JPS TARIFF APPLICATION
2014 – 2019

GOING FOR GROWTH

April 7, 2014
# Table of Contents

**CHAPTER 1: APPLICATION** ................................................................. 17

1.1 INTRODUCTION .................................................................................. 17
1.1.1 Generation Expansion and Renewal .................................................. 18
1.1.2 Ensuring Supply Reliability ............................................................... 20
1.1.3 Tackling System Losses ................................................................. 21
1.1.4 Improving Efficiency with Technology ............................................ 23
1.1.5 Making Customers Satisfaction a Priority ....................................... 23
1.1.6 Corporate Social Responsibility ..................................................... 24
1.2 TARIFF REGULATORY FRAMEWORK .................................................. 25
1.2.1 Filing of Non-Fuel Tariff Application ............................................. 26
1.3 THE PRICE CAP REGIME ................................................................. 27
1.3.1 Performance under Price Cap 2009 – 2014 ...................................... 28
1.3.2 Operating Cost & Productivity Improvements .............................. 29
1.3.3 Improvement in Service Reliability ................................................ 29
1.3.4 Service Standards ........................................................................... 30
1.3.5 Returns to Investors and Risk Management ................................. 30
1.3.6 Fuel Penalty ................................................................................... 31
1.4 OBJECTIVES OF NEW TARIFF SUBMISSION ...................................... 32
1.4.1 Summary of Proposals .................................................................... 33

**CHAPTER 2: ECONOMIC OVERVIEW** ............................................. 47

2.1 OVERVIEW OF THE JAMAICAN ECONOMY .................................. 47
2.2 2009-2013 IN REVIEW – THE DOWNSIDE RULED ............................ 47
2.3 IMPACT OF POLICY AND REGULATORY CHANGES ......................... 49
2.4 POPULATION GROWTH ...................................................................... 51
2.5 GDP GROWTH AND NATIONAL DISPOSABLE INCOME .................. 52
2.6 JAMAICAN/US INFLATION RATES AND FOREIGN EXCHANGE RATES 55
2.7 INTEREST RATES .............................................................................. 56
2.8 FUEL COST AND FUEL RECOVERY .................................................. 57


3.1 BACKGROUND .................................................................................... 59
3.2 POPULATION GROWTH .................................................................................................. 60
3.3 GROSS DOMESTIC PRODUCT .................................................................................... 60
3.4 CONSUMER AND PRODUCERS PRICE INDICES ....................................................... 62
3.5 FOREIGN EXCHANGE RATE ....................................................................................... 63
3.6 FUEL PRICES ............................................................................................................ 64

CHAPTER 4: OPERATIONAL AND FINANCIAL PERFORMANCE ......................... 69

4.1 OPERATIONAL SUMMARY ....................................................................................... 69
4.2 MAJOR EVENTS ......................................................................................................... 71
   4.2.1 Change in Ownership Structure and Licence Amendment ................................. 71
   4.2.2 New CEO ........................................................................................................ 71
   4.2.3 Tax Policy Changes ........................................................................................ 71
   4.2.4 Breach of Debt Covenant ............................................................................. 72
   4.2.5 Issuance of Preference Shares ...................................................................... 72
   4.2.6 New Generation Projects ............................................................................. 72
4.3 FINANCIAL SUMMARY ............................................................................................ 73

CHAPTER 5: TARIFF PERFORMANCE REVIEW .................................................. 76

5.1 REVENUE REQUIREMENT ....................................................................................... 76
5.2 NON-FUEL REVENUE & SALES PERFORMANCE .................................................... 77
   5.2.1 Price Cap vs Revenue Cap ........................................................................... 78
5.3 ADJUSTMENTS TO THE FUEL RECOVERY MECHANISM .................................... 78
5.4 OTHER BUSINESS RISKS ...................................................................................... 79
   5.4.1 Tropical Storm Nicole and Hurricane Sandy ................................................ 79
   5.4.2 Failure of Bogue’s ST14 and Certain IPP Plants ........................................... 79

CHAPTER 6: REVENUE REQUIREMENT ................................................................. 81

6.1 INTRODUCTION ........................................................................................................ 81
6.2 SUMMARY OF REVENUE REQUIREMENT ........................................................... 82
6.3 OPERATING EXPENDITURE .................................................................................... 84
   6.3.1 Purchase Power Costs ................................................................................ 85
   6.3.2 Operating and Maintenance Expenses ...................................................... 85
   6.3.3 Net Finance Costs ....................................................................................... 88
   6.3.4 Foreign Exchange Losses .......................................................................... 88
6.4 CAPITAL COSTS ..................................................................................................... 88
6.4.1 Depreciation ........................................................................................................ 89
6.4.2 Return on Investment .......................................................................................... 90
6.5 OTHER INCOME AND EXPENSES ........................................................................ 93
   6.5.1 Other Income ....................................................................................................... 93
   6.5.2 Other Expenses .................................................................................................... 95
6.6 OTHER ADJUSTMENTS TO REVENUE REQUIREMENT ............................................. 95
   6.6.1 Caribbean Cement Revenue ................................................................................ 95
   6.6.2 Electricity Efficiency Improvement Fund (EEIF) ............................................... 96
6.7 REVENUE REQUIREMENT CALCULATION ................................................................ 96

CHAPTER 7: COST OF CAPITAL ..................................................................................... 97
  7.1 INTRODUCTION ......................................................................................................... 97
  7.2 CAPITAL STRUCTURE ............................................................................................. 99
  7.3 COST OF DEBT ....................................................................................................... 100
   7.3.1 JPS’ Average Borrowing Cost .......................................................................... 100
   7.3.2 Cost of Debt for Similar Firms in the Industry ................................................. 101
  7.4 RETURN ON EQUITY ............................................................................................. 102
   7.4.1 Risk Free Rate ................................................................................................... 103
   7.4.2 Risk Premium .................................................................................................... 103
   7.4.3 Country Risk Premium ...................................................................................... 104
  7.5 WEIGHTED AVERAGE COST OF CAPITAL .......................................................... 107
   7.5.1 Post Tax WACC Methodology ......................................................................... 107
   7.5.2 Pre-Tax WACC Methodology .......................................................................... 107
   7.5.3 Calculation of JPS WACC ................................................................................ 108

CHAPTER 8: TARIFF DESIGN (NON-FUEL) .................................................................... 109
  8.1 NON-FUEL REVENUE REQUIREMENT AND TARIFF DESIGN RELATIONSHIP ........ 109
  8.2 LOAD CHARACTERISATION STUDY ..................................................................... 113
   8.2.1 Principles ........................................................................................................... 113
   8.2.2 Case Presentation .............................................................................................. 114
   8.2.3 Load Profiles Received ..................................................................................... 121
   8.2.4 Load Profiles by Class ..................................................................................... 122
   8.2.5 RT20 General Service ....................................................................................... 122
   8.2.6 Parameter Calculation ....................................................................................... 128
8.2.7 Parameter Results ........................................................................................................ 131
8.2.8 Load Profile Comparative Analysis ............................................................................. 131
8.3 BILLING DETERMINANTS ........................................................................................... 135
8.4 NON-FUEL TARIFS ...................................................................................................... 136
  8.4.1 Tariffs with the Average Cost Approach ................................................................ 137
  8.4.2 Theory of Two-Part Tariff Design ......................................................................... 141
  8.4.3 Proposed Rate Structure by Class .......................................................................... 150
  8.4.4 Proposed Non-fuel Rate Schedules ....................................................................... 175
  8.4.5 Fixed Revenues versus Fixed Costs ..................................................................... 177

CHAPTER 9: PERFORMANCE BASED RATE-MAKING MECHANISM .................. 180
9.1 X-FACTOR .................................................................................................................... 180
  9.1.1 JPS is Efficient ..................................................................................................... 181
  9.1.2 Efficient Frontier Analysis .................................................................................. 190
  9.1.3 Data Envelopment Analysis .............................................................................. 191
  9.1.4 Interpreting the Benchmarking Results ............................................................... 192
  9.1.5 Fundamentals Approach to Setting the X-Factor ................................................ 193
  9.1.6 Calculations Approach to Estimating the X-Factor ............................................ 195
  9.1.7 General Economy TFP Growth Rate .................................................................. 198
  9.1.8 Proposed X-Factor ............................................................................................. 200
9.2 Q-FACTOR – QUALITY OF SERVICE STANDARDS ............................................ 201
  9.2.1 Introduction ......................................................................................................... 201
  9.2.2 Calculation of the Q-Factor ................................................................................. 202
  9.2.3 Benchmarking of SAIDI, SAIFI and CAIDI ...................................................... 204
  9.2.4 Overview of the OUR/KEMA Q Factor Audit ..................................................... 204
  9.2.5 JPS Initiatives to Address Audit Recommendations ......................................... 207
  9.2.6 Adoption of Standardized Definitions ............................................................... 207
  9.2.7 Implementation of OMS ................................................................................... 209
  9.2.8 Business Process Charts and Policy Documents ................................................. 210
  9.2.9 Re-definitions of Organizational Roles and Functions ...................................... 210
  9.2.10 Implementation of Data Collection and Recording Systems ......................... 211
  9.2.11 Validation of Sample Data Reports ................................................................... 212
  9.2.12 Status of JPS’ Q Factor Initiatives .................................................................... 212
9.2.13 Overview of Proposed Data Collection ........................................................... 214
9.2.14 SAIDI, SAIFI and CAIDI Performance - 2009-2014 ..................................... 215
9.2.15 Recommendations for Implementation of Q Factor ..................................... 217

CHAPTER 10: REVENUE CAP ......................................................................................... 219

10.1 INTRODUCTION ................................................................................................. 219
10.2 PRICE CAPS, INCENTIVES AND RISKS .......................................................... 219
  10.2.1 The Theory of Price Caps ............................................................................ 220
  10.2.2 How JPS’ Price Cap Works ................................................................ ........... 221
  10.2.3 Price Caps Create Demand Risk and Perverse Incentives ............................ 221
10.3 UNDERSTANDING A REVENUE CAP .............................................................. 225
  10.3.1 The Theory of Revenue Caps ...................................................................... 226
  10.3.2 How a Revenue Cap Reduces Risks and Aligns Incentives ........................... 227
  10.3.3 Defining a Preferred Revenue Cap Design .................................................. 227
10.4 INTERNATIONAL PRECEDENT FOR A REVENUE CAP .................................... 228
10.5 A REVENUE CAP CREATES GOOD INCENTIVES .......................................... 233
10.6 REVENUE CAP MECHANISM ......................................................................... 234
  10.6.1 Revenue True-Up Mechanism to Align Actual Revenue with the Target .... 234
  10.6.2 The Revenue Cap Requires an Adjusted X-Factor ...................................... 237
  10.6.3 Revisions to the JPS Licence ....................................................................... 238
10.7 TARIFF IMPLICATIONS ..................................................................................... 239
  10.7.1 Under a Revenue Cap, Demand Risk is shared – Not Shifted ..................... 239
  10.7.2 A Revenue Cap is Unlikely to Cause Rate Shock ...................................... 242
10.8 CONCLUSION ................................................................................................... 243

CHAPTER 11: FX LOSSES .............................................................................................. 245

11.1 INTRODUCTION ............................................................................................... 245
11.2 FOREIGN EXCHANGE RISK EXPOSURE ........................................................ 246
11.3 FX RISK ON NON-FUEL ADJUSTMENT MECHANISMS ................................ 248
11.4 FOREIGN EXCHANGE LOSSES / (GAINS) .......................................................... 251
11.5 FX RISK ON THE SETTLEMENT OF BUSINESS TRANSACTIONS ............. 252
11.6 CONCLUSION ................................................................................................... 255
11.7 APPENDIX: DERIVATION OF INFLATION ADJUSTMENT FACTOR .............. 257

CHAPTER 12: FUEL RECOVERY – HEAT RATE TARGET ............................................. 259
12.1 INTRODUCTION .......................................................................................................................... 259
12.2 HEAT RATE TARGET OBJECTIVES ......................................................................................... 261
12.3 SYSTEM HEAT RATE PERFORMANCE – 2009 – 2013 ............................................................. 262
12.4 FACTORS IMPACTING SYSTEM HEAT RATE FORECAST .................................................... 265
  12.4.1 Improvements to Existing Units ....................................................................................... 265
  12.4.2 Impact of New Generation on Economic Dispatch and Heat Rate .............................. 265
  12.4.3 Impact of Fuel Price on Economic Dispatch and Heat Rate ........................................ 266
  12.4.4 Impact of IPP Performance on Economic Dispatch and Heat Rate ............................ 267
12.5 HEAT RATE FORECAST FOR TARIFF PERIOD ................................................................. 267
  12.5.1 Model Assumptions ............................................................................................................. 267
12.6 SYSTEM HEAT RATE MODEL RESULTS ......................................................................... 269
  12.6.1 Heat Rate Forecast 2014 .................................................................................................... 269
  12.6.2 Heat Rate Forecast 2015 .................................................................................................... 270
  12.6.3 Heat Rate Forecast 2016 .................................................................................................... 271
  12.6.4 Heat Rate Forecast 2017 .................................................................................................... 272
  12.6.5 Heat Rate Forecast 2018 .................................................................................................... 273
  12.6.6 Heat Rate Forecast 2019 .................................................................................................... 274
12.7 PROPOSAL FOR HEAT RATE TARGET ............................................................................... 275

CHAPTER 13: FUEL RECOVERY - SYSTEM LOSSES TARGET ............................................. 283
13.1 INTRODUCTION ....................................................................................................................... 283
13.2 SYSTEM LOSSES INITIATIVES ............................................................................................ 283
13.3 THE JPS LOSSES SITUATION – VS. - CHALLENGES ............................................................... 283
  13.3.1 Technical Energy Loss ....................................................................................................... 284
  13.3.2 Non-Technical Energy Loss .............................................................................................. 285
13.4 OVERVIEW OF LOSS REDUCTION ACTIVITIES 2009 – 2013 ........................................... 287
  13.4.1 Loss Reduction Program 2009-2010 .............................................................................. 289
  13.4.2 Loss Reduction Activities 2011 ....................................................................................... 292
  13.4.3 Loss Reduction Activities 2012 ....................................................................................... 295
  13.4.4 Loss Reduction Activities 2013 ....................................................................................... 296
13.5 LOSS REDUCTION INITIATIVES 2014 – 2019 .................................................................... 304
  13.5.1 Non-Technical .................................................................................................................. 306
  13.5.2 Technical .......................................................................................................................... 307
13.5.3 Financing System Losses Program ................................................................. 309
13.6 COMMUNITY RENEWAL PROGRAM ................................................................ 311
13.6.1 Introduction .................................................................................................. 311
13.6.2 The Problem ............................................................................................... 312
13.6.3 Type of Communities .................................................................................... 314
13.6.4 International and Jamaican Experience ......................................................... 316
13.6.5 Strategies for Community Renewal ............................................................... 324
13.7 PROPOSALS FOR SYSTEM LOSSES TARGET .................................................... 328

CHAPTER 14: OTHER FEES .................................................................................... 333
14.1 INTEREST ON ACCOUNTS RECEIVABLES FOR COMMERCIAL CUSTOMERS .... 333

CHAPTER 15: DECOMMISSIONING .................................................................... 335
15.1 DESCRIPTION .................................................................................................. 335
15.2 DECOMMISSIONING STRATEGY ..................................................................... 337
15.2.1 Old Harbour ............................................................................................... 337
15.2.2 Hunts Bay .................................................................................................... 338
15.2.3 Decommissioning Plan ................................................................................ 338
15.2.4 Environmental Clean-up Plan & Implementation ......................................... 338
15.2.5 Decommissioning Time Schedule ............................................................... 338
15.2.6 Decommissioning & Dismantling Cost Estimate ......................................... 340
15.2.7 Re-Powering of Hunts Bay Unit B6 ............................................................. 341
15.2.8 Mothballing Power Plants .......................................................................... 341
15.3 APPENDIX A: OLD HARBOUR - DECOMMISSIONING COSTS ................. 343
15.4 APPENDIX B - HUNTS BAY B6 - DECOMMISSIONING COST .................... 351
15.5 APPENDIX C- HUNTS BAY B6 – REPOWERING ASSUMPTIONS & COSTING .... 356

CHAPTER 16: GUARANTEED AND OVERALL STANDARDS ......................... 357
16.1 INTRODUCTION ............................................................................................... 357
16.2 GUARANTEED STANDARDS .......................................................................... 357
16.3 PERFORMANCE REVIEW ............................................................................... 360
16.4 PROPOSED MODIFICATIONS TO GUARANTEED STANDARDS ............... 368
16.4.1 Effectiveness of Standards .......................................................................... 368
16.4.2 Modification of Compensation Level .......................................................... 369
16.4.3 Exemptions & Exceptions ............................................................................ 370
16.4.4 Modifications to Existing Standards ................................................................. 371
16.4.5 Automatic & Non-Automatic Guaranteed Standards ........................................ 373
16.5 OVERALL STANDARDS ....................................................................................... 374

CHAPTER 17: DEMAND PROJECTIONS ........................................................................ 379
17.1 INTRODUCTION .................................................................................................. 379
17.2 MODELING APPROACH ................................................................................... 379
17.2.1 Forecasting Sales of Electricity ...................................................................... 379
17.2.2 Forecasting System Losses ............................................................................ 385
17.3 MODEL ASSUMPTIONS ....................................................................................... 385
17.3.1 Assumptions for Forecasting Electricity Sales .............................................. 385
17.3.2 Large commercial customers MV (R50) ....................................................... 391
17.3.3 Assumptions for Forecasting JPS’ System Losses ........................................ 393
17.4 SCENARIO RESULTS ......................................................................................... 394
17.4.1 Scenario Assumptions ................................................................................ 394
17.4.2 Comparison of the Results of the Four Scenarios ......................................... 395
17.4.3 Base Case with Natural Gas ....................................................................... 397
17.4.4 Base Case Without Natural Gas ................................................................. 398
17.4.5 Efficient Scenario With Natural Gas ............................................................ 400
17.4.6 Efficient Scenario Without Natural Gas ......................................................... 402

ANNEX A: COST OF CAPITAL STUDY ...................................................................... 405
ANNEX B: X FACTOR STUDY .................................................................................. 406
ANNEX C: DEPRECIATION STUDY ........................................................................ 407
ANNEX D: JPSCO WHEELING PROPOSAL ............................................................. 408
ANNEX E: DECOMMISSIONING STUDY 1: OLD HARBOUR .................................. 409
ANNEX F: DECOMMISSIONING STUDY 2: HUNTS BAY ....................................... 410
ANNEX G: NON – TECHNICAL LOSSES STUDY ................................................... 411
ANNEX H: AUDITED FINANCIAL STATEMENTS .................................................... 412

List of Tables
Table 1-1: Capital Expenditure 2009 - 3013 ................................................................. 19
Table 1-2: Revenue Requirement .............................................................................. 35
Table 1-3: 3yr Rolling Average .................................................................................. 40
Table 8-2: 2012 Demand Structure by Customer Class
Table 8-3: Electricity Flow and Losses by Voltage Level
Table 8-4: Load profiles received
Table 8-5: Breakdown of System Losses
Table 8-6: Parameters
Table 8-7: Test Year Billing Determinants
Table 8-8: Expected RT60 Energy Consumption
Table 8-9: Revenue Requirement by Customer Class
Table 8-10: RT10 Rate Schedule
Table 8-11: Typical Customer Bill Impact for RT10
Table 8-12: RT10 Bill Impact by Decile
Table 8-13: Shares of RT10 Sales by Tier
Table 8-14: RT10 Community Renewal Rate Schedule
Table 8-15: Typical Customer Bill Impact for RT10 Community Renewal
Table 8-16: RT20 Rate Schedule
Table 8-17: Typical Customer Bill Impact for RT20
Table 8-18: RT60 Rate Schedule
Table 8-19: Typical Customer Bill Impact for RT60
Table 8-20: RT40 and RT50 Rate Schedule
Table 8-21: Typical Customer Bill Impact for RT40 and RT50
Table 8-22: RT40 and RT50 Wholesale Tariff Rate Schedule
Table 8-23: RT40 and RT50 Customers by Demand Tier
Table 8-24: Disaggregation of the Current RT40 and RT50 Rate Schedule
Table 8-25: RT40 and RT50 Wheeling Rate Schedule
Table 8-26: RT40 and RT50 Standby Rate Schedule
Table 8-27: R10 and R20 Net Billing Rate Schedule
Table 8-28: RT40 and RT50 Net Billing Rate Schedule
Table 8-29: Non-fuel Final Rate Schedule in USD
Table 8-30: Non-fuel Final Rate Schedule in JMD
Table 8-31: Revenues by Class and Charge
Table 8-32: Fixed Revenues vs Variable Revenues
Table 9-1: JPS’ TFP Index (1991 = 1.0000)
Table 15-7: RFI Budgetary Constraints................................................................. 347
Table 15-8: Power Plant Book Values................................................................. 348
Table 15-9: Hunts Bay B6 Site Demolition Preliminary Costing......................... 351
Table 15-10: Power Plant Book Value ................................................................. 354
Table 16-1: Guaranteed Standards...................................................................... 358
Table 16-2: Complex Connections – Breaches..................................................... 362
Table 16-3: Complex Connections – Potential Compensation (JS)...................... 362
Table 16-4: Compensation Rules.......................................................................... 369
Table 16-5: Overall Standards ............................................................................ 374
Table 16-6: 2013 Performance - Planned Outages .............................................. 375
Table 16-7: 2013 Performance - Supply Restoration ............................................ 376
Table 16-8: 2013 Performance - Percentage of Call Answered Within 20 secs .... 376
Table 16-9: 2013 Performance - First Contact Resolution .................................... 377
Table 16-10: 2013 Performance - Streetlight Repairs ........................................... 377
Table 17-1: Exogenous Variables per Rate Class.................................................. 380
Table 17-2: Model Assumptions for Residential Customers (R10)....................... 386
Table 17-3: Model Assumptions for Small Commercial Customers (R20) .......... 388
Table 17-4: Model Assumptions for Four Largest Customers ......................... 389
Table 17-5: Model Assumptions for Large Commercial Customers LV (R40) ... 390
Table 17-6: Model Assumptions for Large Commercial Customers MV (R50) 391
Table 17-7: Model Assumptions for Street Lighting (R60)..................................... 392
Table 17-8: Assumptions for System Losses ....................................................... 394
Table 17-9: JPS Demand Forecast Scenario Assumptions .................................. 394

List of Figures

Figure 2-1: FX Losses versus Annual Depreciation of the JMD against the USD ... 48
Figure 2-2: Sales Decline and Decline in Real Disposable Income per Capita .... 48
Figure 2-3: Load vs Production of 1 kW PV System for Residential Customer ... 50
Figure 2-4: Number of Customers vs Number of Households ....................... 51
Figure 2-5: Customer Base .............................................................................. 52
Figure 2-6: Average Residential Consumption 2007-2013 .............................. 52
Figure 2-7: Real Disposable income per capita and GDP (2009-2013) ....................................... 53
Figure 2-8: GDP per capital vs Avg Consumption in Rate 40 and 50 Classes............................. 54
Figure 2-9: Disposable Income vs Avg Consumption of Rate 10 Customer ................................ 54
Figure 2-10: US vs Jamaican Inflation Rates ............................................................................... 55
Figure 2-11: Exchange Rate vs Relative PPP Exchange Rate ...................................................... 56
Figure 2-12: Fuel and Non-Fuel Tariffs......................................................................................... 58
Figure 2-13: Fuel Cost vs Fuel Recovery ..................................................................................... 58
Figure 3-1: Forecast Track Record (Source: IMF Country Report No. 13/378) ......................... 62
Figure 3-2: Global LNG Capacity and Demand ........................................................................... 66
Figure 3-3: Asian Future LNG – Contract, Spot & Price Formation ............................................ 67
Figure 5-1: Billed Sales (2009 – 2013) ......................................................................................... 78
Figure 6-1: Components of Revenue Requirement .......................................................................... 82
Figure 6-2: PPA Costs 2008-2013 ................................................................................................. 85
Figure 6-3: Capital Investment ....................................................................................................... 92
Figure 7-1: Actual Bond Spread, Jamaican Bonds v US Treasury Bonds ....................................... 105
Figure 7-2: Comparing the Actual Bond Spread with Jamaica’s Credit Ratings ........................... 106
Figure 8.1: Allocation of the Non-Fuel Revenue Requirement into the Utility Tariff Structure .... 109
Figure 8.2: Cost of Capital by Function ......................................................................................... 111
Figure 8.3: Operating Expenses by Function ................................................................................. 112
Figure 8.4: Total Non-Fuel Revenue Requirement by Function .................................................. 112
Figure 8.5: Allocation of Cost of Service—Fixed v. Variable Costs ............................................. 112
Figure 8.6: TCF Calculation ......................................................................................................... 120
Figure 8.7: Load Profile for RT20 General Service ........................................................................ 123
Figure 8.8: Load Profile for RT60 Street Lighting ......................................................................... 124
Figure 8.9: Load Profile for RT40 STD Low Voltage Power Service ........................................... 124
Figure 8.10: Load Profile for RT40 TOU Low Voltage Power Service ........................................... 124
Figure 8.11: Load Profile for RT50 STD Medium Voltage Power Service .................................... 125
Figure 8.12: Load Profile for RT50 TOU Medium Voltage Power Service .................................... 126
Figure 8.13: Load Profile for Caribbean Cement Company .......................................................... 126
Figure 8.14: Load Profile for Rate 10 System Curve ................................................................. 127
Figure 8.15: Average System Load Profile .................................................................................... 128
Figure 8.16: Low Voltage Load Profile ......................................................................................... 129
Figure 8.17: MV / LV Load Profile ................................................................. 129
Figure 8.18: Medium Voltage Load Profile .................................................... 130
Figure 8.19: JPS System Load Profile .............................................................. 130
Figure 8.20: System Load Profile Comparison ............................................... 131
Figure 8.21: Rate 10 Load Curve Comparison .................................................. 132
Figure 8.22: Rate 20 Load Curve Comparison .................................................. 132
Figure 8.23: Rate 40 and 50 Load Curve Comparisons ...................................... 132
Figure 8.24: Share of Non-Fuel Revenue Requirement by Customer Class .......... 141
Figure 8.25: Two Part Tariff Bill Structure ....................................................... 143
Figure 8.26: Consumer Surplus ........................................................................ 143
Figure 8.27: Consumer Surplus in Electricity .................................................... 144
Figure 8.28: Customer’s Consumer Surpluses .................................................. 148
Figure 8.29: Average Tariff Impact for RT10 ...................................................... 152
Figure 8.30: Average Tariff Impact for RT20 ...................................................... 160
Figure 8.31: Average Tariff Impact for RT40 and RT50 ....................................... 165
Figure 8.32: Average Tariff Impact for RT40 and RT50 Wholesale Tariff ............... 168
Figure 9-1: Productivity Benchmarking—Staff Numbers ..................................... 182
Figure 9-2: Productivity Benchmarking—Staff Cost .......................................... 183
Figure 9-3: Productivity Benchmarking—Non-Fuel, Non-Staff Operating Expense 185
Figure 9-4: Productivity Benchmarking—Non-Fuel Operating Expense ............... 187
Figure 9-5: Productivity Benchmarking—Capital Consumption .......................... 189
Figure 9-6: Efficiency Score of JPS Using Efficient Frontier Analysis ................... 190
Figure 9-7: Data Envelopment Analysis ............................................................. 192
Figure 9-8: JPS’ Demand Growth Has Stalled ................................................. 197
Figure 9-9: Reliability Department Organizational Chart ..................................... 211
Figure 9-10: Performance of Reliability Indices (2009 – 2012) ............................ 217
Figure 10-1: A Stylised Diagram of a Price Cap ............................................... 221
Figure 10-2: A Stylised Diagram of a Revenue Cap ........................................... 226
Figure 10-3: Average Non-Fuel Tariff under a Revenue Cap ............................... 237
Figure 10-4: Three Demand Scenarios, Three Average Non-Fuel Tariff Trajectories 240
Figure 10-5: Demand is More Likely to Increase than Decrease .......................... 241
Figure 10-6: Real Average Tariffs are Relatively Stable ................................. 242
Chapter 1: Application

1.1 Introduction

Jamaica Public Service Limited is a vertically integrated electric utility company licensed by the Government of Jamaica to generate, transmit and distribute electricity in Jamaica.

