done for the site contamination areas.
19. Sewers catch basin and ducts will be collapsed to two feet below grade, filled and sealed on the upstream side.
20. The discharge and intake canals will be left in place; equipment and structures above the sea level will be removed.
21. Crushed rock is assumed to be disposed of on-site by using it for clean fill, or will be recycled by the demolition contractor for beneficial use.
22. All above ground buildings and structures are included for demolition
23. Costs are included to clean out fuel oil tanks and to remove the soil within immediate vicinity.
24. Market conditions may result in cost variations at the time of contract execution
25. Pricing of all estimates is in 2013 dollars?
26. A contingency of 15% was included on the direct cost in the estimate to cover unknowns.
27. Based on Request for Information (RFI) issued by Material Management two bids were received with budgetary costs in keeping with the above dismantling estimate. However, longer time period for estimates would be required as bidders were unable to make site visit and conduct detail assessment due to limited time for RFI submission.

12.3 The RFI Budget Estimates

The estimate was also verified using a RFI from seven (7) international companies for budgetary estimates. Only two firms submitted written non-binding responses due to the time constraint. The results are summarized below in Table 12.3 and these have been compared to the engineer's estimate:

Table 12-3 - RFI Budgetary Estimates

		BIDS		JPS Estimated				
	RFIs Received dated Oct 25, 2013	Demolition less Salvage	Demolition Only	Asbestos	Soil Remediation	Supervision	Contingencies	Total
1	Independent Excavating Inc (Ochio)	3,800,000	3,800,000	1,300,000	1,150,000	680,000	1,545,000	8,475,000
2	Frontier Industrial Corp	(515,000)	2,215,000	1,300,000	1,150,000	680,000	1,545,000	4,160,000
								-
	JPS Engineering Estimate	3,186,360	4,595,000	1,300,000	1,150,000	680,000	1,545,000	7,651,360

12.4 Book Value Plan

Paragraph 16 © of International Accounting Standard (IAS) 16 classifies decommissioning cost as an element comprising the cost of an asset. Per the standard, this cost would include the estimate of the cost of dismantling the item of Property, Plant and Equipment (PP&E) and restoring the site on which it is located at the date of acquisition. Site restoration costs include remediation as required by environmental and legal regulations.

In the present JPS circumstance, these costs were never estimated and included in the varying value of the PP&E. Decommissioning cost therefore has to be treated as an additional cost to be incurred by the regulated business in order to satisfy the requirements of applicable regulations and statutes to restore the sites addressed by this report. In the context of the current regulatory construct where JPS is allowed to recover reasonable non-fuel operating costs, depreciation, taxes and a reasonable return on its investment, these costs would not have been contemplated. In this regard JPS is of the view that it has a reasonable right to apply to the OUR, to seek to have the cost of decommissioning the subject PP&E recovered in the 2014 tariff review application.

In similar manner, due to the need to maintain reliability of service JPS has been forced to extend the life of existing assets to accommodate the delay in bringing new generating capacity to the grid. This has resulted in capital expenditures being incurred in relation to units that are operating several years beyond their stipulated useful lives. These units, as such have considerably higher carrying values. This situation also calls for the inclusion of a known and measurable adjustment to the depreciation rates contemplated in the tariff submission that will allow the Company to recover the carrying values of these assets over their remaining useful lives, set to expire in 2018.

Going forward any maintenance costs on units to be decommissioned would be treated as Operations and Maintenance and not capital expenditure to allow for zero book value at the time of decommissioning.

The Book Value excluding land as of Aug 31, 2013 is shown in Table 12-3 below:

Table 12-4 - Power Plant Book Values

No.	Unit Name	Total NBV	Comments
1	Hunts Bay - B6	2,946,671.73	
	Subtotal	**2,946,671.73**	
1	OH Steam Unit #1	-	Retired Dec 2012
2	OH Steam Unit #2	4,715,559.36	
3	OH Steam Unit #3	11,230,632.13	
4	OH Steam Unit #4	12,958,195.90	
5	Other assets relating to OH	1,432,232.94	
	Subtotal	**30,336,620.33**	
	TOTAL (Aug 31, 2013)	**33,283,292.06**	

13 SOCIAL IMPACT

An assessment of the social impacts to be caused by the closure of the Old Harbour Power Plant is not part of this study. However, the Human Resource Department along with the Director of Generation is also examining this component. A summary of the main considerations is presented here for completeness. The data was extracted from the JPS HR Management System Report.

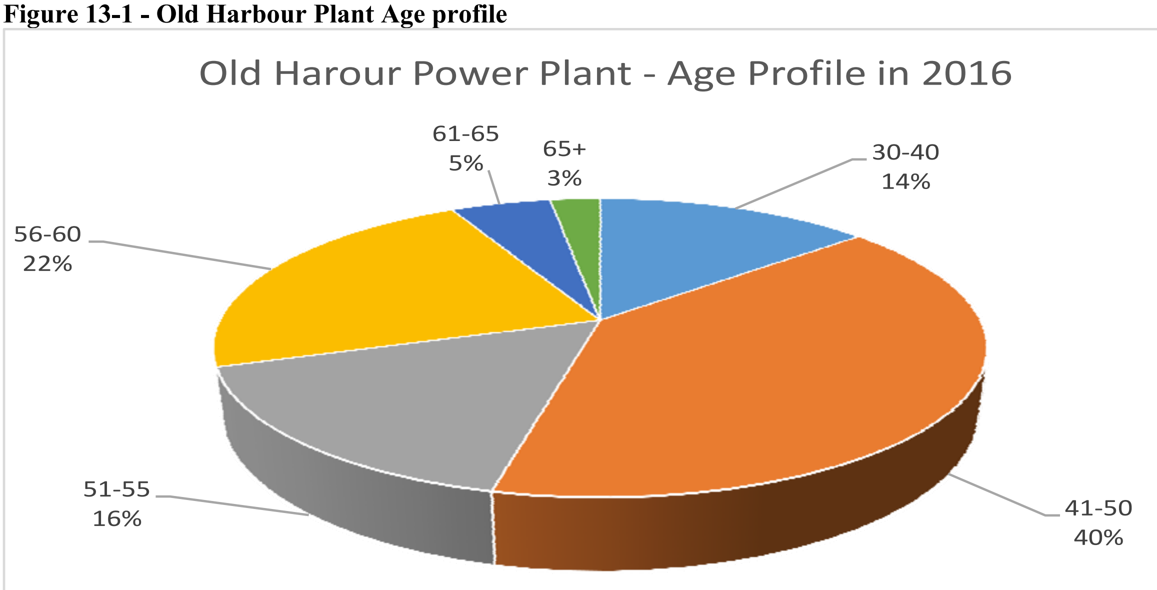
13.1 Current Staff Position

JPS has a staff complement of 1429 employees (as at September 2013) and approximately 250 persons work in the Generation Division. Of this number, just under 78 persons work on the Old Harbour power plant site. The remaining 172 generation staff members are employed to the other power plants New Generation and Generation Operations Support Staff.

13.2 Workforce Age Profile

Based on the data of the 78 employees currently engaged at the JPS Old Harbour Power Plant, the average age of the workforce is 49 years with over 46% aged over 50 and 54% under the age of 50. Only two workers would have reached retirement age by 2016.

Figure 13-1 - Old Harbour Plant Age profile



13.3 Workforce Development Plan

The plan for the development of the workers that will be displaced by the closure of Old Harbour Power Plant and any rationalization of JPS generation work force as a whole is based on five key elements:

1. A proportion of the work force will be deployed in jobs associated with the decommissioning of Old Harbor power plant and the subsequent decontamination and regeneration of the site.
2. A proportion of the workforce will be made redundant. It is anticipated that they will receive support from the HR Dept in terms of counselling, to find alternative employment, either in other companies or through self-employment or small business.
3. A proportion of the work force will retire and leave the labour market
4. A proportion of the workforce may consider employment in the new generation company.
5. In addition, members of the workforce currently associated with external independent contractors may continue to provide services to the other generation companies and other clients.

13.4 Financial Implications of Redundancy

It is difficult at this stage to specify the total cost of reorganization until a number of key decisions have been made. However, we recognize that the GOJ and JPS management would benefit from having indicative costs of a range of measures and options.

Option 1: All units at OH are retired in June 2016, all staff made redundant and an outplacement team with 10 members is formed to operate for two (2) years.
Estimated Redundancy Cost – US$7,420,152

Option 2: All units at OH are retired based on a phased plan starting June 2016 to Dec 2017 and staff used for the closing and safe hand-over, a small out placement team of five (5) persons would operate for a year.
Estimated Cost– US$7.1M

Option 3: All units at OH are retired on a phased basis starting in June 2016 and the option of early retirement offered to persons 55 and over on enhanced terms of half pay. Assume a 50% acceptance rate.
Estimated Redundancy Cost – US$6,004,741

Option 4: Same as Option 3 but an early retirement is offered to persons 60 and over with the assumption of 100% acceptance.
Estimated Redundancy Cost – US$6,008,591

The HR Management model considered the following general assumptions:

1. The salary increase rates (5% , 4% for 2015 & 2016 respectively)
2. The years of service were as at Sep 2013, however 3 years were added to account for their age as at the proposed date of June 30, 2016

3. The vacation leave balance relates only to the 2016 entitlement, as in keeping with the HR Policy, each year's leave would be taken
4. Sick Leave represents the current balances plus an additional 30 days, (ie. 10 days per annum) for the 3 year period ending June 2016

13.5 The Potential to Create New Employment

The existing JPS workforce has many of the skills needed to undertake much of the decommissioning and dismantling activities which have been identified. Employment opportunities during the staged decommissioning and dismantling of Old Harbour power plant are estimated as follows:

1. Decommissioning engineering:	5 engineers for 3 yrs
2. Preparation & Cleaning works	15 unskilled workers for 2 yrs
3. Safety measures:	10 maintenance workers + 20 unskilled workers for 1 yr
4. Demolition works	Depends on EPC strategy Say 30 skilled workers +40 unskilled

The above figures do not take into account jobs which might be created by bringing the entire site back into productive use through the regeneration process.

13.6 Conclusions

In summary the main conclusions for the social considerations are:

- The strategy to minimize the social and economic consequences of the closure should be based on a fundamental restructuring of JPS power generation division activities over at least the next 5 year period from 2014, combined with an early decommissioning of already closed plants to create employment opportunities
- The closure programme and the regeneration of the Old Harbour Power plant site needs to be led by powerful and vigorous social intervention
- There is no one single measure that can form the basis of the strategy, instead it will need a range of different measures, involving a number of public bodies, private agencies, NGOs and other stakeholders. These measures may include:

    - Redeployment of some workforce
    - Natural turnover of staff and early retirement
    - Redundancy of some employees
    - Training and support to redundancy workers to maximize their chances in labour market

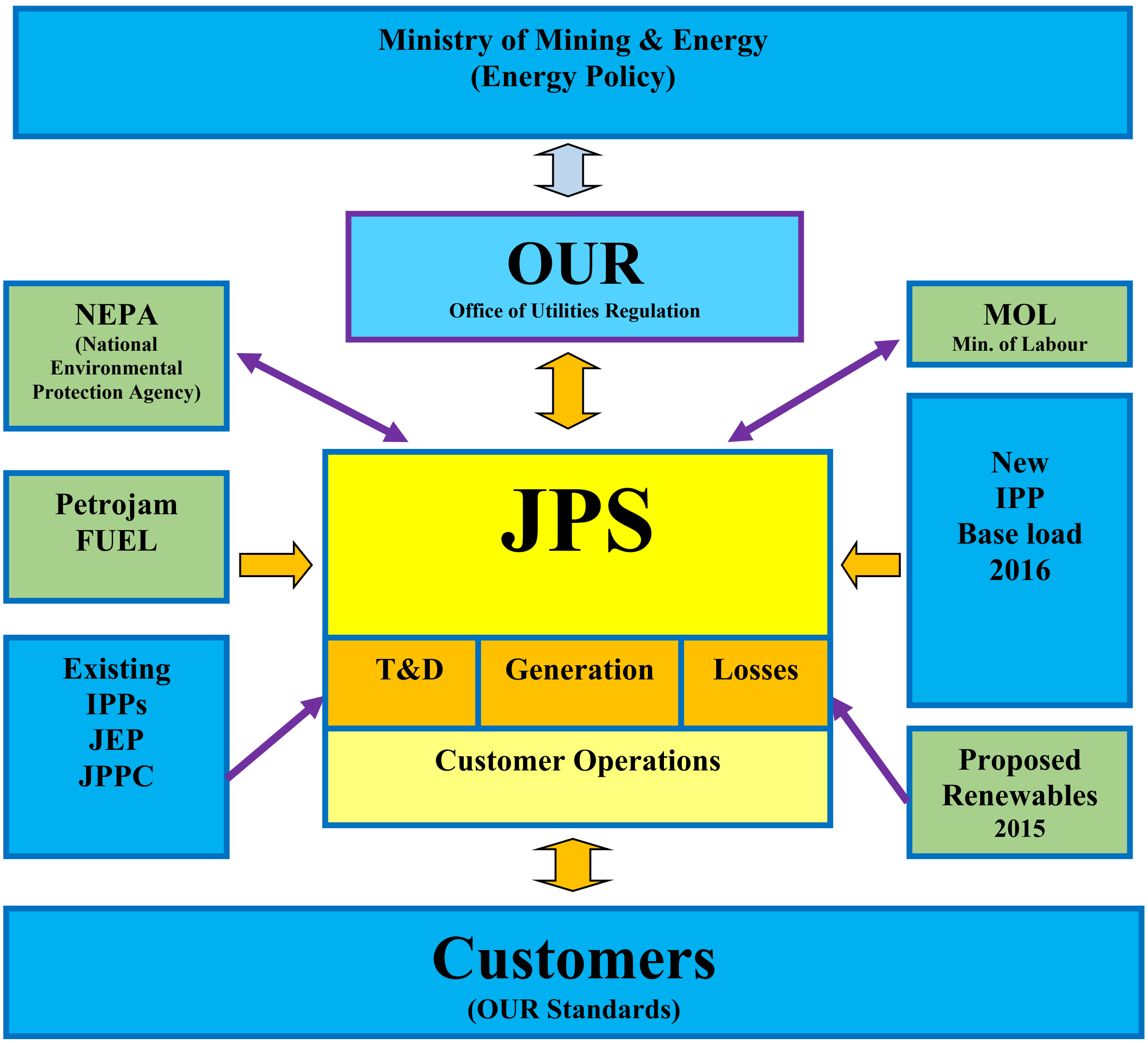
14 SUPPLY SCENARIOS CONSIDERED

The purpose of this section is to identify the electrical supply scenarios in the framework of the JPS power generation and the new generation planned by the OUR, under consideration with different demand growth rate.

14.1 Jamaica Electricity Framework

JPS is a privately owned generation utility company with the sole distribution licence to sell electricity to customers in Jamaica. The OUR since 2010 is responsible for the generation planning for the supply of electricity to the sector and the choice of fuel.

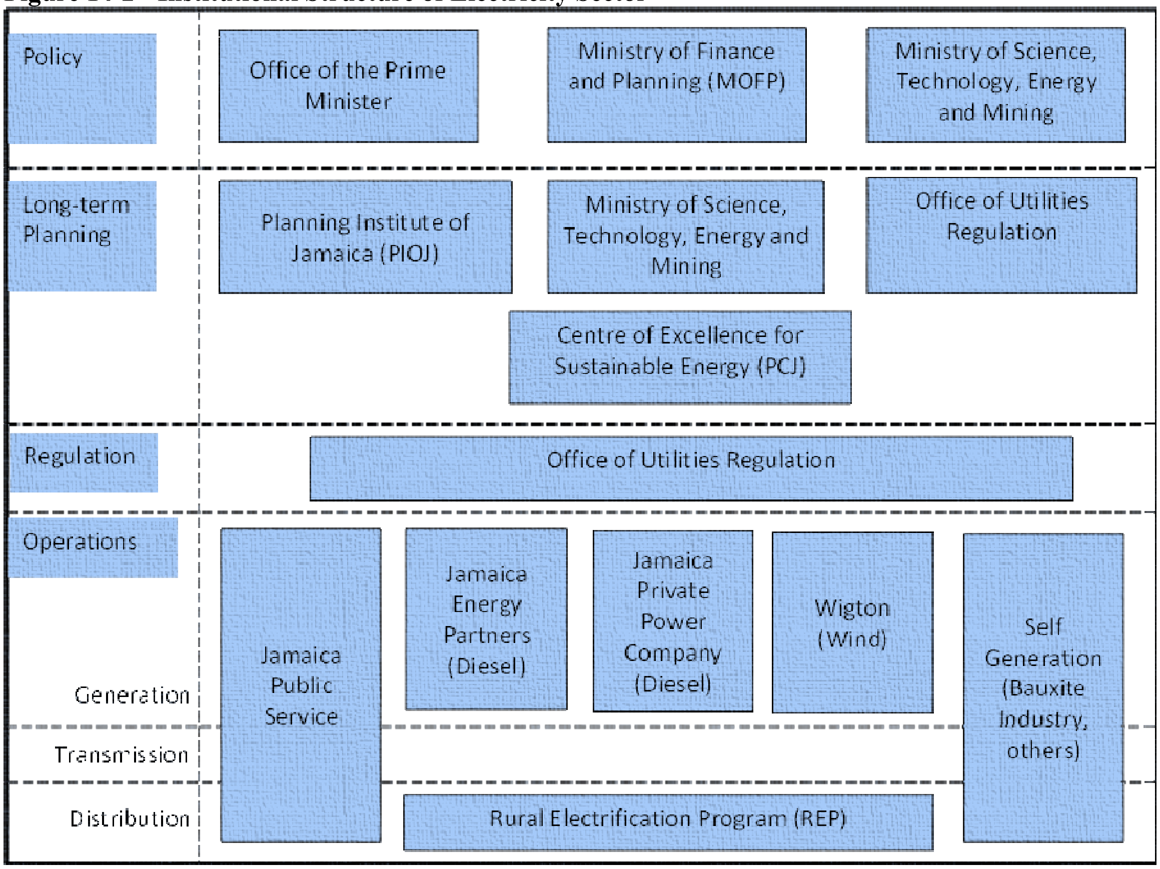
Figure 14-1 - Jamaica Electricity Framework



The Office of Utilities Regulation (OUR) was established by an Act of Parliament in 1995 to regulate the operations of utility companies. Operations began in January 1997. The OUR regulates the electricity sector in Jamaica which includes Jamaica Public Service Company Limited (JPS) and other Independent Power Producers (IPPs).

JPS is regulated by the OUR through the Amended and Restated All-Island Electric Licence, 2011.

Figure 14-2 - Institutional Structure of Electricity Sector

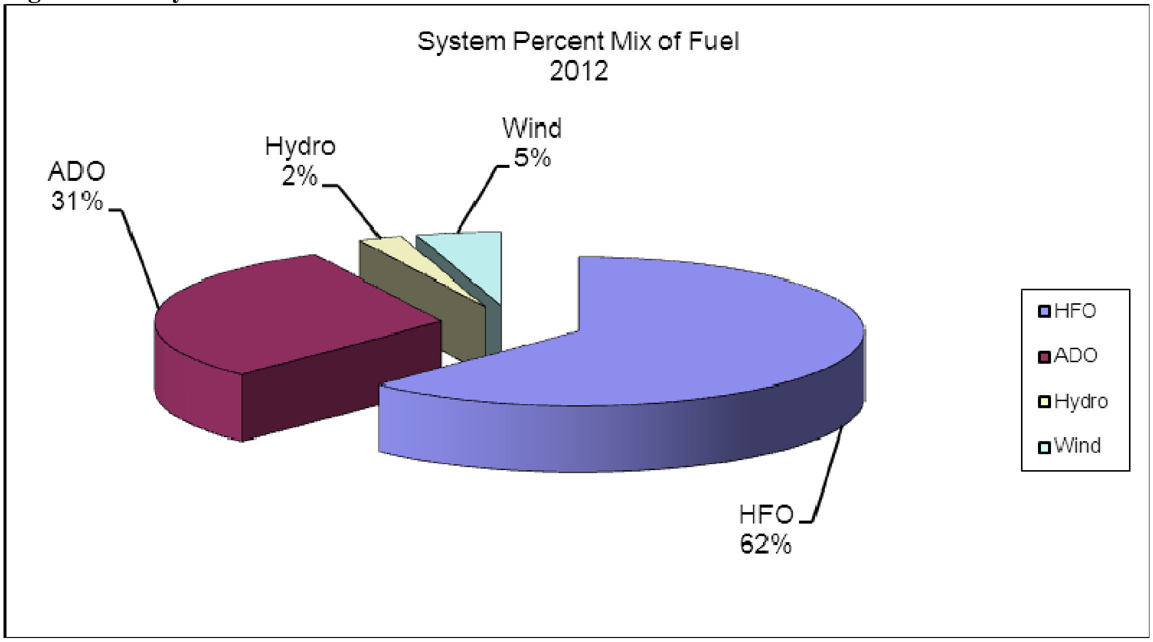


Source: Jamaica Energy Landscape – Strategy Department

14.2 Background

Jamaica power land scape is currently highly dependent on liquid fuel HFO/ADO for approximately 93% of its energy consumption with renewable wind and hydro energy accounting for the remaining 7% (See Figure 14.3 below).

Figure 14-3 - System Fuel Mix



Tables 14.1 and 14.2 shows the share of generating capacity between JPS owned units and units owned by Independent Power Producers (IPP). The table shows that JPS capacity represented 76-71% during the period 2008 -2012 and will be reduced significantly to 23% in 2019 when the proposed 360MW power plant is built and owned by an IPP and 292 MW of JPS generating units are retired. This is against the background of no system growth during 2008 to 2012 and a projected low nominal growth of 1-3% during 2013 to 2019.

Table 14-1 - Generating Capacity (2008-12)

	2008	2009	2010	2011	2012
JPS Total Capacity Start Yr	621	621	623	603	603
JPS Total Capacity End Yr	621	623	603	603	603
IPP Total Capacity	197	197	186	186	251
System Total Capacity	818	820	789	789	854
JPS %	76%	76%	76%	76%	71%
System Peak Demand	627	644	638	625	636
Reserve Margin*****	23%	21%	19%	21%	26%
	2008	2009	2010	2011	2012
Net Generation JPS(MWh)	2,873,508	2,874,076	2,793,852	2,804,441	2,609,273
Net Generation IPP(IPP)	1,257,639	1,333,361	1,343,500	1,332,438	1,541,489
Net Generation (MWh)	4,131,146	4,214,125	4,137,352	4,136,879	4,135,108
JPS % of Net Geneation	70%	68%	68%	68%	63%
System Growth %		2.0%	-1.8%	0.0%	0.0%
System Heat Rate kJ/kWh	10,214	10,178	10,155	9,935	9,764
Production Fuel Cost US	21.00	13.03	13.88	18.35	18.61

Table 14-2 - Generating Capacity (2013-19)

	2013	2014	2015	2016	2017	2018	2019
JPS Total Capacity Start Yr	603	603	609.3	549.3	375.8	307.3	307.3
JPS Total Capacity End Yr	**603**	**609.3**	**549.3**	**375.8**	**307.3**	**307.3**	**307.3**
IPP Total Capacity	250.66	250.66	370.66	610.66	610.66	610.66	730.66
System Total Capacity	853.66	859.96	919.96	986.46	917.96	917.96	1037.96
JPS %	71%	71%	60%	38%	33%	33%	30%
System Peak Demand	626	626	632	638	664	684	697
Reserve Margin*****	**27%**	**27%**	**31%**	**35%**	**28%**	**26%**	**33%**
	2013	2014	2015	2016	2017	2018	2019
Net Generation JPS(MWh)	2,459,106	2,450,070	2,314,301	1,033,736	663,606	774,043	810,116
Net Generation IPP(IPP)	1,662,850	1,615,889	1,714,020	3,035,805	3,554,906	3,554,906	3,601,555
Net Generation (MWh)	4,121,957	4,039,459	4,028,322	4,069,541	4,218,512	4,328,949	4,411,671
JPS % of Net Geneation	60%	61%	57%	25%	16%	18%	18%
System Growth %	-0.3%	-2%	0%	1%	4%	3%	2%
System Heat Rate kJ/kWh	**9,658**	**9,509**	**9,311**	**7,714**	**7,416**	**7,455**	**7,475**
Production Fuel Cost US c/kWh	**19.02**	**19.30**	**18.59**	**11.72**	**10.63**	**10.65**	**10.65**
Fuel Savings US$'000 over 2014			**28,599**	**308,418**	**365,667**	**374,339**	**381,272**
Fuel Cost US$	**778,985,788**	**779,451,990**	**748,703,607**	**476,839,066**	**448,335,258**	**460,972,309**	**470,002,117**

Table 14.1 shows JPS contributing 70-63% of total net generation during the period 2008-2012 and correspondingly significant reduction in net generation to 60-16% during the period 2013-2019 (Table 14.2) with the introduction of the new 360MW power plant and simultaneous retirement of 292MW of JPS units. However, there will be significant reduction in the production fuel cost/kWh, from a high of 21 US cents/kWh in 2008 to a low of 10.64 US cents/kWh in 2016.

The JPS monthly load curve for 2013 (Figure 14.4) below shows the peak period during the months May to September. During these periods all base load equipment has to be running and in the event a unit goes down, the system will require more expensive gas turbines to be utilized.