The Company serves approximately 603,346 customers; 538,600 (approximately 89%) of which are residential consumers. The Residential Class is responsible for approximately 33% of the billed energy sales. Small commercial customers make up 10% of the Company’s customer base and consume 22% of the billed energy. The remaining customer base is made up of large industrial consumers making up less than 1% of the customer base, but consumes 43% of total billed energy.

The Company’s electricity system is comprised of 24 generation plants, 52 substations and over 16,000 kilometres of transmission and distribution lines. The generating systems use a mix of technologies including steam, diesel, hydroelectric and gas turbines to produce electricity. The Company prior to 2010, had an installed capacity of approximately 621 MW complemented by almost 200 MW of firm capacity purchased from Independent Power Producers (IPPs) under long-term Power Purchase Agreements (PPAs).

As at December 31, 2013, the Company’s generation rate base was valued at US$177 million, transmission and distribution valued at US$264 million out of a total rate base of US$607 million. Operating revenues for 2013 were US$1.1 billion comprising US$693 million for fuel revenues and US$406 million for non-fuel revenues.

JPS participated in the procurement exercise in 2009 and was awarded the licence to build a new hydroelectric power plant with 6.3MW of capacity at Maggotty and to install 3MW of wind turbines at Munro. The Munro wind project was completed in 2010 at a cost of approximately US$9 million and the Maggotty project was commissioned in early 2014 at a cost of approximately US$34 million. This represents the first new hydro-electric power plant built in Jamaica in the last 30 years.

JPS entered into new agreements for 18 MW from Wigton Windfarm in 2010, and 65MW from West Kingston Power Producers (WKPP) in 2012. In 2013, 43.5 percent of the electricity sold to customers by JPS was generated by IPPs compared with 30 percent in 2008.

Additionally, there will likely be another 78 MWs of renewable energy developed over the next 18 months under Power Purchase Agreements, which are likely to be finalized with the Developers in the near future. JPS is looking for opportunities to partner with Independent Power Producers (IPP) as part of our commitment to fuel diversification and exploring opportunities to reduce the overall cost of energy for our customers.

The period 2009-2013 was characterized by a combination of challenges and opportunities for JPS. The fortunes of JPS were inextricably linked to, and mirrored, the harsh economic environment in which the Company operated. With the intensification of the global credit crunch and accompanying economic meltdown, the Jamaican dollar devalued from $80.47 to $106.38 to the US Dollar, the inflation rate spiked to 10.35% in 2013, and the volatility of oil prices pushed
electricity costs to their highest level ever. The Jamaican government went to the International Monetary Fund and other lending agencies to obtain further aid. Additionally, the OUR maintained an unreasonable regulatory target that assigned greater risk to JPS and unfair responsibility for theft losses (which are outside its control), and significant tightening of fiscal spending in the country severely affected JPS and its stakeholders.

The main focus of JPS and the rest of Jamaica during the period was the pressing need to add new generation capacity to bring down the overall cost of energy. However, despite the push for lower energy costs, the anticipated new capacity was not installed due to a number of challenges encountered in the tender process, which was outside the control of JPS. At this time, JPS and Jamaica await the development of the new 381MW LNG-fired power plant, which is scheduled to be completed by mid 2016 if the development process begins in the near future. The LNG-fired facility has the potential to reduce the cost of electricity by at least 20% and if the country expands and adds further generation by 2018 there will be the potential to lower the overall tariffs even further.

Customers, faced with the increasing cost of energy, explored their options for more affordable solutions. In fact, over the past five years the usage by the average residential customer has declined from a high of 179 kWh/month to 152 kWh/month; a decline of 16%. JPS, on the other hand, struggled with declining revenues, sluggish demand for electricity, mounting electricity theft, increased operational costs, and stakeholder pressures – especially considerable push back regarding high electricity bills.

Against this background, JPS seized the opportunity to conduct a comprehensive strategic review, restructure critical operational areas and embrace new technologies to make for greater levels of effectiveness and efficiencies, improved service levels and better engagement of stakeholders.

1.1.1 Generation Expansion and Renewal

1.1.1.1 More Renewable Energy

Despite not being able to proceed with the planned base load 381MW power plant, JPS has continued the pursuit of new generation – focusing primarily on the addition of renewables. During the period 2009 – 2013, JPS invested more than US$55 million in capital expenditure to add over 10 MW of renewable energy to the national grid. In 2009 the Company commissioned into service the newly rehabilitated Constant Spring Hydro plant. Just over a year later, in 2010 JPS officially commissioned its very first wind project – the 3 MW JPS Munro Wind Farm. And, at the end of 2013, the Company completed its ninth hydroelectric facility – the new 6.3 MW Maggotty Hydro Plant.

1.1.1.2 Efficiency Improvements

Even as it focused on adding incremental new capacity, JPS made a concerted effort to maximize output on its other generating units. During the five-year period, JPS invested approximately US$74 million in ongoing capital expenditure to ensure the continued reliability of its plants. The result is that the units were at their most efficient level during the period. The
generating fleet in fact recorded continuous improvements in its Heat Rate performance during the period.

JPS made progress in the introduction of new technology to improve the efficiency of its operations. The Rockfort 2 engine benefited from upgrade and rehabilitation works in 2009 that increased its output from 18 to 20MW. Also, in 2009 the Company invested US$3.3 million in capital costs to add 10 MW at the Bogue Power Station in Montego Bay. This investment saw the installation of an Air Inlet Cooling System on the Bogue combined cycle power plant to facilitate the optimal production of electricity. This was the first time that this technology was being used in the English-speaking Caribbean.

Overall, JPS spent a total of US$310 million on generation, generation expansion, T&D and other projects over the past five years. These capital expenditures include investment in both the Old Harbour and Hunt’s Bay facilities to improve reliability and maintain operational viability because both these plants have been operating beyond normal useful life. Please see below for detailed presentation of the capital expenditures for the 2009 – 2013 time period.

Table 1-1: Capital Expenditure 2009 - 3013

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Generation Major</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maintenance</td>
<td>8,337</td>
<td>8,530</td>
<td>14,126</td>
<td>14,660</td>
<td>14,538</td>
<td>60,192</td>
<td>12,038</td>
</tr>
<tr>
<td>Transmission and Distribution</td>
<td>15,425</td>
<td>15,089</td>
<td>20,778</td>
<td>14,937</td>
<td>16,110</td>
<td>82,339</td>
<td>16,468</td>
</tr>
<tr>
<td>Routine Asset Replacements</td>
<td>14,809</td>
<td>13,557</td>
<td>17,928</td>
<td>13,586</td>
<td>15,778</td>
<td>75,658</td>
<td>15,132</td>
</tr>
<tr>
<td><strong>System Improvements</strong></td>
<td>393</td>
<td>1,150</td>
<td>2,251</td>
<td>1,032</td>
<td>332</td>
<td>5,158</td>
<td>1,032</td>
</tr>
<tr>
<td>Transmission</td>
<td>-</td>
<td>190</td>
<td>491</td>
<td>1</td>
<td>263</td>
<td>944</td>
<td>189</td>
</tr>
<tr>
<td>Substation</td>
<td>46</td>
<td>3</td>
<td>1</td>
<td>42</td>
<td>-</td>
<td>91</td>
<td>18</td>
</tr>
<tr>
<td>Distribution</td>
<td>347</td>
<td>958</td>
<td>1,760</td>
<td>989</td>
<td>69</td>
<td>4,122</td>
<td>824</td>
</tr>
<tr>
<td><strong>Protection &amp; Control</strong></td>
<td>223</td>
<td>381</td>
<td>599</td>
<td>320</td>
<td>-</td>
<td>1,523</td>
<td>305</td>
</tr>
<tr>
<td><strong>System Expansion</strong></td>
<td>13,890</td>
<td>20,584</td>
<td>16,389</td>
<td>15,492</td>
<td>28,318</td>
<td>94,674</td>
<td>18,935</td>
</tr>
<tr>
<td>Generation</td>
<td>10,701</td>
<td>10,681</td>
<td>7,161</td>
<td>8,935</td>
<td>19,372</td>
<td>56,850</td>
<td>11,370</td>
</tr>
<tr>
<td>Distribution</td>
<td>3,189</td>
<td>9,903</td>
<td>9,228</td>
<td>6,558</td>
<td>8,946</td>
<td>37,824</td>
<td>7,565</td>
</tr>
<tr>
<td>Transmission</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td><strong>Generation Plant Retirement</strong></td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td><strong>Loss Reduction</strong></td>
<td>6,759</td>
<td>13,384</td>
<td>16,994</td>
<td>10,596</td>
<td>6,258</td>
<td>53,990</td>
<td>10,798</td>
</tr>
<tr>
<td>Information Technology</td>
<td>1,173</td>
<td>1,666</td>
<td>2,137</td>
<td>1,327</td>
<td>4,711</td>
<td>11,013</td>
<td>2,203</td>
</tr>
<tr>
<td>Facilities</td>
<td>517</td>
<td>761</td>
<td>1,464</td>
<td>767</td>
<td>265</td>
<td>3,775</td>
<td>755</td>
</tr>
<tr>
<td>Marketing and Sales</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>46</td>
<td>46</td>
<td>9</td>
</tr>
<tr>
<td>Other</td>
<td>1,232</td>
<td>587</td>
<td>664</td>
<td>637</td>
<td>609</td>
<td>3,729</td>
<td>746</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td>47,333</td>
<td>60,601</td>
<td>72,552</td>
<td>58,418</td>
<td>70,854</td>
<td>309,758</td>
<td>61,952</td>
</tr>
</tbody>
</table>

Additionally, JPS plans to maintain the existing generation fleet and improve its system reliability for the next five years.
1.1.1.3 Future Generation expansion projects and fuel diversification

The key to lowering energy costs in Jamaica over the medium term will be to achieve fuel diversification and inject new base-load efficient generation plant. In this regard we look forward to the introduction of gas in Jamaica and the new 381MW project. The introduction of gas will also provide opportunity for certain IPPs and for our own generation at Bogue to switch from expensive oil to more affordable gas. We believe these projects can be completed in 2016 under the guidance of the OUR and GOJ and that this will lead to substantially lower energy costs for the entire sector.

We also believe there are significant opportunities for key large industrial players in Jamaica to retool and make use of Combined Heat and Power (CHP) energy solutions which can also make available low cost energy solutions for the country and the grid while also supporting the efforts for fuel diversification. We believe this approach, combined with strategic load growth opportunities as planned by the GOJ, will set the tone for several new generation expansion projects which are set to deliver low cost generation solutions for the country again making it possible for the country to substantially reduce the cost of energy and significantly reduce its oil bill from the current amount of US$2.4 billion per annum.

Centralised planning will be critically important to ensure this happens in a structured and coordinated manner. To this extent we will be conducting an Integrated Resource Plan over the upcoming months and offering our continued advice and support to the GOJ. One of our biggest risks now as a nation is having an uncoordinated approach towards generation expansion which results in sub-optimal solutions for the country and excess capacity, as individuals pursue their own best efforts. The risk of over-capacity is real given the long-term commitment that is being made (20 years) for the next round of generation (381 MW) and our need to ensure that we fully utilize this capacity and other planned generation expansion opportunities.

1.1.2 Ensuring Supply Reliability

Service reliability was high on JPS’ agenda during the period 2009 – 2013. JPS has spent more than US$600 million in both Capital and Operating & Maintenance expenses over the period to improve the reliability of supply to customers. While some of this went towards enhancing the performance of its power plants, on the transmission & distribution side, the Company introduced new technology to better track and respond to outages, upgraded some of its substations, and improved the integrity of its power distribution network.

1.1.2.1 Duhaney Substation Reliability Improvement

One of the key initiatives implemented during the period was the Duhaney Substation Reliability Improvement Project. This project is of great significance to JPS and its customers, due to the critical role played by the Duhaney Substation as the hub for electricity moving in and out of the corporate area. Over time Duhaney had become a bottleneck due to limitations and weaknesses in the grid’s security and reliability, which had worsened as the network got older. This is evident in the fact that in the last decade alone, there were four (4) island-wide system blackouts linked to this substation.

The Duhaney Substation Reliability Improvement Project was developed to reconfigure the key elements of the substation, to allow for quicker and more effective isolation of faults so fewer
customers are affected by problems on the system, and to facilitate more effective and timely preventative maintenance. The project successfully improved the substation’s fault clearing capabilities and thereby reduced the likelihood of an extensive system outage as a result of a single fault.

1.1.2.2 Improved Outage Management

In 2013 JPS introduced an Outage Management System (OMS), which models network topology for safe and efficient field operations related to outage restoration. The OMS enhanced the technology solutions that had been implemented on the T&D network incrementally over the five-year period – specifically to identify and correct areas of reliability weakness. In addition to the major capital investment programmes, the Company implemented a number of short term mitigation measures that were gradually built into routine maintenance activities. Among the initiatives were:

1. Utilization of MV Covered Conductors to reduce the impact of vegetation;
2. Acquisition of the SynerGee Software to improve fuse coordination and reduce the extent of outages;
3. Application of Fault Circuit Indicators to improve fault identification and improve response time to outages;
4. Application of ultrasonic leakage current detector (Inspector101) to identify and replace cracked/defective insulators;
5. Utilization of Infra-red scanning of hot joints, enabling maintenance crews to identify potential failure points;
6. Increased Installation of pole-mounted reclosers to reduce the extent and impact of outages;
7. Implementation of the distribution automation initiative; and
8. Implementation of lightning mitigation programmes on selected transmission & distribution circuits.

On the transmission network, a number of substations were modified to prevent any one failure on the transmission line from causing a great impact on substation outages. These include substations on the north coast corridor, Rhoden's Pen, Porus, Highgate and Oracabessa.

The result is the Company recorded a 33% reduction in power outages over the period. In 2009, there was an average of 26.22 outages per customer for the year. However, in 2013, this had been reduced by one-third, to an average of 17.65 outages per customer, as measured by the System Average Interruption Frequency Index (SAIFI).

1.1.3 Tackling System Losses

System Losses, particularly non-technical losses, continued to be a major threat to JPS’s viability over the period 2009 – 2013, especially because of the manner in which OUR has determined the system loss threshold. JPS was forced to take a fresh approach to loss reduction in 2009, which included: the formation of special teams dedicated to losses; the commissioning of a comprehensive study on the factors driving losses; investment of unprecedented levels of capital on losses; the use of technology; and deeper partnerships with the security forces to facilitate the arrest and charging of persons caught stealing electricity.
However, the fundamental problem of electricity theft, remains one which is outside of the control of JPS given this is a socio-economic problem (a criminal act) occurring all across the island. A concerted effort with all of the key stakeholders, including the Government of Jamaica (GOJ), will be key to tackling this problem in a meaningful and sustainable manner, and as described further below, the OUR must objectively set threshold system loss targets rather than setting the thresholds at unreasonable levels that unfairly penalize JPS.

As the evidence demonstrates that losses from such socio-economic issues are beyond JPS reasonable control and would require concerted efforts from the public and GOJ to resolve, JPS has demonstrated that it is unjust and unreasonable to penalize JPS for losses from theft and why revision of the system loss penalty regime is strongly warranted. As discussed below, revision of the performance indices as proposed herein will not impact JPS efforts to reduce all system losses and JPS remains committed to its system loss reduction program outlined below.

1.1.3.1 Multi-Pronged Approach

A range of initiatives were implemented during the period to reduce non-technical losses. The Company carried out a meter replacement project to remove from service degrading electromechanical meters, which were contributing to losses. These were replaced with digital meters. A number of meter centres were also installed, whereby the meters were removed from residences and installed in tamper-proof cabinets (or meter centres) mounted on poles.

JPS maintained its strike force activities and removal of illegal ‘throw-up’ lines, meter inspections and audits, continuous monitoring of large accounts, as well as investigations of accounts with suspected irregularities. Indeed, with the assistance of the police, 2013 was a record breaking year in terms of the number of arrests made by the police for the theft of electricity (there were approximately 1,300 arrests), however, with more than 180,000 households estimated to have illegal access to electricity, we believe there will have to be substantial changes in law and the regulatory approach if we are to seek a meaningful way to bring these persons to ‘books’ and to help them regularise their service.

We have begun discussions with the GOJ and its relevant agencies on a new way forward towards losses, which through the assistance of the GOJ and certain key stakeholders will try to address the fundamental problems through a community renewal effort. In this submission we will be seeking the approval of the OUR to fund these activities which will have a strong focus on social intervention as detailed in great detail in Chapter 13 of this submission. While those efforts are significant and we look forward to working with GOJ and other stakeholders on those programs, JPS expects that the OUR will address the system loss threshold issue in keeping with the recommendations of the KEMA study and cap the risk to JPS.

1.1.3.2 Using Technology to Fight Losses

Technology was an integral part of the anti-theft focus, and included initiatives such as the Energy Balance Project, aimed at allowing the Company to ascertain net generation, transmission and distribution losses, and losses per feeder - with 100% accuracy. JPS implemented the Commercial Anti-theft Advanced Metering Infrastructure (CAAMI) and Residential AMI (RAMI) in high loss communities and saw immediate reductions in losses right after completion of these installations. The results, have been short-lived in some communities, however, so the benefits to the Company have not been sustained.
In spite of its relentless efforts, JPS continues to suffer from significant losses as a result of electricity theft. The Company is therefore engaged in ongoing dialogue with the government and other stakeholders with a view to reducing this threat. This in recognition of the fact that the theft of electricity is a crime which arises out of the socio-economic challenges of the country and a problem which must be addressed by all key stakeholders and not JPS alone.

1.1.4 Improving Efficiency with Technology

The core areas of generation, transmission and distribution, and loss reduction were the main beneficiaries of the new technological solutions, which formed an integral part of the Company’s strategy to improve the efficiency of its operations during the period.

1.1.4.1 Emergency Backup Site for Business Continuity

In 2010, JPS commissioned its Emergency Backup Control Centre in Montego Bay, the country’s second largest load centre, in order to ensure business continuity in the event that its primary System Control Centre (SCC) in the capital city, Kingston, becomes unavailable. The Emergency Backup Site is able to seamlessly take over the critical functions normally carried out by the SCC in maintaining systems reliability and effective grid operations.

1.1.4.2 Mission Critical Systems

During the period, the Company also installed a range of mission critical IT solutions including:

- Mobile Work Force Management System/Service Suite along with the Outage Management System, to ensure automated dispatch of work orders to team members in the field;
- Contact Centre Systems upgrade which included the enhancement of the Company’s Avaya Call Centre System;
- Infrastructure for a Prepaid Metering System to introduce prepaid electricity as a payment option using existing RAMI meters; and
- A Power Quality Monitoring and Reporting System to detect, record and store otherwise unnoticed events and provide a tool to analyze them.

JPS has maintained its focus on the use of technology for greater efficiency, and in 2013 started preliminary work towards the implementation of a new Customer Information System, which is expected to result in significant improvements in customer service when commissioned in August 2014.

1.1.5 Making Customers Satisfaction a Priority

In the past five years, JPS made several organizational changes to facilitate better service and improved customer relations. Most significantly, the Company decentralized its operations to better meet the needs of customers at the local level. This involved the appointment of Regional Directors and Parish Managers, with responsibility for managing the Company’s relationship with customers across the island.
Additionally, as part of its commitment to improve customer satisfaction, in 2012 JPS effected more changes in Customer Care, including the creation of a new dedicated arm of customer service, the Customer Satisfaction team. The work of this team enhanced the efforts of the parish teams and the Customer Care Centre, resulting in notable service level improvements and a reduction in customer complaints.

1.1.5.1 Partnerships with Customers

Building on its ongoing energy efficiency drive, in 2013 JPS established a retail arm, the JPS eSTORE, which provides a range of services and products to help customers manage their electricity usage. The eSTORE formed part of the Company’s strategy to be more than just an electricity provider, but an energy partner – providing an energy solution for every Jamaican.

JPS’ partnership with its stakeholders included the connection of forty-three Net Billing customers, who were empowered to sell excess from renewable generation to the national grid.

Customer feedback continued to be an important part of the customer service improvement process. During the period, JPS continued to do annual Customer Satisfaction Surveys, and use the results to target areas for improvement. The Company also established a Customer Advisory Council, with representatives from different rate classes and sector groups, who provided valuable feedback to help guide the Company’s service improvement efforts.

1.1.6 Corporate Social Responsibility

In recognition of its role as a critical partner in national development, JPS took steps to ensure that it carried out its business in a socially and environmentally responsible manner, while contributing to the country’s economic and social development.

1.1.6.1 Promoting Economic Growth

The Company continued to be a strong supporter of activities and events geared towards Jamaica’s economic growth and development. These included partnerships with business sector groups as well as energy management support for businesses, particularly small companies. JPS sponsored several economic development initiatives in collaboration with JAMPRO and various umbrella business organizations, including: the Young Entrepreneurs’ Association, the Small Business Association of Jamaica, the Jamaica Manufacturers’ Association (JMA), the Jamaica Exports’ Association (JEA), Private Sector Organization of Jamaica (PSOJ), the Jamaica Chamber of Commerce (JCC), and the Jamaica Hotel & Tourist Association (JHTA).

The success of JPS is inextricably tied with the growth and prosperity of Jamaica. The growth of demand in Jamaica over the upcoming years will be the key to supporting the fuel diversification effort and the ability to build new low cost generation projects that will ultimately lower the cost of energy for all of Jamaica.

1.1.6.2 Investing in Jamaica’s Youth

JPS has continued its tradition of providing opportunities for Jamaica’s youth to shine, with ongoing investments in education, sports and community development. The Company invested millions of dollars in the country’s development, through initiatives such as grants to the nation’s
universities – University of Technology, University of the West Indies, and Northern Caribbean University – specifically to support academically outstanding students in need of financial assistance.

The JPS-sponsored homework centres in the vulnerable communities of Denham Town in Kingston, Old Harbour Bay in St Catherine, and Farm Town/Rose Heights in St James, have continued to provide a safe haven for children to access the internet, do homework and study. Additionally, more than 20,000 children benefited each year from JPS’ early childhood nutrition programme. The Company also continued to provide summer employment for hundreds of young people, and provided sponsorship for athletics, as well as community football and netball competitions.

1.1.6.3 The JPS Foundation

With the launch of the JPS Foundation in 2013, the Company intensified its focus on Education and Youth Leadership, which are recognized as areas with the potential for greatest contribution to national development. Early childhood education continues to be a key area of focus. The Foundation launched a model school programme, through which three schools are being developed to meet the standards established by the Early Childhood Commission. JPS Shareholders, Marubeni, is partnering with the Foundation on the model school initiative, with a commitment of US$35,000 towards the development of one of the schools – the Rennock Lodge Infant School in Kingston. The Foundation also launched a Youth Leadership initiative, specifically for students in tertiary institutions. JPS Shareholders, Korea East West Power Company (EWP), is partnering with the Foundation in this area, by providing scholarships for Jamaicans to do post-graduate studies in Korea.

1.2 Tariff Regulatory Framework

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

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

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

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

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

- $\Delta I$ = the weighted average of US and Jamaican inflation (in a proportion equal to the split of domestic and foreign components of non-fuel costs);
- $X$ = the offset to inflation resulting from expected productivity improvements;
- $Q$ = price adjustment to reflect performance against the quality of service targets set by the OUR; and
- $Z$ = price adjustment for special reasons not captured by the other elements of the price cap mechanism including (but not limited to) costs and losses related to natural disasters and other Force Majeure events.

The targets, like the price cap, may be fixed for the five-year period of the price cap and adjusted at tariff resets. However, the existing price cap mechanism has not provided a good economic hedge to ensure the utility’s viability. The company is proposing a global revenue cap to ensure sufficient revenues are collected to cover all prudent costs and provide a proper rate of return to encourage investment. The revenue cap also has the advantage that it aligns the utility’s goals with the GOJ’s policies which promote energy efficiency programs, net billing and wheeling, which in general will reduce the utility’s energy sales. This is a very important consideration given the high proportion of fixed costs which are being recovered through the energy charge which varies with kWh sales.

1.2.1 Filing of Non-Fuel Tariff Application

The current non-fuel tariff rates, fixed by the OUR effective October 1, 2009 are set to expire upon approval of the new rates presented herein. To obtain new non-fuel tariff rates, the Licence stipulates that JPS must submit a filing with the OUR by the succeeding fifth anniversary of the last submission.

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

1. an application for the recalculation of the non-fuel base rate;
2. A report on the quality of service provided by the Company during the last five years; and
3. proposed revisions to several PBRM components with justification;

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

The filing is organized as follows:
Section 1: Presents a summary of the proposals contained within this submission.

Section 2: Presents the economic overview of the Jamaican economy.

Section 3: Presents the macroeconomic outlook for 2014 through 2019

Section 4: Presents the Company’s outlook for the next five years, its forecast of the economic environment in which the business operates, its strategic objectives and the methodologies it will implement to achieve its corporate goals.

Section 5: Presents the Tariff Performance Review

Section 6: Presents the Revenue Requirement calculations using the test year financial data appropriately adjusted for known and measurable changes, with justification

Section 7: Provides the Company’s calculations of the weighted cost of capital (WACC) and all its components.

Section 8: Details the new tariff design and explains the derivation of the new rates.

Section 9: Provides the details and bases for setting the X and Q-Factors for the revenue cap period.

Section 10: Presents the discussion on the proposed Revenue Cap rate adjusting mechanism.

Section 11: Presents the discussion on the proposed Foreign Exchange (FX) adjustment mechanism.

Section 12: Proposes adjustments to the fuel rate and fuel efficiency measures.

Section 13: Discusses the details of the various system losses initiatives, past and present.

Section 14: Shows the calculation of the other fees, such as prepay discount, disconnection, reconnection, and security deposits,

Section 15: Discusses the decommissioning of Old Harbour and Hunts’ Bay

Section 16: Proposes revisions to the quality of service standards.

Section 17: Presents the Load Forecast for the Utility for 2014 through 2019

1.3 The Price Cap Regime

The 2014 – 19 Rate Case Submission by JPS is seeking to build upon the advances made during the 2009 – 14 regulatory period while identifying and proposing solutions to the new challenges that have emerged.

The OUR’s Determination of September 18, 2009, addressed a number of shortcomings with the existing tariff that JPS had identified at the time of its Submission. The Determination provided greater predictability of cost recovery by adequately addressing certain areas of revenue leakage while challenging JPS to improve efficiency through the imposition of tough efficiency and service standard targets.

Highlights of the 2009 Determination include:

- JPS cost of equity was set at 16%. The cost of long-term debt was set at 10.44%. The overall WACC was set at 17.43% with a gearing ratio of 48%.
JPS’s Rate Base was set at US$554 million.

Revision of the fuel rate calculation and reduction of the system heat rate target to 10,400 kJ/kWh. The OUR introduced the philosophy of an annual review and reset after new capacity additions to the national grid.

System loss targets were set at 19.5% for 2009/10 and 17.5% in 2011/12. The amount of 0.4 US ¢/kWh was embedded in the tariff to fund AMI and other anti-theft technology to augment the loss reduction efforts of JPS.

Full recovery of IPP costs. IPP costs in excess of the non-fuel base rate could be recovered through an IPP surcharge included in the monthly fuel rate.

The reconnection fee was set at $1,500.

Adjusted the self-insurance fund, including a gross up for taxes, to US$5M per annum net (US$7.5M gross), which is funded from the non-fuel tariffs.

An X-factor target was set at 0% for 2010. The X-factor for the adjustment for June, 2011 and the adjustment for subsequent years was set at 2.72%.

The OUR established the basis for monitoring the quality of service delivered by JPS and later established specific Q-factor targets.

1.3.1 Performance under Price Cap 2009 – 2014

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

At the time of the 2009 submission, JPS stated that the request for a new tariff was to achieve the following objectives in support of the goal of the PBRM to balance the interest of all stakeholders:

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

JPS can demonstrate that it has made significant success with the first two objectives, those that are more directly within its control. JPS came close to achieving the allowed return on investment in 2009; however, the Company’s net profit fell way below this level from 2010 to 2013. During the review period, the Company’s return on investment was significantly affected by increased business risks and regulatory implementation issues arising from: declining sales, FX losses because of currency depreciation (which occurred in every year except 2010), the under-recovery of fuel costs resulting from the reduction in the regulatory target for system losses compared to the increasing trend in the actual system losses being experienced, and the regulatory application of this target to include losses from theft demonstrably beyond JPS’ control, this was particularly felt from 2011 – 2013 when organic sales fell by 2% per year
because of customer conservation efforts. The effect of these business risks and regulatory implementation issues is discussed in the following section.

1.3.2 Operating Cost & Productivity Improvements

Consistent with the incentives provided in the price cap regime JPS has improved its cost efficiency since the last tariff period as reflected in the containment of operating and maintenance (O&M) costs over the period. This improvement in cost efficiency was confirmed by a benchmarking study of JPS’ non-fuel cost performance conducted by Castalia.

JPS has increased efficiency at an annual rate of 0.5 percent from 2006-2011. JPS is a very efficient utility and its efficiency is comparable to industry leaders, such as Florida Power & Light.

As a result of these productivity gains, JPS is now at the efficiency frontier for its industry, as shown by these three efficiency analysis techniques:

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

Another area that JPS continues to take steps to be cost competitive in is that of head count. Since 2009, JPS has reduced its head count by a further 15% as it seeks to improve the organisation’s efficiency. This resulted in the reduction of full-time employees from 1,247 in 2009 to 1,062 in 2013 while improving the quality of service at the same time.

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

1.3.3 Improvement in Service Reliability

The JPS fleet of generators continues to operate at the highest average level of efficiency and reliability possible for units of their vintage.

Availability of generators, forced outage rates and heat rate (efficiency of conversion of oil to electricity), the three critical measures of performance have shown consistent and sustained gains over the 2009 – 13 period.

JPS has invested significantly in the existing generating units over the past five years to effect such operating improvements. Generally, the heat rate performance of the existing fleet of units represents the best levels that will be achievable over the next five years. Greater levels of efficiency may be achieved with some design improvements or through fuel diversification but would require significant capital investment. Given the retirement schedule for the units it is not considered cost effective.

These statistics have translated into real quality of service improvements for customers as measured by the System Average Interruption Frequency Index (SAIFI) and the System Average Interruption Duration Index (SAIDI) for generation. These gains are evident of the Company’s
delivery on a commitment to invest in the rehabilitation of existing power plants, in tandem with its plans to transition to a modern mix of fuel-diversified power plants.

1.3.4 Service Standards

Beyond power quality and reliability, the main indicators of JPS performance in customer service delivery are the Guaranteed and Overall Standards. In this area JPS continues to make advances and now averages a compliance rate of over 90% with the majority of the standards. Customers have enjoyed the benefit of the Company’s commitment to quality service delivery. In some instances, JPS has opted to operate internally at an even more aggressive standard than mandated by the OUR. For the few standards on which JPS is currently under-performing, the Company has committed, in this submission, to dedicate additional resources to become fully compliant during the 2014 – 19 period.

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

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

1.3.5 Returns to Investors and Risk Management

While the 2009 – 14 tariff regime was a difficult period of success for JPS, despite continued improvement in service and product reliability, as well as efficiency and productivity gains, it fell well short of adequately protecting investors’ opportunity to earn a fair return on capital invested. The tariff regime also protected customers from excessive costs but left the Company vulnerable to risks outside its control.

For the 2010 – 2013 period for which audited financials are available, JPS made an accumulated net profit of $96 million, which amounts to an average annual profit of $24M, or an average ROE of 6% p.a. The target profit for JPS, allowed (not guaranteed) through the revenue requirement, has never been achieved, representing an allowed return on equity (ROE) of 16% that was approved in 2009, which should have resulted in a net profit of approximately US$43 million per annum.

This disappointing trend clearly does not augur well for the long-term prospects of the Company to continue to attract financing to the business in the very capital-intensive electricity sector, particularly given the clear falling trend in profitability all throughout the regulatory period. In this regard JPS is particularly concerned with the regulatory target setting process for system losses, as the setting of the target to 17.5% in July 2011 has had a severe negative financial impact on the Company as will be demonstrated in several sections throughout this document. The viability of the utility is critically dependant on a fair and objective basis for setting the system losses target and its application. Currently, the system loss target unjustly penalizes JPS for third-party theft beyond JPS’ reasonable control, which fails to meet the public interest by
pointlessly punishing and harming JPS for third-party conduct and failing to address the root socio-economic causes behind the losses which, are outside of JPS’ control. The penalty as currently implemented does not help to resolve the system loss issues. Therefore, JPS has included the proposals herein to modify the regime, better tailor it to the issues, and presented more information on its system loss reduction program.

A utility in a highly capital intensive industry needs a stable cash flow to be able to raise much needed long-term sources of capital. It must also maintain a healthy financial position to ensure it complies with the relevant financial covenants to ensure the business is adequately funded.

The current financial performance trend not only bodes a negative outlook for JPS but constrains as well the IPP-based model of generation expansion favoured by regulatory policy. The performance of IPPs is inextricably linked to the financial fortunes of JPS, which pays for purchased power under long-term Power Purchase Agreements (PPA) as the sole off-taker of electricity in Jamaica.

1.3.6 Fuel Penalty

As part of the PBRM framework, the OUR has implemented a penalty/reward system to encourage JPS to operate its generating plants efficiently and also to keep total system losses (including theft) to 19.5%/17.5% of net generation. The penalty is applied to the total monthly fuel cost JPS is allowed to recover from customers through the fuel rate.

Significant investment in plant rehabilitation, the introduction of 65.5 MW of new capacity by one IPP and generally good plant performance across the system has led to improved heat rate performance over the last tariff period. The Company has therefore been able to meet the heat rate target with sufficient regularity to avoid material adverse impact on its earnings.

However, JPS has continued to under-perform against the 17.5% target for system losses, which remains the single most stubborn and pernicious threat to the viability of the electricity sector in Jamaica. At the end of 2013 losses, technical (8.6%) and non-technical (largely theft – 18.04%), stood at a total of 26.64%.

Over the 2009 – 13 period JPS was not allowed to recover US$111 million in fuel costs due to fuel penalties. The magnitude of the penalty varies with the price of oil and the risk exposure was amplified with the spike in the price of oil over the past two years. Fuel is by far the largest element of cost for JPS, representing approximately 70% of the total cost, and therefore, has the most influential and immediate impact on JPS’ financial fortunes. It is for that reason, JPS believes, that the Licence contemplated full recovery of fuel costs subject to reasonable efficiency adjustments.

The Company has made a proposal in this submission to cap the real risk exposure to JPS of fuel cost under-recovery, while preserving the ability of the OUR to target efficiency improvements in heat rate and system losses. The Company has also made a proposal for an objective and fair basis for setting the target in the future which will remove the high level of subjectivity currently adopted in the target setting process.
1.4 Objectives of New Tariff Submission

The objectives of the 2014 – 19 tariff proposals are:

(i) To ensure fair and cost-reflective tariffs that send appropriate price signals but allow all customers affordable access to the product;

(ii) To ensure JPS remains viable so as to continue attracting much needed capital to improve system reliability and quality of service;

(iii) To provide an attractive tariff to the largest industrial customers to encourage economic growth and development for the country;

(iv) To continue the improvement in product quality and service delivery to customers with particular focus on the T&D network and to reducing system losses; and

(v) To mitigate the Company’s exposure to risks outside its control.

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

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

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

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

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

However, to support continued access to electricity service for the most vulnerable social group, JPS has proposed the introduction of a new tariff design that will restrict the increase to both residential and small commercial enterprises that consume at the lowest consumption band. The new tariff design is reflective of the cost to serve the various rate classes. It will also begin to rebalance the proportion of revenue that the Company earns from fixed charges and variable energy charges and so lead to a more cost reflective tariff in terms of fixed cost recovery. Currently approximately 89% of JPS’ non-fuel costs are fixed while only 23% of revenues are recovered through a fixed charge.

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

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

1.4.1 Summary of Proposals

1. Revenue Cap

JPS proposes a Revenue Cap approach, discussed in Section 9, which will allow the Company the flexibility to rebalance the tariff baskets at the annual adjustment for variation in sales mix and sales growth. A revenue cap maintains the desirable efficiency targets and customer protections under the existing price cap approach. It minimises demand risk, avoids a tariff restructuring in relation to the mismatch between fixed costs and fixed charges, and enables JPS to become a full partner in Jamaica’s energy policy goals of generation choice and energy efficiency.

2. Tariff Design (See Section 8 for complete details)

JPS is proposing a new three-tiered rate class structure for residential (Rate10) and four tiered rate class for small commercial (rate 20) customers. Different service/customer charges and energy charges will apply to the tiers. The redesign is a more cost reflective tariff structure that applies a minimal increase to customers consuming at the lowest levels in Rate 10 and Rate 20 classes. With this structure JPS is attempting to keep electricity prices affordable to marginal and vulnerable customers. The new structure will introduce two tiers of service/customer charge for rate 10 customers and four tiers for rate 20 customers. Notably, the customer charge is being replaced with a network access charge to ensure a more appropriate allocation of capacity charges for rate 10 and 20 customers who before paid little or no capacity charge. This reduces the high level of fixed costs that were otherwise being recovered through the energy charge which is not a desirable tariff structure in terms of ensuring the tariffs are cost reflective based on the latest cost of service study.

The following tiered rate structure will result:

- Rate 10 customer with monthly consumption less than 100 kWh/month (1st tier)
- Rate 10 customer with monthly consumption between 101 kWh/month and 500 kWh/month (2nd tier)
- Rate 10 customer with monthly consumption over 500 kWh/month
- Prepaid tariff for residential customers wanting greater control of their usage
- Community Renewal for customers in designated marginal communities seeking regularised service through Government of Jamaica coordinated plans
- Rate 20 customer with monthly consumption less than 100 kWh/month (1st tier)
- Rate 20 customer with monthly consumption between 101 – 1,000 kWh/month (2nd tier)
- Rate 20 customer with monthly consumption between 1,001 – 7,500 kWh/month (3rd tier)
- Rate 20 customer with monthly consumption greater than 7,500 kWh/month (4th tier)

JPS is proposing the elimination of the non-fuel energy rate for Rate classes 40 and 50, while increasing the demand charge for this group based on the cost of service study. This will send a good price signal to customers, which rewards them for having a good load factor. The fuel charge will remain the primary variable charge for this group and will likely represent 70 to 75% of their total bill.

JPS is introducing a wholesale rate for its largest customers based on the cost of service study to encourage the largest customers with demand in excess of 1 MVA to remain on the JPS network as a full service customer. This ensures a practical option to wheeling is provided to such large industrial customers and avoids the loss of large demand loads, which has the potential to drive up the cost of electricity for all remaining customers on the system. It also ensures the efficient allocation of capital for the country, avoids the possibility of excess capacity in Jamaica and encourages economic development which in turn will create more jobs, grow the demand of the country and make electricity more affordable for all customers.

JPS is introducing Wheeling rates for customers who wish to self-generate. These rates will include Standby rates to ensure there is service available for the Wheeling customers if the Wheeling customer’s operating units are not operational due to scheduled maintenance or forced outages. These rates are being designed with Best Available Alternatives in mind to ensure proper pricing for the service.

3. Cost of Capital (See Section 7 for complete details)

JPS proposes that the pre-tax WACC method be used in determining the WACC for the 2014 tariff review. The ROE was calculated using the CAPM methodology and the long-term debt cost reflects the embedded costs of debt for the utility. A summary of how the pre-tax WACC of 19.3% was determined is provided below with a comparison to the adjusted pre-tax WACC for 2009 - 14.

The table below compares the WACC being requested by JPS with the one approved for the previous regulatory period. The table shows that the WACC JPS is requesting is slightly higher than the WACC granted by the OUR in 2009. A higher WACC for JPS from the one granted five years ago makes sense since the risk associated with JPS’s business has increased due mainly to an increase in Jamaica’s country risk.
4. Revenue Requirement (See Section 6 for complete details)

JPS has determined the non-fuel revenue requirement is US$472.8M based on the audited financial statements of the test year 2013, appropriately adjusted to reflect normal operation conditions. The table below provides a summary of the components of the revenue requirement. Following standard regulatory practice, JPS has calculated the revenue requirement consistent with the methodology set out in Schedule 3 of the Amended and Restated All-Island Electric Licence 2011 ("the Licence"). Table 1-2 shows the Company’s revenue requirement for the test year 2013.

Table 1-2: Revenue Requirement

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Risk-free Rate</td>
<td>2.3%</td>
<td>3.4%</td>
<td>2.7%</td>
<td></td>
</tr>
<tr>
<td>Equity Risk Premium (Mature Market)</td>
<td>8.2%</td>
<td>7.5%</td>
<td>5.0%</td>
<td></td>
</tr>
<tr>
<td>Equity Beta Relevered</td>
<td>0.87</td>
<td>0.87</td>
<td>0.86</td>
<td></td>
</tr>
<tr>
<td>Country Risk Premium</td>
<td>4.43%</td>
<td>6.08%</td>
<td>15.0%</td>
<td></td>
</tr>
<tr>
<td>Country Risk Premium Integrated*</td>
<td>4.43%</td>
<td>6.08%</td>
<td>12.9%</td>
<td></td>
</tr>
<tr>
<td>Return on Equity (ROE)</td>
<td>14.9%</td>
<td>16.0%</td>
<td>19.8%</td>
<td></td>
</tr>
<tr>
<td>Cost of Debt</td>
<td>12.6%</td>
<td>10.4%</td>
<td>8.1%</td>
<td></td>
</tr>
<tr>
<td>Tax Rate</td>
<td>33.3%</td>
<td>33.3%</td>
<td>33.3%</td>
<td></td>
</tr>
<tr>
<td>Gearing Ratio (D/D+E)</td>
<td>44.0%</td>
<td>48.0%</td>
<td>48.0%</td>
<td></td>
</tr>
<tr>
<td>Post-tax WACC</td>
<td>12.0%</td>
<td>11.6%</td>
<td>12.9%</td>
<td></td>
</tr>
<tr>
<td>Pre-tax WACC</td>
<td>18.1%</td>
<td>17.4%</td>
<td>19.3%</td>
<td></td>
</tr>
</tbody>
</table>

Operating Costs:

- Purchased Power Costs: 104,111
- O&M Expenses: 150,845
- Net Financing Costs: 12,338
- FX Losses: 14,000

Capital Costs:

- Depreciation: 57,498
- Return on Investment: 93,827
- Long-Term Interest Expense: 23,507

Other Income/Expenses:
In accordance with the Licence the revenue requirement represents the twelve months of operations for the year ending December 2013, adjusted by known and measureable changes to reflect normal operational conditions. The changes include adjustments to O&M Expenses, depreciation and the Self Insurance contribution and were absolutely necessary to ensure that revenues reflect the operating conditions of the rate year. Each known and measureable adjustment will be discussed later in the relevant subsections in this chapter.

As part of the proposed Revenue Requirement, JPS proposes a $4.5 million reduction to the annual funding rate for the Electricity Disaster Fund, and a $1.25 million reduction in costs associated with moving to alternate monthly meter reading for residential customers. These recommended reductions are made primarily to help keep the cost of electricity affordable to our customers in acknowledgment of the need to keep our non-fuel costs to a minimum level without compromising the quality of service to be delivered.

5. Performance Based Rate Making Mechanism Components (See Section 9 for complete details)

i. X–Factor

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

“The X-Factor is based on the expected productivity gains of the Licensed Business. The X-Factor is to 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".”

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

---

1. The rate year is defined as the period when the new price control rates will be put into effect.
• Using the fundamentals approach, the X-factor would be set to zero percent, since the difference between the expected TFP growth of JPS and the expected TFP growth of the economy is zero.
• Using the calculations approach, the X-factor would be set at 0.35 percent for the 2014-2019 tariff period. Additionally, because JPS is operating at the industry efficiency frontier, no stretch factor should apply.

ii. Q-Factor

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

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

• SAIFI—this index is designed to give information about the average frequency of sustained interruptions per customer over a predefined area.
  \[
  SAIFI = \frac{\text{Total number of customer interruptions}}{\text{Total number of customers served}} \\
  \text{(Expressed in number of interruptions per year)}
  \]

• SAIDI—this index is commonly referred to as customer minutes of interruption and is designed to provide information about the average time that customers are interrupted.
  \[
  SAIDI = \frac{\sum \text{Customer interruption durations}}{\text{Total number of customers served}} \\
  \text{(Expressed in minutes)}
  \]

• CAIDI—this index represents the average time required to restore service to the average customer per sustained interruption. It is the result of dividing SAIDI by SAIFI.
  \[
  CAIDI = \frac{\sum \text{Customer interruption durations}}{\text{Total number of interruptions}} \\
  \text{(Expressed in minutes per interruption)}
  \]

Additionally, the OUR proposed the addition of a fourth quality measure known as:
MAIFI—this index is designed to give information about the frequency of momentary outages (those of durations of 5 minutes or less) per customer over a predefined area.

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

(Expressed in number of interruptions per year)

Overall, JPS’ reliability improved between 2009 and 2013, SAIFI declined from 26.22 in 2009 to 10.53 in 2013 and SAIDI also trended downwards moving from 38 hours per customer to 22 hours per customer in 2013. This was the same trend that was seen for the customers minutes lost (CML). The CML for 2011 and 2012 were considerably less than for 2009 and 2010 indicating that generally there is a declining number of customers affected by interruptions. The CAIDI has been more or less consistent over the period although it moved to over 2 hours per interruption in 2013. The system outage in August 2012 contributed to the increase in SAIDI and CAIDI between 2012 and 2013. In addition, a major outage in March 2013 impacted the increase in CAIDI between 2012 and 2013. Under the IEEE 1366-2012 these major events as are all outages would continue to be recorded but separately identified so as to allow for a true and pure assessment of the normal reliability trend.

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

The company is working to finalize outstanding issues with the OMS system and to validate the data from the system as described in Section 5. JPS has estimated that an additional twelve (12) months from March 31, 2014 is required to complete the gathering of accurate reliability indices data for the establishment of a baseline to be used in the computation of the Q factor in the tariff at the 2015 annual adjustment.

6. Efficiency Adjustment measures used in the fuel rate calculation (Section 12, 13)

JPS proposes the introduction of a cap on the fuel incentive mechanism equal to 1.5% of the fuel cost or US$1 million per month, whichever is less, with the application of the fuel efficiency measures, i.e. heat rate and system loss. The proposal is for the cap to be symmetrical thereby reducing the upside or downside exposure of JPS in relation to fuel costs. This is considered necessary to keep the tenants of a good incentive mechanism without exposing the utility to unlimited risk which could easily result in severe financial penalties given the volatility in fuel prices and the fact that theft losses directly affect the recovery of JPS fuel costs, and theft is a crime which JPS cannot by itself contain, nor should it be solely responsible for. This cap is important to ensure the viability of the business.

7. Heat Rate Target (See Section 12 for complete details)
Based on the planned mix of generating units, including IPPs, their projected availability and dispatch, and the possible variation in heat rate for reasons beyond JPS’ control, JPS proposes to keep the System Heat Rate at 10,200 kJ/kWh for the next year and that this be subject to annual review based on the impact of new generation which is added subsequently. We anticipate 78 MWs of renewable energy projects should be commencing operation within the next eighteen months.

JPS further proposes that the heat rate mechanism be reviewed by the OUR when the 381 MW LNG-fired power plant is completed in 2016/17. This is because more than 70% of generation will come from IPPs at that point in time and the current methodology should therefore be reviewed as a matter of regulatory prudence.
8. System Losses Target (See Section 13 for complete details)

JPS believes that for the company to remain viable a more objective basis of setting the system losses target must be established. JPS strongly believes that using historical averages is a better basis for setting the losses target and proposes that the Losses target be based on the last 3 years actual Losses with stretch target of 2 percent. There should also be a cap of US$1M (or 1.5% of the cost of fuel) per month. This would result in an upper limit of US$12M in fuel penalty which should provide enough incentive to the company to reduce system losses without putting the viability of the company at risk. It should be noted that US$12M represents more than 20% of the target ROE of the Company.

The fuel penalty incurred on the system loss performance for the last 5 years.

<table>
<thead>
<tr>
<th>(US$’000)</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>System Loss - Fuel Penalty (Net)</td>
<td>8,038</td>
<td>13,016</td>
<td>13,644</td>
<td>36,508</td>
<td>54,581</td>
</tr>
</tbody>
</table>

The proposed losses target for 2014-2018 are outlined below.

<table>
<thead>
<tr>
<th></th>
<th>Actual (%)</th>
<th>Forecast (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2013</td>
<td>2014</td>
</tr>
<tr>
<td>System Losses - 3 Yr Rolling Average</td>
<td>23.3</td>
<td>24.9</td>
</tr>
<tr>
<td>Stretch Target</td>
<td>2%</td>
<td></td>
</tr>
<tr>
<td>Proposed System Losses Target</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

The forecasts were calculated from 3 year rolling averages of losses based on the impact of the proposed initiatives. The JPS has added a stretch target of 2% on the basis that in addition to JPS’ best effort the Government, OUR and other key stakeholders will work in partnership to ensure that the appropriate supporting legislation and social intervention programmes are implemented in a timely and effective manner. If this support is not implemented it should be appreciated that this stretch target is unlikely to be met.

A summary of the calculations is provided below:

**Table 1-3: 3yr Rolling Average**

<table>
<thead>
<tr>
<th></th>
<th>Actual (%)</th>
<th>Forecast (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Losses - Beginning of the Year</td>
<td>23.32</td>
<td>21.80</td>
</tr>
<tr>
<td>Impact of Proposed Initiatives</td>
<td></td>
<td></td>
</tr>
<tr>
<td>System Losses - 3 Yr. Rolling Average</td>
<td>23.30</td>
<td>23.1</td>
</tr>
</tbody>
</table>

An alternate basis for setting the system loss target is also presented in Chapter 13. This alternate approach provides another objective basis for setting the system losses target each year based on
three key independent variables which are demonstrated as having a significant impact on system losses in many countries around the world. An independent study was conducted which demonstrates clearly the impact of these three variables on system losses here in Jamaica. This once again demonstrates that losses are substantially outside of the control of JPS but instead dependent on the socio-economic conditions prevailing in the country. At any rate, it provides an alternate objective basis for setting the system losses which is adopted by many utility companies and regulators around the world. While JPS is proposing to continue significant efforts to reduce theft losses in cooperation with GOJ and other key stakeholders, the issue of system loss must be addressed in an objective manner that will not impose unfair risks and burdens on JPS.