Figure 14-4 - JPS Monthly Load Curve

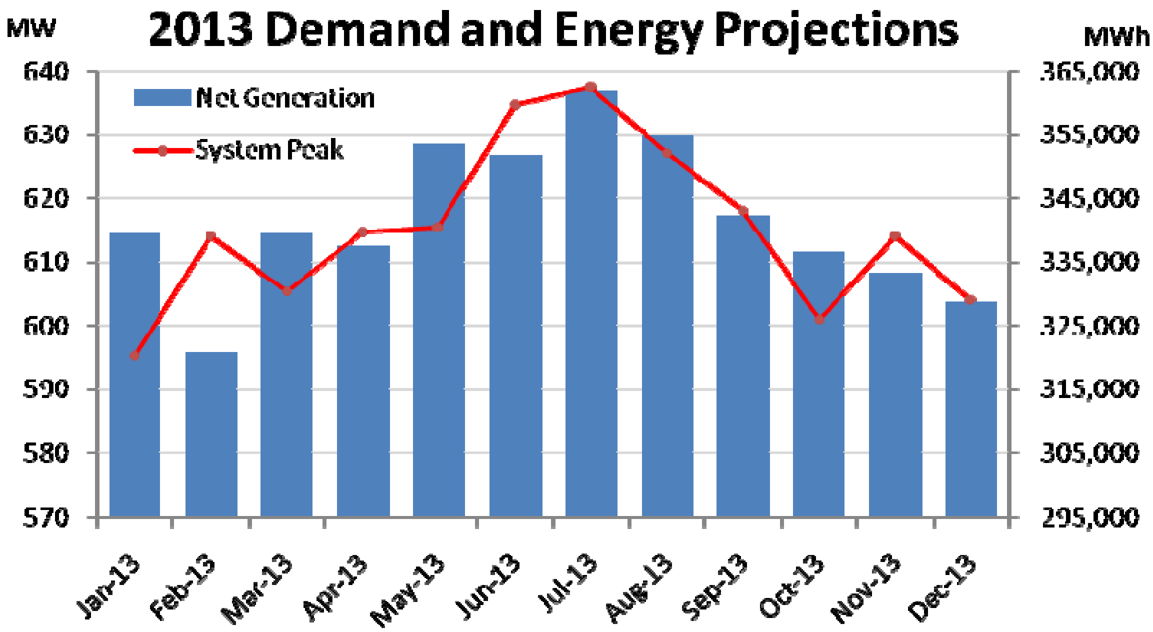
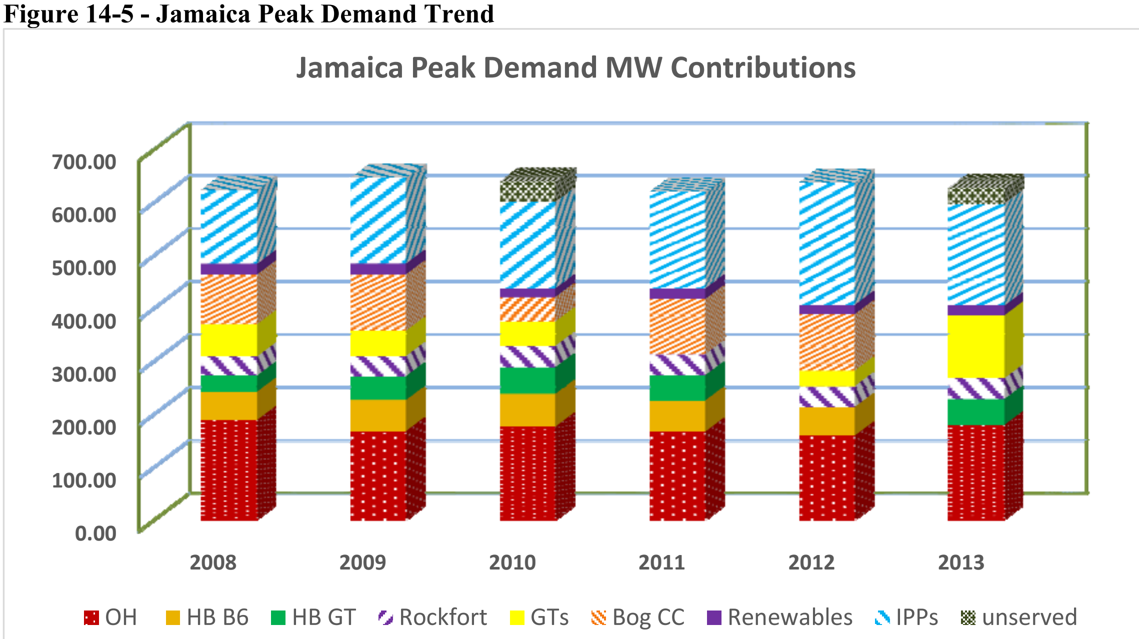


Figure 14.5 illustrates how the load was shared among the various unit types at the time of peak demand. For the year 2013 loading from gas turbines during the time of peak shows an unusually high load due to the fact that Bogue Combine Cycle was operating on simple cycle as a result of a major failure of its steam turbine. The figure also shows the demand of the Old Harbour base load units, however this will be taken by the IPPs when the 360MW is commissioned in 2016 and the Old Harbour units are retired.

Figure 14-5 - Jamaica Peak Demand Trend



14.3 Demand and Supply Forecast

In the latest OUR least cost expansion plan dated Sep 2010, the regulator projected the demand for electricity growing by 4 percent annually. However, based on the current trend, cost of electricity, shift of some larger customers to self-generate and the level of losses, the country has seen no real growth in electricity demand for the last four (4) years.

This trend is expected to continue until a more cost effective base load generation expansion option is installed in Jamaica. This is projected to be installed by 2016 with natural gas fuel diversification.

The current forecast demand projections are as shown in Figure 14.6.

Figure 14-6 - JPS Generation Demand Forecast

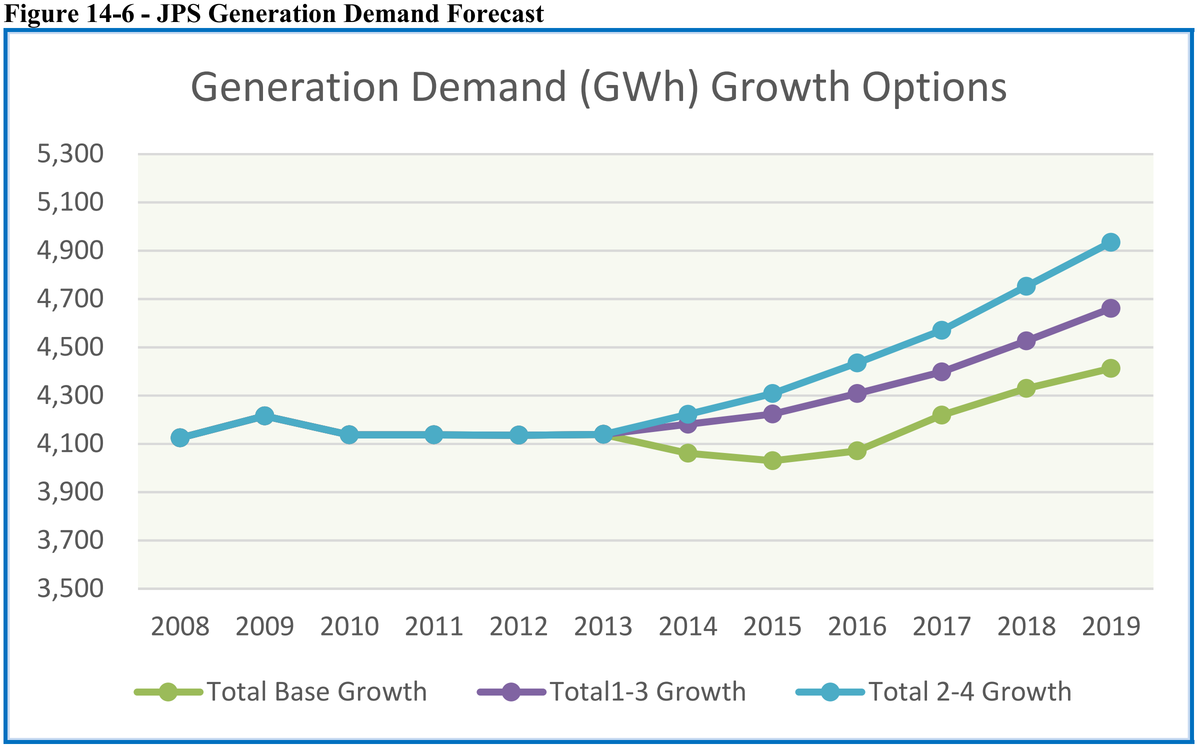


Table 14-3 - Capacity Base Case Projection

Base Case Projection												
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Capacity												
Year Start												
JPS	603	603	603	609.3	609	379	311	311	311	311	311	311
Maggotty				6.3								
Unit #2						-60						
Unit #3						-65						
Unit #4						-65						
Hunts Bay B6							-68.5					
Rockfort						-40						
Gas Turbines												
IPP	186	251	251	251	251	611	611	611	731	731	731	731
New 360MW		65										
Future						360			120			
Total System Capacit	789	854	854	860	860	990	921	921	1041	1041	1041	1041
Peak Demand		636	626	626	632	638	664	684	697	718	725	733
Reserve Margin		26%	27%	27%	27%	36%	28%	26%	33%	31%	30%	30%

Table 14-4 - Generation Present Growth

	Present					
Growth%	**1%**	**2%**	**-2%**	**-0.02%**	**-0.02%**	**0.07%**
Generation (GWh)	2008	2009	2010	2011	2012	2013
OH	1,053	1,059	989	899	841	859
HB B6	400	411	408	395	379	336
Rockfort	241	256	276	289	280	282
GTs	244	253	183	180	165	102
Bog CC	770	749	786	810	778	613
Renewables	207	199	205	243	258	241
IPPs	1,208	1,288	1,290	1,320	1,434	1,705
Total	**4,123**	**4,215**	**4,137**	**4,136**	**4,135**	**4,138**

Tables 14.3 to 14.5 show the a) addition and retirement of generating units/plant b) the energy production over the period 2008-2012 and c) the projected energy production over the period 2013 to 2019; all under the assumption of low growth in energy demand. Table 14.8.1 shows that even with this low growth demand the system will need the addition of a 120MW plant in 2019 to maintain a 25% reserve margin by JPS.

Table 14-5 – Base Case Projections

Base Case Projection						
Growth %	**-2%**	**-1%**	**1%**	**4%**	**3%**	**2%**
Generation (GWh)	2014	2015	2016	2017	2018	2019
OH	824	761	152	-	-	-
HB B6	346	339	103	-	-	-
Rockfort	280	280	232	-	-	-
GTs	87	63	-	-	-	-
Bog CC	717	682	353	470	580	617
Renewables	290	321	479	477	477	477
IPPs	1,516	1,582	2,751	3,271	3,271	3,318
Total Base Growth	**4,060**	**4,028**	**4,070**	**4,218**	**4,328**	**4,412**

Table 14-6 - Growth 1-3%

Growth 1-3 %												
		2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Capacity												
Year Start												
JPS	603	603	603	539	539	309	219	219	219	219	219	219
Maggotty				6.3								
Unit #2						-60						
Unit #3						-65						
Unit #4						-65						
Hunts Bay B6							-68.5					
Rockfort						-40						
Gas Turbines				-70			-21.5					
IPP	186	251	251	251	251	611	611	731	731	731	851	851
New 360MW		65										
Future						360		120			120	
Total System Capacit	789	854	854	790	790	920	830	950	950	950	1070	1070
Peak Demand		636	626	632	638	651	664	684	704	726	747	770
Reserve Margin		26%	27%	20%	19%	29%	20%	28%	26%	24%	30%	28%

Table 14-7 - Generation Growth 1-3%

Growth 1-3 %	**1%**	**1%**	**2%**	**2%**	**3%**	**3%**
Generation (GWh)	2014	2015	2016	2017	2018	2019
OH	824	808	181	-	-	-
HB B6	346	365	206	-	-	-
Rockfort	280	280	232	-	-	-
GTs	92	63	-	-	-	-
Bog CC	833	803	430	504	591	617
Renewables	290	321	479	479	477	477
IPPs	1,516	1,583	2,780	3,414	3,458	3,567
Total	**4,181**	**4,223**	**4,308**	**4,397**	**4,526**	**4,661**

Tables 14.6 to 14.7 shows the a) addition and retirement of generating units/plant b) the projected energy production over the period 2013 to 2019; all under the assumption of 1-3% growth in energy demand. Table 14.3 shows that even with this 1-3% growth demand the system will need the addition of a 120MW plant in 2018 and 2021 to maintain a 25% reserve margin by JPS.

Table 14-8 - Capacity Growth 2-4%

Growth 2-4%												
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Capacity												
Year Start												
JPS	603	603	603	539	539	309	288	288	219	219	219	219
Maggotty				6								
Unit #2						-60						
Unit #3						-65						
Unit #4						-65						
Hunts Bay B6									-69			
Rockfort						-40						
Gas Turbines				-70			-22					
IPP	186	251	251	251	251	611	611	731	731	851	851	851
New 360MW		65										
Future						360		120		120		
Total System Capacit	789	854	854	790	790	920	898	1018	950	1070	1070	1070
Peak Demand		636	626	638	651	670	691	718	747	777	808	840
Reserve Margin		26%	27%	19%	18%	27%	23%	29%	21%	27%	25%	21%

Table 14-9 - Generation Growth 2-4%

Growth 2-4%	**2%**	**2%**	**3%**	**3%**	**4%**	**4%**
Generation (GWh)	2014	2015	2016	2017	2018	2019
OH	866	893	167	-	-	-
HB B6	346	363	197	-	-	-
Rockfort	280	280	232	-	-	-
GTs	92	63	-	-	-	-
Bog CC	832	803	486	528	591	617
Renewables	290	321	477	477	477	477
IPPs	1,516	1,583	2,875	3,564	3,684	3,840
Total	**4,222**	**4,306**	**4,434**	**4,569**	**4,752**	**4,934**

Tables 14.8 and 14.9 show the a) addition and retirement of generating units/plant b) the projected energy production over the period 2013 to 2019; all under the assumption of 2-4% growth in energy demand. Table 14.3 shows that even with this 1-3% growth demand the system will need the addition of a 120 MW plant in 2018 and 2020 to maintain a 25% reserve margin by JPS.

The only challenge and risk is to synchronize the time of new generation with the pre-requirements for planning of old plants retirement; as the OUR plan originally had retirement of the Old Harbour plant in 2014 to synchronize with the proposed 360 MW Natural Gas plant. This has now been delayed to June 2016.

The declining rate of demand however will not significantly affect the retiring of Old Harbour Power Plant as the proposed new generation addition is a clear replacement of capacity with new technology and more efficient units on cheaper and more environmentally friendly fuel. (Natural Gas).

Consequently two options were considered: the new generation expansion set for completion in June 2016 and the new generation expansion being delayed to June 2017 as outlined below.

Option 1- IPP New Generation 360 MW in June 2016
In this option JPS must commence decommissioning planning exercise in Jan 2015. The decommissioning exercises would then be staged from June 2016 to Dec 2017.

Option 2 – IPP New Generation 360 MW delayed to June 2017
In this option JPS must commence decommissioning planning exercise in Jan 2016. The decommissioning exercised would then be staged from June 2017 to Dec 2018. This will mean a further one year of operations of the very inefficient and old units.

15 COST ANALYSIS FOR OPERATIONS

Section 14 reviewed demand and supply for the Jamaica electricity sector and this section will focus on JPS generation related cost.

This section will analyze the cost of operating the Old Harbour power plant until its closure in June 2016, as well as the cost of decommissioning and dismantling. In addition, it will consider other power costs which are directly attributable to the Old Harbour Power Plant closure.

15.1 Cost Input Data

The main generation and consumption data used were taken from Table 15.1 in this study and agreed with the key stakeholders.

Based on the plant past performance and operating conditions, the following cost data have been applied for cost calculations:

15.1.1 Operating & Maintenance cost:

The average O&M over the last five years (2008 - 2012) was approximately US$0.00232/ kWh and Fixed O&M (payroll related) was approximately US$23.88/kW-yr. (Table 15.1). Capital expenditure was as shown in Table 15.2.

Table 15-1 - OH OPEX

	2008	2009	2010	2011	2012	Average
	OPEX (US$/kWh					
OLD HARBOUR						
UNIT 1	$0.00398					
UNIT 2	$0.00474	$0.00293	$0.00293	$0.00368	$0.00194	$0.0032
UNIT 3	$0.00235	$0.00137	$0.00137	$0.00124	$0.00247	$0.0018
UNIT 4	$0.00295	$0.00082	$0.00082	$0.00132	$0.00259	$0.0017
Old Harbour General Plant	$0.00205	$0.00198	$0.00232	$0.00238	$0.00275	$0.0023
	Fixed O&M (Payroll) US$/kW-yr.					
Old Harbour	$ 24.95	$ 21.87	$ 24.74	$ 24.87	$ 22.99	$ 23.88

Table 15-2 - General Plant CAPEX

	2008	2009	2010	2011	2012
	CAPEX US$				
OH General Plant	892,416	303,069	233,381	1,068	622,341
OH1	6,795				
OH2	1,984,853			334,177	
OH3				689,269	434,541
OH4				876,339	6,016,953

15.1.2 Fuel Cost:

The Old Harbour units operated with fuel cost per kWh as shown in Table 15.3 with average HFO prices of US$88/bbl.

Table 15-3 - OH Fuel Cost

	2008	2009	2010	2011	2012	Average
	Fuel Cost US$/kWh					
OLD HARBOUR						
UNIT 1	$ 0.212					
UNIT 2	$ 0.177	$ 0.132	$ 0.174	$ 0.219	$ 0.246	$ 0.190
UNIT 3	$ 0.157	$ 0.121	$ 0.162	$ 0.217	$ 0.224	$ 0.176
UNIT 4	$ 0.154	$ 0.121	$ 0.155	$ 0.229	$ 0.214	$ 0.174
Avg Fuel Cost US$ /bbl	**$ 80.799**	**$ 63.239**	**$ 79.180**	**$ 106.167**	**$ 110.809**	**$ 88.039**

15.1.3 Operating and Maintenance Staff

The station operates with a staff complement of approximately 84 permanent management, operation and maintenance personnel and is not expected to change for the period up to

2016 when the plant is retired. This staff is supplemented by temporary employees during periods of plant shutdown maintenance and major overhauls.

15.2 Projected Annual Cost Breakdown

The following Table 15.4 shows the breakdown and timely dispersion of the cost related to Old Harbor power station operation, decommissioning, dismantling, staff training and management as well as other power imports attributable to the closure for the period 2013 to 2019.

Table 15-4 - Annual Cost - Projected

		Projected							2013-19
No.	**Description**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**TOTAL**
		US$	US$	US$	US$	US$	US$	US$	US$
1	**Fuel**								
	Fuel Cost Unit 1	-	-	-	-	-	-	-	-
	Fuel Cost Unit 2	43,488,645	63,203,986	46,425,862	-	-	-	-	153,118,493
	Fuel Cost Unit 3	73,271,521	65,722,130	66,378,866	22,099,379	-	-	-	227,471,896
	Fuel Cost Unit 4	74,271,521	74,075,967	74,816,181	34,488,549	-	-	-	257,652,218
	OH Fuel Addititives	423,050	793,862	452,551	423,050	-	-	-	2,092,513
	OH Start up oil	40,233	40,233	40,233	20,233	-	-	-	140,932
	Sub-total	191,494,970	203,836,178	188,113,692	57,031,211	-	-	-	640,476,052
2	**Maintenance**								
	OH Gen Plant	2,180,000	2,645,000	2,292,933	7,142,501	114,755	-	-	14,375,189
	OH Gen Plant Capex	-	1,000,000	1,000,000	-	-	-	-	2,000,000
	O&M Unit 1	-	-	-	-	-	-	-	-
	CAPEX Unit 1	-	-	-	-	-	-	-	-
	O&M Unit 2	550,000	750,000	750,000	300,000	-	-	-	2,350,000
	CAPEX Unit 2	350,000	-	-	-	-	-	-	350,000
	O&M Unit 3	1,050,000	1,350,000	800,000	550,000	100,000	-	-	3,850,000
	CAPEX Unit 3	1,000,000	3,000,000	500,000	-	-	-	-	4,500,000
	O&M Unit 4	550,000	750,000	800,000	650,000	379,223	200,000	100,000	3,429,223
	CAPEX Unit 4	-	-		-	-	-	-	-
3	**Staff**								
	Personnel Staff	5,300,000	5,300,000	5,300,000	3,180,000	530,000			19,610,000
	Staff Training		500,000	500,000					1,000,000
	Staff Management								-
	Redundancy	-	-	-					-
4	**Decom/ Dismantling**								
	Dismantling				3,000,000	4,200,000	300,000		7,500,000
	Decontamination				1,100,000	1,300,000	200,000		2,600,000
	Less Sale of Materials				(200,000)	(500,000)	(400,000)	(100,000)	(1,200,000)
	Total Cost	202,474,970	219,131,178	200,056,625	72,753,712	6,123,978	300,000	-	700,840,464

16 CONCLUSION & RECOMMENDATION

16.1 Existing Situation

Old Harbour Power Plant has four units which were constructed during the late 1960s and 1970s. Currently, Unit #1 was shut down in 2010 and Units 2, 3 and 4 are all in operation with Unit 4 just underdoing a major maintenance in 2012.

Old Harbour Power Plant on average provides approximately 968 GWh net power annually into the JPS transmission grid, still accounting for the largest base load power plant in the island and approximately 55% of the total power demand. The remaining power supply comes from Bogue Power Plant, Hunts Bay Power Plant, the Independent Private Power Producers and 5% renewables.

For many years Old Harbour Power Plant has operated with heat rate conversion of approximately 14,000 kJ/kW with the required system heat rate of 9,200kJ/KW. However because the island does not have any coal fuel or natural gas, the current HFO is the best cost fuel existing and the price of electricity has seen many volatility with the rapid changes in heavy fuel oil prices as traded.

Considering the technical and economic status of the units and the related repairs that have been performed, Units 3 and 4 recently had maintenance activities in 2012 and could operate for a very limited period requiring limited maintenance. Unit 2 however has only seen limited capital maintenance in 2011 and may require further repair in 2014 to extend the life beyond 2015/16.

The units at Old Harbour Power station have mainly exceeded their lifetime and large investment/rehabilitation would be needed to bring them close to the required performance standards. Consequently, new more efficient generation is planned to replace these older less efficient units.

16.2 Planned Decommissioning

The release from the OUR to award the next generation expansion to a new IPP for commissioning in June 2016 will create the environmental framework and commercial basis for more efficient power generation throughout the country and to significantly reduce the fuel import bill and the cost of electricity to customers.

The planned decommissioning of all four units at Old Harbour Power Plant should occur within the next 5 years.

The decommissioning and dismantling of Unit 1 and 2 is envisaged in year 2016 as soon as the new generation is online. Unit 3 in late 2016 and Unit 4 in 2017. It will also be important to renew the Water Resources Authority well licences by December 2015 to allow for planned decommissioning activities.

The total cost for the technical decommissioning and decontamination of the Old Harbour Power plant site was estimated to be US$7.651M. In addition, based on capital expenditures to keep the life of the assets running, it is important to include for a known and measurable adjustment to the depreciation rates contemplated in the tariff submission that will allow the Company to recover the carrying values of these assets over their remaining useful lives.

The cost/benefit analysis considered maintaining the status quo, that is the continued operation of Old Harbour at current OPEX and environmental conditions or to decommission Old Harbour and replace with newer technology and natural gas fuel. The closure of Old Harbour is the proposed action.

In technical terms, the decommissioning process of all four units of the Old Harbour Power Station will require a complex procedure regarding activity coordination and timing, and therefore may require up to five (5) years depending on its further commercial use. It is recommended that the initial works for the planning and preparation of a decommissioning permit application is to be commenced no later than Mid-2014 in order to have a well-coordinated decommissioning process after the shutdown of Units 1 and 2 in 2016 and to achieve final site clearance by 2019 at the latest.

Old Harbour Power plant currently directly employs 84? Persons and much more indirectly making it a significant employer in the Old Harbour area. The station is also considered overstaffed based on newer plant experience using advanced technology. The proposed gradual closure of Old Harbour Power Station will have a significant impact on the workforce and local community. While some of the staff (approximately 20%) will reach retirement age between now and decommissioning, the 5 years of dismantling activities offer various work opportunities for some employees (estimated 200). Additional job opportunities may also be offered by the new IPP power plant being commissioned in 2016.

16.3 Comments on Potential Future Outlook

The Units at Old Harbour Power Plant have exceeded their life span and cannot be economically brought into efficient operation and full compliance with current environmental standards. The best economic solution is the systematic decommissioning of the units synchronized with the timely implementation of the new 360 MW power plant. The decommissioning period will overlap after the new 360 MW commissioning to allow a 6 and 12 month window for the last two units to act as spinning reserve on the system.

It is therefore of utmost importance that the new 360MW generation plant be implemented with due diligence to ensure its timely construction. The OUR in October 2013 awarded a bid for the 360MW plant and the scheduled date for implementation is June 2016.

The planning process for the decommissioning of the Old Harbour Plant will start in Jan 2015 and the first two units will be decommissioned in June 2016. The next two Units will be decommissioned over 12 months. The dismantling process will continue through to June 2019.

With the 360 MW natural gas plant planned for 2016 it is also important that the Old Harbour Power Plant decommissioning exercise is scheduled in a timely manner to ensure a smooth transition and mitigation of any negative risk impacts.

APPENDIX A

Waste Material Classification for Sorting

Recyclable Material	Non-Hazardous Material	Hazardous Material
❑ Office paper	❑ Non-salvageable Material	❑ Fluorescent bulbs
❑ Newspapers	o Garbage/Refuse (i.e. putrid material – e.g. kitchen waste, food)	❑ Petroleum contaminated soil
❑ Cardboard	o Grass clippings	❑ PCB contaminated material
❑ Magazines	o Construction debris	❑ Unused, discarded or shelf-life expired chemical products
❑ Telephone directories	o Used Materials	❑ Batteries (e.g. Nickle Cadnium; Lead acid)
❑ PET Plastic bottles	o Insulators	❑ Bulbs - ballast
❑ Glass bottles		❑ Computers
❑ Mobile phones	❑ Salvageable Material	❑ Asbestos Containing Materials (ACM)
❑ Computers	o Transformers - Non PCB	❑ Meters
❑ Printers	o Conductors	❑ Polymer
❑ Ink cartridges	o Photo cells – warranty issue	❑ Mercuroidal switches (and any mercury containing equipment)
	o Drums	
	o Wood	
	o Poles (concrete & wood)	

(Taken from JPS Waste Management Policy and Plan)

APPENDIX B

Natural Resources Conservation Authority
Guidelines for the preparation of a Closure Plan for Industrial Type Projects

Introduction

These guidelines have been prepared in order to assist the Permittee/ owners/ operators in developing Closure Plans for his facility. This guideline describes a Closure Plan as *the procedures for decommissioning of a facility and the removal of all the possible contaminants to air soil and water; equipment decontamination; sampling and laboratory analysis and closure to the satisfaction of the relevant standards and regulations stipulated by the National Environment and Planning Agency*.

A. General

• The activities to be undertaken in the Plan should be clearly listed, with target dates for completion.
• Waste produced due to closure activities must be both classified and quantified and the method of treatment and/or disposal stated.
• The Plan should include soil (and groundwater, if accessible) testing for the presence of contamination. The test methods used for analysis of the soil and groundwater samples should be indicated.

B. Background Information

This should include:

1. The nature of the probable/ possible contamination including list of chemicals used on site
2. Any published or otherwise known information in order to establish whether adjacent property owners are or have been potential sources of contamination
3. Present zoning of the site and details of the zone categories of properties surrounding the site
4. Contour or topographic maps
5. Likely future use of the site
6. Risk Assessment
7. The results of any previous investigations of the site or surrounding land
8. Locations of surface water bodies, particularly where these may be adversely affected by contaminated groundwater or surface drainage from the site
9. Hydrogeological information, which should include:
    - o The extent and use of aquifers in the area
    - o Estimated depth to groundwater
    - o Probable direction of groundwater flow and gradient
    - o Soils and soil properties (soil type, porosity and hydraulic conductivity)
    - o Location of any springs
    - o Sources of local municipal water supply and the location of registered private or industrial wells or bores
10. Solid waste disposal
11. Security of facility/area scheduled for closure. This should include the postage of relevant signs.

Note: The Authority may require remediation for sites found with significant levels of contamination. In such cases a Remediation Plan shall be submitted for review and approval.
Post Closure Monitoring must be conducted for an agreed period for any contamination that may be present on site. The parameters to be monitored, the frequency of monitoring, the test methods used for the analyses and the end points to be achieved must be clearly stated.

APPENDIX C – SCOPE OF WORK FOR DECOMMISSIONING

OLD HARBOUR POWER STATION & B6
DECOMMISSIONING
SCOPE OF WORKS

Background
Jamaica Public Service Company Limited (JPS) Old Harbour Power Station complex is located in Jamaica, St Catherine along the industrial strip of the Old Harbour Bay Area. The Old Harbour Power Station is the largest power plant in the company's generating system with a total generating capacity of 223.5 MW at maximum continuous rating (MCR).

The plant, located in Old Harbour Bay in the parish of St. Catherine consists of four (4) oil-fired No. 6 (HFO) fuel boiler, steam generating units, designated as Unit No.1, Unit No.2, Unit No.3 and Unit No.4. The plant fenced area is approximately 48 acres.

Old Harbour Power Plant Facilities

Unit No.1
Unit 1 was commissioned to service in 1967 with a nameplate rating of 33MW, but was available to the system with a MCR of 30 MW. Except for the excitation system, the unit was operating with all its originally installed equipment. The unit is now out of service since 2012.

Unit No.2
Unit 2 was commissioned to service in 1968 with a nameplate rating of 60MW and is presently available to the system at MCR of 60MW. Except for a new turbine casing, the unit is operating with all its originally installed equipment.