9. Load Forecast (See Section 17 for complete details)

Four load forecasts were evaluated:

1. Base Case with Natural Gas: JPS projects total demand (net generation) to increase at a compounded annual rate (CAGR) of about 0.4 percent per annum from 4,130GWh in 2014 to 4,212GWh in 2019.
2. Base Case without Natural Gas: JPS projects total demand (net generation) to decrease at a CAGR of about 0.5 percent per annum from 4,130GWh in 2014 to 4,026GWh in 2019. The decrease in total demand is due to the decrease in total sales. If JPS does not introduce natural gas, we expect no reduction of the JPS average tariff in 2017.
3. Efficient Case with Natural Gas: JPS projects a decrease of CAGR of about 0.1 percent per annum from 4,184GWh in 2014 to 4,140GWh in 2019. In this scenario, both technical and non-technical losses decrease from 2014 to 2019.
4. Efficient Case without Natural Gas: JPS projects a decrease of CAGR of 0.9% per annum from 4,184GWh in 2014 to 3,960GWh in 2019. In this scenario, both technical and non-technical losses decrease from 2014 to 2019.

There is essentially no load growth forecasted for Jamaica over the next five years due a sluggish economy and the high cost of imported fuel. JPS believes this is another reason to change the rate setting mechanism to a revenue cap; in order to address potential revenue falloffs due to missed sales forecasts.

10. Base Exchange Rate

JPS proposes a base-exchange rate of US$1 = J$112

11. FX Adjustment Factor

JPS recovers revenues through tariffs set on an assumed Base Exchange rate. This exposes the company to high currency risk and settlement risk as a large proportion of its expenses are incurred in US dollars. Consequently, the Licence permits the company to adjust billing rates each month to account for movements in the exchange rate between the US dollar and Jamaican dollar.

Exhibit 3 of the Licence outlines the mechanism used to apply the monthly adjustments. It states that the total tariff, including the Non-Fuel Base Tariff, the Base Fuel Tariff, tariff adjustments for fuel cost variations and tariff adjustments under the Performance Based Related Mechanism will be adjusted for all consumer classes on a monthly basis using a specific formula. The
Licence further specifies that the formula may be changed from time to time after consultation between the Office and the Licensee.

The current mechanism includes a 76 percent foreign exchange adjustment factor which means that the formula indexes 76 percent of the non-fuel base tariffs to the foreign exchange. The factor was set in the 2004 Determination when at that time the currency composition of the company’s cost was 76 percent US related and 24 percent local.

Regulatory policy dictates that the foreign exchange adjustment factor be set based on the currency composition of costs at the beginning of a regulatory period and remain fixed for the duration. This assumes that the cost structure of JPS remains fixed during that period. This is a weakness in the indexation mechanism as the extent the actual composition of costs differ from the composition implied by the adjustment factor, the adjustments may be insufficient to mitigate foreign exchange risks. This results in the under recovery of revenues or slippage. In addition infrequent review and reset of the FX adjustment factor to reflect the actual currency composition of costs prolongs the under recovery.

The current foreign exchange adjustment factor has not been reset since 2004. In the 2009-2014 Tariff Submission JPS recommended that in accordance with the currency composition of expenses in 2008 that the formula should be modified to reflect the fact that the US component of costs had grown to 79%.

However, this proposal was not accepted by the OUR which has resulted in significant under recovery of costs during the last 5 years. In this tariff submission we will ask that the US component of costs included in the formula be adjusted to 80% based on the composition of costs in the 2013 revenue requirement.

12. **Depreciation (See Section 6 for complete details)**

Depreciation represents the imputed costs for the use of fixed assets in the regulated business. The depreciation expenses included in the revenue requirement is used to recover capital investment costs. Under the current regulatory regime the historical test year depreciation charge acts as a proxy for capital expenditure. It is in effect a systematic allocation of investment cost which allows the utility to fund its capital expenditure requirements during the regulatory period.

The depreciation expense of US$49.2M in the 2013 audited financials was based on the useful lives specified in schedule 4 of the Licence. However, JPS is requesting an adjustment of the asset lives based on the recommendations from the Depreciation study conducted by KPMG. JPS commissioned the study in 2013 to review the useful lives of asset classes based on industry best practice and to analyze the actual age of the JPS assets at retirement. KPMG concluded that the current assets lives indicated in the Licence were in several instances longer than the actual economic useful lives of those assets. They recommended that the following adjustments be made to the current asset lives used to determine depreciation rates.

**Table 1-4: KPMG Recommended Asset Lives**

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

If the asset lives were adjusted according to KPMG’s recommendation then there would be an additional amount of test year depreciation of US$8.33M as shown below and the adjusted test year depreciation would be US$57.5M:

**Table 1-5: Additional Depreciation due to Asset Life Adjustment**

<table>
<thead>
<tr>
<th>Category</th>
<th>Asset</th>
<th>Current Life (per Licence)</th>
<th>Recommended Life</th>
<th>Change In Annual Depreciation Charge</th>
</tr>
</thead>
<tbody>
<tr>
<td>Distribution Plant</td>
<td>Meter</td>
<td>30</td>
<td>15</td>
<td>1,186,127</td>
</tr>
<tr>
<td>Distribution Plant</td>
<td>Street-light</td>
<td>30</td>
<td>20</td>
<td>172,890</td>
</tr>
<tr>
<td>General Plant</td>
<td>Electronic Eqpt(Lab Eqpt)</td>
<td>25</td>
<td>10</td>
<td>353,237</td>
</tr>
<tr>
<td>General Plant</td>
<td>Communication Eqpt</td>
<td>15</td>
<td>5</td>
<td>3,631,417</td>
</tr>
<tr>
<td>General Plant</td>
<td>Computer Equipment</td>
<td>15</td>
<td>6</td>
<td>2,763,109</td>
</tr>
<tr>
<td>General Plant</td>
<td>Furniture &amp; Office Eqpt</td>
<td>20</td>
<td>10</td>
<td>192,060</td>
</tr>
<tr>
<td>General Plant</td>
<td>Vehicles</td>
<td>7</td>
<td>4</td>
<td>31,138</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td><strong>8,329,978</strong></td>
</tr>
</tbody>
</table>

**JPS is requesting that the regulator accepts the recommendation on KPMG’s Depreciation study. The above additional amount is included as a known and measureable adjustment to the depreciation expense. We believe that $57.5M is still a conservative estimate as to what it will cost to fund the annual capital expenditure needs of the business over the next three years given our existing aged generation plant. Our annual capital expenditure for the last three years has actually been US$72M and we anticipate this will increase to US$80M on average per annum for the next three years, certainly until the new 381MW of new generation is brought on line.**

**13. Quality of Service Standards (See Section 9 for complete details)**

JPS proposes the following modifications to the Guaranteed and Overall Standards in introduced in the 2004. A detailed discussion is in Section 12.
14. Proposed Rates and Charges (See Section 8 for complete details)

Table 1-6: Summary of New Tariff Rates in JMD: 112 JMD to USD

<table>
<thead>
<tr>
<th>Network Access Charge USD/Month</th>
<th>Energy Charge JMD/kWh</th>
<th>STD and On-Peak</th>
<th>Partial-Peak</th>
<th>Off-Peak</th>
<th>STD and On-Peak</th>
<th>Partial-Peak</th>
<th>Off-Peak</th>
</tr>
</thead>
<tbody>
<tr>
<td>RT 10 Prepaid Rate</td>
<td></td>
<td>25.00</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 10 Community Renewal Program</td>
<td>0.00</td>
<td>7.75</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 10 LV Res. Service &lt; 100 kWh</td>
<td>672.00</td>
<td>10.64</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 10 LV Res. Service 100-500 kWh</td>
<td>1,344.00</td>
<td>24.86</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 10 LV Res. Service &gt; 500 kWh</td>
<td>2,016.00</td>
<td>35.44</td>
<td></td>
<td></td>
<td>0.00</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 10 LV Res. Service - Net Billing</td>
<td>2,016.00</td>
<td>0.00</td>
<td>7,840.00</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 20 LV Gen. Service &lt; 100 kWh</td>
<td>1,008.00</td>
<td>23.07</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 20 LV Gen. Service 100-1000 kWh</td>
<td>1,680.00</td>
<td>22.38</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 20 LV Gen. Service 1000-7500 kWh</td>
<td>2,800.00</td>
<td>21.71</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 20 LV Gen. Service &gt; 7500 kWh</td>
<td>4,480.00</td>
<td>13.46</td>
<td></td>
<td></td>
<td>8,960.00</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 20 LV Gen. Service - Net Billing</td>
<td>2,800.00</td>
<td>0.00</td>
<td></td>
<td></td>
<td>8,960.00</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 60 LV Street Lighting</td>
<td>4,480.00</td>
<td>23.52</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 40 (Std)&lt; 1 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>3,192.00</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 40 (Std)- From 1 MVA to 2 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>3,096.24</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 40 (Std)- From 2 MVA to 3 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>3,000.48</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 40 (Std)- From 3 MVA to 4 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>2,904.72</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 40 (Std)&gt; 4 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>2,808.96</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 40 (Std) - Net Billing</td>
<td>8,960.00</td>
<td>0.00</td>
<td>3,136.00</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 40 (Std) - Wheeling</td>
<td>8,960.00</td>
<td>0.00</td>
<td>1,636.94</td>
<td></td>
<td>1,459.30</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 40 (TOU)&lt; 1 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>1,797.15</td>
<td>1,404.50</td>
<td>135.49</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 40 (TOU)- From 1 MVA to 2 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>1,743.23</td>
<td>1,362.36</td>
<td>131.42</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 40 (TOU)- From 2 MVA to 3 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>1,689.32</td>
<td>1,320.23</td>
<td>127.36</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 40 (TOU)- From 3 MVA to 4 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>1,635.41</td>
<td>1,278.09</td>
<td>123.29</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 40 (TOU)&gt; 4 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>1,581.49</td>
<td>1,235.96</td>
<td>119.23</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 40 (TOU) - Wheeling</td>
<td>8,960.00</td>
<td>0.00</td>
<td>921.63</td>
<td>720.26</td>
<td>69.48</td>
<td>875.52</td>
<td>684.23</td>
</tr>
<tr>
<td>RT 50 (Std)&lt; 1 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>2,930.28</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 50 (Std)- From 1 MVA to 2 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>2,842.37</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 50 (Std)- From 2 MVA to 3 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>2,754.47</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 50 (Std)- From 3 MVA to 4 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>2,666.56</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 50 (Std)&gt; 4 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>2,578.65</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 50 (Std) - Net Billing</td>
<td>8,960.00</td>
<td>0.00</td>
<td>3,024.00</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 50 (Std) - Wheeling</td>
<td>8,960.00</td>
<td>0.00</td>
<td>1,502.73</td>
<td></td>
<td>1,339.65</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 50 (TOU)&lt; 1 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>1,627.92</td>
<td>1,269.78</td>
<td>130.22</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 50 (TOU)- From 1 MVA to 2 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>1,579.08</td>
<td>1,231.69</td>
<td>126.32</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 50 (TOU)- From 2 MVA to 3 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>1,530.24</td>
<td>1,193.60</td>
<td>122.41</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 50 (TOU)- From 3 MVA to 4 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>1,481.44</td>
<td>1,155.50</td>
<td>118.50</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 50 (TOU)&gt; 4 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>1,432.57</td>
<td>1,117.41</td>
<td>114.60</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 50 (TOU) - Wheeling</td>
<td>8,960.00</td>
<td>0.00</td>
<td>834.94</td>
<td>651.18</td>
<td>66.78</td>
<td>793.08</td>
<td>618.60</td>
</tr>
</tbody>
</table>

Bill Impact for Residential and Small Commercial Customers

The residential tariff increases, on average, by 22%. However, the first tier that includes mainly low-income families will receive an average tariff increase of 18%. The number of residential customers affected by this increase is about 220,000 customers, representing 41% of the residential class. The illustration below shows the three customer tiers, the average tariff per customer in US $, the marginal cost of serving them and their Best Alternative Option (BAO).
The General Service, R20, category has on average an increase of 16% for customers with consumption below 7,500 kWh per month. This impacts approximately 98% of the R20 customers who comprise 70% of the total energy sales for that rate class. However, in line with the results of the cost of service study and taking into consideration the Best Alternative Option (BAO) for customers with monthly consumption > 7,500, JPS is recommending an amendment to the tariffs that results in a 5% decrease on average. This impacts 2% of the R20 customers who comprise 30% of the total energy sales for that rate class.
15. Decommissioning (Discussed in Section 15)

JPS has executed a purchased power agreement (PPA) with Energy World International (EWI) to construct a new 381 MW generation facility, which is expected to begin commercial operation in 2016. When the EWI plant begins commercial operation in 2016, it will be necessary to retire the existing Old Harbour Power and Hunts Bay Unit B6 power plants. As directed by the OUR, it is now necessary for JPS to prepare a decommissioning and closure cost report for submission to the National Environmental Planning Agency (NEPA).

Further studies are recommended to arrive at accurate cost estimates for environmental clean-up, dismantling of equipment and site clearance. As such, early soils investigation and asbestos identification are recommended by mid-2014. 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.

California and Texas are two markets in the United States, which transitioned from vertically integrated utilities to unbundled operations, generation, transmission, and local distribution companies. In each of these market deregulation regimes, the cost of stranded and retired generation assets were recovered through rate mechanism to ensure financial and operational viability of the utility provider. Independent evaluations were conducted either by independent auditors or through market-based approaches, such as auctions.

The introduction of the EWI plant into the JPS grid should trigger a special out-of-cycle rate case in the 2016/2017 time-frame, in order to deal with the new system dynamics associated with replacing over half of system peak capacity along with changing the dominant fuel source from HFO to natural gas, along with any transmission upgrades required for system reliability. The decommissioning and severance costs for Old Harbour and Hunts Bay should be addressed in the out-of-cycle rate case.

As such, no costs associated with the future decommissioning of these power plants are being requested as part of this tariff submission at this time given the numerous uncertainties at this time.

16. Three Year Rate Request

JPS is requesting a three-year rate review, which is triggered by the successful commissioning of the 381 MW LNG fired facility being developed by EWI. Upon completion of this facility, over half of JPS’s generation will have been replaced and more than 70% of generation will be IPPs. Furthermore, there will be a substantial amount of renewables added to the JPS system in the interim. These variable resources may require system improvements to accommodate the operational dynamics of wind and solar resources. Also, as discussed above, JPS will then need to retire and decommission the Old Harbour and Hunt’s Bay plants. The decommissioning costs are material and JPS needs to be compensated for these mandated retirements.

JPS believes the most prudent approach is to file a notice with the OUR, at the commercial operation date of the EWI plant for a rate review to address all of the issues discussed above. The three-year rate review would be filed in March of 2017, contingent upon a successful startup of the EWI plant.
Chapter 2: Economic Overview

2.1 Overview of the Jamaican Economy

The Jamaican economy continues to be highly dependent on services which accounted for 63.5% of GDP in 2012 while most of the country’s foreign exchange is derived from tourism, bauxite/alumina and remittances. As a result, the country is highly susceptible to external shocks: the bauxite/alumina industry, for example, was significantly impacted by the global downturn in 2008-2009 and has still not recovered to its pre-crisis level of production.

The country faces some major impediments to economic growth and international competitiveness, including persistent budget deficits coupled with a high debt burden which has been at unsustainable levels for several years. Over the last forty years the Jamaican economy has grown at an annual rate of approximately 0.9%, among the lowest rates of growth in the world over the period. In addition, in the last thirty years, the country’s labour productivity declined by an average of 1.3% per annum.

The onerous debt burden has limited the government’s ability to provide necessary services in order to achieve sustained rates of growth and increased welfare for the citizens and, its inability to secure funding from international and local capital markets at a reasonable rate eventually resulted in the Government of Jamaica (GOJ) entering into an International Monetary Fund (IMF) Agreement in 2012. The required fiscal reform condition for the Government of Jamaica (GOJ) to secure international assistance from the IMF caused the government to launch the National Debt Exchange (NDX) programme in February 2013 to restructure J$860 billion of marketable domestic debt of the GOJ. This was the second debt swap executed by the Jamaican government in three years.

According to the IMF “By streamlining public expenditure and reducing interest payments, Jamaica will have more resources available for investments in education and infrastructure. This will increase growth potential, reduce the vulnerability to external shocks, and put the country in a position to reap the benefits of a recovery in global growth”.

JPS’ financial performance is to a large extent impacted by a number of macroeconomic variables and key policy decisions. The outturn of the key macroeconomic variables and policy and regulatory changes that affected JPS during the period 2009 to 2013 will be discussed in the ensuing sections.

2.2 2009-2013 in Review – The Downside Ruled

JPS financial performance has been rather lackluster over the last five years. Net Income moved from US$42 million in 2009 to (US$45 million) in 2013 while at the same time the company’s Debt to EBITDA ratio has deteriorated from 2.7x in 2009 to 3.5x in 2012, resulting in the company breaching its loan covenants and ending up with qualified audited financial statements, though this improved somewhat in 2013 to 3.3x. Note this deterioration in EBITDA has occurred despite the company having a relatively conservative gearing ratio of 50%. The main drivers for the deterioration in the Company’s financial performance were:
Economic Overview


![Figure 2-1: FX Losses versus Annual Depreciation of the JMD against the USD](image)

- Fuel Penalties arising from the increased divergence of actual system losses vs. the OUR’s set regulatory target of 19.5% in 2009 compared to 17.5% in 2013. This is the main reason for the fuel under-recovery (penalty) increasing from $8 million in 2009 to $42 million in 2013.

- Sales decline from 2009 to 2013. Total billed sales declined by 5.97% between 2009 and 2013 from 3,231 GWh to 3,038 GWh with the largest decline (12.4%) occurring in the Rate 20 customer class. In addition, the proportion of sales at the lifeline rate has been steadily increasing due to conservation efforts of customers. Figure 2-2 shows a close correlation between the decline in sales and the decline in real national disposable income between 2009 and 2012.

![Figure 2-2: Sales Decline and Decline in Real Disposable Income per Capita](image)

The factors that had the greatest impact on JPS’ performance were the movements in the foreign exchange rate, the socio-economic factors impacting system losses and all sales impacting macroeconomic variables including: policy and regulatory changes; population growth; reduction in real GDP and national disposable income, which is to a large extent determined by remittance inflows into the island; US and Jamaican inflation rates; average tariff increase primarily as a result of rising fuel prices and; visitor arrivals into Jamaica.
2.3 Impact of Policy and Regulatory Changes

Changes in the Policy, Regulatory and Legislative environment within the past five years have significantly impacted the operations of Jamaica Public Service. The government tabled the National Energy Policy (2009-2030) in 2010. This policy provides the overarching framework for the development of the energy sector and among its important goals is the increased emphasis on energy efficiency; fuel diversification through natural gas and renewables; and the creation of an eco-industry presumably based on energy services to be provided by the private sector.

The Energy Policy provided the context for the 2011 licence amendment. The 2011 amendments to the All Island Electricity Licence made provisions for the implementation of Power (Self) wheeling, net billing and an “intelligent” network. As a result, the net billing programme was implemented in 2012 with the aim of allowing customers who are owners of dedicated renewable energy equipment, such as wind and solar power, to sell excess power generated from their equipment to the JPS-operated national grid.

Commercial and residential customers can enter a contract with JPS to sell the excess 'as-available energy' from Intermittent Renewable Energy Facilities of up to 100kW for commercial customers or, 10kW for residential customers; facilitated through a five-year license to participate in net billing. As of January 14, 2014, one hundred and sixty-eight (168) applications have been received by JPS representing approximately 2.5MW of installed capacity. Twelve (12) customers have already been granted Standard Offer Contracts with a total installed capacity of 147kW and an estimated annual generation of 295 MWh per annum.

Figure 2-3 shows the energy production versus load of a typical grid-tied PV system for an average residential customer.

An additional thirty-two (32) customers, 516kW of installed capacity, will be commissioned in February 2014. These numbers do not include customers who have installed renewable energy systems but have not sought a Standard Offer Contract with JPS. Given the reduction in the prices of solar photovoltaic equipment in recent years and projections for further decline in cost in the future, it is estimated that more than 2.5 percent of residential (R10) and Rate 20 commercial sales could be lost to net billing and distributive generation by 2019. In addition, an increased proliferation of intermittent renewable energy systems will require that the JPS network to be robust and flexible. This may require investment in ancillary support systems such as storage to accommodate the new technology on the grid.

---

2 JPS Demand Forecast 2014-2018
The Power (Self) Wheeling initiative was introduced in a 2013 OUR Determination Notice and will be implemented in 2014. It is expected to enable large commercial and industrial customers, rate classes R40 and R50, to self-supply electricity using off-site generation. Only one customer has made a formal application to JPS for a power wheeling license however, customer surveys conducted by JPS in 2013 indicates that several large customers are interested in either self-generation or power wheeling, but are awaiting the development of Wholesale tariffs for large industrial customers and a better understanding of timing of the proposed Energy World International’s (EWI) 381MW LNG base-load project before finalizing their resource decisions. A delay or failure of the EWI 381MW LNG project could cause a significant risk to JPS’ electricity sales as these large industrial customers fully appreciate that the fuel cost now represents more than 75% of their total energy cost. Further, the uncertainty with the development and timing of the EWI project and the addition of 78 to 115 MW of renewables not only makes fulfilling the timelines of the national energy policy challenging, and makes managing resources and financial planning difficult for JPS.

The energy landscape has also transformed given the proliferation of projects to create the supporting infrastructure for the development of an Energy Services Company (ESCO) Industry in Jamaica. According to the Government, the ESCO industry has the potential to create new businesses, generate new jobs, and deliver savings in energy consumption and cost, and climate change mitigation through reduced carbon emissions. Currently, there are over forty companies in Jamaica that can be identified as ESCOs which are providing a wide range of energy services including auditing, energy management and sales and servicing of energy efficiency and renewable energy equipment. In addition, the government has announced a raft of initiatives that it is planning to implement to reduce energy consumption in the public sector, for example, it has received USD$20 million dollar from the Inter-American Development Bank (IDB) to implement energy conservation opportunities in public sector buildings and we now understand that local government is resolved to convert all of its streetlights to energy efficient LED lights in the near future. Additionally, the National Water Commission (NWC) has also received separate financing from the IDB to optimize the efficiency of its water distribution system and to improve its energy efficiency. These two entities are in fact JPS’ two largest customers under the existing tariff regime and their conservation efforts will significantly impact the sales outlook for the future.
The increased emphasis placed on energy efficiency, and the introduction of wheeling and net billing will affect the historic relationship between key economic variables that could alter the price elasticity of income and demand where applicable.

2.4 Population Growth

The 2011 Census indicates that between 2001 and 2011 the Jamaican population grew by an average rate of 0.36% and the average household size reduced to 3.1 per household from 3.5 in 2001. There is a high degree of correlation between the number of customers in the Rate 10 class and average household size as illustrated in Figure 2-4. The number of Rate 10 Customers increased from 522,348 in 2009 to 537,707 in 2013.

Figure 2-4: Number of Customers vs Number of Households

The increase in number of customers was more than offset by the reduction in average consumption per customer in the Rate 10 (R10) class as shown in Figure 2-6. The population growth also positively impacted the number of customers in the Rate 20 (R20) category, which grew by 3.55% over the five year period from 60,303 in 2009 to 62,446 in 2013.
According to the World Bank, the Jamaican economy has lost four decades without achieving significant growth. This was certainly true during the five-year review period from 2009 to 2013 where growth was only recorded in 2011 and marginally in 2013. In 2011, the economy managed to enjoy real GDP growth of 1.1%, which represented the first annual increase since the onset of the global economic downturn in 2008. By 2012 this progress was reversed as measured by the consistent contraction in real GDP with only a slight growth occurring in 2013.

Figure 2-5: Customer Base

Figure 2-6: Average Residential Consumption 2007-2013

2.5 GDP Growth and National Disposable Income

According to the World Bank, the Jamaican economy has lost four decades without achieving significant growth. This was certainly true during the five-year review period from 2009 to 2013 where growth was only recorded in 2011 and marginally in 2013. In 2011, the economy managed to enjoy real GDP growth of 1.1%, which represented the first annual increase since the onset of the global economic downturn in 2008. By 2012 this progress was reversed as measured by the consistent contraction in real GDP with only a slight growth occurring in 2013.
Figure 2-7: Real Disposable income per capita and GDP (2009-2013)

Statistical analysis shows that the log of real GDP per capita is a statistically significant parameter for the number of Rate 40 customers, and the log of average consumption for the Rate 40 and Rate 50 customer classes (See Figure 2-8). While growth in the number of Rate 40 customers increased over the review period, the decline in average consumption for Rate 50 and 40 was in line with the downturn in real GDP per capita. Statistical analysis indicates that while the decline in average Rate 40 consumption is due to the decline in real GDP per capita, the decline in Rate 50 consumption is due to a combination of an increase in real average tariff and the decline in real GDP per capita.

In the meantime, real national disposable income per capita has declined since 2007 and was particularly significant in 2009, declining by five-percent (5%) as result of the fallout from the global financial crisis. The log of the average consumption for the Rate 10 class is statistically significant with the log of real national disposable income and is possibly due to the importance of remittance to many households in Jamaica. The relationship between the two variables did show a divergence in 2010 when there was an increase in average consumption but otherwise the average consumption has been on the decline since 2010 up to the present.
Economic Overview

Figure 2-8: GDP per capital vs Avg Consumption in Rate 40 and 50 Classes

Figure 2-9: Disposable Income vs Avg Consumption of Rate 10 Customer
2.6 Jamaican/US Inflation Rates and Foreign Exchange Rates

As a result of the steep recession, which Jamaica underwent in 2009 and the first debt exchange (JDX) which occurred in 2010, Jamaica’s headline inflation rate for 2009-2013 was significantly less than what was recorded in the previous five (5) years. Over the review period the inflation rate reached a high in 2010 of 11.7%, which was mainly attributed to elevated prices on select food products in the last quarter of 2010 due to Tropical Storm Sandy, which badly affected the agricultural sector. Since then, inflation has declined somewhat and Jamaica recorded inflation of 9.45% for 2013. The Bank of Jamaica has indicated that its target range for inflation for the upcoming fiscal year is 8.5-10.5%.

Prices in the US deflated in 2009 as the impact of the 2008 financial crisis continued. As the US economy began its tentative recovery in 2010 and the impact of commodity prices increases were felt, the US inflation rate increased, however, it began declining again in 2012 as the effects of the Fed’s quantitative easing programme took effect. Record low inflation rates were seen in the US in 2013 due the low level of the velocity of money in the US.