Unit No.3
Unit 3 was commissioned to service in 1970 with a nameplate rating of 68.5MW. This unit was the first of its kind to be manufactured by the supplier (General Electric). Based on operational and maintenance experience during the early operation of the unit, the capacity was derated to 55MW in the late 1970s. However, following further evaluation of the unit performance, the decision was taken in March 1996 to upgrade the capacity to 65MW MCR at which it is presently operating.

The alternator excitation system was upgraded in 1994 to the latest EX2000 static excitation supplied by General Electric.

Unit No.4
Unit 4 was commissioned to service in 1973 with a nameplate rating of 68.5 MW. This unit was similar in design to Unit No.3, however, based on the company's experience, the furnace area of the boiler was extended by an additional 13 feet which allowed it to operate at MCR of 68.5MW.

On June 4, 1994 the boiler and other associated equipment were completely destroyed as a result of a massive explosion. The boiler and associated equipment (pumps, compressors, heating set, switch gear, etc) were completely replaced by the original manufacturer, Foster Wheeler. The opportunity was also taken to carry out life extension work on the turbine. These include:

a) Replacement of original turbine governor system with a new state-of-the-art Mark V electronic governor system.
b) Taprogge condenser cleaning system
c) Turbine water induction protection system
d) EX2000 static excitation system.

Following the explosion, the unit was returned to service in January 1996.

Units Specifications

All the units are equipped with Power Plant Monitoring and Control System (PPMCS). This is a microprocessor system which allows the controllers to have on-line monitoring and control of all the major operating systems of the steam units.

The following fuels are utilized at the Old Harbour Power Station:

- No. 6 Fuel oil
- No. 2 / Lubricating oil mixture
- No. 2 / No. 6 Fuel oil mixture
- Transformer oil
- Waste Oil

Other Plant

The site other plant include the following:

- A water treatment plant – demineralization system
- Fuel oil tanks
- Four intake structures
- The flume outfall canal.
- The substation 69kV and 138kV
- Main structures:
    - Five reinforced concrete buildings –
        a. Administrative Building
        b. Inventory Warehouse
        c. Canteen
        d. Laboratory
    - Unit 1 & 2 Generating Plant
    - Unit 3 and Unit 4 Generating Plant
    - Four operating stacks
    - Fuel Oil Storage Tanks with concrete bunds
    - Chemical Storage Tanks with concrete bunds
    - Water Storage Tanks
    - Attendant Pipelines – System water & Fire water pipes

- Laboratory
- Substation
    - Control Room
    - Transformers
    - Oil Circuit Breakers
    - Reclosures
    - Insulators
- Fuel Oil Storage Tanks with concrete bunds
- Fuel Pump Room
- Attendant Pipelines – Fuel Oil Pipes
- Fire System
- Fuel oil containers and dump storage area for soil remediation
- Drainage areas
- Roadways, concrete paved areas and out of service equipment.

Hunts Bay Power Plant – Unit B6

Hunts Bay Power Station complex is located in Jamaica, Kingston along the industrial strip of the Kingston waterfront. The Hunts Bay Power Station is divided into two complexes; the main complex (south side) borders the Petrojam Oil Refinery on Marcus Garvey Drive and is accessible by sea and road transport.

This main complex consists of two units: oil fired (No. 6 HFO fuel) steam generating unit B6 (68.5 MW), and an aero derivative industrial type gas turbine unit – GT 10 (32.5 MW). The secondary complex (north side) is located along Marcus Garvey Drive opposite the main complex and consists of a substation switch yard and an aero derivative industrial type gas turbine unit – GT 5 (21.5 MW). Both gas turbines (GT 5 & 10) are fired on No. 2 (ADO) fuel oil.

Scope:

The scope of work will include:

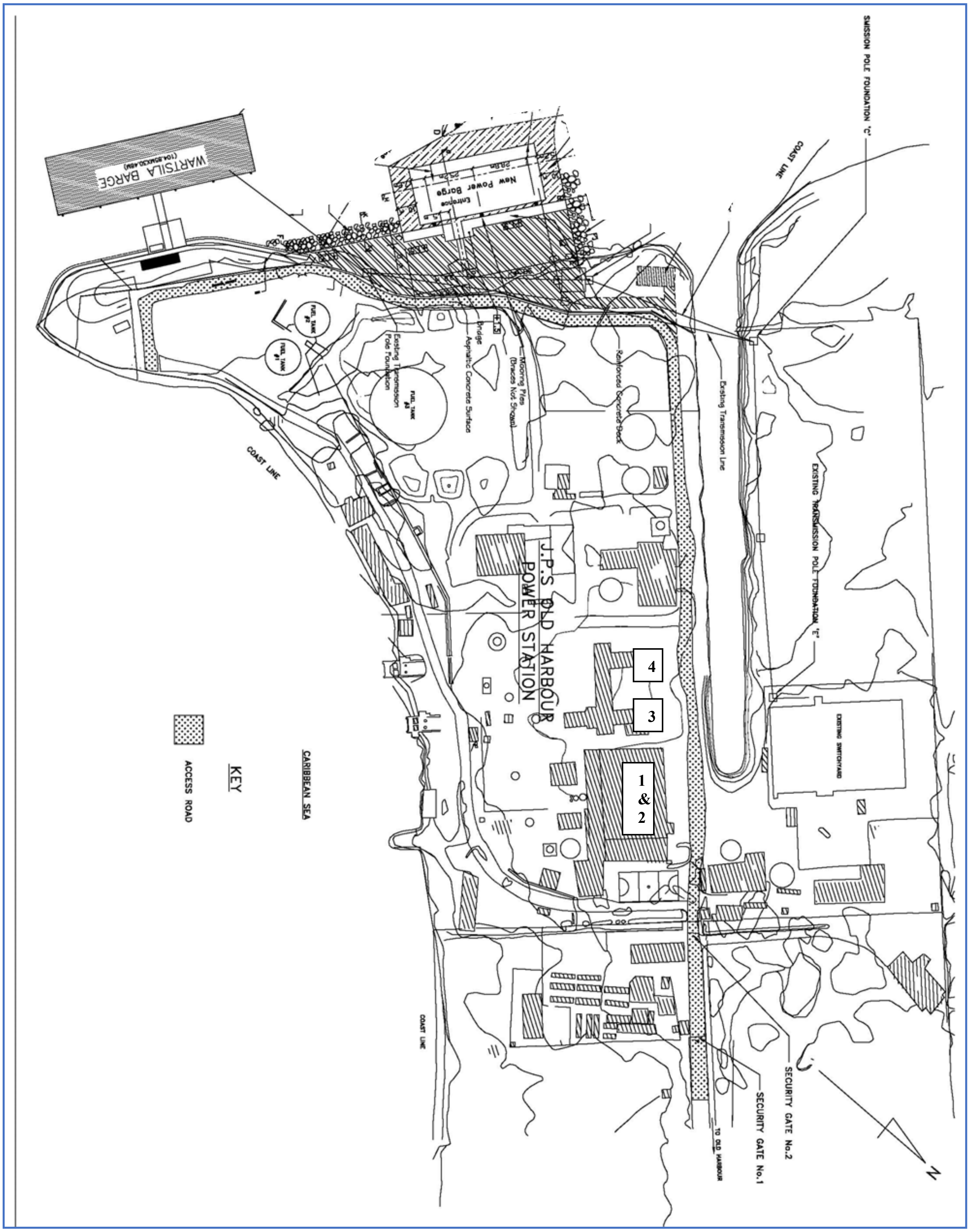
- The closure of Unit operations will be done by JPS Operations
  - Closure of Unit 1 – Dec 2012
  - Closure of Unit 2 – June 2016
  - Closure of Unit 3 – Mar 2017
  - Closure of Unit 4 – Sep 2017
  - Closure of Hunts Bay B6 – Dec 2017

- Old Harbour Power Station:
  - The removal of all metal for re-sale or scrap metal
  - The demolition of all structures.
  - The removal of all demolition materials and disposal to approved dump
  - The soil testing and remediation to remove any soil contamination
  - Restoration of field to green field

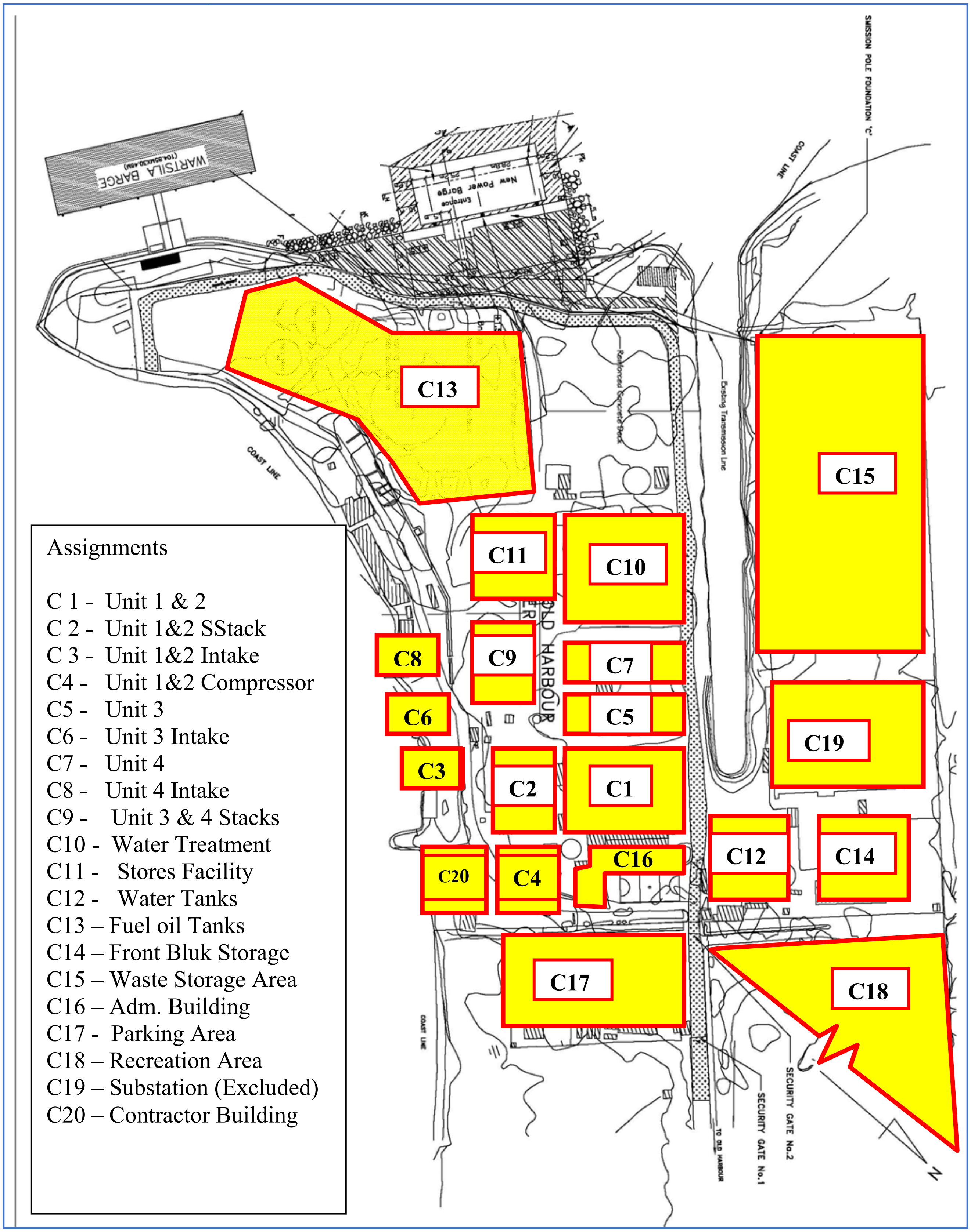
- Hunts Bay Power Station:
  - Removal of the B6 Unit for re-sale of Scrap
  - The demolition of the B6 Unit Structure
  - Removal of all the B6 Unit material to approved dump
  - Restoration of the B6 area
  - The rest of the power plant site will remain in operation

The details material listing is also provided at Appendix F

APPENDIX D1
OLD HARBOUR POWER STATION - SITE LAYOUT TOPO



APPENDIX D 2
OLD HARBOUR POWER STATION – Assignment of Components



APPENDIX E1

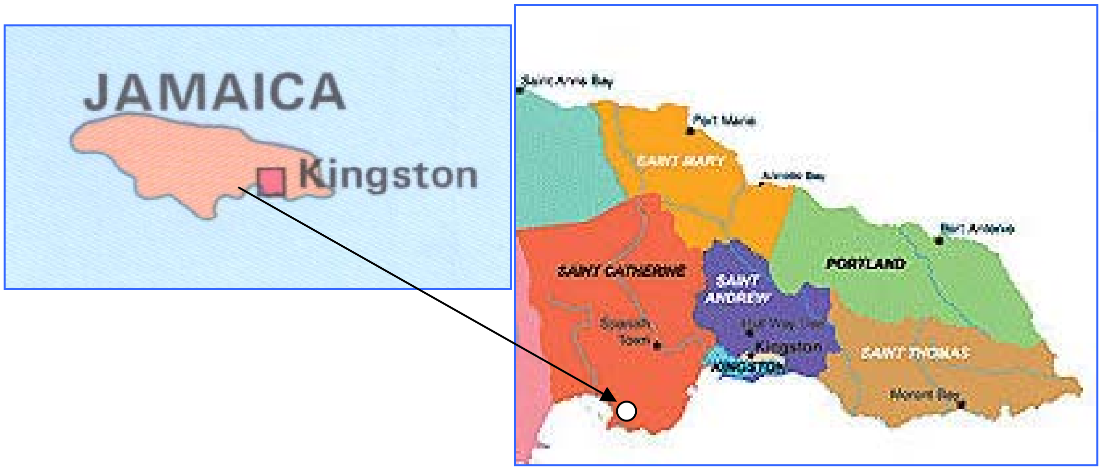
Location of JPS Old Harbour Property St. Catherine -Google

APPENDIX E2

Old Harbour Property (North & South) Google

APPENDIX E3

Old Harbour Property Location Map



The Old Harbour Power plant site is 47 miles from Kingston

Appendix F – Fossil Fuel Retirement Conference Report

	Conference Name: **Fossil Fuel Plant Retirement**

Conference Sponsors: Exelon Generation, Bierlin, Bradenberg, Frontier, GSM, NCM, CBI, TRC, Conestoga-Rovers, Envirocon, National Reclamation Group, (Decommissioning &Demolition Companies and Engineering Consultant and Environment Companies).	**Facilitator:** EUCI
Project Phase: Planning for Decommissioning of Old Harbour Power Plant and Hunts Bay B6 Power Unit.	**Date:** October 14-16, 2013

Time: Monday October 14 - 8:30 AM - 5:45 PM Tuesday October 15 - 8:00 AM - 1:00 PM Wednesday October 16 - 8:30 AM - 11.45 AM	**Conference Report Prepared by:** Clava Mantock	**Location:** Sheraton Inner Harbor Hotel, Baltimore, MD.

Attendance: *Approximately 112 Demolition Companies reps, Environmental Companies reps, Engineering Consultant Companies Reps, Electric Utility Companies reps, Industrial Companies reps.*
JPS Representative: *Clava Mantock*

Conference Objective:
To assist energy provider with best practices for the fossil fuel plant retirement

1	**Topics Covered on Day 1-October 14, 2013**
	➢ Exelon Generation's Approach to Retired Assets. ➢ DTE Energy Fossil Decommissioning Activities and Lessons Learned. ➢ The Decommissioning of Edward Sport Station. ➢ Cost to Shut Down a Plant-Mandatory or Optional. ➢ Decommissioning and Community Engagement. ➢ Generation Fleet Retirements, Decommissioning, and Lessons Learned. ➢ Common Misconceptions Associated with Power Plant Demolition. ➢ Decommissioning Power Plants-Case Histories and Lessons Learned. ➢ Panel Discussion: Repurposing Retired Facilities.
2	**Topics Covered on Day 2-October 15, 2013**
	➢ Exelon's Generation's Long Range Planning: Retired Pennsylvania Case Studies. ➢ Beyond Demolition: Strategic Repositioning of Retired Real Estate ➢ Mohave Generating Station Decommissioning ➢ Tour of Gould Street Generation Station

<table>
<tr><td>3</td><td>Topics Covered on Day 3-October 16, 2013
➢ Demolition and Dismantling Process and Equipment
➢ Bidding, project management and lessons learned on Georgia Power Plant McDonough and American Municipal Power’s RH Gorsch plant.
-Facility Decontamination
-Asbestos Abatement
-Structure Demolition
-Intake and Discharge Closure
-Slab and Foundation Removal
-Stack Demolition
-Backfill, Final Grading and Seeding
➢ Methodologies for evaluating assets to ensure the highest return on the owner’s capital investments
➢ Asset identification, appraisal and marketing</td><td></td></tr>
<tr><td>4</td><td>Take Away from relevant Presentations</td><td></td></tr>
<tr><td></td><td><u>Exelon Generation’s Approach to Retired Assets</u>

▪ Determine Hold Costs
▪ Inspections, façade, Fire Marshall, building, pier, bridge, etc
▪ Building/Site maintenance
▪ FIN 47 ARO
▪ Security
▪ Environmental issues
▪ Taxes/Insurance

Community Issues:
▪ Tax support, Building Moratoriums, zoning, community groups, etc.

▪ Identify Risks
▪ Age of building, stacks, pier, bridges
▪ Security
▪ Environmental

Identify Value of Land and Existing Assets
▪ Land appraisals/Current Zoning/Historical Issues
▪ Work with AO process to determine current value of assets where co-located with retired assets

Review Existing Site Issues
▪ Easements – PECO, N-Star, On-Cor, etc
▪ Utility Relocation/Separation Issues

Identify possible scenarios:
▪ Hold, Demolish & Hold, Demolish & Sell, Sell</td><td></td></tr>
</table>

- **DTE Energy Fossil Decommissioning Activities and Lessons Learned.**

  - Keep Job Site Safety the #1 priority. Proper PPE, Pre Job Briefs, Protective Tagging etc.
  - Normal means of communication may not be 100% applicable, review check-in and check-out specific site safety procedures before visiting demo projects
  - If possible, identify site end use prior to finalizing scope document
  - Bring temporary facilities to Demo site before isolating power block
  - Complete a Phase 1 environmental study to understand the history of the plant site
  - Retain a plant Subject Matter Expert (SME) with plant operating experience. Electrical background is a plus
  - Time is required to identify, tag, cut underground cables from the plant to the electrical mat. Remember control cables, telephone lines
  - Discuss the future of intake and outfall canals

  - Identify both internal (company) and external stakeholders in a communication plan
  - Engage Corporate Legal, Environmental and Community/Gov't Affairs early in project while developing project scope document
  - Identify project risks and mitigation strategies
  - Time is required to transfer permits, solicit project approvals from city, state & federal agencies
  - Review preventative maintenance orders frequency, cancel, retime
  - Empty and clean the Ash and Chem Waste treatment basins preferably before your permits are expired
  - Unused Fuel Oil - send to other company power plants to generate megawatts (Receiving Plant may need special permit)
  - Internal pool charges, corporate overhead allocations - redistribute
  - Engage Corporate in generating/ or updating an existing asset decommissioning / disposition strategy – Think De-construction/Recycle rather than Demolition!

- **<u>The Decommissioning of Edwardsport Station.</u>**

Phase 1- Planning Phase: 2+ Years Before Shutdown

Identify potential project scope.

VERY important to start this ASAP.

- Doesn't have to be 100% accurate.
- Determining POSSIBLE scope will help:
- Identify interface issues.
- Make it possible to start conversations with stakeholders and support groups.
- Identify things that could require extensive engineering/planning/permitting

Identify project interfaces.

- EXTREMELY important to identify these ASAP.
- Can have significant impacts on cost and schedule.
- Types of Interfaces:
- Switchyard equipment in powerhouse.
- Systems shared with active units.
- New assets in the way of demolition.
- Utility disconnects, reroutes, installations.
- Other projects.

Identify project interfaces.

Real Examples of Interface Issues:
- Demolition site used for construction laydown/storage.
- Switchyard relaying equipment in powerhouse.

Water intake system for new plant installed in powerhouse.
Environmental equipment installed around retired stack(s).
natural gas line planned to be installed on retiring structure.
Retiring powerhouse will sever all utilities to remaining facility.
Utilities had to be rerouted to demolish powerhouse.

High level cost and schedule estimating.

- Demolition projects are often much cheaper than expected, due to scrap value.
- Many projects being done for a credit.
- Many projects have been in -$2M to +$2M range.
- Demolition companies have provided more accurate cost estimates than engineering firms.
- Example:
- Engineering Company Estimate: +$18M
- Demolition Company Estimate: +$1.5M
- Project Actual: +$1.2M

Initiate asset recovery process.

Start ~2 years prior to plant shutdown.
- Marketing assets can take a long time.
- Markets typically saturated with equipment due to # of retirements.
- Consider intercompany asset transfer opportunities.
- Exhaust all transfer/sale opportunities BEFORE getting close to the demolition bid process. (6 months out?)
- MUST put a firm, drop dead date on the asset sales window

Begin reducing storeroom material inventories.

- Reduce the value of the inventory write-off that will hit the O&M budget AFTER the plant is retired.
- MUST budget for write-off in the O&M budget.
- Have seen a number of write-offs in the $2-7M range.
- Exhaust all intercompany asset transfer options first.

Begin reducing chemical/oil inventories.

Reduce oil and chemical inventories that will be left AFTER plant retirement.

- Reduces the chances for the site to become a Large Quantity Generator (LQG) during decommissioning.
- Reduce environmental liabilities.

Coal/Oil inventory planning.

Reduce coal/oil inventory that will be left AFTER plant shutdown.

- Consider implementing a decrement to pricing ($/MWh) so units have better chances of being dispatched.
- Value of decrement based on cost to move coal/oil.
- Consider doing forced burns on units.
- Implement during high demand periods.
- Economics for the above are often better than shipping coal offsite.
- Multiple sites have been left with over 100K tons after retirement.

Review environmental permits.

- Identify which ones might still be needed after retirement.
- Examples: NPDES, SPCC, UST, Dredging, E&SC, etc.
- Identify new permits that could be needed for demolition.
- Especially need to identify any work near waterways that could require permitting - long lead times.
- Identify when permit fees are due.
- Some fees could hit O&M after plant is retired.
- Some paid multiple years after cost is incurred.

Start creating staffing plans.

- Create exit plans for existing employees.

- Consider resources that will be needed for decommissioning.
- Budget for severances (if any) in O&M budget.
- Start thinking about staffing for the demolition project.

Phase 2- Decommissioning Phase:

The goal IS NOT to place the plant in a long term lay-up state.
• The goal IS to prepare the site for demolition.
• Shut systems down.
• Make the site safe.
• Remove wastes.

Drain oils, chemicals, water, hydrogen, etc. from systems.
• Make plans and checklists BEFORE shutdown.
• Document, document, document!
• Use labels in the field to identify drained/purged.
• Create waste disposal tracking methods BEFORE wastes start leaving the site.

Vacuum/wash boilers, precipitators, sump pits, etc.
• Vacuum/wash boilers and precipitators IMMEDIATELY after shutdown.
• Existing sluicing systems still available.
• Ash will only get more challenging to remove as it sits.

Coal yard cleanup.
• Establish clear guidelines/criteria for "How Clean is Clean?".
• Negotiate disposal options for comingled soil/coal
• Landfill (might use for cover or roads in landfill)
• Reclaim (send to coal mine to be reclaimed)
• Backfill (send to surface mine for use as backfill)
• Saved ~ $500,000

Tunnel Closures.
• Close intake/discharge tunnels and pipes BEFORE demolition activities begin.
• Reduces chances of a spill to the waterway.
• Helps prevent water infiltration to the basement.

Transfer inventory items/inventory write-offs.
• Develop a list of inventory items that will still be needed.
• Make final attempts at inventory transfers.
• Complete the write-off.

Asset sales.
• Sell large power transformers outside of the demolition scope.
• Often produces greater returns.
• Provides funding for some decommissioning activities.
• $150-300K for my projects.

Asbestos survey.

• Complete survey post retirement so destructive testing can be done.
• Typical asbestos building surveys cannot properly account for materials inside equipment (i.e. boilers, fans, air heaters, etc.)
• PACM
• Aggressive destructive sampling
• Important to use asbestos inspectors that have extensive experience with power generation equipment.
• Historic knowledge and sampling data can be misleading.

Other environmental surveys.

• PCB
• Lead Paint
• Masonry

Execute interface projects.
• Decouple the facilities that will be demolished from assets that are to remain.
• MUST consider future demolition plans when routing utilities and new infrastructure

Document retention.
• MUST consider legal holds.
• Consider retaining hard copy drawings at the site until completion of demolition.
• Consider starting the retention process early to preserve integrity of the records.

Staffing reductions.
• Reduce staffing by:
• Transfers to other sites.
• Retirements (Voluntary Severance Packages).
• Involuntary Severance Packages.
• Need to maintain a group of competent employees from the site to execute the decommissioning activities.
• Challenging to balance productivity with job security.

Install temporary facilities/utilities.
• Important to establish these early so that all decoupling can be completed prior to the start of demolition.
• Plan for contractor needs.
Asbestos Abatement and Demolition Phase:

Bid asbestos abatement/demolition Scope of Work.
• Establish vendor prequalification criteria early.
• Bundle asbestos abatement and demolition into one contract.
• Consider firm fixed price contracts.
• Important to have a well defined/delineated scope.
• Establish T&M rates to handle unexpected finds.

Asbestos Abatement
• Not all asbestos abatement contractors are qualified to complete full powerplant abatement projects.
• Value in having a full time, third party, asbestos oversight contractor onsite.

Demolition
• Conditions constantly change.
• Expect the unexpected.
• Important to have a strong team onsite to oversee contract work.
• 4 Key Roles:
• Project Manager
• Technical
• Environmental
• Health and Safety
• Site Specific Knowledge

Remediation?
• Be prepared to address the unexpected.
• Have environmental guidelines in place before demolition activities begin.

Site Restoration and Project Closeout Phase: Immediately After Completion of Demolition

Site backfill.
• Consider completing all major backfill work with a civil contractor.
• Consider beneficially reusing demolition debris as backfill material.
• Environmental considerations.

Finalize project turnover documents.
• VERY important to complete a comprehensive turnover package for the project.
• Project Narrative(s)
• Pictures
• As-Left Drawings
• Waste Records

Lessons Learned: General
- Not everyone will welcome the idea of demolition.

- Justifications for demolition projects can be very challenging.
- Demolition projects are often treated as an afterthought.
- Make sure that everyone understands the magnitude of the project. The total cost for the project can be deceiving.
- □End of plant operation DOES NOT mean end of O&M budget.
- □Demolition IS NOT construction.
- □All sites come with unique opportunities.
- □Expect the unexpected.

➢ **<u>Cost to Shut Down a Plant-Mandatory or Optional.</u>**

Decommissioning Process Review

- □Define End Use Objectives
- □Determine likely decommissioning scenarios
- □Plan the scenarios adequately enough to develop financial plans for each
- □Conduct a business analysis
- □Realize that the final decision is a result of financial and non-financial drivers

Typical Scenario Descriptions

- Deactivation (“Care and Feeding”)
- Selective decommissioning/demolition to reduce public safety and environmental risks
- Full demolition to slab
- Full demolition and site remediation to Greenfield condition

Cost Categories Within a Scenario

- Each scenario has corresponding costs:
- Decommissioning Project Costs
- Mandatory costs
- Discretionary (optional) costs
- Holding or Carrying Costs
- Typically site security, taxes, insurance, maintenance, utilities, environmental encapsulation, permit compliance, etc.

Cost Type Definition

- Mandatory Costs

- Safety or Security Related
- Environmental or Regulatory Required
- Tasks to meet Company Standards or Policy
- Discretionary Costs
- Above minimum required scope in any area of environmental decommissioning, demolition, or restoration

Financial Analysis

- The financial analysis should be based on a comparison of total DISCRETIONARY COSTS vs. HOLDING COSTS for each scenario
- Mandatory costs should not drive the decision; they will be spent regardless
- ARO Management
- ARO definition
- Ensure that the Company ARO value "on the books" is corrected to the planned retirement/removal date of the asset
- Structure all cost estimate sheets, bid forms, and contractor invoicing documents to capture ARO related activities by line item - as they are listed on the Company books

➢ **Generation Fleet Retirements, Decommissioning, and Lessons Learned.**

Lessons Learned: Looking forward

- Open vessels can attract wildlife
- Plan, Plan, and then Plan more
- If you are trying to maintain the operability of remaining units, it will always be more expensive than you think
- Oil tanks leak
- Site security during demo should be a high priority

➢ **Panel Discussion: Repurposing Retired Facilities.**

Repurposing Generation Facilities

- Identify early in the decommissioning process options
- Decide if asset will be held or sold
- If held, what are the options for repurposing?
- Fuel switch
- New plant

- Other

Key Takeaways

- Repowering market poised to **grow substantially**

- Repowerings present unique challenges but can offer **considerable benefits** over greenfield projects

- Keys to success:
  - Experienced development team
  - Existing facility conditions (as-builts, subsurface)
  - Reuse of existing systems
  - Life-extensions
- **Final Takeaway** Repowerings can provide **significant advantages** to owners relative to a greenfield project

Maximizing Assets, Identifying Hidden Costs and Avoiding Risks in DDD Projects

<u>Define your Goals</u>

- Curtailment – Idle a facility for the short or long term
- Closure – Present or future decontamination/demolition
- Combination of curtailment and closure
- Retain ownership or sell facility and property

<u>Determine where you are in the Deactivation Process</u>

- Decision Making
- Planning and Permitting
- Site Investigation and Bid Solicitation
- Implementation and Oversight

Site Deactivation Process

<u>Decision Making</u>

Assess carrying and building maintenance costs
Verify or estimate scrap metal and asset values in local market
Prepare an engineering estimate of reclamation costs
Evaluate the net present value of the costs and property value

<u>Planning and Permitting</u>

Create a contracting strategy
Gain stakeholder input
Identify and relocate assets
Review regulatory requirements and characterize documents
Review and value permits

<u>Investigating Site and Soliciting Bids</u>

Investigate Facility Hazards and Characterize Wastes
Survey the Facility for Asbestos and Lead
Prepare Project Manual and Bid Documents
Qualify Bidders
Evaluate Submitted Bids
Review Scope with Potential Contractor

Implementation and Oversight

Manage Safety Aspects of the Project
Manage Documents
Manage Budget and Change Order

DDD Process

- Pre-Bid Engineering
- Bidder Qualification
- Bid Review and Selection
- Kickoff Meeting and Planning
- Mobilization
- Decommissioning/Decontamination
- Demolition
- Project Closeout

Decommissioning Missteps

- Not fully Characterizing Environmental Concerns
- Allowing Assets to become Liabilities
- Loose Scope of Work and Specifications
- Not following Established Processes and Procedures
- Not Establishing Minimal Contractor Screening Standards
- Not having Procedures in Place to Recognize Emerging Issues

.

Common Risks and Liabilities

Environmental Risks

- Transformer Oils
- Miscellaneous Hazardous Wastes
- Open Process Vessels and Sumps
- Tank and Piping Infrastructure
- Pumps
- Equipment Deterioration

Physical Risks

- Vandalism
- Theft
- Weather
- Facility and Equipment Deterioration

Recognizing Assets

- Raw Materials
- Inventory
- Equipment
- Residual Values
    - Scrap
    - Recyclables

	Capitalizing on Up Markets • Partnerships • Contracts • Transparency • Project Projections **Best Practices** • Comprehensive and Excellent Planning • Maximize Value • Screening and Bonding of Contractors • Understanding Regulatory Issues • Manage Change • Document - Document	
	Contacts were made with several of the Demolition companies present and copies of the RFI (prepared by Lorrise) emailed to them. The attendance at the conference was very beneficial and would be of benefit to other persons (engineers and environmentalist) within the company.	

Appendix G – OH Power Plant Detail Materials Listing

Old Harbour Power Plant - UNIT No. 1								
Materials listing								
Description	**Operating Conditions**	**Comments**	**Material**	**Dimensions**				
	***G/S/ O**			**length**	**width**	**height**	**diameter**	**weight**
				(ft)	**(ft)**	**(ft)**	**(ft)**	**(Lbs)**
Boiler								
Lower Drum	O	5455 gal.	Made of SA515-70, Aluminium	25			3.1	
Upper Drum	O	13059 gal.	Made of SA515-70, Aluminium	25.6			4.8	
Forced Draft Furnace	O		Tubes					
Boiler Bank Tubes	O		SA210-A1					
Floor Tubes	O		SA210A1, lined with brick					
Side Wall Tubes	O		SA210A1					
Front Wall Tubes	O		SA210A1					
Superheater Header	O							
Superheater Tubes	O		SA-213-T22					
Burners	O		SA-213-T22					
Economiser	O		Special alloyed metal piping					
Regenerative Airheater	O		SA210-A1					
Sootblowers	O		Made of laminated metal					
Fuel Oil Heating Set	O							
Forced Draft Fan	O	400hp, 2.3kv, manufactured by Triestine						
Feedwater Heaters	O		GE- motor coupled with fan					
Boiler Stop Valve	O							
Main Steam Line	O							
Stack	O		Concrete base, made of metal and is brick lined			150	15	
Turbine								
Turbine Casing	O							
Turbine Rotor	O							27,000
Turbine Buckets	O							
Turbine Diaphragms	O							
Journal Bearings	O							
Thrust Bearings	O							

Turbine Main Stop Valve	O							
Turbine Governor & Controls	O							
Lubrication System	O							
Steam Extraction System	O							
Turning Gear	O							
Generator								
Generator Stator	O		Copper strips and metal					
Generator Rotor	O		Copper strips and iron core					
Generator Exciter	O							
Excitation Control	O							
Journal Bearings	O							
Generator PTs	O							
Generator CTs	O							
Generator Output Cables	O		High grade copper cables					
Power Potential Transformer	O							
Transformers (KVA)								
Main Transfomer	O			6.885	6.375	13.125		85000
Unit Auxilliary	O	The core and coil weighed 17364 lbs and tank and fitting weight 10505 lbs. The oil inside the transformer						35269
Unit Auxilliary	O							
Station Auxilliary	O							
Distribution	O							
Condenser								
Condenser Tubes	O		Copper nickel 90/10 alloy tube					
Condenser Waterbox	O		Iron metal casing					
Taprogge System	O							
Inlet Pipes and Valves	O							

Outlet Pipes and Valves	O							
Condenser Hotwell	O		Steel tanks					
Cooling Water Heat Exchanger	O		Made of 90-10 Cu/Ni contains 306 tube					
Major Motors								
Boiler Feed Pump Motor A	O		US Electric motor coupled to pump					
Boiler Feed Pump Motor B	O		US Electric motor coupled to pump					
Circulating Water Pump Motor A	O		Large motor and high flow vertical pump					
Circulating Water Pump Motor B	O		Large motor and high flow vertical pump					
Condensate Pump Motor A	O							
Condensate Pump Motor B	O							
Forced Draft Fan Motor	O							
Other Motors								
Heavy Oil Pump Motor A	O		Motor- 40HP, 460V					
Heavy Oil Pump Motor B	O		Motor- 40HP, 460V					
Light Oil Pump Motor A	O							
Light Oil Pump Motor B	O							
Fuel Oil Transfer Pump Motor A	O		GE, Motor/ screw type pump					
Fuel Oil Transfer Pump Motor B	O		GE, Motor/ screw type pump					
Main Oil Pump Motor	O							
Bearing and Seal Oil Pump Motor	O							
DC Oil Pump Motor	O		Motor- KINAMATIC D					
Vapor Extractor Motor	O							
Water Separator and Blower Motor	O							
Bearing Cooling Water Pump Motor A	O		Motor coupled to pump					
Bearing Cooling Water Pump Motor B	O		Motor coupled to pump					
Seawater Cooling Pump Motor A	O							
Seawater Cooling Pump Motor B	O							
Screen Wash Pump Motor A	O							

Screen Wash Pump Motor B	O							
Travelling Water Screen Motor A	O							
Travelling Water Screen Motor B	O							
Service Water Pump Motor A	O		US motor, metal centrifuge					
Service Water Pump Motor B	O		US motor, metal centrifuge					
AirHeater Drive Motor	O							
AirHeater Lube Oil Pump Motor	O							
Boiler Feed Pump Aux. Oil Pump Motor A	O							
Boiler Feed Pump Aux. Oil Pump Motor B	O							
Condensate Makeup Pump Motor A	O							
Condensate Makeup Pump Motor B	O							
Instrument Air Compressor Motor	O							
Service Air Compressor Motor	O							
Switchgear & MC								
2.4 kV Switchgear	O							
480 V Switchgear	O							
Station Service 480 V Motor Control Centre	O							
Turbine 480 V Motor Control Centre	O							
Boiler 480 V Motor Control Centre	O							
Intake Structure 480 V Motor Control Centre	O							
110V DC Distribution Panel	O							
Pipes & Valves								
Circulating Water Pipeline from Intake	O							
Circulating Water Pipeline to Discharge	O							
Feedwater Pipeline	O							
Compressed Air Pipeline	O							
Fuel Oil Pipeline from tankfarm	O							
Fuel Oil Pipeline to Fuel Oil Heaters	O							
Fuel Oil Pipeline from Heaters to Burners	O							
Lubricating Oil Pipeline	O							
Seawater Cooling Pipeline	O							
Service Water Pipeline	O							
Fire System Pipeline	O							

Old Harbour Power Plant - UNIT No. 2

Description	Operating Conditions *G/S/ O	Comments	Material	Dimensions length (ft)	width (ft)	height (ft)	diameter (ft)	weight (Lbs)
Boiler								
Lower Drum		7504	Made of SA515-70, Aluminium	38.5			3	
Upper Drum		24638	Made of SA515-70, Aluminium	39.5			5.5	
Forced Draft Furnace			Tubes					
Boiler Bank Tubes			SA210-A1					
Floor Tubes			SA210A1, lined with brick					
Side Wall Tubes			SA210A1					
Front Wall Tubes			SA210A1					
Superheater Header								
Superheater Tubes			SA-213-T22					
Burners			SA-213-T22					
Economiser			Special alloyed metal piping					
Regenerative Airheater			SA210-A1					
Sootblowers			Made of laminated metal					
Fuel Oil Heating Set								
Forced Draft Fan								
Feedwater Heaters			GE- motor coupled with fan					
Boiler Stop Valve								
Main Steam Line								
Stack			Concrete base, made of metal and is brick lined			150	15	
Turbine								
Turbine Casing			Metal casing					
Turbine Rotor								27000
Turbine Buckets								
Turbine Diaphragms								
Journal Bearings								
Thrust Bearings								
Turbine Control Valves			Steel cams, springs and metal arms					
Turbine Main Stop Valve								
Turbine Governor & Controls								
Lubrication System								
Steam Extraction System								
Turning Gear								

Old Harbour Power Plant - UNIT No. 3								
Description	Operating Conditions *G/S/ O	Comments	Material	Dimensions				
				length (ft)	width (ft)	height (ft)	diameter (ft)	weight (Lbs)
Boiler								
Lower Drum			Made of SA515-70, Aluminium treated and is 3 3/4" thick	26.25			2	
Upper Drum			Made of SA515-70, Aluminium treated and is 4" thick	26.25			3.6	
Forced Draft Furnace			Tubes	29.36	24.25	22.75		
Boiler Bank Tubes			SA210-A1				0.25	
Floor Tubes			SA210A1, lined with brick					
Side Wall Tubes			SA210A1				0.25	
Front Wall Tubes			SA210A1					
Superheater Header								
Primary Superheater Tubes			SA-213-T22				0.166	
Secondary Super Heater			SA-213-T22				0.1875	
Burners			Special alloyed metal piping					
Economiser		Tubes	SA210-A1				0.166	
Regenerative Airheater			Made of laminated metal					
Sootblowers								
Fuel Oil Heating Set								
Forced Draft Fan			GE- motor coupled with fan					
Feedwater Heaters								
Boiler Stop Valve								
Main Steam Line								
Stack			Concrete base, made of metal and is brick lined			150	15	
Turbine								
Turbine Casing		Exhaust casing lower half including diaphragm 25000 lbs	High pressure head cast alloy steel	18.5	12	12		46500
Turbine Rotor			Exhaust hood cast iron					27000
Turbine Buckets			Higrade alloy steel					
Turbine Diaphragms		High pressure head lower half including diaphragm 21000 lbs	Carbon steel					
Journal Bearings			Forge steel					
Thrust Bearings			Forge steel					
Turbine Control Valves		High pressure head upper half turbine including diaphragm and	Hardened alloy, steel cams, springs and metal arms					32000
Turbine Main Stop Valve		Front end sole plate stop valve 10,000 lbs	Hardened alloy, metal casing containing a specialized valve, operated by hydraulic oil					10000
Turbine Governor & Controls			Hardened alloy					
Lubrication System			Carbon steel					
Steam Extraction System			Carbon steel					
Turning Gear			Carbon steel					
Turbine Front Standard			Metal casing containing					

Old Harbour Power Plant - UNIT No. 4

Description	Comments	Material	Dimensions				
			length	width	height	diameter	weight
			(ft)	(ft)	(ft)	(ft)	(Lbs)
Boiler							
Lower Drum		Made of SA515-70, Aluminium treated and is 3 3/4" thick	26.25			2	
Upper Drum		Made of SA515-70, Aluminium treated and is 4" thick	26.25			3.6	
Forced Draft Furnace		Tubes					
Boiler Bank Tubes		SA210-A1	29.36	24.25	22.75		
Floor Tubes		SA210A1, lined with brick				0.25	
Side Wall Tubes		SA210A1					
Front Wall Tubes		SA210A1				0.25	
Superheater Header							
Superheater Tubes		SA-213-T22				0.166	
Burners		SA-213-T22					
Economiser	Tubes	Special alloyed metal piping				0.1875	
Regenerative Airheater		SA210-A1					
Sootblowers		Made of laminated metal				0.166	
Fuel Oil Heating Set							
Forced Draft Fan							
Feedwater Heaters		GE- motor coupled with fan					
Boiler Stop Valve							
Main Steam Line							
Stack		Concrete base, made of metal and is brick lined			150	15	
Turbine							
Turbine Casing	Exhaust casing lower half including diaphragm 25000 lbs		18.5	12	12		46500
Turbine Rotor		Exhaust hood cast iron					27000
Turbine Buckets		Higrade alloy steel					
Turbine Diaphragms	High pressure head lower half including diaphragm 21000 lbs	Carbon steel					
Journal Bearings		Forge steel					
Thrust Bearings		Forge steel					

Old Harbour Plant
Fuel Oil & Water Tanks

Fuel Oil	Capacity		Material	Dimensions				
	barrels	Gallons		length (Ft)	width (Ft)	height (Ft)	diameter	weight (Lbs)
Old Harbour								
No. 1 Heavy Oil Tank	25,000		Metal steel sheet tank, with steel framed structure			51 ft.	60 ft.	
No. 2 Heavy Oil Tank	25,000		Metal steel sheet tank, with steel framed structure			51 ft.	60 ft.	
No. 3 Heavy Oil Tank	50,000		Metal steel sheet tank, with steel framed structure			125ft.	23 ft.	
Unit # 3 Day Oil Tank (HFO)	500		Metal steel sheet tank, with steel framed structure			26.5	21	
Unit # 4 Day Oil Tank (HFO)	500		Metal steel sheet tank, with steel framed structure			26.5	21	
Unit # 1 Light Oil Tank		25,000	Metal steel sheet tank, with steel framed structure			16	12.5	
Unit # 3Light Oil Tank		50,000	Metal steel sheet tank, with steel framed structure			32	12.5	
Raw Water Storage Tank # 1		200,000	Metal steel sheet tank, with steel framed structure			32	33.5	
Raw Water Storage Tank # 2		200,000	Metal steel sheet tank, with steel framed structure			32	33.5	
Raw Water Storage Tank # 3		200,000	Metal steel sheet tank, with steel framed structure			32	33.5	
Demineralised Water Tank #1		200,000	Steel sheets with metal beam frame			32	33.5	
Demineralised Water Tank #2		200,000	Steel sheets with metal beam frame			24	39	
Demineralised Water Tank #3		360,000	Steel sheets with metal beam frame			32	43.5	
Diesel Oil Tank #1		12,012	Cylindrical steel tanks			12.5		
Diesel Oil Tank #2		7,518	Cylindrical steel tanks			20.5		

Old Harbour Power Plant -

Demin Plant

		Capacity		Material	Dimensions				
	Comment	barrels	Gallons		length	width	height	diameter	weight
Old Harbour									
Acid Tank			7500	Metal tank lined with ruber					
Caustic Tank			47000	Metal tank lined with ruber					
Demin Control Cubicle				Concrete					
Reverse Osmosis Unit				Ceramic type material					
Acid Pump				Single stage centrifugal pump					
Caustic Pump				Single stage centrifugal pump					
Acid Pump Motor									
Caustic Pump Motor									
Carbon Filter	Three on site and are the same size			Metal tank containing carbon			8.5	5.5	
Cartridge Filter				Metal cylinder casing with thread cartridge					
Anion Tank	Three on site and are the same size			Metal Cylindrical tank with rubber lining tanks containing resins			11	6.5	
Cation Tank	Three on site and are the same size			Metal Cylindrical Tank with rubber lining tanks containing resins			12	6.5	
Mix Bed Tank	Three on site and are the same size			Metal Cylindrical tank with rubber lining tanks containing resins			5	5	
Reverse Osmosis Cartridge				Plastic like material					
High Pressure Pump				Multi stage centrifugal pump					
Acid Pump				Single stage centrifugal pump					
Caustic Pump				Single stage centrifugal pump					
SHMP Pump				Single stage centrifugal pump					
Acid Day Tank			2250	Metal tank lined with rubber					
Caustic Day Tank			4400	Metal tank lined with rubber					
Demin Water Transfer Pump				Single stage centrifugal pump					
Product Pump				Single stage centrifugal pump					
Neutralization Pump				Single stage centrifugal pump					
Neutralizing Tank			45000	Steel Cylindrical Tank	51			12	
Demin Plan Structure				Steel pipe lined with rubber					
Piping				Steel pipe lined with rubber					

Old Harbour Plant

Structures

		Material	Dimensions				
			length	width	height	diameter	weight
Old Harbour			(Ft)	(Ft)	(Ft)		
Administration and Workshop Building		Concrete, glass, steel beams and dry wall interior	171	39			
Canteen and Changeroom		Concrete building					
Bulk Storage House(Front)		Zinc and steel with concrete floor contain old boiler tubes and old electrical motors	63	33			
First Aid Building		Concrete, zinc roof	24	18			
Firepump and Emergency Diesel House		Zinc sheeting and steel beam					
Unit No 1 and No 2 Bolier Turbine Building		Zinc sheeting and steel beam	126	120			
Uint No 3 and 4 Boiler Turbine Building		Zinc sheeting and steel beam	54	45			
Main Stores Building		Concrete building with zinc and steel beams	141	60			
Bulk Storage House(Back)		Zinc roof with steel beams					
Mechanical Workshop		Concrete building with zinc and	81	60			
Laboratory and Chemistry Building		Concrete with zinc roof	63	30			
Compressor House		Concrete					
Relay House		Metal beam and zinc roof	48	21			
Inner and Outer Guard House		Concrete	5.1	5.1			
Sports Club Building		Concrete building with metal frame and zinc roof					
Oil Room		Small concrete building					
Scaffolsing House		Concrete	51	36			
Contractor Change Room		Concrete	60	36			
Contractor Offices (Trailers)		Metal Container	20/40		8		

Old Harbour Plant

Instrumentation

		Material
Instumentation		
Level Switch		Cast and black iron
Temperature Switch		Aluminium
Flow Switch		Aluminium
Pressure Switch		Aluminium
Temperature Gauge		Stainless steel
Pressure Guage		Pressure gauge
Flow Transmitter		Aluminium
Pressure Transmitter		Aluminium
Temperature Transmitter		Aluminium
Level Transmitters		Body made of black iron
Flow Meter		Body made of black iron
Control Valves		Body made of black iron

Fire System						
		Dimensions				
		length	width	height	diameter	weight
Fire System		(ft)	(ft)	(ft)	(ft)	(Lbs)
Diesel Fire Pump						
Diesel Engine - Cummings Engine Company Model 6BTA 5.9 F2, single stage centrifugal pump	230 FTHD, 1500GPM, 100psi					
Electric Fire Pump						
RETROFITTED MOTOR: MODEL 5K445EK211,AMPS=147AMPS, VOLTS -460V, PH=3, FRAME:445T, INS CL:F , single stage centrifugal pump	125HP,RPM-1475, HZ-50 AMB-40 DEGC, TYPE:K SERVICE FACTOR 1.15, 1500GPM, 100PSi					
Jockey Pump						
Pressure Maintenance Tank	Metal tank					
Fire Pump House						
Fire ring Main (10" pipe)	10" black iron pipe		500		0.83	

Annex F: Decommissioning Study 2: Hunts Bay

Final Report
November 30, 2013

HUNTS BAY POWER STATION
UNIT No. B6

DECOMMISSIONING PLAN
November 30, 2013

Jamaica Public Service Co. Ltd.
New Generation Department
6 Knutsford Boulevard
Kingston 5

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Appendices

References

1 EXECUTIVE SUMMARY

The OUR proposal is to construct a new generation facility and retire the existing Old Harbour Power Plant in 2016, and Hunts Bay Unit B6 in 2017. It is therefore necessary for JPS to prepare a decommissioning and closure cost report for submission to the environmental agency. JPS will also be required to include this cost in the next OUR rate case submission. However for Hunts Bay B6 the team has looked at two options:

1) Closure of the unit as per OUR requirement
2) Repowering of the unit by converting the fuel source to LNG.

"Closure" of a facility refers to the process by which the facility is secured, at the end of its useful life to prevent or minimize future impacts to human health and/or the environment. The facility may either be completely decontaminated or treated so that exposure to the remaining contamination is minimized. ***(Source: RCRA)***.

Review Existing Situation
The Hunts Bay B6 (68.5 MW) was commissioned into service in 1976 and is still in good physical shape. The retirement of this plant in 2017 would result in the company losing a major asset, but one which could be considered for repowering.

Decommissioning Strategy
The closure of Hunts Bay Unit B6 is being planned in accordance with the OUR Generation Least Cost Expansion Plan Oct 2010. The OUR has now selected a preferred bidder for the generation expansion of 360 MW for implementation by June 2016. This will include the introduction of natural gas and as such Hunts Bay B6 was recommended to be closed based on the current load growth and the age of the plant. It has therefore been agreed that the timetable for shut down will be June 2017 (subject to the Unit B6 re-powering option review and approval).

The decommissioning process itself consists of various phases, comprising a strategic preparation phase first, followed by a decision-making and engineering planning phase, defining steps of decommissioning and demolition work with an agreed time schedule and coordination with the remaining share of generation capacity to ensure a continued safely balanced national power supply.

The demolition process itself starts with in-depth planning to obtain the necessary permission from the OUR and clarification and the necessary budget to be prepared for the continued operation in the event the new 360MW generation plant is delayed. Decommissioning shall be performed by an external demolition contractor with the support of external consultants.

Decommissioning Plan
This Decommissioning and Closure Plan (DCP) will document the process the Jamaica Public Service Company will undertake to decommission equipment when it becomes necessary at the end-life of the plant and or equipment. Consideration will be given to the applicable regulations, guidelines, and the disposal options on the island at the time,

the economic feasibility and more importantly due consideration to health of workers and surrounding community and environment.

This Conceptual DCP outlines the general process and consideration that will be employed to decommission any equipment or facility and closure of the Unit B6 at the appropriate time.

The Decommissioning and/or Closure Plan should be finalized and submitted to the National Environment Planning Agency, Kingston and St. Andrew Corporation and any other relevant authorities for approval at least six (6) months prior to decommissioning and closure respectively of any facility on site or the entire site.

Environmental Clean-up Plan & Implementation

The team identified some areas at the Unit which are most likely to contain some asbestos, mineral fibres and mineral oils which will require special attention before dismantling and disposal.

Time Schedule

A total period of 5 years starting from June 2015 is estimated to be needed for all the technical measures for decommissioning and dismantling of Hunts Bay Unit B6 which is scheduled for June 2017 after the Old Harbour Power Plant is closed. See schedule Summary at Figure 1.1.

Figure 1-1 - Hunts Bay Summary Schedule

		Start	2015		2016				2017				2018				2019			
No.	Activity	Date	J	S	J	M	J	S	J	M	J	S	J	M	J	S	J	M	J	S
1	Preparation Evaluation	Sep-15																		
2	**Decommisioning Option 1**																			
3	Application for HB Unit B6	Sep-16																		
4	Start Engineering	Jan-17																		
5	Decom Hunts Bay Unit B6	Jun-17																		
6	**Re- Engineering Option 2**																			
7	Engineering	Mar-16																		
8	Re-Powering for LNG	Jun-17																		

Cost Estimate of Decommissioning & Dismantling

The total cost of decommissioning and dismantling for Hunts Bay Unit B6 to reach a brown field level of decontamination has been estimated at US$2.702M.

The cost for dismantling and demolition works at the site, the preparation of the demolished materials, their transportation and disposal are included in the above cost. Preliminary estimate for asbestos removal and revitalization cost for contaminated soils were also included.

In addition to the dismantling cost, based on capital expenditures to keep the life of the assets running, it is important to include for a known and measurable adjustment to the depreciation rates contemplated in the tariff submission that will allow the Company to recover the carrying values of these assets over their remaining useful lives.

An overall social impact study was not a part of this study, however two mitigation options were identified: the potential for re-powering and continuation of the overall plant operation. The severance payments, out placement cost and or early retirement options were reviewed and the estimated costs range from US$1.5 M to US$2.4 M. This assumed a 50% reduction in Hunts Bay Power Plant staff.

Re-Powering of Hunts Bay Unit B6

It is common practice in the power industry to perform repowering of older generating units to remain in operation for a further 20 years. Major aspect of repowering includes 1) conversion from one fuel source to another 2) upgrading of boiler plant 3) life extension of turbine and generator and 4) replacement of main auxiliary equipment.

The proposed 360MW power plant includes the installation of an LNG land based facility as such the availability of gas makes the prospect of repowering of Hunts Bay B6 very feasible. The estimated cost of repowering B6 is US$18M, and would result in a capital cost of US$262/kW. Using LNG fuel cost at US$13.5/MMBTU the operating fuel cost/kWh for Hunts Bay B6 would reduce from present US$0.2256/kWh (HFO price/bbl of US$116) to US$0.16/kWh.

Conclusion and Recommendations

The Hunts Bay Unit B6 has exceed its life span and while large investment would be needed to bring it to the required environmental standards using HFO, the consideration of re-powering the unit to use LNG may have significant benefits.

The planning process for the decommissioning should start ideally three (3) years before dismantling commences with the control of inventory and inventory management. As such it is important that further study be undertaken to review the decommissioning of Unit B6 versus re-powering potential of Hunts Bay Unit B6, in light of the new generation expansion and LNG introduction to Jamaica.

2 BACKGROUND

This study has been prepared by Jamaica Public Service Company, Generation Expansion team and other support departments in fulfillment of the OUR requirements to meet the generation expansion plans and facilitate closure of older and less efficient plants.