![Figure 2-10: US vs Jamaican Inflation Rates](image)

As of end of December 2013, the Jamaican/USD exchange rate was J$106.37:US$1. The exchange rate has depreciated roughly by 32% between 2009 and 2013. This reflects an annual devaluation rate of approximately 7.6% per annum which is primarily reflective of the difference in the average annual inflation rates between the two countries for the same period. The significant depreciation of the Jamaican dollar relative to the United Stated dollar is problematic given the JPS’ overall reliance on the US dollar which is reflected by the fact that 90% of all of JPS’ operating costs (including 100% of fuel) are denominated in US dollars; and substantially all capital plant is imported and priced in US dollars. The Company’s revenues are capped at test year levels with monthly adjustments of base billing rates in theory to compensate the Company for these fluctuations. However, a sharp devaluation of the currency during the adjustment periods places severe pressure on working capital and exposes the company to substantial settlement risk which manifest itself in foreign exchange losses.

Figure 2-11 illustrates that relative Purchase Price Parity (PPP) has been a fairly good predictor for end of period exchange rate for Jamaica between 2004 and 2013 even though the divergence was greatest in 2010 when the Jamaican currency appreciated and, in 2013 where there was a
steep devaluation of the currency perhaps due to the tightening of fiscal policy and the uncertainty it created in the market.

![Figure 2-11: Exchange Rate vs Relative PPP Exchange Rate](image)

**Figure 2-11: Exchange Rate vs Relative PPP Exchange Rate**

The inflation rate differential between the US and Jamaican currencies is therefore an important predictor of JPS’ foreign exchange gains and losses.

### 2.7 Interest Rates

JPS usually accesses large multinational banks in the local debt market for its short term US$ credit financing. Interest rates are usually fixed or influenced by global capital market interest rates, typically, 3-month or 6-months LIBOR plus a 500 basis-points spread by the bank providing the financing. Similarly, long term financing required for capital projects are influenced chiefly by the 3 or 6-month LIBOR rates plus 580 basis points spread. JPS has minimal JA$ debt but the rate for these tend to be influenced by local Treasury Bill rates, which in turn are influenced by international interest rates, expected currency depreciation, and monetary policy. Between 2009 and 2012, the gradual depreciation of the value of the J$ relative to the US$ and the downward trend in inflation rate allowed the central bank to maintain a relatively relaxed monetary policy regime. However, since the GOJ debt restructuring in 2013 there is very limited J$ financing that is available in the local market for terms longer than one year.

JPS’ gearing ratio continues to increase as it has sought to increase its leverage closer to 50%. At the same time the cost of debt has decreased primarily because of the favourable LIBOR rates in the international capital markets. The company’s gearing ratio moved from 45% in 2008 to 50% at the end of 2013 while it lowered its all-in average cost of borrowing by 150 basis points while maintaining its interest cover above 3.2 times.
Despite the favourable cost of debt, the company breached its loan covenant agreement for failing to meet the debt: EBITDA ratio in 2012, which was 3.0:1 under numerous loan agreements and which JPS had to renegotiate with its lenders to 3.5:1 for 2013 and 2014 (and which will revert to 3.0:1 as of 2015). Currently, the actual Debt to EBITDA ratio stands at approximately 3:00:1 which, while it is an improvement from 2012’s debt: EBITDA ratio of 3:52:1, still places the company at significant risk of breaching the renegotiated loan covenants and prevents it from being able to pay dividends to its ordinary and preference shareholders.

### 2.8 Fuel Cost and Fuel Recovery

Between 2009 and 2013, JPS’ non-fuel tariff increased by US 1.8 ¢ (12.5%) versus the US 6.3 ¢ increase for the fuel tariff (19%) as a result of a general increase in the world oil prices over the period. From 2009 to 2013 (see Figure 12) JPS fuel costs exceeded its fuel revenue largely because the company was unable to meet the 17.5% System Losses target that was set by the Regulator in 2009.
Economic Overview

Figure 2-12: Fuel and Non-Fuel Tariffs

![Bar chart showing fuel and non-fuel revenues over time]

Figure 2-13: Fuel Cost vs Fuel Recovery
Chapter 3: Macroeconomic Outlook (2014 – 2018)

3.1 Background

After six consecutive quarters of negative growth, the Jamaican economy realized an anaemic real GDP increase of 0.5% in the third quarter of 2013 and 1.4% in the fourth quarter over the corresponding quarters in the previous year. Overall, real GDP growth for 2013 is estimated at 0.1%. A tentative recovery in the economy therefore seems to be underway and the improving economic performance of the United States along with the persistent high growth in China (even if, at lower rate of expansion) and recovery in the Euro zone area are all factors that should provide a positive headwind for Jamaica’s growth.

Perhaps more significant for Jamaica’s economic fortune in the medium term, is its Economic Reform Programme (ERP) which is central to the four year Memorandum of Economic and Fiscal Policies (MEFP), which charts the extent of funding support, framed under the US$958 million Extended Fund Facility (EFF) with the IMF. Some of the Government of Jamaica’s (GOJ) key obligations under the ERP are to: reduce Jamaica’s debt from 145 percent of the gross domestic product (GDP), to ninety-six percent (96%) by 2020; attain a seven and a half percent (7.5%) primary budgetary surplus target; rebuild official reserves; and expenditure containment, inclusive of public sector salary restructuring to reduce the ratio to GDP from 10.6 percent, as of March 31, 2013, to nine percent (9%) by fiscal year 2015/16. The tight budgetary and fiscal constraints imposed under the ERP should position Jamaica along a more sustainable and competitive growth path but will naturally contract the economy. The ERP seeks to counterbalance the fiscal contraction by implementing a raft of growth inducing structural reform initiatives which includes among other things:

- Maintaining the social safety net
- Creation of an enabling business environment conducive to investment and growth
- Increasing the support for MSME’s and Community-based enterprises
- Reducing the uncompetitive cost of energy
- Tax Incentive and tax administration reform geared at meeting the structural benchmarks for doing business
- Leverage capacities in non-traditional areas (ICT, Animation, Sports, Entertainment)
- Asset mobilization and in particular leverage Jamaica’s strategic location to become an integral link in the Global Supply Chain (Logistics hub)

The government has already passed several legislations in its efforts to meet the structural benchmarks, including the Omnibus Tax Incentive Act, which was approved in the latter half of 2013.

Given the current lack of major drivers for the Jamaican economy and susceptibility to exogenous shocks, the macroeconomic outlook for Jamaica is very much uncertain and is highly dependent on the success of the ERP. However, despite the IMF’s positive review of the country’s progress in implementing adjustments and reform under the EFF, the 2013 third Quarter business and consumer confidence indices fell to its lowest since 2009 which provides some indication that growth will be slow and tedious. Hence, the World Bank’s caution of Jamaica’s near to medium term growth prospects.
The ensuing sections detail anticipated trajectories of some of the major macroeconomic variables which are expected to impact JPS’ business environment over the tariff review period.

### 3.2 Population Growth

The number of dwellings and the average household size are key drivers of energy demand in the residential sector. These in turn are influenced by population growth. Table 3-1: Population Statistics gives the Statistical Institute of Jamaica’s (Statin’s) projection of population growth to 2018.

**Table 3-1: Population Statistics**

<table>
<thead>
<tr>
<th>Year</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>Change</td>
<td>0.40</td>
<td>0.43</td>
<td>0.39</td>
<td>0.39</td>
<td>0.43</td>
</tr>
<tr>
<td>Size</td>
<td>2,729,621</td>
<td>2,741,429</td>
<td>2,752,253</td>
<td>2,763,077</td>
<td>2,774,885</td>
</tr>
<tr>
<td>Size</td>
<td>3.1</td>
<td>3.1</td>
<td>3.1</td>
<td>3.1</td>
<td>3.1</td>
</tr>
</tbody>
</table>

### 3.3 Gross Domestic Product

Table 3-2 provides forecasts by the IMF, World Bank and Bank of Jamaica of GDP growth for the Jamaican economy for the 2014 – 2018 period.3

**Table 3-2: GDP Growth Forecasts for 2014 – 2018**

<table>
<thead>
<tr>
<th>Year</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>WB</td>
<td>1.0</td>
<td>1.2</td>
<td>1.3</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>IMF</td>
<td>1.25</td>
<td>1.7</td>
<td>2.1</td>
<td>2.425</td>
<td>2.65</td>
</tr>
<tr>
<td>BoJ</td>
<td>1.4</td>
<td>1.8</td>
<td>2.2</td>
<td>2.5</td>
<td>2.7</td>
</tr>
</tbody>
</table>

The major drivers of growth are anticipated to be:

- The reciprocal impact of economic recovery in the US and Europe and the continued growth in China.
  - Jamaica receives around US$2 billion of annual remittances, which represents approximately 13.8% of GDP. The level of remittance declined for the first half of 2013 but showed improvement in the last quarter of the year and is expected to continue improving as the US economy (especially) strengthens.
  - The World Investment Report 2013 indicates that FDI inflows increased sharply in 2012 compared to 2011 and this was primarily due to inflows into the business process outsourcing sector particularly, the ICT industry. The government is continuing its efforts to improve the attractiveness of Jamaica as a “near shore” investment location for North America and it is expected that this and other external factors will continue to improve FDI inflows into the country.
- The anticipated positive impact of Structural Reform

---

3 The BoJ has indicated that its projections are within a 10% confidence interval.
The tax reform bill, which was passed in December 2013 seeks to “establish a transparent and coherent regime to govern all tax incentives”\(^4\) and should act as a catalyst for investment.

Tax Incentive and tax administration reform should allow the government to recover loss revenues thereby improving the government’s fiscal position.

- The implementation of major infrastructure projects

  - The implementation of the EWI 381MW LNG-fired Power plant project in the 2016-2017 time frame should see major FDI inflows and job creation. The project is also slated to reduce the cost of electricity by at least 20% and should help to improve the competitiveness of local manufacturing.

  - Less certain is the successful outcome of the government’s push to transform Jamaica into a major global logistics hub over the next 2 – 3 years.

- Recovery of traditional sectors

  - The Agricultural sector seems to have just began its recovery from the devastating impact of Hurricane Sandy and received its first positive growth since the storm of 5.4% quarter over quarter for the third quarter of 2013. The government has earmarked 8,000 acres of unused government land to develop agro processing parks to facilitate integrated agricultural production. Despite its early issues, the agro parks are anticipated to facilitate growth of the sector.

  - Tourism and mining are likely to improve given the positive global growth prospects.

The outlook for Jamaica is subject to a number of downside risks. Jamaica remains quite vulnerable to external shocks, for example, geopolitical events negatively impacting the oil market, or the availability of the PetroCaribe facility over the medium term and the impact of adverse weather events. In addition, even though the market response has been calm so far, the tapering of quantitative easing in the US could see a rise in interest rates in developed economies thus, leading to a reduction of the much needed FDI inflows that the government is depending on for the implementation of its major growth initiatives. The growth prospect for Jamaica is therefore by and large, very uncertain and given that it is hinged on the success of key initiatives of government that are still in the nascent stages, the JPS remains cautiously optimistic especially given the fact that the BOJ has generally tended to be optimistic in projecting real GDP growth as indicated in Figure 3-1 from the IMF’s 3rd Quarterly Review document.

\(^4\) Jamaica Information Service quote
3.4 Consumer and Producers Price Indices

Projections for Producers and Consumer Price Indices in the US and the Consumer Price Index in Jamaica are detailed in Table 3-3.

Table 3-3: CPI (Jamaica) and PPI (US) Forecasts for Jamaica 2014 – 2019

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>IMF</td>
<td>9.95</td>
<td>9.1</td>
<td>8.655</td>
<td>8.255</td>
<td>7.70</td>
</tr>
<tr>
<td>Bank of Jamaica</td>
<td>9.0</td>
<td>8.5</td>
<td>8.5</td>
<td>8.0</td>
<td>7.4</td>
</tr>
</tbody>
</table>

Forecasted CPI for USA 2014-2019

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>IMF</td>
<td>1.673</td>
<td>1.866</td>
<td>2.045</td>
<td>2.205</td>
<td>2.229</td>
</tr>
<tr>
<td>Seattle City Office</td>
<td>2.3</td>
<td>2.5</td>
<td>2.5</td>
<td>2.4</td>
<td>2.4</td>
</tr>
<tr>
<td>Federal Reserve Bank of Philadelphia</td>
<td>2.0</td>
<td>2.2</td>
<td>2.1</td>
<td>2.1</td>
<td>2.1</td>
</tr>
</tbody>
</table>

Forecasted PPI for USA 2014-2019

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2015</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wells Fargo</td>
<td>1.925</td>
<td>2.525</td>
</tr>
</tbody>
</table>

In the US, according to an article in Forbes Magazine (December 12, 2013), Economists are expecting to see inflation increase in 2014 but are expecting it to fall short of the Federal Reserve’s target of 2%. This is despite an acceleration in economic activity in the latter half of 2013. Some of the factors that seem to be contributing to the low inflation rate in the US are:

---

5 Survey of Professional Forecasters
• The continued slack in the labour market (labour force participation rate continues to decline), which seems to have kept wages relatively flat and demand relatively tempered. Additionally, the increased costs in benefits have added to the cost of labour in the US.

• Commodity markets including food and energy are relatively sluggish

The headline PPI for finished goods increased in December 2013 by 0.4% (Bureau of Labor Statistics) after declining in November and October of 2013. There is thus some support for an increase in the CPI, at least, in the first quarter of 2014. By 2015, inflation is expected to move closer to the Fed’s 2% target to between 1.8% and 2.5%. The wide range of expectations for US inflation over the next five years may be due to concerns that the excess liquidity in the economy may give rise to a liquidity bubble which could drive a sharp increase in inflation if and when it collapses.

Spurred in part by the rapid devaluation of the Jamaica dollar over the past year (14%) and increases in the cost of public transportation (25%) and water utility rates (18%), consumer price inflation has been trending higher over the past 12 months, exceeding the ten percent (10%) year over year mark in the last quarter of 2013. The estimated inflation for 2013 was 9.45% which was slightly below the midpoint of the Bank of Jamaica’s (BOJ) target range of 8.5-10.5%. The BOJ expects a gradual stabilization of inflation to single-digit levels over the coming two years. Although price stability will remain compromised in the near term, subdued economic activity, wage restraint and moderate oil prices may mitigate price pressures stemming from exchange rate weakness. In its third quarterly update on Monetary Policy in 2013, the Bank of Jamaica states that it maintains a bias towards monetary policy accommodation and continues to offer its regular 30-day certificate of deposit at the 5.75% annual rate.

3.5 Foreign Exchange Rate

The Jamaican dollar (JMD) remains vulnerable despite the slight economic recovery in 2013; expectation of future growth in the economy, albeit less than its peers in the Caribbean, and the IMF’s approval thus far of the execution of the government’s economic recovery programme. The JMD, trading at 109.48 per USD as of March 26, 2014, has depreciated by 2.9% since the beginning of the year and, although tempered somewhat since the 14% devaluation in 2013, remains extremely volatile. The BOJ’s intervention to support the currency has seen net international reserves decline by 68% in the last 29 months to the current level of US$835 million although it recovered to some extent in the last quarter of 2013.

A hefty public sector debt overhang, 138% of GDP, a wide current account deficit (10% of GDP) and tough measures to execute structural economic reforms will keep the JMD on the defensive in the near term. In addition, the JMD will come under pressure as the USD regains strength, heightening emerging-market volatility.

Over the next five years, based on PPP and adjustments, which takes into account the BOJ’s Monetary Policy and anticipated macroeconomic conditions, JPS’ expects an annual currency devaluation of between 7 – 10%. Due to its propensity for extreme asymmetric volatility, foreign exchange rates are very difficult to forecast and will continue to be a major settlement risk for the JPS.
Interest Rates

Global bond yields are highly dependent on the US Federal Reserve’s quantitative easing policy. Anticipation of tapering of quantitative easing in 2013 saw the 10-Year Treasury bond yield jump from a low of 1.63% in May to near 3% by year end. The rise in interest rates might indicate that a taper related sell off is already factored into prices. In addition, it seems that the Fed is more likely to embark on a gradual tapering off which should have a modest impact on prices in 2014. The speed at which the Fed will taper is perhaps the main driver of market uncertainty and this is largely determined by the extent to which economic growth meets the consensus expectation of 2.25% - 3.0%6 for 2014. Nonetheless, US bond yields are not expected to move much higher until 2015.

Table 3-4: Year Benchmark Global Bond Yields

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2015</th>
</tr>
</thead>
<tbody>
<tr>
<td>US (10 Year Bond)</td>
<td>2.9</td>
<td>3.4</td>
</tr>
<tr>
<td>Europe/Germany</td>
<td>1.875</td>
<td>2.0</td>
</tr>
<tr>
<td>UK</td>
<td>2.8</td>
<td>3.3</td>
</tr>
<tr>
<td>Emerging Markets</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Source: National Australian Bank

Table 3-5: End of Year Libor Rates

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>3-mth LIBOR</td>
<td>0.4</td>
<td>1.095</td>
<td>1.96</td>
</tr>
<tr>
<td>6-mth LIBOR</td>
<td>0.55</td>
<td>1.20</td>
<td>2.05</td>
</tr>
<tr>
<td>BOJ 182-Day Treasury Bill Rates</td>
<td>7.5-8</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Source: Bloomberg (January 28, 2014) and Victoria Mutual Wealth Management (January 2014)

If executed faster than the market anticipates, tapering could lead to a surge in long-term interest rates in developed and developing countries and a sell-off in global equity markets, a sharp decline of capital inflows to emerging economies and a spike in the risk premium for external financing in emerging economies. This is the downside risk that JPS faces in the medium term.

3.6 Fuel Prices

Petroleum Products

The January 2014 edition of the EIA’s Short Term Energy Outlook and the early release of the 2014 Annual Energy Outlook are predicting that WTI and Brent crude oil prices will continue to fall from 2014 – 2020. The US shale gas revolution is pushing the US closer to being able to export rather than import crude oil and tensions between Iran and the West have improved in recent months. In addition, western Libyan production appears to be ramping up even though there are continued problems in the eastern part of the country.

6 Wells Fargo forecasted a 2.4% GDP growth in 2014 while Credit Suisse forecasted 3.4%
Based on the EIA’s STEO\(^7\) projections for WTI prices for 2014 and 2015 and the AEO\(^8\) prices for Brent Crude between 2016 and 2019, JPS’ forecast for the cost of Fuel Oil #6 and Automotive Diesel Oil delivered to the plant (excluding taxes) for 2014 – 2019 is shown in Table 3-6 below:

**Table 3-6: Fuel rice Forecast - Petroleum Products\(^9\)**

<table>
<thead>
<tr>
<th>Year</th>
<th>Fuel Oil #6</th>
<th>Diesel #2</th>
<th>Fuel Oil #6</th>
<th>Diesel #2</th>
<th>Fuel Oil #6</th>
<th>Diesel #2</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014</td>
<td>82.92</td>
<td>110.69</td>
<td>97.65</td>
<td>133.99</td>
<td>117.26</td>
<td>165.88</td>
</tr>
<tr>
<td>2015</td>
<td>80.71</td>
<td>107.29</td>
<td>97.35</td>
<td>133.52</td>
<td>119.47</td>
<td>169.33</td>
</tr>
<tr>
<td>2016</td>
<td>78.53</td>
<td>104.14</td>
<td>96.84</td>
<td>132.78</td>
<td>121.21</td>
<td>171.86</td>
</tr>
<tr>
<td>2017</td>
<td>76.46</td>
<td>101.15</td>
<td>96.41</td>
<td>132.15</td>
<td>122.82</td>
<td>174.19</td>
</tr>
<tr>
<td>2018</td>
<td>74.68</td>
<td>98.58</td>
<td>96.19</td>
<td>131.83</td>
<td>124.13</td>
<td>176.08</td>
</tr>
<tr>
<td>2019</td>
<td>73.06</td>
<td>96.22</td>
<td>96.04</td>
<td>131.62</td>
<td>125.22</td>
<td>177.67</td>
</tr>
</tbody>
</table>

The low and high oil price scenarios for 2014-2015 were generated from a confidence interval derived from options market information for the 5 trading days ending Feb. 6, 2014. For 2016-2019, the EIA’s AEO forecast for high, low and reference oil price scenarios for Brent Crude were used (also taking into account the basis differential between WTI and Brent).

*Liquefied Natural Gas (LNG)*

As a result of the anticipated completion of the EWI 381MW LNG project in 2016-2017, the price of LNG will become an important variable in JPS’ fuel tariff. There is still some uncertainty as to where the product will be sourced for the project and long-term prices are unknown, at present.

A 2013 report by Ernst and Young (EY) on the Global LNG market indicates that the demand for LNG will strengthen over the next 10 to 20 years growing by an average of 5-6% per year to 2020. After 2020, demand growth is expected to continue but is projected to slow to around 2 to 3% per annum. By 2030, global demand for LNG could almost double the estimated 2012 level of approximately 250 million metric tonnes.

Up to 2030; Japan, South Korea, and Taiwan will continue to be the main drivers of demand in the LNG market; however, China and India are expected to be the biggest source of anticipated demand increase. China has developed a five-year plan to add natural gas into its energy mix and plans to increase the gas share from four percent (4%) in 2010 to eight percent (8%) by 2015 and ten percent (10%) beyond 2020. The country has ambitions of developing its shale gas resources and its import pipeline extensions, but the bulk of its gas demand is expected to be met by LNG imports. Aside from China and India, Europe’s LNG demand is also expected to grow.

---

\(^7\) Short Term Energy Outlook  
\(^8\) Annual Energy Outlook  
\(^9\) All Prices are in US$/BBL and represents cost of fuel delivered to JPS’ plants (ex taxes)
as local production\textsuperscript{10} declines and total gas demand grows resulting from economic growth and environmental preferences. The primary risks to LNG demand growth are the uncertainties around global economic growth and gas-on-gas competition.\textsuperscript{11}

On the supply-side, a number of new LNG export facilities are under construction primarily in Australia. Australia has sanctioned more than 60mtpa of greenfield LNG projects which are equivalent to about 25% of current LNG demand and there are 25 other countries (including those in North America and East Africa) with little or no existing export capacity which are anticipated to provide 30% of the world’s LNG capacity by 2020. The US, for example, granted 16 export licenses in 2013 for export to FTA countries, only one was granted to a non-FTA country.

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{Figure3-2.png}
\caption{Global LNG Capacity and Demand}
\end{figure}

Over the next three to five years however, there is anticipated to be tighter markets (as illustrated in Figure 3-2). As a result, the price of LNG in the Asian and Atlantic markets are expected to increase between 2014 and 2018. In addition, the pricing structure in regional markets is beginning to change which is driven by supply and demand factors including: the shale gas boom in the US; the Fukushima nuclear disaster and; continued financial crisis in the EU. The oil indexation, which has long been used in the Asian market is becoming less tenable with greater competition between sellers and more price-sensitive buyers. In the long-term as the LNG market becomes more globalised, we expect to see a gradual migration from oil-linked pricing to hub-based pricing. Already, some Asian buyers have begun to sign contracts for future US-based cargoes at Henry Hub-linked prices. In the medium term though, LNG pricing is expected to be dominated by long term contracts as indicated in Figure 3-3.

\textsuperscript{10} Primarily from the North Sea
\textsuperscript{11} Unconventional gases that include shale gas, tight gas and coal seam gas
Figure 3-3: Asian Future LNG – Contract, Spot & Price Formation

The Oxford Institute for Energy Studies projects that between 2014 and 2019, LNG on the Asian Spot market will trade at about US$6.50/MMBTU above the Henry Hub Spot price, similarly, the Japan Long term contracts using 90% Japan Crude Cocktail (JCC) pricing, would trade US$3.50 above the Asian Spot Market. We expect the price of the LNG to trade somewhere within this range. At the low end of the scale, LNG is projected to trade at the Asian Spot market price, the reference case lies mid-way between the Asian spot market and the JCC. The pricing scenarios are illustrated in the table below.

<table>
<thead>
<tr>
<th>Year</th>
<th>Henry Hub Natural Gas Forecast (EIA)</th>
<th>Low LNG Price Scenario</th>
<th>Reference Case</th>
<th>High LNG Price Scenario</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014</td>
<td>3.74</td>
<td>10.24</td>
<td>12.74</td>
<td>15.24</td>
</tr>
<tr>
<td>2015</td>
<td>3.74</td>
<td>10.24</td>
<td>12.74</td>
<td>15.24</td>
</tr>
<tr>
<td>2016</td>
<td>4.14</td>
<td>10.64</td>
<td>13.14</td>
<td>15.64</td>
</tr>
<tr>
<td>2017</td>
<td>4.40</td>
<td>10.90</td>
<td>13.40</td>
<td>15.90</td>
</tr>
<tr>
<td>2018</td>
<td>4.80</td>
<td>11.30</td>
<td>13.80</td>
<td>16.30</td>
</tr>
<tr>
<td>2019</td>
<td>4.66</td>
<td>11.16</td>
<td>13.66</td>
<td>16.16</td>
</tr>
</tbody>
</table>

12 Source: The Oxford Institute for Energy Studies, 2013
13 Shipping cost differentials between Japan and Jamaica are expected to have a minor impact on prices.
14 All Prices are in US$/MMBTU and represents cost of fuel delivered exclusive of taxes
Chapter 4: Operational and Financial Performance

4.1 Operational Summary

The Global Economic Crisis in 2008 precipitated a slowdown in most developed economies which had a contagion effect on developing countries which was particularly significant for Jamaica because of its linkage to the United States economy. The tariff review period, 2009 – 2013, was a challenging period for JPS as it was for Jamaica. The Company’s financial performance was generally well below expectation over the review period and was particularly affected by the increases in fuel price, rapid devaluation of the Jamaican dollar, the increase in electricity theft, declining sales and natural disasters such as Hurricanes Sandy and Nicole. The key performance indicators for the review period, which highlight some of the challenges faced by the Company, are laid out in Table 4-1.

One of the most significant challenges that the Company and by extension Jamaica has faced during the review period has been the rising price of oil, the effect of which, when combined with the currency depreciation, has almost doubled the average fuel tariff from J$12.53 per kWh in 2009 to J$22.37 in 2013, as reflected in Table 4-1 below. This increase was driven by factors totally outside of JPS’s control and has resulted in increased curtailment in customer consumption levels and increased levels of electricity theft. This is evident in the 14% decline in the average consumption per residential customer falling from 174 kWh per month in 2009 to 152 kWh per month in 2013. This is the continuation of a trend from the previous review period. Concomitantly, system losses rose to 25.88% on average in 2013, up from 24% in 2009 despite numerous initiatives implemented by the Company in its persistent efforts to reduce losses. Moreover, while energy sales were relatively flat for the first three years of the review period, there was a sharp falloff in the last two years, with sales falling by 2.5% in 2012 and 2.1% in 2013. This fall in sales was experienced across all rate categories. Indeed, this represents the first time in recent history (certainly the last 20 years) that the company has experienced two consecutive years of declining sales. It is against this background that the lowering of the system losses target from 19.5% to 17.5% in June 2011 is viewed as an action on the part of the regulator that was out of sync with the reality of the challenge facing JPS.