2.1 Terms of Reference (TOR)

The terms of reference comprise the following main tasks:

- To guide the Power Plant closure process in compliance with OUR, NEPA and international lending agencies requirements
- To estimate the cost, technical and manpower requirements for decommissioning of Hunts Bay B6 by Oct 30
- To ensure cost is included in the JPS rate case in Nov 2013 and the five (5) year Plan

2.2 Purpose

The purpose of this report is to support the OUR strategy for the closure of older and less efficient plants in an effort to meet the GOJ overall energy strategy for fuel diversification. The report assumes that the new generation expansion awarded by the OUR for 360MW will be commissioned by June 2016.

The planned decommissioning of Hunts Bay Units B6 will follow the decommissioning of Old Harbour power plant. The OUR five year generation expansion plan is to create an environment for more efficient power generation throughout the country.

This report will also present an alternative for the regasification of Hunts Bay B6 as an option to closure. This could extend the life of Unit B6 once LNG is available in 2016.

2.3 Project Team

The study was prepared from September 2013 to November 2013. The team comprised a local integrated group from various departments of the power utility. The areas represented were: New Generation, Generation Operations, Transmission, Environment, Health, Security & Safety, Material Management, Financial Control, HR and Legal. Team meetings were held bi-monthly and several site visits were made.

Responsibility Assignment Matrix is provided in Table 2-1 below:

Table 2-1 - Team Responsibility Assignment Matrix

No.	AREAS	RESPONSIBILITY						
		D. Cook PM	C. Mantock	M. Dunn/ A. Lawson	L. Higgins/ G. Scarlett	J. Williams. G.Llewellyn	V. McDonald	H. Messado
		New Generation		Environ.	Materials	Operations	HR	Finance
1	Introduction/ Background	R	S	S				
2	Power Plant Facilities	S	R			S		
3	Environment Health & Security	S		R				
4	Risk Management	R		S		S		
5	Closure Plan Objectives	R		S			S	
6	Decommissioning Plan	R		S		S	S	
7	Social Impact	S					R	
8	Cost Estimating	S	S		R			
9	Book Value Strategy	S						R
10	Cost Analysis	S	R					S
11	Scheduling	R						
12	Report Drafting	R	S	S		S		
13	Report Review	R	R	S	S	S	S	S
14	Executive Summary	R	S	S				
15	Final Report	R	S	S				

Key

P - Participant, S- Support,	S
R - Responsible	R

2.4 Definitions

The following terms and understandings are agreed:

Decommissioning – refers to in this study as the process of a well-coordinated shutdown of plant systems at the end of their economic life taking into consideration environmental and safety requirements

Dismantling – referred to in this study as the well-coordinated demolition and recycling of decommissioned plants, related buildings and installations for the site clearance and environmental clean-up in order to achieve brown field level enabling the rather flexible further commercial use of the power plant site.

Brown Field - Land previously used for industrial purposes or some commercial uses. The land may be contaminated by low concentrations of hazardous waste but in this case is removed and has the potential to be reused

3 HUNTS BAY EXISTING FACILITIES

3.1 Power Plant Units

Jamaica Public Service Company Limited (JPS) Hunts Bay Power Station complex is located in Kingston along the industrial strip of the Kingston waterfront. The Hunts Bay Power Station is divided into two complexes; the main complex (south side) borders the Petrojam Oil Refinery on Marcus Garvey Drive and is accessible by sea and road transport. This main complex consists of two units: oil fired (No. 6 HFO fuel) steam generating unit - Unit B6 (68.5 MW), and an industrial type gas turbine unit – GT 10 (32.5 MW). The secondary complex (north side) is located along Marcus Garvey Drive opposite the main complex and consists of a 69kV switch yard and an industrial type gas turbine unit – GT 5 (21.5 MW). Both gas turbines (GT 5 & 10) are fired on No. 2 (ADO) fuel oil.

At this time only the Hunts Bay Unit B6 and associated equipment are being considered for decommissioning. As such this will be a partial decommissioning of Hunts Bay Power Plant. Nevertheless the full plant description is provided below.

The Hunts Bay Units contain the following fuels/oils:

- No. 2 Fuel oil
- No. 2 / Lubricating oil mixture
- No. 2 / No. 6 Fuel oil mixture
- Transformer oil
- Waste Oil

Also on the site are the retired A-station and two (2) gas turbines units. JPS decommissioned the A-Station in 2007 with removal of all electro-mechanical equipment and asbestos containing material (ACM) located within that station.

In a letter dated April 22, 2010 the National Environment and Planning Agency (NEPA) requested Closure Plan for the facility.

3.2 Property Description

The Hunts Bay Power Plant is on the Kingston shoreline and consists of a large power plant with stack, above ground water tanks, above ground fuel oil tanks (No. 2 and No. 6), an open storage yard and other attendant facilities. Site soils consist of marl, fill and concrete rubble. Groundwater flow is expected to be southwest towards the adjacent bay.

The following is a list of the major structures at the Hunts Bay Power Station:
South Site

- ♦ Five reinforced concrete buildings –
  a. Administrative Building
  b. GT 10 Control Room & MCC Room
  c. Inventory Warehouse
  d. Canteen & Laboratory

- B6 Generating Plant
- G 10 Unit and attendant facilities
- Fuel Oil Storage Tanks with concrete bunds
- Chemical Storage Tanks with concrete bunds
- Water Storage Tanks
- Attendant Pipelines
- Laboratory

North Site

- Substation
    - Transformers
    - Oil Circuit Breakers
    - Reclosures & Insulators
- Gas Turbine 5 and attendant facilities
- Retired Gas Turbine 4
- Fuel Oil Storage Tanks with concrete bunds
- Fuel Pump Room & Attendant Pipelines
- Old Training Facility

Other structures on the facilities are roadways, concrete paved areas and out of service equipment.

3.3 Hunts Bay Unit B6 Components

The main structures of the power plant Unit B6 include: the turbine buildings, generators, smoke stacks, workshops, demineralization building, boilers. All the facilities of the B6 unit are listed in Appendix E. The other general plant facilities are excluded.

Photo 1 – Hunts Bay Power Plant Unit B6 – Crane Structure

Unit B6 Intake

Photo 2 – Hunts Bay Unit B6 Intake

Hunts bay B6 - Fuel Tanks.

Photo 3 – Hunts Bay - HFO Fuel Tank

Hunts bay Unit B6 - Stack

Photo 4 – Hunts Bay Stack

Hunts Bay B6 Steel Structures

Photo 5 – Hunts Bay B6 – Crane Structure

Hunts Bay B6 – Transformer

Photo 6 – Hunts Bay – Unit B6 transformer

Hunts Bay Unit B6 – Turbine Front Standard

Photo 7 – Hunts Bay Unit B6 – Turbine front Standard Control Compartment

Hunts Bay B6 – Demin Tanks

Photo 6 – Hunts Bay B6 – Demin Water Tanks

Hunts Bay Unit B6 - Generator

Photo 7 – Hunts Bay B6 Generator Casing

3.4 Surrounding Area Description

The lands to the west and north-north west of the JPS Hunts Bay site have heavy industrial, light industrial, commercial facilities and residential settlements. The southern boundary of the site borders the Kingston Harbour. The eastern boundary has heavy to light industrial facilities and commercial facilities.

Lands to the north are mainly residential communities with commercial and open spaces. There are schools, a cemetery and other government facilities to the North and North West of the Hunts Bay site.

3.5 Hydro-geological Description

The geological setting of the JPS Hunts Bay Facilities embraces the southwestern coastal section of the Liguanea Plains Formation. This is a heterogeneous alluvial formation of sand and gravel interspersed with clay lenses resulting in variations of the transmissivity at different locations in the aquifer. Groundwater in the aquifer is not suitable for drinking due to contamination by nitrate from sewage.

The Plant Facilities adjoins the shoreline (reclaimed wetland) and the high clay content of the retrieved samples indicates that:

- Transmissivity of the formation would be very low throughout the site
- Yields from the boreholes would be very poor.
- The rate of movement of solutes or pollutants through the formation would be slow, aided by adsorption of organic matter in the formation.

3.6 Wells

Two wells are located on the north side of the facility. These wells are for production of water used in boilers.

3.7 Waste Disposal

Waste disposal within JPS operations are guided by the JPS Waste Management Policy and Plan – 2009.

3.8 Industrial Solid Waste

Currently there is no local facility for the treatment of industrial waste that is deemed hazardous. Non-hazardous industrial waste, which is salvageable, is typically handled through contractors, who have established markets for such non-hazardous salvageable material. The industrial waste handled by contractors is limited to metals, used fuel and lubricating oils (*excerpt JPS Waste Management Policy and Plan – 2009).*

The National Solid Waste Management Authority is responsible for domestic solid and non-hazardous waste collection within the area. The NSWMA or contracted services transport the waste to the Riverton City landfill located in St. Andrew, approximately 8 kilometers (~5 miles) west of the Hunts Bay Power Station site.

3.9 Hazardous Waste

Once waste material is deemed hazardous it is disposed of in accordance with the Natural Resources (Hazardous Waste) (Control of Transboundary Movement) Regulations 2002 and any other regulatory guideline.

For the management of asbestos containing materials (ACM), NEPA has guidelines for the management of ACM. Final land disposal for ACM is facilitated through the NSWMA via land disposal within a designated “cell” of their ‘land fill’.

If there is no suitable disposal option on the island the requisite steps are taken to secure the hazardous waste until a disposal option is available.

3.10 Security of Facility

The Hunts Bay site presently has a perimeter chain link fence and toe-wall and has 24 hour Contracted Security & Surveillance System.

4 CLOSURE PLAN OBJECTIVES

4.1 Closure Plan

The closure plan describes the procedures for the removal of all the possible contaminants to air, soil and water; equipment decontamination; sampling and laboratory analysis and closure to the satisfaction of the relevant standards and regulations stipulated by the National Environment and Planning Agency.

(Source: National Environment & Planning Agency guidelines NEPA website)

Two options are currently being considered for the decommissioning and closure of the Hunts Bay facility:

1) Clean closure
2) Risk-based closure.

Clean closure occurs when all hazardous wastes and any associated contamination at the facility are removed to the extent that laboratory analysis shows the contaminants remaining are either below the detection limits of the analytical method or below background levels.

(Source: RCRA)

Risk-based closure occurs when a facility leaves any amount of contamination in place at the site, but it is determined to be of no danger to human health or the environment through health-based levels.

(Source: RCRA)

It should be noted that the Hunts Bay Power Plant is still in operation and the management systems in place will allow for continuous handling and disposal of materials that can cause or result in impact on the environment. Hazardous materials handling on the site is done according to established plans and procedures – Spill Management, Emergency Management, and Waste Management Plans.

Hazardous wastes generated on the site are handled based on the above Management Plans/Procedures. On an ongoing basis, hazardous materials will be disposed of on a case-by-case basis based on prudent environmental and safety practices as well as options available on the island.

Decommissioning of equipment will occur as practicable.

4.2 Closure Plan Scope

The Scope of the DCP document will address:

- Hunts Bay Site
- Facility Well Sites
- All Attendant facilities
- Exclude the Substation

5 CONCEPTUAL DECOMMISSIONING AND CLOSURE PLAN (DCP)

5.1 Purpose

The purpose of the conceptual Decommissioning and Closure Plan (DCP) is to describe the general objectives for the Hunts Bay facility, and the planning processes leading to development of a final DCP.

This conceptual DCP includes the following management components:

- Planning to ensure each component of decommissioning of equipment or facilities and the Closure of the facility is done using best practice and to ensure proper management to ensure human health and the environment are protected.
- Decommissioning and removal of plant, infrastructure and other materials
- Retention of specific infrastructure if applicable
- Testing and removal of contaminated material (if relevant)
- Monitoring & reporting

This decommissioning and closure plan will be used to establish the Terms of Reference (TOR) for procedures that will be performed during closure and is required when an industrial facility is to be closed by voluntary means or as a regulatory requirement.

5.2 Planning

JPS will ensure that all wastes generated from the decommissioning and closure of the Hunts Bay Facility operations are appropriately managed and disposed of. All waste must be handled, stored, collected, transferred, transported, processed, and disposed of, or reclaimed in a manner consistent with the requirements of a detailed plan. The detailed Decommissioning and Closure Plan will identify and quantify the waste that will be generated from the Closure of the Facility.

The detailed Decommissioning and Closure Plan will address such areas as

- ♦ Scheduling for removal of plant, infrastructure and other materials
- ♦ Retention of specific infrastructure if applicable
- ♦ Site access/fencing and security
- ♦ Environmental monitoring – soil and groundwater
- ♦ Removal of contaminated material (if relevant)
- ♦ Maintenance of equipment retired in place
- ♦ Reporting
- ♦ Facility closure and signoff where required

Industry best practice requires that planning of closure be undertaken progressively throughout the lifetime of an operation. As such the conceptual plan will be reviewed and details added as it becomes available. The Decommissioning and/or Closure Plan will be finalized and submitted to the National Environment & Planning Agency, Kingston and St. Andrew Corporation and any other relevant authorities for approval at least two (2) to six (6) months prior to decommissioning and closure respectively of any facility on site or the entire site.

5.3 Decommissioning of Equipment

Decommissioning of equipment or a unit may occur in stages/phases during the life cycle of the Plant as the present units will be retired on a phased basis. In this context 'decommissioning' refers only to the removal (or appropriate retention) of infrastructure and assessment and notification of contaminated materials.

The specific objectives in managing the decommissioning process will be:

- To ensure that decommissioning is carried out in a planned sequential manner, consistent with best practice.
- To avoid any deleterious effects on human health and the environment
- To ensure storage and or disposal of any or all materials are done according to a well-established plan and at a facility that is licensed or approved to dispose of the matter.
- Decommissioning is done according to the relevant regulations and or guidelines established by the Regulatory Agency.

The decommissioning, removal and disposal of fuel and chemical storage tanks will include the following procedures but not limited to:

- Outline technical aspects related to the removal of all residual oil and chemical from storage tanks and associated pipelines
- How the decommissioning process will prevent any further filling of storage tanks with any product
- Ensuring the decommissioning of all tanks (fuel and chemical) is executed with strict environmental and safety practices.
- Ensuring that the waste produced due to decommissioning of the tanks (fuel and chemical) and other equipment is classified and quantified and disposed of appropriately
- The Plan will include general steps for soil testing for the presence of contamination and soil remediation as required

5.4 Application for Necessary Permits

At the requisite time JPS will apply for the necessary permits environmental or otherwise required for decommissioning the facilities.

5.5 Infrastructure Removal

Removal of plant, infrastructure and other materials and retention of specific infrastructure if applicable.

Removal of plant, other infrastructure and materials will depend on the future use of the site, the existing condition of the site and how well it fits in the plans of the new site. The removal will therefore be selective and will occur under certain engineering requirements.

5.6 Scrap Metal Generated

Scrap Metal generated will be disposed of based on the regulatory and business requirements at the time of decommissioning and/or closure of any area of the facility.

5.7 Other Materials

Other waste generated will also be disposed of based on the disposal requirements and proper location for disposal on island or where necessary off island.

5.8 Site Decontamination

Whilst it is not anticipated that any major contamination of the site will occur, there is always the possibility of contamination occurring via an incident or accident on site. JPS current management systems are designed to minimize the risk of major contamination of the site occurring, by its spill management practices/procedure of reporting spills, clean up and proper disposal. The primary and major risk of contamination is via a hydrocarbon spill.

The basic requirements that will be considered during decontamination of any equipment, materials or the physical environment follows, derived from RCRA Closure Handbook, April 2010:

A complete work plan detailing methods for the decontamination of any contaminated area or equipment (tanks (fuel and chemical), containment areas, concrete pads, etc.) and other areas will be developed based on sampling and analysis to determine if there is contamination, as well as the types and the levels of contamination. Based on detailed assessments/analysis decontamination will be undertaken of the different areas where necessary.

Decontamination of equipment and materials depend on the types and levels of contamination. Several means of decontamination are available. The method for decontamination will depend on the materials, equipment or soil and location of the particular contamination.

Decontamination of non-porous surfaces such as tanks and metal piping may be accomplished by washing. Tanks may require entry procedures for a confined space. A detergent may or may not be employed. Steam cleaning is another option. The efficient removal of hazardous waste residues is the goal. *(Excerpts from RCRA Closure Handbook, April 2010)*

Porous surfaces provide a unique problem for decontamination. Decontamination method will be determined based on levels and types and economic feasibility; from complete removal to partial removal, etc. The main goal of the process is to remove the contamination in the most efficient and effective manner possible. *(Excerpt from RCRA Closure Handbook, April 2010)*

6 CLOSURE PLAN MONITORING

The performance-monitoring programme will be established based on the detailed plans. The final DCP will identify those monitoring requirements and all monitoring records will be collected as per any relevant standards or Monitoring Plan.

6.1 Quality Review

Monitoring results will be reviewed by JPS environmental personnel and Engineering Consultant to enable a response to be implemented if required. The results of the entire monitoring programme will be reviewed internally every quarter as part of the Monitoring Plan that will be established for each component of the decommissioning and closure plan.

6.2 Compliance Audit

The auditing of conformance with this Decommissioning and Closure Plan and any conditions or commitments related to environmental management will be conducted. The auditing will be conducted as per the Project Audit Schedule and will be based on the assigned responsibilities – internal JPS and third party services Contractor.

6.3 Reporting

A report describing the performance of the final DCP, based on monitoring results, and the extent to which it has been complied with, will be submitted to the Authority.

6.4 Current and Foreseeable Land Uses

Hunts Bay Power Station is an active electricity generating plant located adjacent to the coastline. Based on current future plans for the Hunts Bay sites, the facility will remain prime location for generation expansion projects based on the classification of the area as industrial.

6.5 Management Commitment

The planning and supervision for the decommissioning and dismantling of the power plant must be carried out with trained staff and management. Objectives of the supervision team are:

- To ensure that rehabilitation and decommissioning are carried out in a planned sequential manner according to schedule and consistent with best practice
- To ensure that agreed land-use outcomes are achieved, and
- To avoid ongoing liability
- Prepare Final Decommissioning and Closure Plan at least six months prior to closure of the site. Necessary approvals will be sought where necessary prior to the execution of certain decommissioning and closure operations.

7 RISK MANAGEMENT PLAN – ENVIRONMENT AND SAFETY

7.1 Safety

The required safety equipment and materials will be used during the entire operations. The Contractor and his personnel will be guided by JPS Safety procedures for the duration of operations.

- HSSE orientation of all new personnel is to be performed before the project commences.

- Compliance with the required PPE for the job will be ensured and if there are changes to the planned activity these will also be considered. Contractors will be responsible for providing all the necessary PPE gears for all their employees.
- JPS Job Briefing exercise will be conducted at the job site(s) for all personnel involved in the activities - Contractors, Sub Contractors and their employees and all JPS personnel. This will be conducted at the start of each workday. Any change in work scope will require a job safety analysis (JSA) prior to the start of work.

- Contractors and Sub-Contractors will be trained in areas such as (a) Confined Space Entry Procedure (b) Hazard Communication (c) Personal Protective Equipment (d) Spill Prevention Control and Response Plan.
- Contractors must be knowledgeable about (a) Requirement for safe entry and cleaning of Petroleum tank (b) Factors contributing to confined space fatalities (c) Guidelines and Procedures for entering and cleaning of Petroleum tank. (d) Safe guarding of tanks for entry and cleaning.
- All personnel entering tank must be equipped with respirator and adhere to Plants Respiratory Protection and Confined Space Programmes
- Gas monitors must be in good working condition
- Rescue team must be on-site at all times and at least trained as an Entrant.
- Emergency Response Plan Procedures will be in force

Hazard Management processes include:

- Lockout/Tagout programme
- Hot Work management programme
- Confined space entry operation
- Compressed gas handling
- Hazcom programme
- Fall prevention/protection
- Job Briefings
- JHA-as required
- Hearing Conservation
- Respiratory protection
- Asbestos Management

- Illumination/lighting

7.2 Environmental

Environmental considerations which must be reviewed and implemented during the decommissioning exercise will include:

- Mitigation measures: Spill plans, spill mats, spill pallets, plastic sheet, etc. to be in place to avoid/minimize any spill.
- Good housekeeping practices to be observed at all times.
- Waste material (oily rags, gasket material etc) must be properly stored and disposed of at the end of the project.
- All entry to tanks to be governed by established plant Confined Space Entry procedures.
- All recovery, transfer, removal and handling of oil will be guided by established plant Spill Prevention & Control procedures.
- Soil Testing and Remediation

7.3 Risk Mitigation

A team will establish a risk mitigation plan, through the identification of all associated risk and impact on the closure and probability of occurrence. An expected value will then be calculated and a risk mitigation response plan developed based on identified triggers.

Figure 7-1 - Risk Matrix

No	Risk	Prob. (HML)	Impact (HML)	Expected Valve	Mitigation
1	More soil remediation required than budgeted	M	M	MM	Earlier soils investigations to obtain details of contamination
2	OUR Generation expansion project delayed	M	H	**MH**	Work closely with OUR and preferred bidder to track schedule.
3	Likelihood of a hurricane and flooding during dismantling	M	M	MM	Weather monitoring and safety procedures
4	Possibility of a major safety Incident during dismantling	L	H	LH	Full safety procedures
5	Social unrest and objections to dismantling	L	M	LM	Ensure early communication and all stakeholders involved
6	Salvage value of steel and copper falling again	L	L	LL	Allow for contingencies
7	Asbestos contamination larger than expected	M	M	MM	Early assessment and estimation

8 TIME SCHEDULE FOR DECOMMISSIONING

A period of five (5) years is estimated for all the general measures for the decommissioning and dismantling process.

The sequence of activities will be staggered, according to the progress achieved within the consecutive actions. Some activities will be done in parallel, assuming sufficient resources including staff.

Figure 8-1 - Decommissioning Schedule

		Start	2015		2016				2017				2018				2019			
No.	**Activity**	**Date**	**J**	**S**	**J**	**M**	**J**	**S**	**J**	**M**	**J**	**S**	**J**	**M**	**J**	**S**	**J**	**M**	**J**	**S**
1	Preparation Evaluation	Sep-15																		
2	**Decommisioning OLd Harbour**																			
3	Application for Deccommissioning / Dismantling Permit	Jan-16																		
4	In Depth Hazard Appraisal	Mar-16																		
5	Start of Detailed Engineering	Mar-16																		
6	Start of dismantling Supervision	Jun-16																		
7	Decommissioning of Unit 1	Jun-16																		
8	Decommissioning of Unit 2	Jun-16																		
9	Decommissioning of Unit 3	Mar-17																		
10	Decommissioning of Unit 4	Sep-17																		
11	Site Remediation Works	Mar-18																		
12	Hand-over Site	Jun-19																		
13	**Decommisioning HB - Option 1**																			
14	Application for HB Unit B6	Sep-16																		
15	Start Engineering	Jan-17																		
16	Decom Hunts Bay Unit B6	Jun-17																		
17	**Re- Engineering HB - Option 2**																			
18	Engineering	Mar-16																		
19	Re-Powering for LNG	Jun-17																		

9 ROUGH COST ESTIMATE

The total preliminary cost estimate for dismantling of the Hunts Bay Unit B6 is US$2.702M

9.1 Dismantling Cost

The total preliminary expenditure is made up of the following:

Table 9-1 - Hunts Bay Unit B6 Site Demolition Preliminary Costing

Hunts Bay Power Station		Unit B6 - 66 MW							
Site Demolition Cost Summary									
No.	**Description**	**Unit**	**Quan.**	**Labour**	**Material /Equip**	**Disposal**	**Environ.**	**Total Cost**	**Salvage**
GENERAL									
	Planning Cost	LS	1	102,250				102,250	
	Safety Measures	LS	1	125,000				125,000	
	Supervision of Dismantling	LS	1	142,000				142,000	
	Sub-total			369,250	-	-	-	369,250	-
UNIT B6									
	Mobilize & Demobilization	LS	1	20,000	20,000			40,000	
	Asbestos Remidiation	CF	400				500,000	500,000	
	Boiler & Auxillary & Stack	LS	1	112,000	112,000			224,000	
	Steam Turbine & Building	LS	1	145,000	145,000			290,000	
	Intake	LS	1	30,000	30,000			60,000	
	GSU & Other Transformers	LS	1	40,000	30,000			70,000	
	Onsite Concrete Crushing & Spreading	CY	100	30,000	30,000			60,000	
	Debris Handling, Haulage & Disposal	CY	300			180,000		180,000	
	Scrap Steel ($140/TN)	TN	320					-	(44,800)
	Scrap Non -Ferrous ($3800/TN)	TN	110					-	(308,000)
	Sub-total			377,000	367,000	180,000	500,000	1,424,000	(352,800)
Fuel Oil Facilities									
	No. 1 Heavy Oil Tank	CF	144218	20,000	20,000			40,000	
	Unit # 3 Day Oil Tank (HFO)	CF	9180	5,000	5,000			10,000	
	Soil Remediation	SF					700,000	700,000	
	Scrap metal	TN							(45,000)
	Sub-total			25,000	25,000	-	700,000	750,000	(45,000)
Common Unit B6 Facilities									
	Fire System	LS		10,000	10,000			20,000	
	Instrumentation	LS		10,000				10,000	
	Maintain Services to BOP	LS		5,000	5,000			10,000	
	Sub-total			25,000	15,000	-	-	40,000	-
	Total Demolition Station Cost			796,250	407,000	180,000	1,200,000	2,583,250	(397,800)
PROJECT RESERVES									
	Project Indirects (5%)							129,163	
	Contingencies (15%)							387,488	
	LESS TOTAL PROJECT SALVAGE							397,800	
TOTAL PROJECT COST								2,702,100	

9.2 Cost Assumptions

1. Cost of Dismantling/ Demolition include:
    a. All site facilities prep work, dismantling and demolition works
    b. The storage of materials for sale
    c. the preparation of demolition materials, transportation & disposal
    d. Recyclability of mineral demolition materials (concrete)
    e. Overfilling of mineralized material at location
2. Disposal of other demolition materials in a radius of 50km from site
3. Map of potential Asbestos & Oil Contamination limited to areas shown
    a. Asbestos in Unit B6 Steam pipe lagging only
    b. Soil contamination areas, fuel tank and storage area
4. Transmission and switch yard and substations within the plant boundary are not a part of the demolition scope. All other plant except Unit B6 direct related plant is included in cost.
5. Step up transformers, auxiliary transformers and spare transformers are included for demolition in all estimates
6. Abatement of asbestos will precede any other work. After final air quality clearances have been reached, demolition can proceed.
7. All PCB oil will be removed and disposed of properly
8. Only estimates for soil clean-up has been included and soils investigation will be required to ascertain the final quantities.
9. All structures 2 feet below grade will be abundant in place unless deemed hazardous by NEPA.
10. Major equipment and structural steel is included in scrap value. All other demolished materials is considered debris
11. Costs of off-site disposal are included in excess of the onsite inert debris disposal capacity.
12. Valuation and sale of land and all replacement generation cost are excluded from this scope
13. Credit for salvage value are based on scrap value alone. Resale equipment and materials are not included. This is also considered very limited.
14. Labour cost is based on regular 40 hr work week without overtime.
15. Soil testing has not been done for the site contamination areas.
16. The discharge and intake canals will be left in place; equipment and structures above the sea level will be removed.
17. Crushed rock is assumed to be disposed of on-site by using it for clean fill, or will be recycled by the demolition contractor for beneficial use.
18. All above ground buildings and structures are excluded for demolition
19. Costs are included to clean supply HFO fuel oil tanks and to remove the soil within immediate vicinity.
20. Market conditions may result in cost variations at the time of contract execution
21. Pricing of all estimates is in 2013 dollars
22. Based on Request for Information (RFI) issued by Material Management two bids were received with budgetary cost which was in keeping with the above dismantling estimate. However, longer time period for more detail estimates would be required as bidders were unable to make site visit and conduct detail assessment due to limited time for RFI submission.