For every year in the review period, the Company under-recovered its fuel costs primarily because actual system losses were significantly above the regulated system losses target. This has occurred despite efficiency improvements in generation, evidenced by the general improvement in system heat rate while largely maintaining a consistent forced outage rate. The fuel under-recovery was particularly significant during 2012 and 2013. During 2013, JPS under-recovered its fuel cost by US$45 million despite the recovery of $10 million through the Fuel Cost Recovery Adjustment (FCRA) implemented in July 2013, and during 2012 the net loss on fuel was $30 million. The FCRA was the Regulator’s response to JPS’ request in the 2013 annual tariff inflation adjustment submission for a 1.5% cap on the fuel penalty.

FX losses had a very significant impact in both these years as well. The company incurred net FX losses of $14.9M and $21.1M in 2012 and 2013 respectively, arising from the 7.4% and 14.3% devaluation of the Jamaican dollar respectively. These adverse operating conditions resulted in the Company’s failure to achieve the required Debt to EBITDA loan covenant ratio.
(3.0:1), forcing a renegotiation of loan convent agreements with the Company’s international lenders and resulting in the qualification of the audited financial statements in 2012.

**Table 4-1: Key Performance Indicators**

<table>
<thead>
<tr>
<th></th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Sales (GWh)</strong></td>
<td>3,203.9</td>
<td>3,187.5</td>
<td>3,216.0</td>
<td>3,134.0</td>
<td>3,069.7</td>
</tr>
<tr>
<td><strong>Net Generation (GWh)</strong></td>
<td>4,214.0</td>
<td>4,137.3</td>
<td>4,136.9</td>
<td>4,135.9</td>
<td>4,141.6</td>
</tr>
<tr>
<td><strong>System losses</strong></td>
<td>24.0%</td>
<td>23.0%</td>
<td>22.3%</td>
<td>24.2%</td>
<td>25.9%</td>
</tr>
<tr>
<td><strong>System losses target</strong></td>
<td>19.50</td>
<td>19.50</td>
<td>19.5/17.50</td>
<td>17.50</td>
<td>17.50</td>
</tr>
<tr>
<td><strong>Heat rate (kJ/kWh)</strong></td>
<td>10,167</td>
<td>10,183</td>
<td>10,112</td>
<td>9,965</td>
<td>9,884</td>
</tr>
<tr>
<td><strong>Heat rate target (kJ/kWh)</strong></td>
<td>10,400</td>
<td>10,400</td>
<td>10,470</td>
<td>10,200</td>
<td>10,200</td>
</tr>
<tr>
<td><strong>Equivalent availability factor (EAF)</strong></td>
<td>80.6%</td>
<td>82.1%</td>
<td>81.9%</td>
<td>80.4%</td>
<td>75.4%</td>
</tr>
<tr>
<td><strong>Equivalent outage factor (EFOR)</strong></td>
<td>10.9%</td>
<td>8.5%</td>
<td>8.1%</td>
<td>10.4%</td>
<td>17.4%</td>
</tr>
<tr>
<td><strong>Gain/(loss) on fuel US$'000</strong></td>
<td>(7,337)</td>
<td>(13,362)</td>
<td>(7,818)</td>
<td>(30,041)</td>
<td>(45,635)</td>
</tr>
<tr>
<td><strong>Average Fuel prices (US$)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>- No. 6 fuel</td>
<td>63.36</td>
<td>79.63</td>
<td>106.95</td>
<td>111.72</td>
<td>104.74</td>
</tr>
<tr>
<td>- No. 2 fuel</td>
<td>86.81</td>
<td>108.98</td>
<td>146.87</td>
<td>150.18</td>
<td>144.42</td>
</tr>
<tr>
<td><strong>Annual non-fuel tariff increase (PBRM)</strong></td>
<td>N/A</td>
<td>4.79%</td>
<td>-1.70%</td>
<td>2.09%</td>
<td>10.35%</td>
</tr>
<tr>
<td><strong>Avg. fuel tariff (JS/kWh)</strong></td>
<td>12.53</td>
<td>15.55</td>
<td>20.26</td>
<td>21.18</td>
<td>22.37</td>
</tr>
<tr>
<td><strong>Avg. non-fuel tariff (JS/kWh)</strong></td>
<td>9.12</td>
<td>10.24</td>
<td>10.41</td>
<td>10.80</td>
<td>12.68</td>
</tr>
<tr>
<td><strong>Avg. exchange rate</strong></td>
<td>88.82</td>
<td>87.34</td>
<td>86.09</td>
<td>89.23</td>
<td>101.26</td>
</tr>
<tr>
<td><strong>Avg. fuel tariff (U.S. cents/kWh)</strong></td>
<td>14.31</td>
<td>17.73</td>
<td>23.57</td>
<td>23.85</td>
<td>22.82</td>
</tr>
<tr>
<td><strong>Avg. non-fuel tariff (U.S. cents/kWh)</strong></td>
<td>10.36</td>
<td>11.69</td>
<td>12.10</td>
<td>12.16</td>
<td>12.66</td>
</tr>
<tr>
<td><strong>Avg. monthly consumption per residential customer (kWh)</strong></td>
<td>174</td>
<td>179</td>
<td>170</td>
<td>161</td>
<td>152</td>
</tr>
<tr>
<td><strong>EBITDA margin</strong></td>
<td>15.9%</td>
<td>14.8%</td>
<td>12.0%</td>
<td>6.2%</td>
<td>6.7%</td>
</tr>
<tr>
<td><strong>Net profit margin</strong></td>
<td>5.3%</td>
<td>4.2%</td>
<td>3.0%</td>
<td>1.0%</td>
<td>0.6%</td>
</tr>
<tr>
<td><strong>ROE (Return on opening equity)</strong></td>
<td>10.9%</td>
<td>9.8%</td>
<td>8.5%</td>
<td>3.7%</td>
<td>2.2%</td>
</tr>
<tr>
<td><strong>Capital expenditure (US$ Million)</strong></td>
<td>50</td>
<td>60</td>
<td>72</td>
<td>61</td>
<td>83</td>
</tr>
<tr>
<td><strong>Dividends paid (US$ Million)</strong></td>
<td>28</td>
<td>44</td>
<td>44</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td><strong>Year-end exchange rate (JS:US$)</strong></td>
<td>89.61</td>
<td>85.86</td>
<td>86.60</td>
<td>92.98</td>
<td>106.40</td>
</tr>
<tr>
<td><strong>Total debt (US$ Million)</strong></td>
<td>322</td>
<td>343</td>
<td>423</td>
<td>415</td>
<td>368</td>
</tr>
<tr>
<td><strong>Debt to equity ratio</strong></td>
<td>44.56</td>
<td>46.54</td>
<td>53.47</td>
<td>52.48</td>
<td>49.51</td>
</tr>
<tr>
<td><strong>Current ratio</strong></td>
<td>1.5:1</td>
<td>1.6:1</td>
<td>1.6:1</td>
<td>1.6:1</td>
<td>1.4:1</td>
</tr>
<tr>
<td><strong>Number of employees (permanent)</strong></td>
<td>1,247</td>
<td>1,099</td>
<td>1,065</td>
<td>1,042</td>
<td>1,062</td>
</tr>
</tbody>
</table>

15 Normalized Sales, i.e. Normalized Sales = Billed Sales + Unbilled Sales
Despite the financial challenges during the regulatory review period, JPS consistently invested a higher level of capital expenditure in the business than the annual depreciation charge. The average capital spend during the period was $64 million annually, peaking at US$83 million in 2013 while the equivalent average depreciation charge was $46 million. In 2012, of the $61 million spent on CAPEX $30 million was spent on loss reduction initiatives. In 2013, JPS continued its massive investment in loss reduction initiatives spending another $30 million in total. In addition, due to the anticipated delay in materializing the 381MW gas-fired project, the company spent a further $20M maintaining old generating plants in order to sustain operational reliability. This demonstrates the company’s commitment to ensuring reliability in its power generation and delivery endeavours.

4.2 Major Events

The major events underpinning JPS’ performance during the tariff review period are highlighted below:

4.2.1 Change in Ownership Structure and Licence Amendment

In April 2011, Korea East West Power (EWP) bought 50% of Marubeni’s shares held in JPS. Thus, effectively, EWP purchased 40% of the ordinary shares of JPS. Following the change in the Company’s ownership structure, the All Island Electric License was amended and restated in August 2011. The amended license made provisions for power Wheeling and net billing among other things.

4.2.2 New CEO

Following the resignation of Mr Damian Obligio in November 2011, Mrs Kelly Tomblin took over the reins of the JPS as President and CEO in April 2012. The organization was restructured in 2012 following Mrs Tomblin’s arrival.

4.2.3 Tax Policy Changes

In March 2010, the supply of electricity to the public became a taxable supply and general consumption tax (GCT) at the rate of 10% was implemented on the sale of the service to residential and commercial customers. The tax was applicable to residential customers whose usage exceeded 200kWh per month and 10% for the entire consumption of commercial and industrial customers. Government departments and agencies were zero rated for the purposes of applying the tax. Following a change of government in December 2011 and public outcry against the tax, the threshold for residential customers was raised from 200kWh/month to 300kWh/month effective June 1, 2012. The tax level was also raised from 10% to 16.5%. Two weeks later the GCT on all residential consumption was removed following an announcement by the Prime Minister in her budget presentation. There were no changes for commercial customers which meant that effective June 1, 2012, commercial customers were required to pay the increased rate of 16.5% GCT on their electricity consumption.
While the introduction of the GCT on electricity consumption did not directly affect JPS’ financial performance, it was likely to have an indirect effect since it effectively increased the tariff to customers and therefore would have had an adverse effect on sales in those rate classes which are responsive to a 10% /16.5% increase in the electricity tariff. The Government of Jamaica also cleared the way in 2013 for JPS to be able to claim GCT incurred on its production inputs.

4.2.4 Breach of Debt Covenant

In March 2012, JPS became noncompliant in respect of one of its debt covenant ratio requirements. The Company was required to maintain a debt to EBITDA ratio of 3:1. This instance of noncompliance remained in effect until October 2013 when the Company renegotiated this loan covenant with the affected lenders, resulting in a temporary increase in the required debt to EBITDA ratio for 2013 and 2014 from 3:1 to 3.5:1. The primary factors which affected the company’s ability to meet its debt obligation were the significant fuel penalties suffered on account of the high level of system losses ($30M in 2012 and $45M in 2013) relative to the 17.5% regulatory target introduced in July 2011 and the decline in sales during 2012 and 2013 leading to a decline in revenues.

4.2.5 Issuance of Preference Shares

During the third quarter of 2013, JPS issued US$ indexed cumulative non-redeemable Class F Preference Shares to the market. This instrument raised a total of US$24.6 million at an interest rate of 9.5% in long term funding. Subsequently, in October 2013 the majority shareholders, Marubeni and the Government of Jamaica (GOJ) were offered US$3 million of Class G redeemable preference shares which was fully subscribed while EWP opted for issuing a long-term loan to the Company on terms that were similar the class “G” preference share. The class F preference shares were listed on the Jamaica Stock Exchange and will form a permanent part of the capital funding (equity) of the Company.

4.2.6 New Generation Projects

The Company continued its commitment to improving the efficiency of its generating units and in 2009 installed a new turbocharger in one of the Rockfort units, increasing the output by 2MW while also improving the heat rate. A new Air Inlet Cooling Technology chiller unit was installed as an addition to the combined cycle generating unit at Bogue. This increased the capacity by 10MW and significantly improved the overall efficiency of the generating unit.

In March 2008, the OUR invited bids for the supply of 640,000 MWh of electricity to the grid from renewable energy technologies. JPS participated in the procurement exercise and in 2009 was awarded the license to expand the Maggotty hydro plant by 6.3MW and to install 3MW of wind turbines at Munro. The Munro wind project was completed in 2010 and the Maggotty project was commissioned in January 2014. Further renewable energy additions were made when Wigton Wind Farm commissioned an additional 18MW of installed wind capacity in 2011. Wigton’s wind project was procured through an unsolicited bid. Additional generation capacity was brought online in 2012 when the 65.5 MW West Kingston Power plant (WKPP) was completed after the Jamaica Energy Partners won the right to build and operate the plant in a competitive tender.
During 2010, the OUR issued RFPs to twenty-eight local and international companies, including the Jamaica Public Service Company Limited (JPS) in 2010, to supply 480MW of new generating capacity. At the time, it was envisioned that the project would be carried out in two phases. The first phase would see the installation of 381MW in 2014, the additional 120MW would be installed by 2016. In December 2011, the OUR approved JPS’ proposal to spend over US$620 million to build 381MW of new generating capacity. The plant was supposed to be a gas-fired plant to be commissioned into service in early 2015. The government had taken the responsibility of bringing the LNG to Jamaica; however, the project took an unexpected turn when the GOJ requested that JPS source the LNG for the project in September 2012. The delay in negotiation between the JPS and OUR eventually lead to the termination of the original tender in January 2013 and the OUR issued new RFPs in April of that year. Energy World International (EWI) was eventually awarded the bid for the project in mid 2013 after the preferred bidder Azurest/Cambridge could not post the bid bond. JPS has since signed a PPA with EWI and the Minister of Energy is to issue a generating licence to perfect the PPA. The Company is also negotiating PPA’s with three renewable energy developers (Wigton, Blue Mountain Renewables and WRB Enterprises Inc) who were selected by the OUR in October 2013 to develop 78MW of renewable energy following the issuance of an RFP for 115MW of Renewable Energy by the OUR in October 2012.

4.3 Financial Summary

JPS prepares its financial statements in accordance with International Financial Reporting Standards (“IFRS”) and has a financial year that ends on December 31 in keeping with Conditions 5 (1) of the Licence. A selection of key financial information from JPS’ audited financial statements for the 2009 – 13 tariff review period is highlighted in Table 4-2 below.

<table>
<thead>
<tr>
<th>Table 4-2: Income Statement</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Operating revenues:</strong></td>
</tr>
<tr>
<td>Fuel revenues</td>
</tr>
<tr>
<td>Non-fuel revenues</td>
</tr>
<tr>
<td><strong>Total operating revenues</strong></td>
</tr>
<tr>
<td><strong>Cost of sales:</strong></td>
</tr>
<tr>
<td>Fuel</td>
</tr>
<tr>
<td>Purchased Power (excluding fuel)</td>
</tr>
<tr>
<td>eStore</td>
</tr>
<tr>
<td><strong>Total cost of sales</strong></td>
</tr>
<tr>
<td><strong>Gross profit</strong></td>
</tr>
<tr>
<td><strong>Operating expenses</strong></td>
</tr>
<tr>
<td><strong>EBITDA</strong></td>
</tr>
<tr>
<td><strong>Depreciation</strong></td>
</tr>
<tr>
<td><strong>Net finance costs</strong></td>
</tr>
</tbody>
</table>
Table 4-2 indicates that the Company made cumulative profits of US$135 million during the five-year period from cumulative sales of US$5.1 billion. While the company did not have a net loss over the period, the net profit declined steadily over the five years, eventually reaching an extremely low level of US$7 million in 2013. In the 2009 Determination Notice, the OUR determined that the targeted return on equity (or profit after taxation) was J$3.82 billion, which at the base exchange rate of J$89:1US established then by the OUR, was equivalent to US$42.98 million. Hence, if the tariff had performed to projection, the Company was expected to have made annual profits amounting to US$42.98 million. Thus, while the Company’s net profit was only slightly less than the allowed return on equity in 2009 (bear in mind the approved tariffs did not come into effect until November 2009), thereafter it consistently performed well below the return anticipated in the tariff determination between 2010 and 2013.

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

Throughout the review period, there was a general upward trend in cost of sales driven by the constant rise in fuel and IPP costs over that period. Fuel costs increased on account of the rise in fuel prices and the IPP costs rose on account of the new IPPs added to the grid during the period. Whilst O&M costs trended up during the first three years of the review period there were significant reductions in the last two years resulting in the test year O&M for 2013 being 12% below that for 2009. This is testament to the Company’s commitment to operate the business efficiently and deliver electricity to the consumer at the lowest possible price. O&M cost is the main item of costs that management has real control over in terms of driving down the price of the product. Net finance costs remained fairly stable in the first three years but increased significantly during the last two years on account of the high level of foreign exchange losses and additional interest charges related to bank overdraft necessitated by the harsh economic climate, large level of arrears by the GOJ and the low levels of working capital at JPS.

A review of the balance sheet demonstrates the significant capital investment that the Company has made in property, plant, and equipment as well as the significant amount of capital required to fund the business. As at December 31, 2013, the Company had fixed assets of more than US$700 million and total debt of more than US$360 million, making it one of the largest private sector companies in Jamaica in terms of asset base. The same would be true about revenues, with revenues exceeding US$1 billion in 2013. The depletion
of working capital in 2013, driven mainly by the significant levels of fuel penalty and FX losses suffered over the last two indicates a need for short term funding to ensure the business has sufficient working capital support. However, the Company was restrained from taking on additional funding given its marginal compliance with its loan financial covenants.

Table 4-3: Balance Sheet

<table>
<thead>
<tr>
<th>US$’000</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Current Assets</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cash &amp; cash equivalents</td>
<td>9,950</td>
<td>9,143</td>
<td>8,830</td>
<td>26,493</td>
<td>3,854</td>
</tr>
<tr>
<td>Accounts receivable</td>
<td>221,153</td>
<td>229,905</td>
<td>187,900</td>
<td>200,024</td>
<td>186,877</td>
</tr>
<tr>
<td>Inventories</td>
<td>50,291</td>
<td>51,593</td>
<td>60,132</td>
<td>66,723</td>
<td>40,871</td>
</tr>
<tr>
<td>Other</td>
<td>8,659</td>
<td>15,263</td>
<td>18,666</td>
<td>19,120</td>
<td>23,210</td>
</tr>
<tr>
<td><strong>Total Current Assets</strong></td>
<td>290,053</td>
<td>305,904</td>
<td>275,528</td>
<td>312,360</td>
<td>254,812</td>
</tr>
<tr>
<td><strong>Current Liabilities</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Short-term loans</td>
<td>47,858</td>
<td>26,641</td>
<td>0</td>
<td>25,000</td>
<td>0</td>
</tr>
<tr>
<td>Accounts payable &amp; provisions</td>
<td>115,975</td>
<td>128,696</td>
<td>147,733</td>
<td>181,027</td>
<td>188,826</td>
</tr>
<tr>
<td>Current maturity on long-term debt</td>
<td>24,175</td>
<td>24,317</td>
<td>49,493</td>
<td>36,906</td>
<td>37,492</td>
</tr>
<tr>
<td>Other</td>
<td>9,865</td>
<td>11,331</td>
<td>22,473</td>
<td>5,580</td>
<td>3,195</td>
</tr>
<tr>
<td><strong>Total Current Liabilities</strong></td>
<td>197,873</td>
<td>190,985</td>
<td>219,699</td>
<td>248,513</td>
<td>229,513</td>
</tr>
<tr>
<td><strong>Working capital</strong></td>
<td>92,180</td>
<td>114,919</td>
<td>55,829</td>
<td>63,847</td>
<td>25,299</td>
</tr>
<tr>
<td><strong>Non-current Assets</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Property, plant and equipment</td>
<td>637,038</td>
<td>652,107</td>
<td>655,534</td>
<td>657,680</td>
<td>698,571</td>
</tr>
<tr>
<td>Employee Benefit Asset</td>
<td>22,062</td>
<td>22,307</td>
<td>27,180</td>
<td>20,066</td>
<td>20,389</td>
</tr>
<tr>
<td>Other</td>
<td>4,897</td>
<td>5,139</td>
<td>11,782</td>
<td>13,565</td>
<td>15,930</td>
</tr>
<tr>
<td><strong>Total Non-current Assets</strong></td>
<td>663,997</td>
<td>679,553</td>
<td>694,496</td>
<td>691,311</td>
<td>734,890</td>
</tr>
<tr>
<td><strong>Financed by:</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Shareholders' equity</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Share capital &amp; reserves</td>
<td>303,275</td>
<td>303,275</td>
<td>281,829</td>
<td>281,687</td>
<td>281,687</td>
</tr>
<tr>
<td>Retained earnings</td>
<td>102,929</td>
<td>98,809</td>
<td>33,376</td>
<td>40,089</td>
<td>47,066</td>
</tr>
<tr>
<td><strong>Total Shareholders' equity</strong></td>
<td>406,204</td>
<td>402,084</td>
<td>315,205</td>
<td>321,776</td>
<td>328,753</td>
</tr>
<tr>
<td><strong>Non-current liabilities</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Long-term loans</td>
<td>250,213</td>
<td>292,279</td>
<td>356,295</td>
<td>353,572</td>
<td>326,442</td>
</tr>
<tr>
<td>Customer deposits</td>
<td>27,919</td>
<td>28,833</td>
<td>31,058</td>
<td>30,917</td>
<td>26,827</td>
</tr>
<tr>
<td>Other long-term liabilities</td>
<td>76,124</td>
<td>71,841</td>
<td>47,767</td>
<td>48,893</td>
<td>78,167</td>
</tr>
<tr>
<td><strong>Total Non-current liabilities</strong></td>
<td>349,973</td>
<td>392,388</td>
<td>435,120</td>
<td>433,382</td>
<td>431,436</td>
</tr>
</tbody>
</table>

The financial information from Table 4-2 and Table 4-3 are extracted from the audited financial statements. For complete details of the 2013 Financial Statements please see Annex D.
Chapter 5: Tariff Performance Review

5.1 Revenue Requirement

The revenue requirement in the 2009 rate case determination was set based predominantly on the 2008 test year results with some adjustment for known and measurable changes. The details of the actual revenue requirement as determined by the OUR are set out below:

<table>
<thead>
<tr>
<th>Table 5-1: 2009 Revenue Requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>JS’000</strong></td>
</tr>
<tr>
<td>PPA Costs</td>
</tr>
<tr>
<td>Operating Expenses</td>
</tr>
<tr>
<td>Depreciation</td>
</tr>
<tr>
<td><strong>Total Operating Expenses</strong></td>
</tr>
<tr>
<td>Net finance cost (excl. long term debt):</td>
</tr>
<tr>
<td>Interest on short term loans</td>
</tr>
<tr>
<td>Interest on customer deposits</td>
</tr>
<tr>
<td>Interest - other</td>
</tr>
<tr>
<td>Interest capitalised during construction (AFUDC)</td>
</tr>
<tr>
<td>Loan Finance Fees</td>
</tr>
<tr>
<td>Finance Income (269,658)</td>
</tr>
<tr>
<td><strong>Total Other Expenses</strong></td>
</tr>
<tr>
<td>Other Income</td>
</tr>
<tr>
<td>Self-insurance fund contribution</td>
</tr>
<tr>
<td>Gross Up for taxes on SIF</td>
</tr>
<tr>
<td><strong>Total Other Income</strong></td>
</tr>
<tr>
<td>Return on Investment</td>
</tr>
<tr>
<td>Taxation</td>
</tr>
<tr>
<td>Long Term Interest Expenses</td>
</tr>
<tr>
<td><strong>Revenue Requirements, net of credits</strong></td>
</tr>
<tr>
<td>Less Caribbean Cement Revenue</td>
</tr>
<tr>
<td>Loss Reduction Fund</td>
</tr>
<tr>
<td><strong>Adjusted Revenue Requirement</strong></td>
</tr>
<tr>
<td>Sales forecast (kWh)</td>
</tr>
<tr>
<td>Rate per kWh (JS/kWh - US¢/kWh)</td>
</tr>
<tr>
<td>FX Rate</td>
</tr>
</tbody>
</table>

At the FX rate of J$89: US$1, the allowed non-fuel revenue and return on investment that was established by OUR in 2009 were US$357 million and US$42.98 million respectively. As highlighted in Table 4-2, while JPS came close to achieving the allowed return on investment in 2009, the Company’s net profit fell way below this level from 2010 to 2013.
During the review period, the Company’s return on investment was significantly impacted by increased business risks and regulatory implementation issues arising from declining sales, FX losses because of currency depreciation which occurred in every year except 2010 and, the under recovery of fuel costs resulting from the effect of the regulatory treatment of system losses in the fuel tariff mechanism. The 14.4% depreciation of the Jamaican currency in 2013 was unusually high and coupled with the high level of arrears at J$15 billion on average, resulted in the largest FX losses (US$21M) that JPS has ever seen. FX losses continues to be a major risk to the Company as the average settlement period of around 52 days results in considerable exposure to currency fluctuations. Table 5-2 shows the FX losses for the company between 2011 and 2013.

### Table 5-2: FX Losses 2011 - 2013

<table>
<thead>
<tr>
<th></th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Receivables</td>
<td>2,349,326</td>
<td>15,579,331</td>
<td>30,223,586</td>
</tr>
<tr>
<td>Payables</td>
<td>844,485</td>
<td>(2,769,131)</td>
<td>(11,965,449)</td>
</tr>
<tr>
<td>Other</td>
<td>81,787</td>
<td>2,068,456</td>
<td>2,855,995</td>
</tr>
<tr>
<td><strong>FX Losses</strong></td>
<td><strong>3,275,598</strong></td>
<td><strong>14,878,655</strong></td>
<td><strong>21,114,132</strong></td>
</tr>
</tbody>
</table>

#### 5.2 Non-Fuel Revenue & Sales Performance

Table 5-3 shows JPS’ Non-Fuel Revenue Performance versus the OUR’s projected non-fuel revenue calculated from the new tariff and the previous year’s billing determinants in the annual tariff adjustments between 2010 and 2013.

It is clear from the table, in 2010/2011, 2011/2012 and 2012/2013, the actual non-fuel revenue fell short of the revenue that was projected by the OUR in its determination notices. The revenue shortfall is primarily attributed to the decline in billed sales from one period to the next. Between 2010 and 2013, sales declined at an average rate of 2% as is shown in Figure 5-1. In 2012/2013, the revenue from energy sales was over J$2 billion less than OUR’s projection using the 2011 billing determinants.