9.3 Book Value Plan

Paragraph 16 © of International Accounting Standard (IAS) 16 classifies decommissioning cost as an element comprising the cost of an asset. Per the standard, this cost would include the estimate of the cost of dismantling the item of Property, Plant and Equipment (PP&E) and restoring the site on which it is located at the date of acquisition. Site restoration costs include remediation as required by environmental and legal regulations.

In the present JPS circumstance, these costs were never estimated and included in the varying value of the PP&E. Decommissioning costs therefore has to be treated as an additional cost to be incurred by the regulated business in order to satisfy the requirements of applicable regulations and statutes to restore the sites addressed by this report. In the context of the current regulatory construct where JPS is allowed to recover reasonable non-fuel operating costs, depreciation, taxes and a reasonable return on its investment, these costs would not have been contemplated. In this regard JPS is of the view that it has a reasonable right to apply to the OUR, to seek to have the cost of decommissioning the subject PP&E recovered in the 2014 tariff review application.

In similar manner, due to the need to maintain reliability of service JPS has been forced to extend the life of existing assets to accommodate the delay in bringing new generating capacity to the grid. This has resulted in capital expenditures being incurred in relation to units that are operating several years beyond their stipulated useful lives. These units as such have considerably higher carrying values. This situation also calls for the inclusion of a known and measurable adjustment to the depreciation rates contemplated in the tariff submission that will allow the Company to recover the carrying values of these assets over their remaining useful lives, set to expire in 2018.

Going forward any maintenance costs on units to be decommissioned would be treated as Operations and Maintenance and not capital expenditure to allow for zero book value at the time of decommissioning.

The Book Value excluding land as of Aug 31, 2013 is shown in Table 9-2 below:

Table 9-2 - Power Plant Book Value

No.	Unit Name	Total NBV	Comments
1	Hunts Bay - B6	2,946,671.73	
	Subtotal	**2,946,671.73**	

10 ALTERNATIVE PROPOSAL TO DISMANTLING HUNTS BAY B6

10.1 Repowering of Hunts Bay B6

The Hunts Bay B6 which was commissioned into service in 1976 is still in good physical condition. The Generation Operations Department is planning to spend approximately US$6M in 2014 to rehabilitate major area of plant equipment inclusive of boiler, turbine and condenser. The retirement of this plant in 2017 would result in the company benefitting from two (2) years of this capital expenditure.

It is common practice in the power industry to perform repowering of older generating units to remain in operation for a further 20 years. Major aspect of repowering includes 1) conversion from one fuel source to another 2) upgrading of boiler plant 3) life extension of turbine and generator and 4) replacement of main auxiliary equipment.

The proposal for the supply of new 360MW power plant includes the installation of an LNG land based facility which will provide LNG to the power plant and have available gas for distribution to other off-takers. The optimistic availability of gas makes the prospect of repowering of Hunts Bay B6 very feasible. By repowering this unit 68.5MW which would have been retired would become available to the system which will require the addition of at least 120MW of new plant in 2018 with even marginal growth in demand for electricity.

10.2 Hunts Bay Unit B6 Repowering Cost

Using an estimated repowering cost of US$18M would result in a Capital cost of US$262/kW for retaining the unit compared to US$1200/kW for latest technology combine cycle combustion turbine. Using LNG fuel cost at US$13.5/MMBTU the operating fuel cost/kWh for Hunts Bay B6 would reduce from present US$0.2256/kWh(HFO price/bbl of US$116) to US$0.16/kWh) which would be equating approximately to JEP/WKGN operating fuel cost of US$0.162kWh (HFO price/bbl of US$116) and JPPC of US$0.1523/kWh.

Taking advantage of the repowering of Hunts Bay B6 would result in the system maintaining base load generation closer to the load center as it is anticipated that the new 360MW plant will be built in Old Harbour. Hunts Bay B6 would also benefit from the availability of major spare equipment from either Old Harbour Unit 3 or 4 (only exception been for 4.16kV motors).

11 SOCIAL IMPACT

An assessment of the social impacts caused by the closure of the Hunts Bay Power Plant is not part of this study. However, the Human Resource Department along with the Director of Generation is also examining this component. A summary of the main considerations is presented here for completeness. The data was extracted from the JPS HR Management System Report.

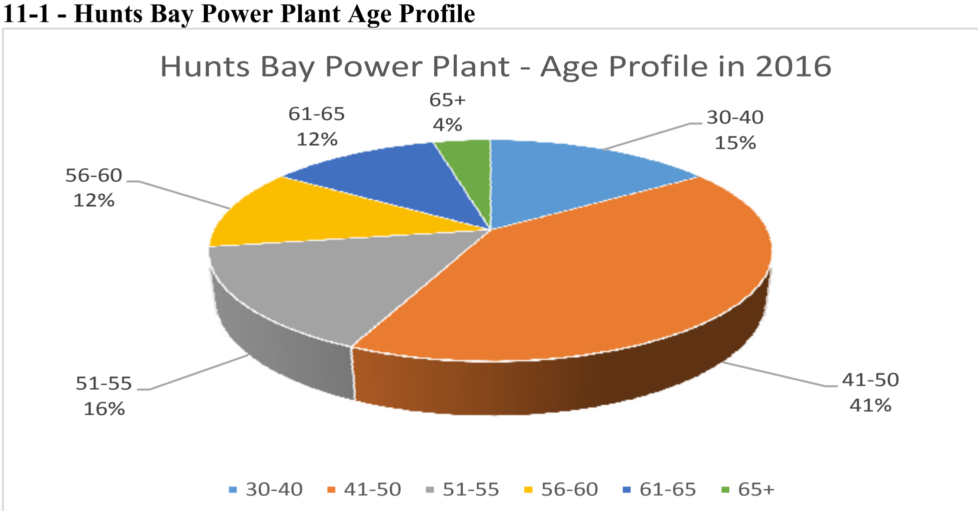
11.1 Current Staff Position

JPS has a staff complement of 1429 employees (as at September 2013) and approximately 250 persons work in the generation operations division. Of this total, just under **51** persons work on the Hunts Bay power plant site. The remaining 199 generation staff numbers are employed to the other power plants, , New Generation Dept and the Generation Operations Support Staff.

11.2 Workforce Age Profile

Based on the data of the 51 employees in the JPS Hunts Bay Power Plant, the workforce is of average age 49 with over 28% over age 55 and 56% under the age of 50. Only four workers would have reached retirement age by 2016.

Figure 11-1 - Hunts Bay Power Plant Age Profile



11.3 Workforce Development Plan

The plan for the development of the work force that will be displaced by the closure of Hunts Bay Unit B6 and any rationalization of JPS generation work force as a whole is based on five key elements:

1. A proportion of the work force will be deployed in jobs associated with the decommissioning of B6 and the subsequent decontamination and regeneration of the area.
2. A proportion of the workforce will be made redundant and be supported by HR through counselling, to find alternative employment, either in other companies or through self-employment or small business.

3. A proportion of the work force will retire and leave the labour market
4. A proportion of the workforce may consider employment in the new generation company.
5. In addition, members of the workforce currently associated with external independent contractors may continue to provide services to the other generation companies and other clients.
6. In the event the decision is taken to repower Hunts Bay B6 instead of retiring then the majority of the existing staff would maintain their job.

11.4 Financial Implications of Redundancy

It is difficult at this stage to specify the total cost of reorganization until a number of key decisions have been made. However, we recognize that JPS management would benefit from having indicative costs of a range of measures and options. It is assumed that a reduction in staff of 50% is appropriate for estimates.

Option 1: Unit B6 at HB is retired in June 2017, and 50% of staff made redundant and an outplacement team with 3 members is formed to operate for one year.
Estimated Redundancy Cost – US$2,419,400

Option 2: Unit B6 at HB is retired based on a phased plan starting June 2017 to Dec 2018 and staff used for the closing and safety hand-over; a small out placement team of two persons would operate for a year.
Estimated Cost– US$2.1M

Option 3: Unit B6 at HB is retired on a phased basis starting in June 2017 and the option of early retirement offered to persons age 55 and over on enhanced terms of half pay. Assume a 50% acceptance rate.
Estimated Redundancy Cost – US$1.5M

Option 4: Repowering of B6 could be achieved by June 2017 once LNG is available by June 2016. This would have no staff settlement cost.

11.5 Conclusions

In summary the main conclusions for the social consideration are:

- The strategy to minimize the social and economic consequences of the closure should be based on a fundamental restructuring of JPS power generation division activities over at least the next 5 year period from 2014, combined with an early decommissioning of already closed facilities to create employment opportunities.
- The strategy should also engage early evaluation of the re-powering of the Hunts Bay Power Plant Unit B6 to use LNG and extending the life another 20 years.

12 CONCLUSION & RECOMMENDATION

12.1 Existing Situation

Hunts Bay Power Plant has one Steam unit and three gas turbines in service which were constructed during the 1970s and 1990s. Currently, GT4 was shut down in 2010 but the other three units are all in operation.

Hunts Bay B6 is a base load unit for production while GT 10 and GT 5 are peak units. Hunts Bay Power Plant on average provides approximately 522 GWh net power annually into the JPS transmission grid. The remaining power supply comes from Bogue Power Plant, Old Harbour Power Plant, the Independent Private Power Producers and 5% from renewables.

While the B6 unit has exceeded its lifetime large investment/rehabilitation was needed to bring it to the required performance standards. Consequently, while this is being considered for closure the option exists for re-powering should LNG become available in the future for the 360 MW plant.

12.2 Planned Decommissioning

The decommissioning and dismantling of Unit B6 is envisaged in year 2017 as soon as the new generation awarded by OUR is online and after the decommissioning of Old Harbour.

The total cost for the technical decommissioning and decontamination of the Hunts Bay Unit B6 is estimated to be US$2.702M. In addition, based on capital expenditures to keep the life of the assets running, it is important to include for a known and measurable adjustment to the depreciation rates contemplated in the tariff submission that will allow the Company to recover the carrying values of these assets over their remaining useful lives.

The cost/ benefit analysis to either maintain the status quo, that is the continued operation of Hunts Bay Unit B6 at today's OPEX and environmental conditions or to decommission B6 and replace it with newer technology and natural gas fuel was considered. The closure of Unit B6 is the proposed action. However if LNG is available, the evaluation for repowering B6 does present a viable alternative, which can be reviewed closer to the planned closure date.

12.3 Comments on Potential Future Outlook

The B6 Unit at Hunts Bay Power Plant have exceeded its life span and while it is not economical to use HFO fuel for future operation to comply fully with current environmental standards, the option for re-engineering to use LNG is an option.

The best economic solution is the consideration to re-power Hunts Bay B6 after LNG is available and extend the life at a much more economic value.

It is therefore of utmost importance that the new 360MW generation plant be implemented with due diligence to ensure its timely construction and availability of LNG by 2016. The OUR in October 2013 awarded a bid for the 360MW plant based on their evaluation process and the current date for implementation is June 2016.

The planning process for the decommissioning of the Hunts Bay Unit B6 would start in Jan 2016 and by this time a reasonable assessment can be made regarding the availability of LNG to consider the re-powering option.

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APPENDIX A

Waste Material Classification for Sorting

Recyclable Material	Non-Hazardous Material
❑ Office paper ❑ Newspapers ❑ Cardboard ❑ Magazines ❑ Telephone directories ❑ PET Plastic bottles ❑ Glass bottles ❑ Mobile phones ❑ Computers ❑ Printers ❑ Ink cartridges 	❑ Non-salvageable Material o Garbage/Refuse (i.e. putrid material – e.g. kitchen waste, food) o Grass clippings o Construction debris o Used Materials o Insulators ❑ Salvageable Material o Transformers - Non PCB o Conductors o Photo cells – warranty issue o Drums o Wood o Poles (concrete & wood)

Hazardous Material
❑ Fluorescent bulbs ❑ Petroleum contaminated soil ❑ PCB contaminated material ❑ Unused, discarded or shelf-life expired chemical products ❑ Batteries (e.g. Nickle Cadnium; Lead acid) ❑ Bulbs - ballast ❑ Computers ❑ Asbestos Containing Materials (ACM) ❑ Meters ❑ Polymer ❑ Mercuroidal switches (and any mercury containing equipment)

(Taken from JPS Waste Management Policy and Plan)

APPENDIX B

Natural Resources Conservation Authority
Guidelines for the preparation of a Closure Plan for Industrial Type Projects

Introduction

These guidelines have been prepared in order to assist the Permittee/ owners/ operators in developing Closure Plans for his facility. This guideline describes a Closure Plan as *the procedures for decommissioning of a facility and the removal of all the possible contaminants to air soil and water; equipment decontamination; sampling and laboratory analysis and closure to the satisfaction of the relevant standards and regulations stipulated by the National Environment and Planning Agency*.

A. General

• The activities to be undertaken in the Plan should be clearly listed, with target dates for completion.
• Waste produced due to closure activities must be both classified and quantified and the method of treatment and/or disposal stated.
• The Plan should include soil (and groundwater, if accessible) testing for the presence of contamination. The test methods used for analysis of the soil and groundwater samples should be indicated.

B. Background Information

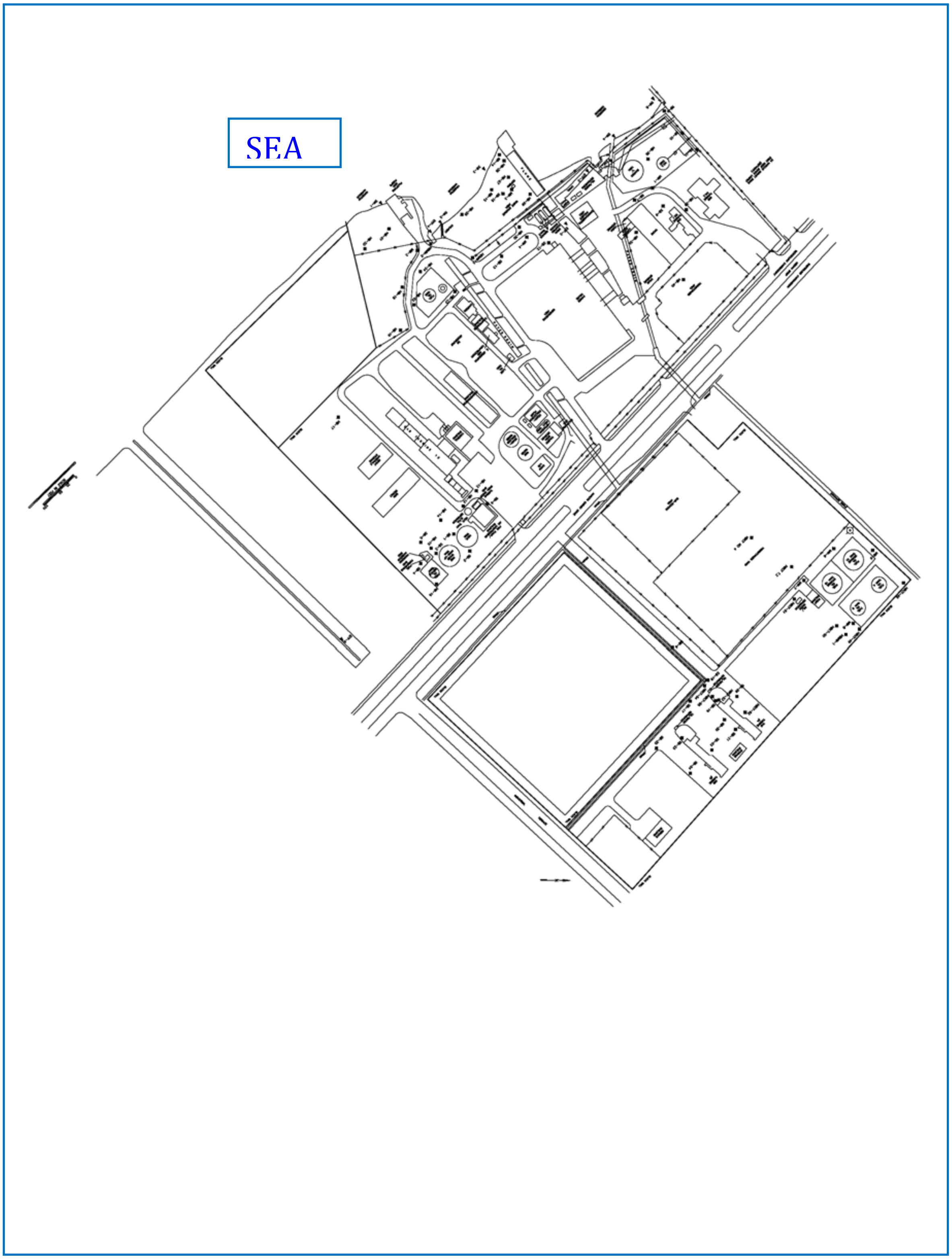
This should include:

1. The nature of the probable/ possible contamination including list of chemicals used on site
2. Any published or otherwise known information in order to establish whether adjacent property owners are or have been potential sources of contamination
3. Present zoning of the site and details of the zone categories of properties surrounding the site
4. Contour or topographic maps
5. Likely future use of the site
6. Risk Assessment
7. The results of any previous investigations of the site or surrounding land
8. Locations of surface water bodies, particularly where these may be adversely affected by contaminated groundwater or surface drainage from the site
9. Hydrogeological information, which should include:
    - The extent and use of aquifers in the area
    - Estimated depth to groundwater
    - Probable direction of groundwater flow and gradient
    - Soils and soil properties (soil type, porosity and hydraulic conductivity)
    - Location of any springs
    - Sources of local municipal water supply and the location of registered private or industrial wells or bores
10. Solid waste disposal
11. Security of facility/area scheduled for closure. This should include the postage of relevant signs.

Note: The Authority may require remediation for sites found with significant levels of contamination. In such cases a Remediation Plan shall be submitted for review and approval.
Post Closure Monitoring must be conducted for an agreed period for any contamination that may be present on site. The parameters to be monitored, the frequency of monitoring, the test methods used for the analyses and the end points to be achieved must be clearly stated.

Appendix C

HUNTS BAY POWER STATION - SITE LAYOUT



Appendix D

Location of JPS Hunts Bay Property (North & South)

Appendix E - Hunts Bay Unit B6 Detail Material Listing

Description	Comments	Material	Dimensions				
			length	width	height	diameter	weight
			(ft)	(ft)	(ft)	(ft)	(Lbs)
Boiler							
Lower Drum		Made of SA515-70, Aluminium treated and is 3 3/4" thick	26.25			2	
Upper Drum		Made of SA515-70, Aluminium treated and is 4" thick	26.25			3.6	
Forced Draft Furnace		Tubes					
Boiler Bank Tubes		SA210-A1	29.36	24.25	22.75		
Floor Tubes		SA210A1, lined with brick				0.25	
Side Wall Tubes		SA210A1					
Front Wall Tubes		SA210A1				0.25	
Superheater Header							
Superheater Tubes		SA-213-T22					
Burners		SA-213-T22				0.166	
Economiser	Tubes	Special alloyed metal piping				0.1875	
Regenerative Airheater		SA210-A1					
Sootblowers		Made of laminated metal				0.166	
Fuel Oil Heating Set							
Forced Draft Fan							
Feedwater Heaters		GE- motor coupled with fan					
Boiler Stop Valve							
Main Steam Line							
Stack		Concrete base, made of metal and is brick lined			150	15	
Turbine							
Turbine Casing	Exhaust casing lower half including diaphragm 25000 lbs		18.5	12	12		46500
Turbine Rotor		Exhaust hood cast iron					27000
Turbine Buckets		Higrade alloy steel					
Turbine Diaphragms	High pressure head lower half including diaphragm 21000 lbs	Carbon steel					
Journal Bearings		Forge steel					
Thrust Bearings		Forge steel					

Turbine Control Valves	High pressure head upper half turbine including diaphragm and control gear	Hardened alloy, steel cams, springs and metal arms					32000
Turbine Main Stop Valve	Front end sole plate stop valve 10,000 ll	Hardened alloy, metal casing containing a specialized valve, operated by hydraulic oil					10000
Turbine Governor & Controls		Hardened alloy					
Lubrication System		Carbon steel					
Steam Extraction System		Carbon steel					
Turning Gear		Carbon steel					
Turbine Front Standard		Metal casing containing					
Turbine Lube Oil Tank		Mild steel					
Turbine Auxillary Oil Pump		GE,motor/ Pump submerged in tank					
Turbine Bearing and Seal Oil Pump		GE,motor/ Pump submerged in tank					
Lube Oil Conditioner							
Turbine Oil Cooler		small heat exchanger					
Piping		From 1" to 2' pipe					
Hogging Ejector		Metal tubing with valves and nozzle					
Main Ejector		Pressure vessel with tubes					
Gland Seal Regulator		A special Metal steam control valve					
Gland Seal Exhaust System		Motor and special type of vapor pump					
Full Flow Oil Filters		Cylindrical metal casing					
Generator		Copper strips and metal casing					226000
Generator Stator	Less outer end shields	Copper strips and iron core					48000
Generator Rotor							
Generator Exciter							
Excitation Control							
Journal Bearings							
Generator PTs							
Generator CTs							
Generator Output Cables							
Power Potential Transformer							

Transformers							
Main Transfomer	The core and coil weighed 65340 lbs and tank and fitting weight 155760 lbs.	Copper bar/wire and iron core filled with oil	18.9	13.95	19.65		396000
Unit Auxilliary	The core and coil weighed 17364 lbs and tank and fitting weight 10505 lbs. The oil inside the transformer weighed 7400 lbs (1043 gal)						35269
Unit Auxilliary							
Station Auxilliary							
Distribution							
Condenser							
Condenser Tubes	Length for each side of condenser	Copper nickel 90/10 alloy tube	34	5.5	8		
Condenser Waterbox		Iron metal casing					
Taprogge System							
Inlet Pipes and Valves							
Outlet Pipes and Valves							
Condenser Hotwell							
Cooling Water Heat Exchanger		Made of 90-10 Cu/Ni contains 306 tube					
Major Motors							
Boiler Feed Pump Motor A		GE- motor coupled to pump					6000
Boiler Feed Pump Motor B		GE- motor coupled to pump					6000
Circulating Water Pump Motor A		Large motor and high flow vertical pump					
Circulating Water Pump Motor B		Large motor and high flow vertical pump					
Condensate Pump Motor A		Motor- sterling electric/ small pump attached					
Condensate Pump Motor B		Motor- sterling electric/ small pump attached					
Forced Draft Fan Motor							
Other Motors							
Heavy Oil Pump Motor A	Motor coupled to pump	Motor- 40HP, 460V					

Heavy Oil Pump Motor B	Motor coupled to pump	Motor- 40HP, 460V					
Light Oil Pump Motor A	Motor coupled to pump						
Light Oil Pump Motor B	Motor coupled to pump						
Fuel Oil Transfer Pump Motor A	Motor coupled to pump	GE, Motor/ screw type pump					
Fuel Oil Transfer Pump Motor B	Motor coupled to pump	GE, Motor/ screw type pump					
Main Oil Pump Motor	Motor coupled to pump						
Bearing and Seal Oil Pump Motor	Motor coupled to pump						
DC Oil Pump Motor	Motor coupled to pump	Motor- KINAMATIC D					
Vapor Extractor Motor	Motor coupled to pump						
Water Separator and Blower Motor	Motor coupled to pump						
Bearing Cooling Water Pump Motor A	Motor coupled to pump						
Bearing Cooling Water Pump Motor B	Motor coupled to pump						
Seawater Cooling Pump Motor A	Motor coupled to pump						
Seawater Cooling Pump Motor B	Motor coupled to pump						
Screen Wash Pump Motor A	Motor coupled to pump						
Screen Wash Pump Motor B	Motor coupled to pump						
Travelling Water Screen Motor A	Motor coupled to pump						
Travelling Water Screen Motor B	Motor coupled to pump						
Service Water Pump Motor A	Motor coupled to pump	US motor, metal centrifuge pump					
Service Water Pump Motor B	Motor coupled to pump	US motor, metal centrifuge pump					
AirHeater Drive Motor	Motor coupled to pump						
AirHeater Lube Oil Pump Motor	Motor coupled to pump						
Boiler Feed Pump Aux. Oil Pump Motor A	Motor coupled to pump						
Boiler Feed Pump Aux. Oil Pump Motor B	Motor coupled to pump						
Condensate Makeup Pump Motor A	Motor coupled to pump						
Condensate Makeup Pump Motor B	Motor coupled to pump						
Instrument Air Compressor Motor	Motor coupled to pump						
Service Air Compressor Motor	Motor coupled to pump						
Switchgear & MC							
2.4 kV to 4.16 kV Switchgear							
480 V Switchgear							
480 V Station Auxillary MCC							
480 Unit Auxillary MCC							

Intake Structure 480 V Motor Control Centre							
110V DC Distribution Panel							
Pipes & Valves							
Circulating Water Pipeline from Intake							
Circulating Water Pipeline to Discharge							
Feedwater Pipeline							
Compressed Air Pipeline							
Fuel Oil Pipeline from tankfarm							
Fuel Oil Pipeline to Fuel Oil Heaters							
Fuel Oil Pipeline from Heaters to Burners							
Lubricating Oil Pipeline							
Seawater Cooling Pipeline							
Service Water Pipeline							
Fire System Pipeline							
Major Pumps							
Boiler Feed Pump A	The base metal plate weighs 6000 lbs	Chrome steel and heat treated. The base metal plate weighs 6000 lbs					
Boiler Feed Pump B	The base metal plate weighs 6000 lbs	Chrome steel and heat treated. The base metal plate weighs 6000 lbs					
Circulating Water Pump A	Motor coupled to pump	N1 resist type 2, 316 stainless steel			450	4	
Circulating Water Pump B	Motor coupled to pump	N1 resist type 2, 316 stainless steel			450	4	
Condensate Pump A	Motor coupled to pump	Cast iron					
Condensate Pump B	Motor coupled to pump	Cast iron					
Forced Draft Fan	Motor coupled to pump						
Heavy Oil Pump A	Motor coupled to pump						
Heavy Oil Pump B	Motor coupled to pump						
Light Oil Pump A	Motor coupled to pump						
Light Oil Pump B	Motor coupled to pump						
Fuel Oil Transfer Pump A	Motor coupled to pump	Cast iron, meehanite nitrided steel, bronze and frame size 256T					

Fuel Oil Transfer Pump B	Motor coupled to pump	Cast iron, meehanite nitrided steel, bronze and frame size 256T					
Main Oil Pump	Motor coupled to pump						
Bearing and Seal Oil Pump	Motor coupled to pump						
DC Oil Pump	Motor coupled to pump						
Vapor Extractor	Motor coupled to pump						
Water Separator and Blower	Motor coupled to pump						
Bearing Cooling Water Pump A	Motor coupled to pump	Cast iron, bronze and steel, frame size 326 T					
Bearing Cooling Water Pump B	Motor coupled to pump	Cast iron, bronze and steel, frame size 326 T					
Seawater Cooling Pump A	Motor coupled to pump						
Seawater Cooling Pump B	Motor coupled to pump						
Screen Wash Pump A	Motor coupled to pump	Stainless steel					
Screen Wash Pump B	Motor coupled to pump	Stainless steel					
Travelling Water Screen A	Motor coupled to pump	Stainless steel wire cloth					
Travelling Water Screen B	Motor coupled to pump	Stainless steel wire cloth					
Service Water Pump A	Motor coupled to pump	Cast iron, bronze and steel, frame size 286 Ts					
Service Water Pump B	Motor coupled to pump	Cast iron, bronze and steel, frame size 286 Ts					
AirHeater Lube Oil Pump	Motor coupled to pump						
Boiler Feed Pump Aux. Oil Pump A	Motor coupled to pump						
Boiler Feed Pump Aux. Oil Pump B	Motor coupled to pump						
Condensate Makeup Pump A	Motor coupled to pump						
Condensate Makeup Pump B	Motor coupled to pump						
Instrument Air Compressor							
Service Air Compressor							

REFERENCES

Guidelines

- Natural Resources Conservation Authority Draft Guidelines For A Closure Plan
- Interim Standards for Petroleum in Ground Water and Soil – Pollution Prevention and Control Branch
- RCRA Closure Handbook April 2010

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- Burns & Mc Donnell - Report on Dismantlement Cost Study, Florida Fossil Fuel Plants – (October 2008)
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- Exelon Generation - Retired Fossil Fuel Fired Power Plants – Philadelphia area Presentation
- DTE Energy - Fossil Decommissioning Activities & lessons learnt
- Dominon Resource Services Inc – Cost to Shut Down Plants mandatory or Optional
- Brandenburg – lessons Learnt
- Exelon – Assets Management Presentation
- NCM Presentation – Inventory Recovery Value Realized.
- Environcon Environmental services – Sample Power plant Coal Feasibility Cost Estimate
- NV Energy – Generation Fleet Retirement decommissioning and Lessons Learnt.