**Table 5-3: Non-Fuel Revenue Performance**

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>OUR’s Determination</td>
<td>389,704</td>
<td>391,192</td>
<td>409,546</td>
</tr>
<tr>
<td>Actual Non-Fuel Revenue</td>
<td>383,278</td>
<td>374,288</td>
<td>386,392</td>
</tr>
<tr>
<td><strong>Non-fuel Revenue Under-recovery</strong></td>
<td><strong>(6,426)</strong></td>
<td><strong>(16,904)</strong></td>
<td><strong>(23,154)</strong></td>
</tr>
<tr>
<td>Billed Sales (MWh)</td>
<td>3,084,190</td>
<td>3,029,339</td>
<td>2,949,064</td>
</tr>
<tr>
<td>Demand (kVA)</td>
<td>6,030,808</td>
<td>5,950,580</td>
<td>5,853,713</td>
</tr>
</tbody>
</table>

16 The revenue from Caribbean Cement is not included. The revenues in US dollar were converted from the Jamaican equivalent using the Base Exchange rate established by the OUR.
Demand revenues also declined considerably between 2010 and 2013, and in addition the distribution of sales changed adversely over the review period as the proportion of Rate 10 lifeline sales increased from 45.8% in 2010 to 48.3% in 2012.

### Table 4-1: Billed Sales (2009 – 2013)

<table>
<thead>
<tr>
<th>Year</th>
<th>Sales</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>3,130</td>
</tr>
<tr>
<td>2009</td>
<td>3,231</td>
</tr>
<tr>
<td>2010</td>
<td>3,235</td>
</tr>
<tr>
<td>2011</td>
<td>3,176</td>
</tr>
<tr>
<td>2012</td>
<td>3,103</td>
</tr>
<tr>
<td>2013</td>
<td>3,038</td>
</tr>
</tbody>
</table>

5.2.1 Price Cap vs Revenue Cap

The declining sales performance has severely affected the company’s financial performance and presents a significant risk to the viability of the company. Note that while JPS is not guaranteed a profit under the regulatory regime, it is entitled to a reasonable opportunity to make its target return as specified by the revenue requirement. Accordingly, the tariff structure should be cost reflective, providing an economic hedge against uncontrollable variables, such as adverse sales movements, inflation and foreign exchange risk. The existing price cap mechanism has not provided an effective economic hedge to ensure the utility’s viability. The company is therefore proposing a global revenue cap to ensure sufficient revenues are collected to cover all prudent costs and provide a proper rate of return to encourage investment. The revenue cap also has the advantage that it aligns the utility’s goals to the GOJ policies that could dampen sales growth including energy efficiency programs, net billing and wheeling.

5.3 Adjustments to the Fuel Recovery Mechanism

Table 4-1 highlights the fact that JPS consistently under recovered its fuel cost over the tariff review period. The level of under-recovery rose to remarkable levels in 2012 and 2013, contributing significantly to the loan covenant breach in 2012. JPS has made significant investment in loss reduction initiatives, a significant portion of which was in the continued implementation of capital intensive residential advanced metering infrastructure (RAMI) and
commercial AMI (CAMI) solutions. Despite the massive investment and the efforts that the Company has put into loss reduction, losses rose significantly over the tariff review period aided by the unprecedented level of sales decline due to conservation efforts. Crime generally, and by extension the illegal abstraction of electricity, has been a very pervasive and elusive problem in Jamaica. The level of crime and theft is dictated by socio-economic and cultural conditions; thus, the practical extent to which the JPS can control losses is limited and surely requires wider stakeholder participation and particularly strong Government support in legislation. A review and correction of the regulatory treatment of system losses is urgently required given its significant impact on the viability of the Company.

5.4 Other Business Risks

The preceding sections highlighted some of the market risks which impacted JPS’ tariff performance over the review period. Outside of these, there were other operational issues which impacted the company’s performance as outlined below.

5.4.1 Tropical Storm Nicole and Hurricane Sandy

Tropical Storm Nicole which hit the island on September 29, 2010 caused only minimal damage to the transmission system while the distribution network was moderately affected. Forty eight percent (48%) of customers lost power during the storm. The storm impacted the island for three (3) days but service was restored to 95% of customers by October 4, 2010. The total cost of recovery was US$1.15M.

The recovery cost for Hurricane Sandy which hit Jamaica on October 24, 2012, was US$6.1M. Approximately 70% of the customer base was affected with the eastern and southern parishes having the greatest levels of outages and network damage. The hurricane caused a deterioration in SAIDI and CAIDI for the month of October 2012 (which were more than the averages for that year excluding values in August 2012 when there was system shutdown). However, despite the severity of the storm, power was restored to the majority of the customers within three weeks. The Company’s restoration efforts were recognized by the Edison Electric Power Institute.

5.4.2 Failure of Bogue’s ST14 and Certain IPP Plants

In June 2013, a problem with the turbine lube oil system at Bogue led to the failure of ST14 which was out of service for approximately 4 months. The failure of ST14 coupled with generation problems at other IPP plants caused the System Heat Rate to move from 9,805 kJ/kWh in June to 10,298 kJ/kWh in August 2013 and to 10,522 kJ/kWh in September when the combined effects of approximately 50 MWs in IPP capacity was also unavailable to the system due to forced outages.
Chapter 6: Revenue Requirement

6.1 Introduction

The revenue requirement is the level of non-fuel revenues required by the Company to ensure that it is able to provide a safe, reliable and affordable electricity service for its customers. This revenue requirement is equal to the Company’s total approved capital (rate base) and operating expenditure for a test year (in this case 2013) with appropriate adjustments for known and measurable changes plus a fair return on its rate base. To determine rates the expenses and rate base should reflect a normal level of sales and service.

The Licence describes how the revenue requirement should be calculated:

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

Non-Fuel Revenue Requirement = non-fuel operating costs + depreciation + taxes + return on investment…”

The expenses comprising the revenue requirement are taken from a historical test year. The test year is a measure of the operations and investments in some specified 12 month period. The Licence defines the test year as follows:

"Test year" shall comprise the latest twelve months of operation for which there are audited accounts and the results of the test year adjusted to reflect:

Normal operational conditions, if necessary;

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

Such changes in accounting principles as may be recommended by the independent auditors of the Licensee.”
The non-fuel revenue requirement for the first year of the new regulatory period, 2014-2019, is US$472.8M. This is based on the results of from the audited financial statements for the 2013 test year as adjusted for known and measurable adjustments and is included in Section 6.7 of this Application. This revenue requirement amount represents a 12 percent increase over the 2013 non-fuel revenues generated from the existing regulatory approved tariffs. The increase is primarily driven by the expansion in the company’s rate base and increases in purchased power costs and net finance costs. This chapter describes the determination of the revenue requirement and explains the known and measurable adjustments included in the calculations to ensure that expenses reflect normal operations and any changes in the level of expenses which will take effect within 12 months of the filing. Figure 6-1 describes the various components of the revenue requirement.

**Figure 6-1: Components of Revenue Requirement**

![Diagram of Revenue Requirement Components]

### 6.2 Summary of Revenue Requirement

Following standard regulatory practice, JPS has calculated the revenue requirement consistent with the methodology set out in Schedule 3 of the Amended and Restated All-Island Electric Licence 2011 (“the Licence”). Table 6-1 shows the Company’s revenue requirement for the test year 2013.

**Table 6-1: Revenue Requirement**

<table>
<thead>
<tr>
<th>(US dollar thousands)</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Operating Costs:</strong></td>
<td></td>
</tr>
<tr>
<td>Purchased Power Costs</td>
<td>104,111</td>
</tr>
<tr>
<td>O&amp;M Expenses</td>
<td>150,845</td>
</tr>
<tr>
<td>Net Financing Costs</td>
<td>12,338</td>
</tr>
<tr>
<td>FX Losses</td>
<td>14,000</td>
</tr>
<tr>
<td><strong>Capital Costs:</strong></td>
<td></td>
</tr>
<tr>
<td>Depreciation</td>
<td>57,498</td>
</tr>
</tbody>
</table>

**Rate Base**

**Rate of Return**
Return on Investment 93,827
Long-Term Interest Expense 23,507

Other Income/Expenses:
Other Income (2,822)
Other Expenses 3,000

Revenue Requirement - Net of Credits 456,304

Adjustments:
Caribbean Cement Revenue (4,936)
Loss Reduction Fund Revenue + Taxes 13,000

Adjusted Revenue Requirement 464,368

In accordance with the Licence the revenue requirement represents the twelve months of operations for the year ending December 2013, adjusted by known and measurable changes to reflect normal operational conditions. The changes include adjustments to O&M Expenses, depreciation and the Self Insurance contribution and were absolutely necessary to ensure that revenues reflect the operating conditions of the rate year\(^\text{17}\). Each known and measurable adjustment will be discussed later in the relevant subsections in this chapter.

The revenue requirement calculated above represents a 32 percent increase over than the amount approved in 2009 (US$357M). The increase in revenue requirement is driven primarily by increases in PPA costs, finance expenses and capital costs. The increase in PPA costs resulted from a higher proportion of power being provided by Independent Power Producers (IPPs) rather than JPS generating units. During the 2009-2014 regulatory period, 2 new PPA agreements were signed by JPS to supply 83 MW of power to the grid. IPPs now provide over 43 percent of the power supplied to JPS’ customers. This trend is expected to continue given the recent issuing of a generating licence to Electric World International (EWI) for the production and supply of 381 MW of power to the grid by mid 2016.

Debt financing costs also increased during the regulatory period due to the overall increase in the rate base although the average cost of debt has fallen from 10.44% in 2009 compared to 8.07% currently. Additionally, there has been some increase in finance costs associated with increased working capital needs. Over the past 2 years JPS has been having considerable difficulty collecting on Government of Jamaica balances which has led to an increase in the need for working capital support and increased exposure to foreign exchange losses. The latter has been further exacerbated by higher rates of devaluation of the Jamaican dollar which exceeded 14 percent in 2013 alone.

The increased capital costs are due to the increase in the rate base since the 2008 test year. The company has consistently spent over US$70M per annum in capital expenditure throughout the 2009 to 2014 regulatory period on projects to improve all aspects of power generation and service delivery.

\(^\text{17}\) The rate year is defined as the period when the new price control rates will be put into effect.
6.3 Operating Expenditure

Operating expenses are the costs JPS incurs in providing electricity services and maintaining and operating its generation, transmission, distribution and general plant assets. These costs are not associated with capital investments thus the recovery of operating costs does not provide any return to shareholders. The main non-fuel operating expenses include purchased power costs, labor costs and finance costs. Operating costs included in the revenue requirement are based on test year audited financial results in accordance with the provisions of the Licence. These costs are provided in Table 6-2 below and their components are examined in the subsequent subsections:

Table 6-2: Test Year Operating Costs

<table>
<thead>
<tr>
<th>(US dollar thousands)</th>
<th>Audited Financials</th>
<th>Adjustments</th>
<th>Application</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Operating Costs:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Purchased Power Costs</td>
<td>104,111</td>
<td>-</td>
<td>104,111</td>
</tr>
<tr>
<td><strong>O&amp;M Expenses:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Payroll, benefits &amp; training</td>
<td>58,958</td>
<td>7,468</td>
<td>66,426</td>
</tr>
<tr>
<td>Third party services</td>
<td>25,830</td>
<td>-</td>
<td>25,830</td>
</tr>
<tr>
<td>Materials &amp; equipment</td>
<td>8,544</td>
<td>-</td>
<td>8,544</td>
</tr>
<tr>
<td>Office &amp; Other expenses</td>
<td>24,778</td>
<td>(1,250)</td>
<td>23,528</td>
</tr>
<tr>
<td>Insurance expense</td>
<td>6,811</td>
<td>1,362</td>
<td>8,174</td>
</tr>
<tr>
<td>Bad debt write-off</td>
<td>18,342</td>
<td>-</td>
<td>18,342</td>
</tr>
<tr>
<td><strong>Total O&amp;M Expenses</strong></td>
<td>143,265</td>
<td>7,580</td>
<td>150,845</td>
</tr>
<tr>
<td><strong>Net Financing Costs:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Interest on Short-term Loans</td>
<td>1,403</td>
<td>-</td>
<td>1,403</td>
</tr>
<tr>
<td>Interest rate swap</td>
<td>1,232</td>
<td>(1,232)</td>
<td>-</td>
</tr>
<tr>
<td>Preference dividends</td>
<td>1,075</td>
<td>(1,075)</td>
<td>-</td>
</tr>
<tr>
<td>Interest on Consumer Deposits</td>
<td>549</td>
<td>-</td>
<td>549</td>
</tr>
<tr>
<td>Bank Overdraft Interest and Other</td>
<td>5,721</td>
<td>-</td>
<td>5,721</td>
</tr>
<tr>
<td>Interest Income</td>
<td>(1,615)</td>
<td>-</td>
<td>(1,615)</td>
</tr>
<tr>
<td>Debt issuance costs and expenses</td>
<td>4,829</td>
<td>-</td>
<td>4,829</td>
</tr>
<tr>
<td>Int. Capitalized during construction</td>
<td>1,450</td>
<td>-</td>
<td>1,450</td>
</tr>
<tr>
<td><strong>Net Finance Costs</strong></td>
<td>14,644</td>
<td>(2307)</td>
<td>12,338</td>
</tr>
</tbody>
</table>

Foreign Exchange Losses | 21,114 | (7,114) | 14,000 |

**Total Operating Costs** | 282,759 | (1,841) | 281,293 |
6.3.1 Purchase Power Costs

The test year Purchase Power Costs of US$104.11M represents the total amount paid to IPPs for power delivered to the grid. These payments are made in accordance with their respective PPA agreements. PPA costs incurred in the test year is 54 percent higher than the amount approved in 2009. This is due to new PPAs being signed since the last rate review. JPS entered into new agreements for 18 MW from Wigton in 2010 and 65MW from West Kinston Power Producers (WKPP) in 2012. In 2013, 43.5 percent of the electricity sold to customers by JPS was generated by IPPs compared with 30 percent in 2008. The figure below shows the annual PPA costs incurred between 2008 and 2013 and the percentage of the power supplied by IPPs in each year.

Figure 6-2: PPA Costs 2008-2013

6.3.2 Operating and Maintenance Expenses

The test year O&M costs was US$150.8M which represents a 7 percent reduction compared to the amount $162M level recorded in the audited financial statements for 2008. This is a notable reduction in O&M costs during the regulatory period especially in light of the fact that US inflation for the period was 10 percent. The company remains committed to keeping its operations as efficient as possible to constrain the impact of increased operating cost on rates despite the ageing status of its generating plant and the imminent need to retire 292MW. Note that the relative efficiency of operations was confirmed by the X Factor study conducted by Castalia in 2013 which provided evidence that the company is being operated efficiently and benchmarked well against other efficiently run utilities including Florida Power and Light.
To further reduce the costs to customers the company has proposed to the OUR that it be allowed to record actual meter readings for residential customers in alternate months (instead of going out to read meters every month), with the estimated bills being issued in the intervening months calculated based on the last three actual readings. JPS estimates that this will save approximately US$1.25M annually and has included this amount as savings to the customer in the revenue requirement assuming the OUR will agree to this change.

6.3.2.1 Payroll, Benefits & Training

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

The test year figures for payroll costs were also increased by 5 percent to reflect the across the board salary increase granted to employees which came into effect on January 1, 2014. In 2011 the Company signed a three year Heads of Agreement with all of its bargaining units which secured salary increases of 4%, 5% and 5% in 2012, 2013 and 2014 respectively for all unionized employees. The company has four (4) separate unions representing approximately 80% of the current staff complement. The Agreements come to an end in November 2014 as it relates to employee salaries and benefits. An analysis of the adjustments to payroll costs is shown in Table 6-3 below.

Table 6-3: Payroll Analysis

<table>
<thead>
<tr>
<th>(US$ '000)</th>
<th>Actual 2013</th>
<th>5% Wage Adjustment</th>
<th>Pension Benefit Adjustment</th>
<th>Adjusted 2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Payroll</td>
<td>53,038</td>
<td>2,652</td>
<td></td>
<td>55,690</td>
</tr>
<tr>
<td>Employee Benefits</td>
<td>5,919</td>
<td>296</td>
<td>4,520</td>
<td>10,736</td>
</tr>
<tr>
<td><strong>TOTAL PAYROLL AND RELATED EXPENSES</strong></td>
<td><strong>58,957</strong></td>
<td><strong>2,948</strong></td>
<td><strong>4,520</strong></td>
<td><strong>66,426</strong></td>
</tr>
</tbody>
</table>

6.3.2.2 Insurance Expense

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

The Willis 2013 review of the power industry notes that the Property insurance market for companies in the power sector remains one in which the dynamics of pricing and losses, and
supply and demand, combine to create an uneasy state of flux. The market is neither soft nor hard, and the experience for buyers varies depending on their risk and loss profile.

The main component of the JPS insurance is the Property All Risks policy, which represents approximately 80 percent of the overall insurance budget. This insurance policy currently renews on June 1 each year and covers all real and insured property including the generating assets. The Company’s insurance broker has indicated that a premium increase is imminent given; the company’s overall risk profile in relation to age of the generating asset, the exposure of the generating equipment in relation to natural catastrophe, overall industry losses, and the company’s individual loss record among other variables. The company’s broker typically obtains quotes from numerous insurance service providers around the world to ensure that our insurance premium is competitively priced.

Approximately 85% of the company’s property insurance is comprised of the generating equipment. The age of the generating equipment and availability of repair and replacement parts have presented significant challenges towards maintaining continuous operation. The company currently has 6 generating units with an average age of 42 years, producing 305MW of electricity with this being considered as high risk. The remaining six generating units in the company’s fleet are averaging 20 years. From a loss control standpoint, the large rotating machinery and associated equipment that is aging, has an increased inherent risk factor. Although the equipment is still being maintained it is past, or getting to the end of life cycle for the boilers and associated auxiliary equipment. Over the last insurance cycle, we have seen whereby seven insurers, including large insurers such as AIG, Zurich and Aegis have withdrawn from the JPS programme, citing the aged generating equipment and insufficient premium. As the unit continue to age, securing coverage at reasonable cost will become more difficult. In fact JPS does not have replace coverage for the steam units, as Insurers declined to provide same.

Claims are of course one of the fundamental drivers of market conditions, the accumulation of “risk” and natural catastrophe losses in recent years has meant that few insurers have returned an underwriting profit over 2013, with some power loss ratios exceeding 200%. Globally, losses from natural catastrophes in 2013 was US$ 125bn and insured losses of around US$ 31bn. Jamaica has a high exposure to natural hazards, with the country being classified as being in Munic Re zone 4 for Hurricane and Zone 3 for earthquake. The main exposure is from Hurricanes which has affected the country many times in the recent past. The coastline of Jamaica is exposed to Tsunami, with this having a direct impact on the JPS generating asset, given that three of four generating stations are situated on the coastline. Insurers are therefore focusing on natural catastrophe perils of flood, windstorm and earthquake.

Machinery breakdown and the associated business interruption exposure remains a key underwriter concern. Major power sector losses in 2013 exceeded US$1.3B. JPS was not immune to this situation, given the loss on Steam turbine 14 located at the Bogue Power Station which rendered the unit out of service for four months.

Given these facts, the Company’s broker has indicated that JPSs ability to obtain properly insurance at reasonable rates will be extremely difficult in the next couple years and increases such as the one imminent will continue until the aging fleet is decommissioned.
6.3.3 Net Finance Costs

Net finance costs were US$14.2M in 2013 which includes $5.7M in interest costs associated with the low levels of working capital and US$4.8M for amortization of debt issuance costs. The main driver of the increase was the increase debt issuance costs and interest charges on bank overdraft. The working capital costs relate to bank overdraft charges and supplier interest charges for the low levels of working capital due to the high levels of government receivables. Please note the corresponding significant fall in the level of working capital being included in the rate base which has fallen from US$89M in 2008 to US$25M in 2013. As it relates to the debt issuance costs in 2013 (US$4.8M) compared to the level in 2008 (US$1.5M), please note the all-in cost of borrowing is 9.74% in 2013 which compares favorably to the all-in cost of 11.01% in 2008. The higher debt issuance costs and lower interest rate is simply the reflection of more export credit agency funding currently in our debt mix which generally have lower interest rates but higher debt issuance costs in the form of up-front fees.

6.3.4 Foreign Exchange Losses

The net financial impact of foreign exchange losses on JPS’ financial performance for 2013 was US$21M. This amount has been adjusted to US$14M in the revenue requirement to ensure that the amount included reflects normal operating conditions. Note that foreign exchange losses were not included as a recoverable expense in the 2009 rate review. The US$7M reduction in the amount to US$14M is to reflect our estimate as to what the rate of devaluation will be during 2014 and its impact on JPS in that year.

The company has been experiencing significantly higher levels of FX losses over the last 3 years. This is mainly the result of volatility in the foreign exchange markets and inadequate provisions in the regulatory framework to mitigate these losses. This point is developed further in chapter 7 of the Application but JPS is requesting that this be explicitly included in the revenue requirement and be subject to a true-up mechanism annually to ensure that only the actual FX losses incurred are recovered through tariffs.

6.4 Capital Costs

Capital costs comprise a return on investment (return of capital) and a depreciation allowance (return of capital), which in the current regulatory framework represents a proxy for capital expenditure. For this reason, one can assume that the rate base will be constant over the regulatory period. That is to say, it is assumed that the utility will be investing in the rate base (through capital expenditure) at the same rate that the rate base is depreciating annually. If it does this then its rate base will remain constant over the regulatory period and it is fair for it to be paid a WACC on a constant rate base figure for that period. So, the cash earned from the depreciation charge (note depreciation is really a non-cash item) is assumed to be reinvested in the form of capital expenditure for the rate base to remain constant. It is also therefore an assumption that the utility will be able to re-finance its existing debt over the regulatory period as well, so as to keep its debt as a constant proportion of the rate base. Lastly, if the utility chooses to invest in the rate base at a rate which exceeds the annual depreciation then it will obviously have to wait until the next rate review period before it can earn a return from such excess investment.
6.4.1 Depreciation

Depreciation represents the imputed costs for the use of fixed assets in the regulated business. The depreciation expenses included in the revenue requirement is used to recover capital investment costs as noted above. Under the current regulatory regime the historical test year depreciation charge acts as a proxy for capital expenditure. It is in effect a systematic allocation of investment cost which allows the utility to fund its capital expenditure requirements during the regulatory period.

The depreciation expense of US$49.2M in the 2013 audited financials was based on the useful lives specified in schedule 4 of the Licence. However, JPS is requesting an adjustment of the asset lives based on the recommendations from the Depreciation study conducted by KPMG. JPS commissioned the study in 2013 to review the useful lives of asset classes based on industry best practice and to analyze the actual age of the JPS assets at retirement. KPMG concluded that the current asset lives indicated in the Licence were in several instances longer than the actual economic useful lives of those assets. They recommended that the following adjustments be made to the current asset lives used to determine depreciation rates.

Table 6-4: KPMG Recommended Asset Lives

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

If the asset lives were adjusted according to KPMG’s recommendation then there would be an additional amount of test year depreciation of US$8.33M as shown below and the adjusted test year depreciation would be US$57.5M:

Table 6-5: Additional Depreciation due to Asset Life Adjustment
<table>
<thead>
<tr>
<th>Category</th>
<th>Asset</th>
<th>Current Life (per Licence)</th>
<th>Recommended Life</th>
<th>Change In Annual Depreciation Charge</th>
</tr>
</thead>
<tbody>
<tr>
<td>Distribution Plant</td>
<td>Meter</td>
<td>30</td>
<td>15</td>
<td>1,186,127</td>
</tr>
<tr>
<td>Distribution Plant</td>
<td>Street-light</td>
<td>30</td>
<td>20</td>
<td>172,890</td>
</tr>
<tr>
<td>General Plant</td>
<td>Electronic Eqpt(Lab Eqpt)</td>
<td>25</td>
<td>10</td>
<td>353,237</td>
</tr>
<tr>
<td>General Plant</td>
<td>Communication Eqpt</td>
<td>15</td>
<td>5</td>
<td>3,631,417</td>
</tr>
<tr>
<td>General Plant</td>
<td>Computer Equipment</td>
<td>15</td>
<td>6</td>
<td>2,763,109</td>
</tr>
<tr>
<td>General Plant</td>
<td>Furniture &amp; Office Eqpt</td>
<td>20</td>
<td>10</td>
<td>192,060</td>
</tr>
<tr>
<td>General Plant</td>
<td>Vehicles</td>
<td>7</td>
<td>4</td>
<td>31,138</td>
</tr>
</tbody>
</table>

JPS is requesting that the regulator accepts the recommendation on KPMG’s Depreciation study. The above additional amount is included as a known and measureable adjustment to the depreciation expense. We believe that $57.5M is still a conservative estimate as to what it will cost to fund the annual capital expenditure needs of the business over the next three years given our existing aged generation plant. Our annual capital expenditure for the last three years has actually been US$72M and we anticipate this will increase to US$80M on average per annum for the next three years, certainly until the new 381MW of new generation is brought on line.

6.4.2 Return on Investment

The return on investments describes the return the Company is allowed to earn to reward capital investment. The concept is defined in the Licence as:

“the required rate of return which allows the Licensee the opportunity to earn a return sufficient to provide for the requirements of customers and acquire new investments at competitive costs”

The return on investment is calculated by multiplying the weighted average cost of capital (WACC) by the Company’s test year rate base.

6.4.2.1 Rate Base

Rate base comprises the assets used by JPS to provide electricity services. The following principles are applied in determining the value of the rate base used in revenue requirement calculations:

- The rate base should include only the assets necessary to provide electricity services
- It is based on the depreciated value of fixed assets
- It includes an allowance for working capital

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

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

Employing this definition the table below calculates the current rate base as US$606.7M. This represents a 9 percent increase over 2008 rate base of $554.6M primarily due to the capital expenditure over the regulatory period.