Internal Documents

- JPS Waste Management Policy and Plan
- Hunts Bay Conceptual Decommissioning Plan

Annex G: Non – Technical Losses Study

QUANTUM

NON-TECHNICAL LOSSES

Jamaica Public Service Company Limited

CHANGING LIVES WITH OUR ENERGY

March

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1 Introduction

The following document presents the developments and analysis that have been carried out in order to establish the level of Non-technical energy losses achievable by JPS according to the actual socio-economic context in which the company is operating and supplying the electricity service.

The objective of this work is to demonstrate that there is a strong relationship between Non-technical losses (NTL) and the social conditions of the population living in the area served by JPS. In order to confirm the hypothesis that NTL are higher in those utilities operating in regions that have living conditions that are less favourable, in this study data about utilities of Anguilla, Curaçao, Bahamas, Cayman Island, Dominica, Suriname, Grenade, Belize, St Lucia, Turks & Caicos, Bermudas, Argentina, Bolivia, Brazil, Guatemala, El Salvador and the Dominican Republic corresponding to the years 2004 – 2011 are used.

The interest in incorporating Caribbean utilities in the sample to be evaluated was facilitated through the Caribbean Electric Utility Services Corporation (Carilec). Through this agency country members were invited to participate in this study, which allowed us to obtain first-hand information of 5 Caribbean companies. The Caribbean countries who have contributed with data are: Curaçao, Cayman Island, Belize, St Lucia and Turks & Caicos. Another seven Caribbean countries were considered based on data collected by Quantum or supplied by JPS, a member of the Carilec.

2 JPS Case Study

Given the network between generation, transmission and distribution, NTL losses are obtained as a result of subtracting the following flows to the total net generation:

- Energy sales
- Transmission (TR) losses
- Medium Voltage (MV) losses
- MV/LV losses
- Low Voltage (LV) technical losses

Thus, JPS' 2012 energy movement is as follows:

Concept	Unit	2012	Losses (% of Net Generation)
Net Generation	**MWh**	**4,154,446**	
Tr Losses	MWh	112,170	2.70%
	%	2.70%	
Caribbean Cement Company	MWh	87,173	
Energy entered in MV	**MWh**	**3,955,103**	
MV Losses	MWh	74,780	1.80%
	%	1.89%	
RT 50 (Power Service - TOU)	MWh	113,766	
RT 50 (Power Service - STD)	MWh	408,237	
Energy entered in MV/LV	**MWh**	**3,358,319**	
MV/LV Losses	MWh	54,008	1.30%
	%	1.61%	
RT 40 (Power Service - TOU)	MWh	128,089	
RT 40 (Power Service - STD)	MWh	669,982	
Energy entered in LV	**MWh**	**2,506,240**	
LV Technical Losses	MWh	166,178	4.00%
	%	6.63%	
Non Technical Losses	MWh	644,346	15.51%
	%	25.71%	
RT 60 (Street Lighting)	MWh	70,060	
RT 20 (General Services)	MWh	600,501	
RT 10 (Residential)	MWh	1,025,155	

A summary of the percentages of energy losses, referred to Net Generation, in the next table are shown:

Voltage level	Unit	2012
Transmission	%	2.70%
MV	%	1.80%
MV/LV	%	1.30%
LV Technical	%	4.00%
LV Non-technical	%	15.51%
Total	**%**	**25.31%**

The percentages of technical losses by voltage level were obtained from the Wheeling Framework Determination Notice (page 30), while the level of non-technical losses, as was said before, was obtained by difference between the total energy generated (or purchased) and the amount of energy sold plus technical losses.

NTL represents:

- ***15.51***% of the total net generation.
- ***25.84***% with regards to LV energy sales

NTL in electricity distribution include mainly electricity theft, but also losses due to poor equipment maintenance, calculation errors and accounting mistakes.

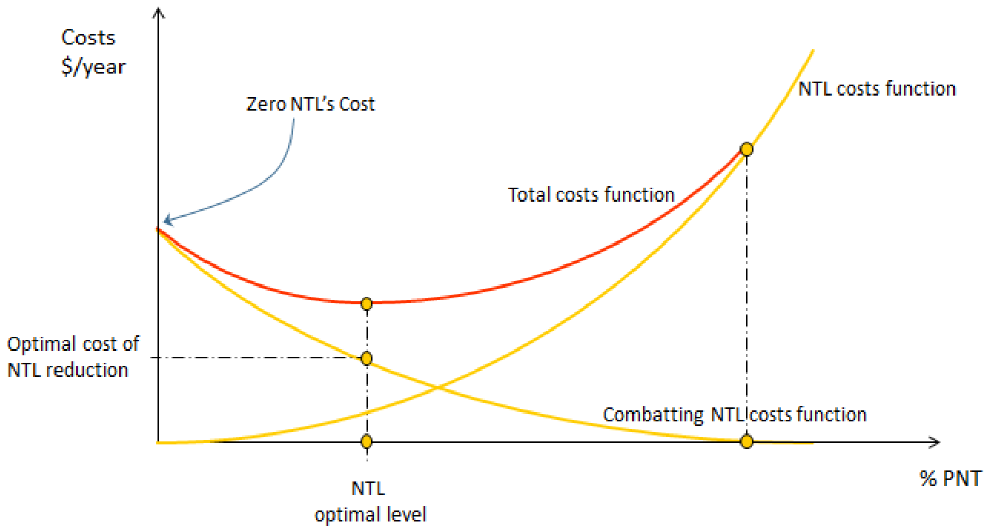
Main factors contributing to NTL can be characterized to include the following:

- Meters tampering to record lower rates of consumption
- Stealing by bypassing meters or by making illegal connections

- Inadequacies and inaccuracies of meter reading
- Errors in technical losses computation
- Inaccurate customer electricity billing
- Losses due to faulty meters and equipment
- Loss or damage of equipment (e.g. protective equipment, cables, etc.)

Even though there are many techniques and measures that a utility can adopt to identify, detect and predict customers with fraud activities and abnormalities, from an economic point of view it is not optimal to reduce NTL to zero, because the operational cost to meet this goal is often greater than the savings which are achieved with the NTL avoided (i.e. the marginal cost exceeds the marginal revenues).

In theory there exists an optimal point for NTL where total costs for the society are minimized.



However, in general there are strong environmental factors (social, economical and legal) that impact NTL. It is worth noting that environmental factors are exogenous or non-managerial variables that definitely affect the level of NTL, becoming in many cases a significant constraint for the utilities to meet the NTL optimal level established from the economic standpoint.

3 Background

The linkage between NTL and the environment in which electricity distributors are located is a field of study that has gained relevance in recent years. Two works carried out in Brazil can be mentioned. The first, carried out by the Brazilian Electricity Regulator (ANEEL)[1], indicated that the respect for the law by the members of the society is a measure of governability that affects the performance of the utilities. Additionally, the study noted that in comparing companies within the sector, environmental variables are not always considered, which, as it is demonstrated, affect the performance of the utilities. The study analyses the relationship between demographic characteristics, violence, schooling, income, inequality, infrastructure, labour informality, the

[1] Agência Nacional de Energia Elétrica - "Methodology for non-technical energy losses regulatory treatment", Technical Note 342/2008-S

temperature and the market characteristics of the Brazilian electrical distributors for the period 2001-2006.

In the other study, the author (Araujo 2007)[2] claims that NTL can be explained by socio-economic variables (education, income, inequality), infrastructure of the concession area, as well as the characteristics of the market (percentage of residential customers) and the average tariff charged by each utility. The author indicates the importance for the regulator to consider these factors when recognizing NTL and presents statistically significant results that confirm the hypotheses that NTL and the bad debt of the distributors are negatively associated with the development of the region and the level of income of their inhabitants, and positively associated with the cost of electricity and the levels of violence and inequality.

4 The Model

The model developed for this study is based on the hypothesis that NTL are influenced by socio-economic characteristics of the concession area of the utilities and the inefficiency of each company to tackle them, which can be expressed as follows:

Equation 1

$$NTL_i = \alpha + \sum_{k=1}^{K} \beta_k x_{ki} + I_i + \varepsilon_i$$

Where NTL_i represents the percentage of NTL of company i, x_{ki} are the k socio-economic variables of the concession area of company i (poverty, violence, etc.), I_i is the level of efficiency to tackle NTL_i and ε_i is the error term of the model, which is assumed to be normally distributed with a zero mean and constant variance. The term α represents the effect of not specified variables that affect NTL and β_k are coefficients that indicate the effects of each socioeconomic variable on NTL. All the variables are expressed in natural logarithms.

The objective of this study is to determine to what extent the socio-economic variables, which are exogenous, that is to say, are out of control of the utilities, explain the level of NTL the analysed companies have, without specifying the variables that capture the ability and the effort to tackle them.

Based on information collected by Quantum, regression models were run and evaluated in order to identify the socio-economic variables of greater impact on NTL. It must be stated that the availability of information about different Brazilian utilities given the scale of the country as well as the diversity of regions with unique characteristics allowed us to significantly increase the sample size.

The NTL to LV sales ratio was the variable defined to be explained. The reason for choosing this variable is based on the following facts:

- Most NTL occur in LV; and
- The consideration of another ratio involving NTL might result in less robust results due to the existence of large loads (mainly industrial) in the voltage levels upstream.

[2] "Losses and bad debt in the activity of electricity distribution". Thesis for PHD. Coordination of Post Graduate Programs in Engineering, Federal University of Rio de Janeiro, Rio de Janeiro.

The proposed model to explain the percentage of NTL due to the social reality of the concession area is as follows:

Equation 2

$$lNTL_i = \alpha + \beta_1 lpoverty_i + \beta_2 lbill\_income_i + \beta_3 lviolence_i + \sum_{j=1}^{J} \delta_i country_{ji}\ \varepsilon_i$$

where *lNTL$_i$* is the logarithm of the percentage of NTL to LV sales of company i, *lpoverty$_i$* is the logarithm of the proportion of population of the concession area that lives in conditions of poverty, *lbill_income$_i$* is the logarithm of the proportion of the residential annual average bill in relation to the income per capita of the area of concession and *lviolence$_i$* is the logarithm of the murder rate per 100,000 people in the concession area of company i. The constant of Equation 2 represents the independent level of NTL and ε_i is the difference between the observed NTL level and the estimated NTL level of each company. A dummy variable for the country where the utility is located is included. For instance, for the ones located in Brazil, a dummy called Brazil assumes 1 and 0 otherwise, for the ones located in Guatemala, a dummy called Guatemala assumes 1 and 0 otherwise, and so on.

The coefficients associated to the variables are their respective elasticities. The coefficient β_i, associated to the proportion of poor population, is expected to have a positive sign, since the greater the amount of inhabitants who live in conditions of poverty the smaller their willingness to pay for electricity and the greater the possibility of them committing fraud. The second variable represents the percentage of the electricity bill relative to the average income. It is expected that its coefficient presents a positive sign since the more onerous the electricity bill the greater the incentive to commit fraud. The coefficient associated to the last variable that represents the magnitude of the violence of the zone in which the utility operates must also be positive, since it is expected that violence and disrespect for the law encourage the theft of energy and also make it difficult for the utility to control this problem. Delinquency rates (robbery and homicides per 100,000 inhabitants) were used as a proxy for the society's propensity to commit fraud.

Finally, the coefficient δ_i of the country variable represents the level of the *lNTL* when the other variables are zero. These coefficients capture the effect of the national regulatory policy and the other environmental characteristics surrounding the distributors.

5 Model's input data

In order to carry out the present study, a database considering the following variables was built:

- NTL to LV sales index
- Poverty index
- Average residential rate versus GDP per capita index
- Violence index

The integration of information obtained mainly from official sites determined the availability of consistent data for the period 2007 – 2012 (246 observations). These data correspond to 65 distribution companies of Latin America and the Caribbean. The composition of the sample is as follows:

Countries	Companies
Anguilla	1
Curaçao	1
Bahamas	1
Barbados	1
Cayman Island	1
Dominica	1
Suriname	1
Grenada	1
Belize	1
St Lucia	1
Turks & Caicos	1
Bermudas	1
Argentina	3
Bolivia	1
Brazil	39
Dominican Republic	2
El Salvador	5
Guatemala	2
Jamaica	1
Total	65

The sources from which the data was obtained to run the model are mentioned below:

- NTL. The percentage of NTL is the level of non-technical losses in reference to energy sold at the low voltage level. For the companies of Brazil – the information was taken from ANEEL; for El Salvador – from the Bulletin of Electric Statistics 2008 and 2011 from SIGET[3]; for the Dominican Republic – from CDEEE[4]. The rest of information was provided to Quantum by the individual companies. In the case of the Caribbean utilities, certain utilities completed a survey that included a request of information related to Non-technical loses (MWh) and LV Energy Sales (MWh).

[3] SIGET: Superintendencia General de Electricidad y Telecomunicaciones

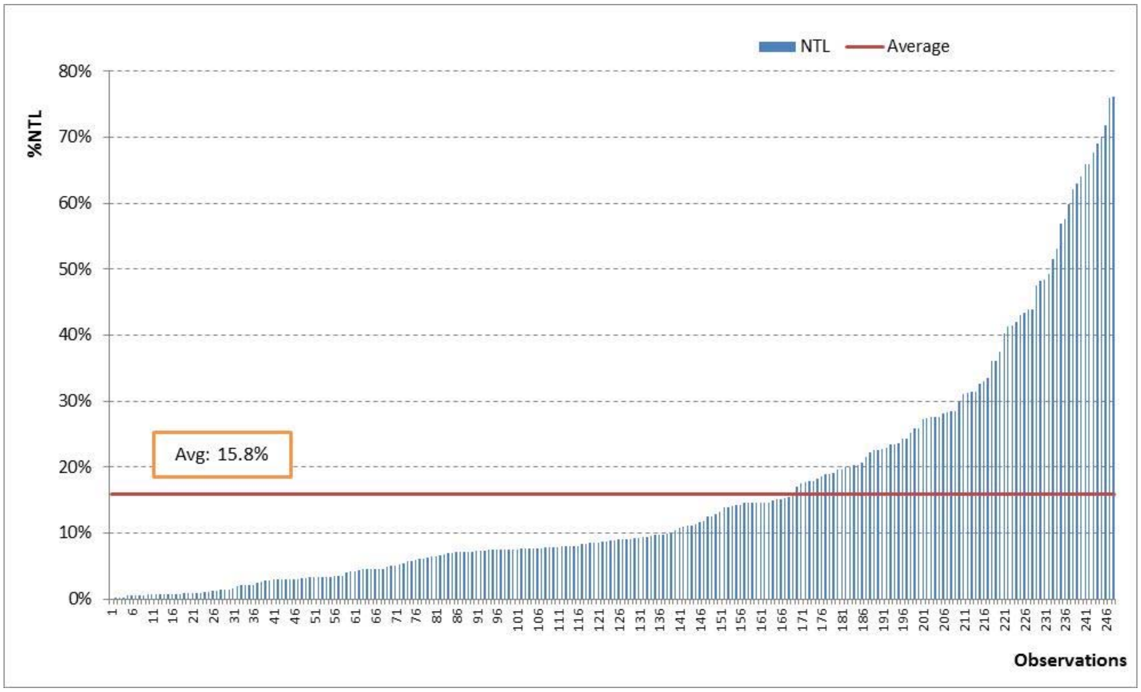
[4] CDEEE: Corporación Dominicana de Empresas Eléctricas Estatales

- People below the poverty line. For the companies of Brazil, the percentage of people that earned less than half of the minimum wage by municipality was considered. For the rest, except the Caribbean utilities, the proportion of the population living in conditions of extreme poverty was calculated by the SEDLAC[5]. The proportion of people below the poverty line in Jamaica was taken from the PIOJ[6] website. Finally, the poverty indicator for the rest of Caribbean utilities was taken mainly from the Publications of the Caribbean Development Bank (www.caribank.org).
- Proportion of the income devoted to electricity expenses. It was calculated as the ratio between the average annual bill for a residential customer and the gross domestic product per capita of the area of concession of the utility.
    - Residential customer annual average bill. It was calculated as the product of the residential annual average consumption by the residential average tariff of each company. The residential annual average consumption was obtained by dividing total energy sold to residential customers by the number of residential customers. The residential average tariff was calculated as dividing the income from residential customers by the amount of energy sold to these customers. For the Brazilian companies, the information for these calculations was taken from the website of ANEEL, whereas for the remaining companies the calculations were made using the data provided by the companies.
- GDP per capita. For the utilities of Brazil, the GDP per capita of the municipalities of the concession area of each utility weighted by the amount of inhabitants. For the rest of Non-Caribbean utilities, the GDP per capita of the country where they are located, as published by the United Nations was used. For JPS, the data was obtained from the Statistical Institute of Jamaica. For the rest of Caribbean utilities, the GDP per capita was taken principally from the International Monetary Fund website (www.imf.org).
- Murders per 100,000 people. For the utilities of Brazil, the murder rate was calculated considering the murder rate of the municipalities of the concession area of each utility weighted by the amount of inhabitants each municipality has. The rate of homicides by municipality of Brazil was obtained from the IBGE[7], whereas for the utilities of the remaining countries diverse sources were used. For Argentina and Bolivia information of the Latin American Institute in Sciences of Security was used, for Guatemala and Dominican Republic the Central American Observatory on Violence, for El Salvador www.fundemospaz.org, for Jamaica data from the Jamaican Constabulary Force (JCF) and for the rest of Caribbean countries homicides statistics the United Nation Office on Drugs and Crime was viewed (www.unodc.org).

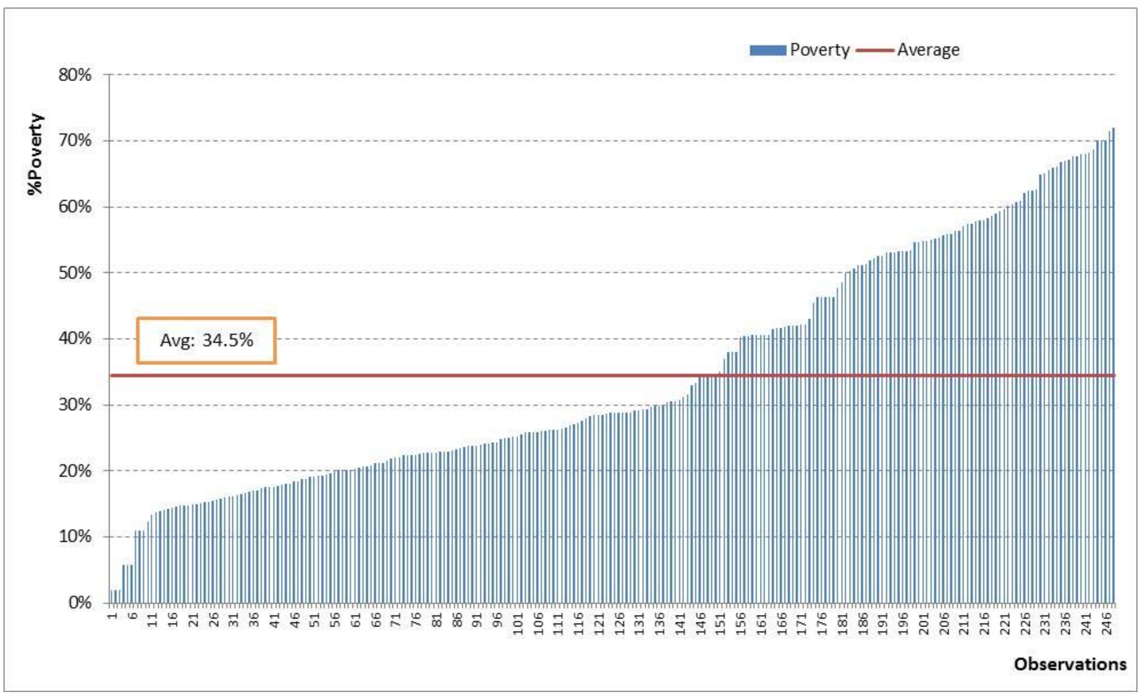
Next, graphs of the data used for the estimation of the model are presented:

[5] Socio-economic Database for Latin America and the Caribbean
[6] Planning Institute of Jamaica
[7] Instituto Brasileiro de Geografia e Estatística (Brazilian Institute of Geography and Statistics)

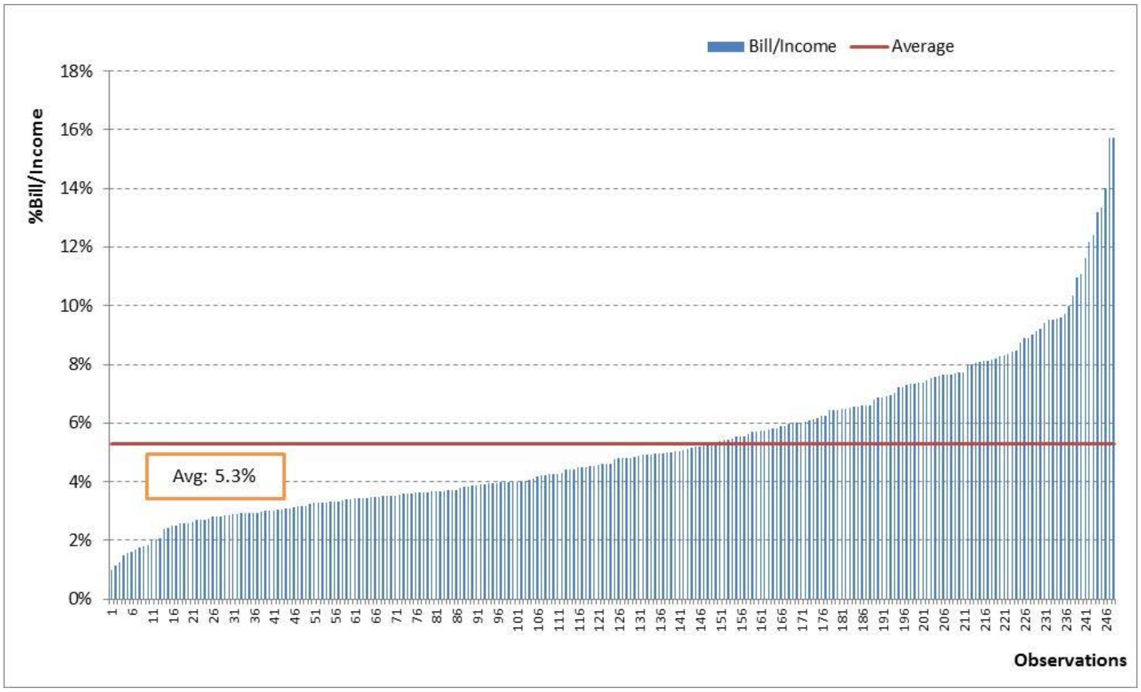
NTL % - Non-Technical Losses to LV Energy Sales Ratio



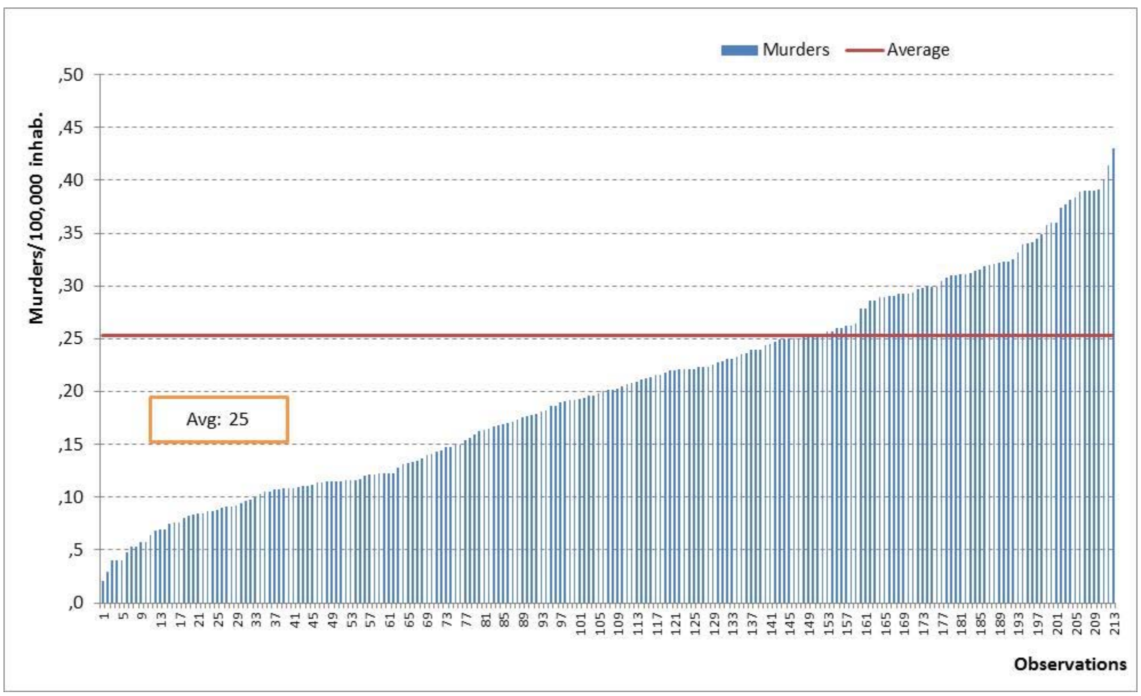
Low income % - Percentage of people below the poverty line



Electricity bill/GDP per capita Ratio (in %)



Murders /100,000 inhabitants



For 2012, the indices that apply for JPS and their comparison with the mean values are as follows:

	% NTL	Poverty	Bill / Income	Murders
Sample Average	15.8%	34.5%	5.3%	25.3
JPS	25.8%	17.6%	13.3%	40.1

In the case of the proportion of people below the poverty line, the last known official datum for Jamaica corresponds to 2010.

6 Results

The model formulated in Equation 2 was estimated by ordinary least squares corrected by heteroscedasticity, using the data of the 53 utilities previously indicated. The software Stata 11.0 was used in the estimation. The constant was dropped to avoid perfect multicolinearity[8], being the estimated model the following:

$$lNTL_i = \beta_1 lpoverty_i + \beta_2 lbill\_income_i + \beta_3 lviolence_i + Anguilla + Curacao + Bahamas + Barbados + Cayman\ Island + Dominica + Suriname + Grenada + Belize + St\ Lucia + Turks\ \&\ Caicos + Bermudas + Brazil + Argentina + Guatemala + Bolivia + El\ Salvador + Dominican\ Republic + Jamaica + \varepsilon_i$$

A coefficient of determination (adjusted R^2) of ***0.917*** was obtained, which indicates that ***91.7***% of the variability of the NTL of the companies in the study is explained by the variables included in the model. All the coefficients estimated present the expected sign and are highly statistically significant, as it can be observed in the following table:

[8] Note the sum of the vectors containing the dummies of the seven countries equals a 1 vector, that is, the vector of constants, being impossible to estimate the coefficients by OLS since perfect multicolinearity. The solution is to eliminate the constant of the model, which is replaced by the coefficient of the respective country variable.

ln_ntl	Coef.	Std. Err.	t	P>t	[95% Conf. Interval]	
ln_poverty	0.6065	0.1675	3.6	0.000	0.276	0.937
ln_murders	1.1531	0.1089	10.6	0.000	0.938	1.368
ln_bill	0.6387	0.2033	3.1	0.002	0.238	1.039
Anguilla	-2.0239	0.6981	-2.9	0.004	-3.400	-0.648
Curacao	-4.7072	0.7837	-6.0	0.000	-6.251	-3.163
Bahamas	-3.3278	0.9636	-3.5	0.001	-5.227	-1.429
Barbados	-3.8690	0.6820	-5.7	0.000	-5.213	-2.525
Cayman Islar	-6.2974	0.8153	-7.7	0.000	-7.904	-4.691
Dominica	-4.2555	0.6720	-6.3	0.000	-5.580	-2.931
Suriname	-1.4941	0.8778	-1.7	0.090	-3.224	0.236
Grenada	-5.6890	0.6575	-8.7	0.000	-6.985	-4.393
Belize	-6.0612	0.6863	-8.8	0.000	-7.414	-4.709
St Lucia	-4.9669	0.6979	-7.1	0.000	-6.342	-3.591
Turks & Caic	-2.5956	0.6660	-3.9	0.000	-3.908	-1.283
Bermudas	-2.8944	0.7863	-3.7	0.000	-4.444	-1.345
Brazil	-3.1210	0.6133	-5.1	0.000	-4.330	-1.912
Argentina	-0.6830	0.8289	-0.8	0.411	-2.317	0.951
Guatemala	-4.3955	0.7693	-5.7	0.000	-5.911	-2.880
Bolivia	-3.2653	0.6260	-5.2	0.000	-4.499	-2.032
El Salvador	-5.5019	0.6744	-8.2	0.000	-6.831	-4.173
Dominican R	-2.0633	0.6528	-3.2	0.002	-3.350	-0.777
Jamaica	-3.4702	0.9970	-3.5	0.001	-5.435	-1.505

A model of stochastic frontier (SFA) was also run, confirming that the model of ordinary least squares is efficient, which means that the deviations of the model are only attributed to random errors.

SFA is a statistic approach that considers a production function (in this case a function for NTL) and segregates the error term into inefficiency and random errors. The NTL function has a structure similar to the one presented in section 4 with a breakdown of the error term into the two components mentioned above:

Equation 3

$$NTL_i = \alpha + X_i \beta + v_i + u_i$$

$$v_i \sim N(0, \sigma_v^2)$$

$$u_i \geq 0$$

Where NTL_i is the percentage of NTL in logarithm of firm i, X_i are the NTL drivers in logarithm of firm i. The βX_i term is the deterministic component of the NTL function and $v_i + u_i$ is the total error component. The v_i term is the random noise, deviations from the deterministic component due to omission of some explanatory variable or measurement errors in the variables. The mean of these errors is supposed to be zero, since positive deviations compensate the negative ones, and its variance is constant. $\beta X_i + v_i$ define the stochastic frontier, which is not observable because v_i errors are not observable. The u_i term reflects the inefficiency of the firms, the distance between the stochastic frontier and the observed value. Note that u_i is positive, because it indicates the excess of the NTL level over the NTL level of the stochastic frontier and is null in case the firm is efficient. It is generally assumed that u_i follows a semi-normal, exponential or normal truncated distribution, in order to assure that, it always assumes greater or equal to zero values.

By estimating the NTL function (Equation 3), it is possible to test the statistical significance of $\boldsymbol{u_i}$. In this study the hypothesis test for $\boldsymbol{u_i} \geq 0$ was rejected at a confidence level of 99%, so it is concluded that the model estimated by OLS[9] is compatible with the frontier approach. In other words, on average utilities' NTL levels in the sample are not linked to inefficiencies of the utilities in tackling fraud.

7 Conclusions of the Results

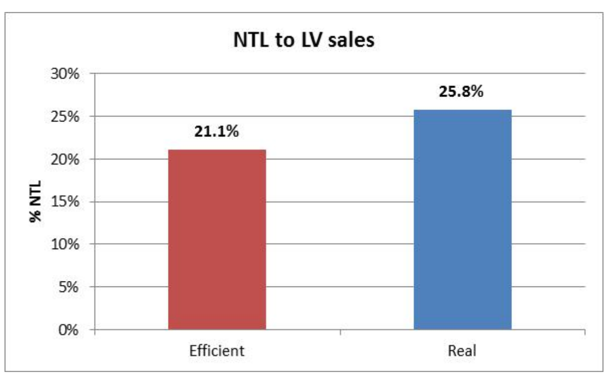
The estimated model indicates that ***91.7***% of the variability in the NTL is explained by socio-economic variables. It has been confirmed that NTL depend positively on the poverty level, on the payment capabilities of the population and the degree of violence present in the environment where the utility operates. In fact, for each 1% of increase in the proportion of the population that lives in conditions of poverty, the NTL level increases in ***0.61***%. This result confirms the importance of the social dimension on the performance of the electric utilities, indicating that the companies that operate in regions with high levels of inequality face more adverse conditions to tackle fraud.

The result associated with how much represents the residential electricity bill of the total income per capita is also significant and has the expected positive sign. According to the model run, an increase of 1% in the proportion of the electricity bill to the income of the families increases the level of NTL by ***0.64***%. It can be concluded that the utilities in whose concession areas the electricity service represents a significant burden for the population have higher levels of NTL on average.

Finally, it is remarkable the significant impact on the NTL level that violence and the disregard for the law have. The results confirm a direct relationship between the murder rate and the level of NTL. The elasticity estimated is ***1.15***, which suggests that the ineffectiveness of the police force and justice system favour the occurrence of fraud.

Given the robustness of the estimated model and considering that all the explanatory variables for Jamaica in the year 2012 are available, the level of NTL for JPS for this year was estimated. The value of each exogenous variable and the outcome are shown below:

				Non-technical losses		
	Poverty	Murders	Bill / Income	Efficient	Real	Difference
2012	17.6%	40.09	13.3%	21.1%	25.8%	-4.7%



9 OLS: Ordinary Least Square

The value of the resulting NTL is of ***21.1***% that indicates that if the level of NTL were only determined by exogenous conditions to the company, that is to say, by the poverty, the payment capacity and the violence of the country, then NTL level would reach this value. This result suggests that the difference between this NTL level and the real one can be attributed to variables not considered in this study such as the efficiency of the company to deal with fraud.

For the Base Year 2012, if we redo the energy movement replacing the real NTL by the ones calculated with the percentage predicted by the model we have:

			2012	
Concept	**Unit**	**2008**	**Real**	**With proposed NTL level**
Net Generation	**MWh**	**4,123,290**	**4,154,446**	**4,024,258**
Tr Losses	MWh	116,689	112,170	108,655
	%	2.83%	2.70%	2.70%
Caribbean Cement Company	MWh	94,304	87,173	87,173
Energy entered in MV	**MWh**	**3,912,297**	**3,955,103**	**3,828,430**
MV Losses	MWh	76,962	74,780	72,437
	%	1.89%	1.89%	1.89%
RT 50 (Power Service - TOU)	MWh		113,766	113,766
RT 50 (Power Service - STD)	MWh	496,267	408,237	408,237
Energy entered in MV/LV	**MWh**	**3,342,059**	**3,358,319**	**3,233,990**
MV/LV Losses	MWh	53,746	54,008	52,315
	%	1.61%	1.61%	1.62%
RT 40 (Power Service - TOU)	MWh		128,089	128,089
RT 40 (Power Service - STD)	MWh	759,744	669,982	669,982
Energy entered in LV	**MWh**	**2,528,569**	**2,506,240**	**2,383,603**
LV Technical Losses	MWh	167,658	166,178	160,970
	%	6.63%	6.63%	6.75%
Non Technical Losses	MWh	608,932	644,346	526,916
RT 60 (Street Lighting)	MWh	69,373	70,060	70,060
RT 20 (General Services)	MWh	650,424	600,501	600,501
RT 10 (Residential)	MWh	1,032,182	1,025,155	1,025,155

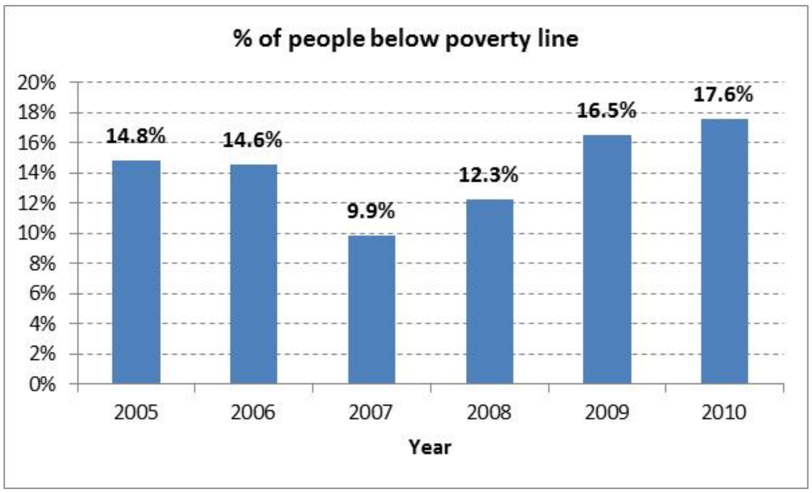
NTL / Sales below MV/LV	Real	24%	25.84%	
	Estimated			21.13%

Losses by voltage level related to net generation

	2012	
Level	**Real**	**With proposed NTL level**
Transmission	2.7%	2.7%
MV	1.8%	1.8%
MV/LV	1.3%	1.3%
LV technical	4.0%	4.0%
Non technical	15.5%	13.1%
Total	**25.3%**	**22.9%**

Efficient NTL and total system losses with respect to Net Generation are ***13.1***% and ***22.9***% respectively.

A phenomenon that has contributed to the impossibility of NTL reduction has to do with the deterioration of the poverty index. According to the 2012 PIOJ report (Jamaica Country Assessment), *"…The prevalence of poverty at the national level was 17.6 per cent in 2010 compared with 16.5 per cent in 2009. Prior to 2007, both nationally and regionally, poverty had generally shown a trend of decline. However, in 2008, with the increase in food and oil prices and the subsequent onset of the global economic crisis in 2009, poverty rates began to increase and have been trending upwards since."*



According to the new scenario JPS is facing, regulatory losses target should be established close to ***22.9***% with the possibility of reviewing annually this threshold based on changes the exogenous variables may experience.

Note for example the importance of the Poverty index and the number of incidents of murders. If poverty reduction initiatives were successful and 2007 poverty index was met again, then regulatory losses target could be set at ***19.4***%. Additionally if the number of murders decreases, following the trend of the last years, let's assume the average of the sample is achieved (25.9 murders / 100,000 inhabitants), then losses target should be fixed at ***15.7***%.

Meanwhile it is important to be aware of the problems the country is going through and set a reasonable losses target given the economic impact it has on JPS' financial sustainability. NTL experienced by many electricity supply utilities worldwide have major impacts on financial and economic outcomes and political stability. Financial impact is critical for JPS, as it involves reduction in profits, shortage of funds for investment in improving the power system and its capacity, and the necessity for implementing measures to deal with the power system losses. For sure the reduction of NTL is very important for electricity distribution networks as it will ensure that the costs for both the supplier and the customers will be minimized, and the efficiency of the distribution network will be improved. However this task cannot be performed by JPS alone, but requires the joint efforts of Regulator, Government, JPS, JPS' customers and other industry players.

8 Dataset

Company	Country	Year	NTL (LV) (%)	Murders/ 100000 Inhab.	Ratio Electricity bill / Income (%)	Poverty (%)
ANGLEC	Anguilla	2010	7%	9	6%	6%
ANGLEC	Anguilla	2011	8%	12	8%	6%
ANGLEC	Anguilla	2012	7%	15	7%	6%
AQUALECTRA	Curacao	2010	13%	82	8%	37%
AQUALECTRA	Curacao	2011	18%	82	7%	35%
AQUALECTRA	Curacao	2012	14%	82	8%	33%
BEC	Bahamas	2012	18%	34	11%	17%
BLPC	Barbados	2010	4%	11	5%	19%
BLPC	Barbados	2011	1%	10	6%	17%
BLPC	Barbados	2012	1%	8	7%	14%
CUC	Cayman Islar	2010	0%	14	7%	2%
CUC	Cayman Islar	2011	0%	11	8%	2%
CUC	Cayman Islar	2012	0%	7	8%	2%
DOMLEC	Dominica	2010	3%	22	7%	29%
DOMLEC	Dominica	2011	3%	8	8%	29%
DOMLEC	Dominica	2012	1%	8	8%	29%
EBS	Suriname	2010	10%	4	3%	70%
EBS	Suriname	2011	9%	4	2%	70%
EBS	Suriname	2012	5%	4	2%	70%
GRENLEC	Grenade	2010	1%	11	9%	38%
GRENLEC	Grenade	2011	0%	11	10%	38%
GRENLEC	Grenade	2012	2%	11	10%	38%
BEL	Belize	2010	3%	41	16%	42%
BEL	Belize	2011	3%	39	16%	42%
BEL	Belize	2012	3%	45	14%	42%
LUCELEC	St Lucia	2010	3%	25	8%	29%
LUCELEC	St Lucia	2011	3%	22	8%	29%
LUCELEC	St Lucia	2012	2%	24	9%	29%
FORTIS	Turks & Caic	2010	8%	9	8%	26%
FORTIS	Turks & Caic	2011	8%	9	7%	26%
FORTIS	Turks & Caic	2012	7%	9	7%	26%
BELCO	Bermudas	2010	2%	11	3%	11%
BELCO	Bermudas	2011	3%	12	2%	11%
BELCO	Bermudas	2012	2%	12	2%	11%
AES SUL	Brasil	2004	3%	16	4%	19%
AES SUL	Brasil	2005	3%	17	4%	21%
AES SUL	Brasil	2006	3%	17	4%	21%
AES SUL	Brasil	2007	3%	18	3%	20%
AES SUL	Brasil	2008	4%	20	3%	18%
AMPLA	Brasil	2004	36%	44	4%	24%
AMPLA	Brasil	2005	36%	51	4%	28%
AMPLA	Brasil	2006	31%	48	4%	29%
AMPLA	Brasil	2007	28%	46	4%	26%
AMPLA	Brasil	2008	25%	37	3%	25%
BANDEIRANTE	Brasil	2004	7%	34	3%	23%
BANDEIRANTE	Brasil	2005	10%	26	3%	24%
BANDEIRANTE	Brasil	2006	8%	29	3%	24%
BANDEIRANTE	Brasil	2007	9%	19	3%	22%
BANDEIRANTE	Brasil	2008	20%	21	3%	21%
BOA_VISTA_ENERGIA	Brasil	2004	28%	21	9%	30%
BOA_VISTA_ENERGIA	Brasil	2005	26%	23	9%	28%
BOA_VISTA_ENERGIA	Brasil	2006	28%	22	8%	28%
BOA_VISTA_ENERGIA	Brasil	2007	18%	26	6%	27%
BOA_VISTA_ENERGIA	Brasil	2008	15%	25	5%	22%
BRAGANTI	Brasil	2004	1%	8	3%	20%
BRAGANTI	Brasil	2005	1%	12	3%	20%
BRAGANTI	Brasil	2006	1%	10	3%	20%
BRAGANTI	Brasil	2007	1%	8	4%	19%
BRAGANTI	Brasil	2008	1%	9	4%	18%
CAIUA	Brasil	2004	1%	12	3%	22%
CAIUA	Brasil	2005	1%	11	3%	24%
CAIUA	Brasil	2006	1%	9	3%	24%

Company	Country	Year	NTL (LV) (%)	Murders/ 100000 Inhab.	Ratio Electricity bill / Income (%)	Poverty (%)
CAIUA	Brasil	2007	1%	12	5%	22%
CAIUA	Brasil	2008	1%	12	5%	20%
CEAL	Brasil	2004	48%	29	7%	66%
CEAL	Brasil	2005	53%	43	7%	67%
CEAL	Brasil	2006	68%	53	6%	66%
CEAL	Brasil	2007	63%	61	5%	63%
CEAL	Brasil	2008	62%	60	5%	61%
CEB	Brasil	2004	9%	36	2%	19%
CEB	Brasil	2005	8%	32	2%	17%
CEB	Brasil	2006	9%	32	2%	18%
CEB	Brasil	2007	10%	33	1%	15%
CEB	Brasil	2008	10%	34	1%	16%
CEEE	Brasil	2004	15%	25	4%	18%
CEEE	Brasil	2005	14%	25	4%	20%
CEEE	Brasil	2006	21%	23	4%	20%
CEEE	Brasil	2007	21%	30	3%	19%
CEEE	Brasil	2008	23%	30	3%	18%
CELESC	Brasil	2004	3%	11	4%	15%
CELESC	Brasil	2005	3%	11	4%	15%
CELESC	Brasil	2006	3%	11	3%	15%
CELESC	Brasil	2007	5%	11	3%	15%
CELESC	Brasil	2008	5%	13	3%	16%
CELG	Brasil	2004	8%	26	5%	24%
CELG	Brasil	2005	8%	25	5%	29%
CELG	Brasil	2006	7%	25	5%	28%
CELG	Brasil	2007	7%	25	4%	24%
CELG	Brasil	2008	7%	29	3%	22%
CELPA	Brasil	2004	27%	22	8%	51%
CELPA	Brasil	2005	33%	28	8%	55%
CELPA	Brasil	2006	41%	29	8%	55%
CELPA	Brasil	2007	43%	31	7%	55%
CELPA	Brasil	2008	44%	39	6%	51%
CELPE	Brasil	2004	23%	50	7%	56%
CELPE	Brasil	2005	20%	51	6%	57%
CELPE	Brasil	2006	19%	53	6%	56%
CELPE	Brasil	2007	16%	54	5%	56%
CELPE	Brasil	2008	15%	50	5%	55%
CEMAR	Brasil	2004	33%	12	10%	68%
CEMAR	Brasil	2005	31%	15	9%	72%
CEMAR	Brasil	2006	31%	15	8%	72%
CEMAR	Brasil	2007	28%	18	7%	67%
CEMAR	Brasil	2008	28%	19	6%	65%
CEMAT	Brasil	2004	15%	32	5%	26%
CEMAT	Brasil	2005	13%	32	5%	30%
CEMAT	Brasil	2006	13%	31	6%	30%
CEMAT	Brasil	2007	15%	31	5%	32%
CEMAT	Brasil	2008	14%	31	4%	26%
CEMIG	Brasil	2005	3%	23	4%	30%
CEMIG	Brasil	2006	9%	22	4%	29%
CEMIG	Brasil	2007	9%	22	3%	29%
CEMIG	Brasil	2008	8%	20	3%	27%
CEPISA	Brasil	2004	44%	12	10%	66%
CEPISA	Brasil	2005	48%	13	10%	69%
CEPISA	Brasil	2006	48%	14	8%	68%
CEPISA	Brasil	2007	60%	13	8%	58%
CEPISA	Brasil	2008	51%	12	6%	58%
CERON	Brasil	2004	76%	36	8%	31%
CERON	Brasil	2005	76%	36	7%	42%
CERON	Brasil	2006	70%	38	8%	42%
CERON	Brasil	2007	72%	30	6%	34%
CERON	Brasil	2008	69%	29	5%	34%
CHESP	Brasil	2004	1%	20	4%	29%

Company	Country	Year	NTL (LV) (%)	Murders/ 100000 Inhab.	Ratio Electricity bill / Income (%)	Poverty (%)
CHESP	Brasil	2005	1%	16	4%	34%
CHESP	Brasil	2006	1%	15	4%	34%
CHESP	Brasil	2007	1%	22	5%	29%
CHESP	Brasil	2008	1%	22	5%	27%
COELBA	Brasil	2004	15%	16	5%	56%
COELBA	Brasil	2005	15%	20	5%	58%
COELBA	Brasil	2006	15%	23	5%	58%
COELBA	Brasil	2007	11%	26	4%	56%
COELBA	Brasil	2008	9%	32	4%	53%
COELCE	Brasil	2004	8%	19	6%	60%
COELCE	Brasil	2005	8%	21	7%	59%
COELCE	Brasil	2006	6%	22	6%	59%
COELCE	Brasil	2007	5%	24	6%	57%
COELCE	Brasil	2008	4%	23	5%	53%
COSERN	Brasil	2004	12%	12	6%	53%
COSERN	Brasil	2005	10%	14	7%	53%
COSERN	Brasil	2006	8%	15	6%	53%
COSERN	Brasil	2007	7%	20	6%	50%
COSERN	Brasil	2008	5%	21	5%	46%
CPEE	Brasil	2004	3%	7	3%	22%
CPEE	Brasil	2005	3%	11	3%	23%
CPEE	Brasil	2006	3%	11	3%	24%
CPEE	Brasil	2007	6%	6	4%	22%
CPEE	Brasil	2008	6%	2	3%	20%
CPFLPAULISTA	Brasil	2007	7%	11	3%	15%
CPFLPAULISTA	Brasil	2008	4%	10	3%	14%
EBO	Brasil	2007	15%	32	4%	43%
EBO	Brasil	2008	12%	35	4%	40%
ELEKTRO	Brasil	2004	9%	19	3%	26%
ELEKTRO	Brasil	2005	8%	16	3%	27%
ELEKTRO	Brasil	2006	7%	18	3%	28%
ELEKTRO	Brasil	2007	7%	13	4%	25%
ELEKTRO	Brasil	2008	5%	13	4%	23%
ELETROACRE	Brasil	2004	34%	18	9%	59%
ELETROACRE	Brasil	2005	27%	19	10%	60%
ELETROACRE	Brasil	2006	22%	23	10%	61%
ELETROACRE	Brasil	2007	24%	20	8%	55%
ELETROACRE	Brasil	2008	23%	19	6%	52%
ENERSUL	Brasil	2004	14%	29	5%	31%
ENERSUL	Brasil	2005	15%	28	6%	34%
ENERSUL	Brasil	2006	19%	30	5%	33%
ENERSUL	Brasil	2007	20%	32	4%	31%
ENERSUL	Brasil	2008	24%	29	3%	30%
ENF	Brasil	2004	7%	24	3%	13%
ENF	Brasil	2005	5%	38	3%	16%
ENF	Brasil	2006	6%	25	3%	16%
ENF	Brasil	2007	4%	39	5%	15%
ENF	Brasil	2008	3%	30	4%	14%
EPB	Brasil	2004	30%	17	6%	55%
EPB	Brasil	2005	31%	19	6%	53%
EPB	Brasil	2006	28%	21	5%	53%
EPB	Brasil	2007	27%	22	6%	55%
EPB	Brasil	2008	23%	26	5%	51%
ESCELSA	Brasil	2004	20%	51	4%	25%
ESCELSA	Brasil	2005	18%	49	3%	26%
ESCELSA	Brasil	2006	19%	53	3%	26%
ESCELSA	Brasil	2007	20%	58	3%	23%
ESCELSA	Brasil	2008	17%	57	3%	23%
ESE	Brasil	2004	23%	26	5%	49%
ESE	Brasil	2005	23%	26	5%	53%
ESE	Brasil	2006	19%	32	5%	52%
ESE	Brasil	2007	18%	29	4%	48%

Company	Country	Year	NTL (LV) (%)	Murders/ 100000 Inhab.	Ratio Electricity bill / Income (%)	Poverty (%)
ESE	Brasil	2008	20%	30	4%	50%
EVP	Brasil	2007	1%	3	4%	24%
EVP	Brasil	2008	1%	9	4%	22%
IENERGIA	Brasil	2004	7%	10	4%	23%
IENERGIA	Brasil	2005	7%	17	4%	23%
IENERGIA	Brasil	2006	9%	20	4%	23%
IENERGIA	Brasil	2007	11%	8	3%	23%
IENERGIA	Brasil	2008	13%	17	3%	25%
LIGHT	Brasil	2004	42%	52	4%	18%
LIGHT	Brasil	2005	38%	44	4%	21%
LIGHT	Brasil	2006	40%	45	4%	21%
LIGHT	Brasil	2007	43%	38	4%	19%
LIGHT	Brasil	2008	41%	25	3%	19%
CIOL	Brasil	2004	1%	6	3%	17%
CIOL	Brasil	2005	1%	11	3%	18%
CIOL	Brasil	2006	1%	11	3%	18%
CIOL	Brasil	2007	1%	9	4%	17%
CIOL	Brasil	2008	1%	12	4%	15%
PIRATININGA	Brasil	2004	7%	23	3%	15%
PIRATININGA	Brasil	2005	7%	17	3%	16%
PIRATININGA	Brasil	2006	10%	18	3%	16%
PIRATININGA	Brasil	2007	9%	16	2%	15%
PIRATININGA	Brasil	2008	7%	14	2%	14%
SANTAMARIA	Brasil	2004	8%	21	4%	25%
SANTAMARIA	Brasil	2005	8%	20	4%	26%
SANTAMARIA	Brasil	2006	8%	25	4%	26%
SANTAMARIA	Brasil	2007	8%	29	6%	23%
SANTAMARIA	Brasil	2008	8%	31	6%	23%
SULGIPE	Brasil	2004	9%	14	5%	62%
SULGIPE	Brasil	2005	9%	22	3%	68%
SULGIPE	Brasil	2006	11%	18	3%	67%
SULGIPE	Brasil	2007	10%	19	4%	62%
SULGIPE	Brasil	2008	15%	22	4%	65%
ENERSA	Argentina	2007	9%	5	2%	31%
ENERSA	Argentina	2010	9%	5	2%	17%
EDENOR	Argentina	2007	4%	5	1%	21%
EDELAP	Argentina	2008	15%	6	1%	14%
DEOCSA	Guatemala	2007	11%	45	4%	68%
DEOCSA	Guatemala	2011	11%	39	5%	68%
DEORSA	Guatemala	2007	7%	45	5%	62%
DEORSA	Guatemala	2011	14%	39	8%	53%
CRE	Bolivia	2007	8%	8	13%	60%
CRE	Bolivia	2008	7%	8	12%	57%
CRE	Bolivia	2009	6%	7	12%	51%
Del Sur	El Salvador	2008	7%	71	7%	46%
Del Sur	El Salvador	2011	7%	78	8%	41%
CAESS	El Salvador	2008	2%	46	6%	46%
CAESS	El Salvador	2011	6%	53	7%	41%
AES CLESA	El Salvador	2008	4%	63	5%	46%
AES CLESA	El Salvador	2011	6%	76	6%	41%
EEO	El Salvador	2008	2%	34	6%	46%
EEO	El Salvador	2011	5%	52	7%	41%
DEUSEM	El Salvador	2008	2%	29	5%	46%
DEUSEM	El Salvador	2011	4%	48	7%	41%
EDENORTE	Dominican R	2009	49%	24	6%	42%
EDENORTE	Dominican R	2010	57%	25	5%	42%
EDENORTE	Dominican R	2011	57%	31	5%	40%
EDESUR	Dominican R	2009	64%	24	12%	42%
EDESUR	Dominican R	2010	66%	25	9%	42%
EDESUR	Dominican R	2011	66%	31	7%	40%
JPS	Jamaica	2008	24%	60	11%	12%
JPS	Jamaica	2012	26%	40	13%	18%

Annex H: Audited Financial Statements

The Audited Financials will be submitted as a separate document