**Table 6-6: Rate Base**

<table>
<thead>
<tr>
<th>(US dollar thousands)</th>
<th>2008</th>
<th>2013</th>
<th>Change</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Fixed Assets:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Property Plants and Equipment</td>
<td>623,439</td>
<td>698,571</td>
<td></td>
</tr>
<tr>
<td>Intangible Assets</td>
<td>4,007</td>
<td>9,877</td>
<td></td>
</tr>
<tr>
<td>Rural Electrification Programme Assets</td>
<td>1,097</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>Other Asset</td>
<td>4,606</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Long-Term Receivables</td>
<td>1,447</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Construction Work in Progress</td>
<td>(56,617)</td>
<td>(14,516)</td>
<td></td>
</tr>
<tr>
<td>Exclusion of JPS managed IPP assets</td>
<td>(43,319)</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Net Fixed Assets</strong></td>
<td>571,926</td>
<td>656,667</td>
<td>15%</td>
</tr>
<tr>
<td><strong>Offsets:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Customer Deposits</td>
<td>30,078</td>
<td>26,827</td>
<td></td>
</tr>
<tr>
<td>Employee Benefits Obligations</td>
<td>17,706</td>
<td>6,908</td>
<td></td>
</tr>
<tr>
<td>Deferred Expenditure (Tax)</td>
<td>58,418</td>
<td>39,917</td>
<td></td>
</tr>
<tr>
<td>Deferred Revenue</td>
<td>-</td>
<td>1,654</td>
<td></td>
</tr>
<tr>
<td><strong>Total Offsets</strong></td>
<td>106,202</td>
<td>75,306</td>
<td>-29%</td>
</tr>
<tr>
<td><strong>Total Long Term Assets</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Current Assets:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cash and Short-Term Deposits</td>
<td>7,208</td>
<td>3,854</td>
<td></td>
</tr>
<tr>
<td>Repurchase Agreements/ Restricted Cash</td>
<td>8,139</td>
<td>21,642</td>
<td></td>
</tr>
<tr>
<td>Receivables</td>
<td>172,428</td>
<td>186,877</td>
<td></td>
</tr>
<tr>
<td>Tax Recoverable</td>
<td>2,420</td>
<td>420</td>
<td></td>
</tr>
<tr>
<td>Inventories</td>
<td>43,929</td>
<td>40,871</td>
<td></td>
</tr>
<tr>
<td><strong>Total Current Assets</strong></td>
<td>234,124</td>
<td>253,664</td>
<td>8%</td>
</tr>
<tr>
<td><strong>Current Liabilities:</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bank Overdraft</td>
<td>775</td>
<td>1,938</td>
<td></td>
</tr>
<tr>
<td>Short Term Loans + Current Maturity</td>
<td>66,002</td>
<td>37,492</td>
<td></td>
</tr>
<tr>
<td>Payables</td>
<td>78,254</td>
<td>189,385</td>
<td></td>
</tr>
<tr>
<td>Corporation Tax Payable</td>
<td>-</td>
<td>(1,148)</td>
<td></td>
</tr>
<tr>
<td>Related Companies balances</td>
<td>161</td>
<td>698</td>
<td></td>
</tr>
<tr>
<td><strong>Total Current Liabilities</strong></td>
<td>145,192</td>
<td>228,365</td>
<td>57%</td>
</tr>
<tr>
<td><strong>Net Current Assets (Working Capital)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rate Base</td>
<td>554,656</td>
<td>606,660</td>
<td>9%</td>
</tr>
</tbody>
</table>
Revenue Requirement

The increased rate base is primarily the result of greater capital investments which resulted in a 15 percent increase in Net fixed assets. This is driven by the fact the company has been investing a higher level of capital expenditure in acquiring new plant than that recovered through the depreciation charge. This primarily reflects the commitment of JPS to modernizing the T&D grid and improving the service reliability and quality for its customers.

Net Fixed Assets

Net fixed assets comprises the property plant and equipment and intangible assets used in the provision of electricity services. The test year Net Book Value (NBV) of these assets was adjusted for the removal of the NBV of the new Maggoty Hydro power plant and the Munroe wind plant. These will be operated as virtual IPPs with signed PPA agreements with JPS and therefore should be excluded from the regulatory rate base.

Net fixed assets increased by US$84.7M since 2008 primarily due to the capital expenditure invested by the company over the last 5 years. The company spent an average of US$65M on capital projects to maintain its fleet of generating units, to modernize and improve its transmission and distribution network and on projects aimed at reducing system losses. Figure 6-3 shows the levels of expenditure each year during the preceding regulatory period.

Figure 6-3: Capital Investment

Working Capital

The Licence allows for the inclusion of any working capital requirements that may exist as at the test year. Working capital is measured as current assets minus current liabilities and indicates the allowance for resources to meet short term obligations. According to Schedule 3 of the Licence

Working capital shall include, among other things, the cost of an appropriate level of fuel which is held in inventory, cost of appropriate levels of other inventories and an appropriate percentage of annual non-fuel operating expenses less any appropriate offsets
The level of working capital according to the test year audited financials is only US$25M, 72% smaller than the amount included in the 2008 rate base.

6.4.2.2 Return on Investment Calculation

The return on investments was derived by multiplying the rate base by the weighted average cost of capital (WACC). JPS’ WACC for the 2013 test year was derived by International consultants Castalia LLC using the CAPM model and JPS loan portfolio data. The methodology used by Castalia is discussed in the Cost of Capital section in Chapter 7: of this Application. The table below summarizes the results of the study.

<table>
<thead>
<tr>
<th>Particulars</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost of Debt</td>
<td>8.07%</td>
</tr>
<tr>
<td>Rate of return on equity</td>
<td>19.83%</td>
</tr>
<tr>
<td>Tax Rate</td>
<td>33%</td>
</tr>
<tr>
<td>Gearing Ratio (Deemed)</td>
<td>48.00%</td>
</tr>
<tr>
<td>Rate Base</td>
<td>606,660</td>
</tr>
<tr>
<td>Post Tax WACC</td>
<td>12.89%</td>
</tr>
<tr>
<td>Pre Tax WACC</td>
<td>19.34%</td>
</tr>
<tr>
<td>Return on Equity</td>
<td>62,552</td>
</tr>
<tr>
<td>Taxation</td>
<td>31,276</td>
</tr>
<tr>
<td>Interest Expense</td>
<td>23,507</td>
</tr>
</tbody>
</table>

6.5 Other Income and Expenses

6.5.1 Other Income

Other Income comprises predominantly proceeds from the sale of scrap, rental income and other miscellaneous settlements. During 2013, other income amounted to US$4.4 million dollars, however, this is not typical of a normal year’s operation primarily because of the inclusion of income arising from an insurance claim settlement. This settlement which relates to Bogue plant ST14 Power Plant was US$1.6M and is deemed to be a one off payment that should not be expected to recur in the future. As such, the adjusted amount for Other Income to be included in the revenue requirement as an offset is $2.8M.

6.5.1.1 Loyalty Reward Fund

Other income includes an amount of US$1.037M which relates to the net amount earned from the Early Payment Incentive (EPI)/Late Payment Fee Initiative (LPF). This will be treated as an offset to the revenue requirement.

In the 2013 Annual Tariff Determination the OUR gave its no objection to the EPI/LPF initiative proposed by JPS. The initiative was developed to help reduce the over JS1 billion in receivables (arrears) owed by residential customers thus reducing the amount that is included in the rate
base, which tends to have an upward pressure on tariffs. This also helps to reduce JPS’ settlement risk and therefore the levels of foreign exchange losses incurred each year.

The program was introduced on August 1, 2013 and is applicable to residential customers only. The terms and conditions of the program are as follows:

**Early Payment Incentive**
- Two hundred and fifty dollar ($250.00) incentive for payment made *in full* on or before the due date i.e. customers who make payments *in full* on or before their due date will automatically receive this credit incentive on their next bill.

**Late Payment Fee**
- Two hundred and fifty dollar ($250.00) penalty fee plus GCT (16.5%) for payments made after the due date i.e. customers who did not pay their bill in full by the due date will automatically be charged a $250 penalty fee plus GCT (16.5%) on their next bill.

**Deposit greater than or equal to $5,000**
- Accounts with a deposit greater than or equal to $5,000 with an outstanding balance on the current bill will be charged a late fee. However, these accounts will receive an additional 15 days grace period from their original due date to clear the outstanding balance before they become liable for disconnection.
- Accounts that have a balance brought forward from previous bills will be charged a late fee and will not receive the additional 15 days grace period.

The program has worked very well so far with the compliance level improving from 35 percent at the beginning of the program to 45 percent as at February 2014. In February 2014, 236,070 customers paid their bills on or before the due date earning a total payout of J$59M. Since the start of the program J$332M has been credited to customer accounts in the 6 months of implementation. JPS expects this trend to continue as customers take advantage of the $500 incentive to reduce the amount owed on their bills and avoid the late payment fee.

Despite its success in constraining the growth of residential receivables, continuing the program as it is currently constituted involves significant risks. As compliance grows above 50 percent JPS will have to fund the difference between the EPI and LPF from its own resources. The Licence indicates that the Company’s tariffs are intended to recover all costs incurred by JPS in serving its customers once they are prudently incurred. Consequently JPS believes that the costs of this program should also be embedded into the rates similar to other programs providing comparable benefits.

Additionally, to avoid any unfair gain or loss to JPS, or its customers who are funding these amounts, we recommend an annual true-up to this exercise whereby the actual payout incurred is compared to the estimated amount included in the revenue requirement. The over or under-recovery could be included as an annual adjustment and JPS could also apply annually to seek an adjustment to the actual amount of the fee charged.

Accordingly, we recommend that the current EPI/LPF regime be continued but recommend that there be an annual true-up mechanism to the program to ensure that JPS is not gaining or losing from the administration of the program. The objective is to encourage customers to pay on a timely basis as this will help to reduce the working capital levels and levels of foreign exchange
losses. We have a similar recommendation for commercial customers albeit slightly more complex in Chapter 14: Other Fees where we are asking for the right to charge interest to commercial customers without directly impacting the initial revenue requirement. Instead we recommend an annual true-up mechanism for that exercise as well whereby the portion of the interest charge that is earned from commercial customers to offset the foreign exchange losses would be treated as an offset to the true-up mechanism which we are requesting for foreign exchange losses itself.

6.5.2 Other Expenses

Other expenses in the revenue requirement allow for the recovery of additional recurrent expenses that are not operational expenses. Contributions to the Self-Insurance Fund have been funded through this allowance since 2004. The table below shows the amounts included in the revenue requirement.

<table>
<thead>
<tr>
<th>Table 6-8: Revenue Requirement - Other Expense</th>
</tr>
</thead>
<tbody>
<tr>
<td>Other Expenses</td>
</tr>
<tr>
<td>Contribution to Self-Insurance Fund</td>
</tr>
<tr>
<td></td>
</tr>
</tbody>
</table>

As at December 31, 2013 the self-insurance fund (SIF) stands at US$21.6 million and it is now at a level where, all things considered, we recommend a reduction to the annual funding rate. It is our recommendation that the annual rate of funding should be reduced from US$7.5 million gross (US$5M net) to US$3 million gross (US$2M net). We further recommend, as done in the past, that the funding rate be reviewed each year for appropriateness depending on the actual experience in relation to natural disasters and giving consideration to the Net Book Value (NBV) of JPS assets. As at December 31, 2013, the NBV of JPS’ fixed assets was US$699M, with an amount of US$361M specifically in relation to T&D assets which are quite susceptible to natural disaster and for which JPS cannot obtain conventional insurance cover. As such, the SIF value now covers 5.8% of the uninsured value of fixed assets. We believe the recommendation to reduce the funding rate is particularly useful at this time as this will help to reduce the non-fuel tariffs.

6.6 Other Adjustments to Revenue Requirement

6.6.1 Caribbean Cement Revenue

Annual non-fuel revenues over the period 2009-2013 for Caribbean Cement Company have remained flat at US$4.9 million dollars. This is the case even though there has been an 11% reduction in sales. Their average consumption has reduced from 93,000 MWh per annum in 2008 to 83,000 MWh per annum 2013 as the construction industry has been in decline over the past five years and this has negatively affected the demand for the product and there is increased competition from cheap imported cement in the Jamaican market.
6.6.2 Electricity Efficiency Improvement Fund (EEIF)

The EEIF was introduced in the last rate case filing in 2008 to fund loss reduction activities. This fund was used primarily to purchase capital equipment to construct Residential Automated Metering Infrastructure (RAMI) for the purpose of controlling losses in inner-city areas. The program was successfully implemented in several communities in the parishes of Kingston, St. Andrew, St. Catherine and St. James.

In the new regulatory tariff period the company is moving to introduce the community renewal programme which is a softer approach to controlling losses. This programme will also provide assistance to poor customers with wiring their households in order to facilitate the safe consumption of electricity. It will also fund a subsidized billing program to help these persons who are currently illegal consumers of electricity transition to legitimate paying customers. In this regard, JPS recommends the continuation of the EEIF program for the purpose of funding this and other new initiatives aimed at reducing system losses. The details of the programme is provided in Chapter 13 of this application.

6.7 Revenue Requirement Calculation

A reconciliation of the amounts included in the test year revenue requirement and the adjustments applied is provided below:

**Table 6-9: Adjusted Revenue Requirement**

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>Additions/Exclusions</th>
<th>Rate Increase</th>
<th>Adjusted Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Purchased Power Costs</td>
<td>104,111</td>
<td></td>
<td></td>
<td>104,111</td>
</tr>
<tr>
<td>Operating Expenses</td>
<td>143,265</td>
<td>3,270</td>
<td>4,310</td>
<td>150,845</td>
</tr>
<tr>
<td>Net Financing Costs</td>
<td>14,645</td>
<td>(2,307)</td>
<td></td>
<td>13,570</td>
</tr>
<tr>
<td>FX Losses</td>
<td>21,114</td>
<td>(7,114)</td>
<td></td>
<td>14,000</td>
</tr>
<tr>
<td>Other Income</td>
<td>(4,425)</td>
<td>1,603</td>
<td></td>
<td>(2,822)</td>
</tr>
<tr>
<td>Other Expenses</td>
<td>3,000</td>
<td></td>
<td></td>
<td>3,000</td>
</tr>
<tr>
<td>Depreciation</td>
<td>49,168</td>
<td>8,330</td>
<td></td>
<td>57,498</td>
</tr>
<tr>
<td>Return on Investment</td>
<td>93,827</td>
<td></td>
<td></td>
<td>93,827</td>
</tr>
<tr>
<td>Long-Term Interest Expense</td>
<td>23,507</td>
<td></td>
<td></td>
<td>23,507</td>
</tr>
<tr>
<td><strong>Revenue Requirement</strong></td>
<td>455,426</td>
<td>3,782</td>
<td>4,310</td>
<td>456,304</td>
</tr>
</tbody>
</table>

**Adjustments:**

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Caribbean Cement Revenue</td>
<td>(4,936)</td>
</tr>
<tr>
<td>Loss Reduction Fund Revenue + Taxes</td>
<td>13,000</td>
</tr>
</tbody>
</table>

**Adjusted Revenue Requirement**

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Adjusted Revenue Requirement</td>
<td>463,490</td>
</tr>
</tbody>
</table>
Chapter 7: Cost of Capital

7.1 Introduction

The non-fuel revenue requirement JPS is allowed to recover through the tariff includes a component for the return on investment. This return is to compensate JPS investors for capital costs incurred by investing in the utility’s regulated asset base. Schedule 3 (Section 2(C)) of the All-Island Electric License describes this return in the following manner:

“This component is calculated based on the approved Rate Base of the Licensee and the required rate of return which allows the Licensee the opportunity to earn a return sufficient to provide for the requirements of consumers and acquire new investments at competitive costs....

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

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

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

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

The principle of the return on investment is based on a trade-off principle. The risk return trade-off principle states, assuming risk averse investors, potential return on investments must rise with an increase in risk. Therefore, if it is proven by objective means the environment JPS will
operate between 2014 and 2019 is inherently more volatile than the previous rate review period, ex ante, then the allowed rate of return should be higher.

In other words, the rate of return on investment authorized in the previous determination should be adjusted commensurate with the changing risk and liquidity environment faced by investors in the utility, which in JPS’ case will be measured primarily by the country risk premium.

According to the 2009 Rate Case Determination Notice, the OUR determined the following relating to the calculation of JPS’ return on investment:

- **Cost of Debt** - The OUR accepted the weighted cost of outstanding debt of 10.44% as per the test year’s audited financial statements.
- **Real Cost of Equity** – The OUR approved a real rate of return on investment of 16.00% based on the CAPM Methodology
- **Capital Structure** – The OUR accepted a gearing ratio of 48% as per the audited financials.
- **WACC** – The OUR approved a post-tax WACC of 11.62%, which implies a pre-tax WACC of 17.43%.

The business environment JPS operates in continues to be volatile. JPS currently faces an extremely risky economic environment and will continue to do so for foreseeable future. The Company must operate in an environment characterized by domestic and contraction in some of its trading partners, inflationary spiral and volatile foreign exchange market.

- **Macroeconomic environment** – In 2011, the economy grew by 1.1%, which represented the first annual increase since the onset of the global economic downturn in 2008. By 2012 this progress was reversed as measured by the consistent contraction in real GDP with only a slight growth occurring in 2013. Due to the slow recovery from the global financial crisis the outlook remains uncertain with the possibility of a supply shock triggering an economic downturn.

- **Electricity Demand** – Demand for electricity has decreased from the high in 2010 and is actually contracting for residential customers. JPS expects demand to continue to be weak, and believed will only grow with the introduction on natural gas to island.

- **Financial Markets** – The local credit markets have been in flux since the second quarter of 2008 due to the meltdown of the US financial markets. The situation is still fluid in respect to capital markets. The credit rating for Jamaica in 2013 was Caa3, as determined by credit rated agencies. There has been a slight improvement, recently, but rating agencies are still show concern about Jamaica’s long-term credit situation.

- **Power Purchase Agreements (PPAs)** - The source of these risks come mainly from contractual performance risks due to the PPA structure and performance guarantees.

- **Interest Rate** – Short-term interest rates have become less volatile since January 2010.

These developments indicate that JPS is still operating in a risky environment and the additional risk should be reflected in the return on investment the OUR authorizes in the current rate case.
7.2 Capital Structure

According to the License, the cost of capital the utility is allowed to recover should be based on either the actual capital structure or “an appropriately adjusted capital structure which adjustment is required to keep parity of the interests of the consumers and investors”. In the 2009 determination, the OUR indicated that in its view an appropriate gearing for JPS was 48%, despite the actual level being 45%. The OUR nonetheless accepted the actual gearing for use in calculation of the JPS’ WACC.

The Company’s capital structure for the test year, as reflected in its gearing ratio of 48%, represents a sub-optimal level of debt currently used to finance the Company’s regulated asset base. According to Castalia’s Cost of Capital Study included in Annex A of this submission, the average gearing of energy companies that are similar to JPS is 48%. However, JPS has been constrained in its efforts to obtain additional credit financing due to increased levels of lost revenues from non-technical losses, which have made it difficult for JPS to secure financing for its operations. Consequently, it has been virtually impossible for JPS to find reasonably priced credit at preferred tenures. Instead the Company has reluctantly resorted to obtain short-term financing with the option to refinance at longer tenures when the crisis recedes. Table 7-1 outlines the components of the current structure.

Table 7-1: JPS’ Capital Structure

<table>
<thead>
<tr>
<th>Year</th>
<th>Equity (in US$ million)</th>
<th>Debt (in US$ million)</th>
<th>D/E Ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>378</td>
<td>408</td>
<td>107.8%</td>
</tr>
</tbody>
</table>

Source: JPS December 2013 Management Accounts

Table 7-2: Rate Base Capital Structure

<table>
<thead>
<tr>
<th>J$ Million</th>
<th>2013 Audited Financials</th>
<th>Reclassification</th>
<th>Additional Borrowing</th>
<th>FX Adjustment</th>
<th>2013 Adjusted</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current Assets</td>
<td>18,328</td>
<td>402</td>
<td>246</td>
<td>18,976</td>
<td></td>
</tr>
<tr>
<td>Current Liabilities</td>
<td>(11,621)</td>
<td>504</td>
<td>3,622 (345)</td>
<td>(7,840)</td>
<td></td>
</tr>
<tr>
<td>Net current assets</td>
<td>6,707</td>
<td>504</td>
<td>4,024 (99)</td>
<td>11,136</td>
<td></td>
</tr>
<tr>
<td>Non-Current Assets</td>
<td>56,195</td>
<td>3,044</td>
<td>59,239</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other Long-term Liabilities</td>
<td>(10,921)</td>
<td>(10,921)</td>
<td>51,981</td>
<td>504</td>
<td>4,024</td>
</tr>
<tr>
<td>Shareholder's equity</td>
<td>32,191</td>
<td>(805)</td>
<td>1,531 (32,917)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Long-term Loans</td>
<td>19,790</td>
<td>504</td>
<td>4,829 (1,414)</td>
<td>26,537</td>
<td></td>
</tr>
<tr>
<td>Gearing ratio</td>
<td>38%</td>
<td>45%</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
7.3 Cost of Debt

The cost of debt represents the costs that a company must pay to borrow from commercial lenders to fund its operations. In general terms, the cost of debt depends on the default risk that lenders perceive on the firm. When companies have bonds that are liquid and trade frequently, the perceived default risk is visible and the cost of debt is estimated as the yield to maturity on those bonds. However, JPS does not have bonds that are liquid and the company is not rated by a rating agency. There are two options that can be used to estimate the cost of debt in this case:

- The first option is to simply use JPS’ average borrowing cost
- The second option is to assume that the private firm can borrow at the same rate as similar firms (in terms of size) in the industry

We think the best approach is to use JPS’ average borrowing cost, which gives a result of 8.1 percent in pre-tax, nominal USD terms (this value is rounded up from 8.07 percent as calculated below). We explain our reasoning below.

7.3.1 JPS’ Average Borrowing Cost

For firms that are not rated but still borrow money from banks, such as JPS, the most recent borrowings made by that firm give a sense of the default spread being charged by banks. Therefore, if the debt on the books of the company is long term and recent, then the cost of debt for that company can be calculated using the interest rate of the debt outstanding. Because JPS’ borrowings are long term and recent, then this approach can be used to estimate the cost of debt for the company.

To calculate the company’s cost of debt using this approach, we estimate a weighted average based on the cost of long term debt reported in JPS’ Management accounts\(^\text{18}\) as at December 2013.

Table 7-3 shows a summary of each of the obligations outstanding and the cost associated with each obligation. The table shows that JPS’ average borrowing rate is 8.07 percent.

\(^{18}\) According to JPS, the liability values in these Management Account are the same as the ones that will be published in the 2013 Audited Financial Statements
## Table 7-3: JPS’ Average Borrowing Cost

<table>
<thead>
<tr>
<th>2013 LT Debt Obligations</th>
<th>Amount (US$ '000)</th>
<th>Interest Rate</th>
<th>Date of Maturity</th>
</tr>
</thead>
<tbody>
<tr>
<td>KFW Loan - DM 14M</td>
<td>414.00</td>
<td>7.00%</td>
<td>12/30/2015</td>
</tr>
<tr>
<td>KFW Loan - DM 7M</td>
<td>4,941.00</td>
<td>7.00%</td>
<td>12/30/2030</td>
</tr>
<tr>
<td>Int'l Finance Corporation</td>
<td>10,000.00</td>
<td>6.89%</td>
<td>8/30/2015</td>
</tr>
<tr>
<td>Int'l Finance Corporation</td>
<td>23,333.34</td>
<td>5.95%</td>
<td>9/15/2020</td>
</tr>
<tr>
<td>Credit Suisse</td>
<td>811.00</td>
<td>11.00%</td>
<td>7/6/2016</td>
</tr>
<tr>
<td>Credit Suisse</td>
<td>179,189.00</td>
<td>11.00%</td>
<td>7/6/2021</td>
</tr>
<tr>
<td>Citibank</td>
<td>6,000.00</td>
<td>6.63%</td>
<td>1/16/2015</td>
</tr>
<tr>
<td>Citibank</td>
<td>9,000.00</td>
<td>7.50%</td>
<td>1/16/2015</td>
</tr>
<tr>
<td>FCIB Syndicated Loan</td>
<td>12,000.00</td>
<td>7.11%</td>
<td>12/30/2015</td>
</tr>
<tr>
<td>FCIB Syndicated Loan</td>
<td>2,167.00</td>
<td>7.09%</td>
<td>12/30/2015</td>
</tr>
<tr>
<td>Espirito Santo Bank</td>
<td>4,008.62</td>
<td>6.50%</td>
<td>8/26/2015</td>
</tr>
<tr>
<td>Export Development Canada</td>
<td>2,731.00</td>
<td>1.91%</td>
<td>10/17/2015</td>
</tr>
<tr>
<td>Citibank Japan/NEXI Loan</td>
<td>56,875.00</td>
<td>2.36%</td>
<td>12/27/2020</td>
</tr>
<tr>
<td>Proparco Loan</td>
<td>47,055.00</td>
<td>6.18%</td>
<td>11/30/2020</td>
</tr>
<tr>
<td>OPEC Fund</td>
<td>19,444.00</td>
<td>5.78%</td>
<td>11/30/2020</td>
</tr>
<tr>
<td>Preferred Shares</td>
<td>122.00</td>
<td>5.00%</td>
<td>n/a</td>
</tr>
<tr>
<td>Preferred Shares</td>
<td>24,566.00</td>
<td>9.50%</td>
<td>n/a</td>
</tr>
<tr>
<td>Preferred Shares</td>
<td>2,999.00</td>
<td>11.00%</td>
<td>n/a</td>
</tr>
<tr>
<td>Shareholder Loan</td>
<td>2,000.00</td>
<td>11.00%</td>
<td>n/a</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>407,656.00</strong></td>
<td><strong>8.07%</strong></td>
<td></td>
</tr>
</tbody>
</table>

Source: JPS December 2013 Management Accounts

### 7.3.2 Cost of Debt for Similar Firms in the Industry

This approach averages the cost of debt for similar firms in the industry. Similar firms would be defined as having a similar size and a similar company and country credit profile as JPS.

This is hard to do because there are not many traded companies that have size and default risk similar to JPS’. For example, out of the 743 companies used by Damodaran to estimate a beta for the power sector, there are only two companies in a country with credit risk similar to Jamaica’s (Cyprus and Greece). We do not think this is a large enough sample size to find a meaningful average of the cost of debt. Therefore, we do not estimate a cost of debt using this approach.
7.4 Return on Equity

In its 2009 rate case determination, the OUR established a real, allowed return on equity (ROE) for JPS of 16.0%. This allowed ROE had two components. The first was a real cost of equity determined through the capital asset pricing model (CAPM), equal to 9.92%. The second was a country risk premium (CRP) to reflect the differential risks of investing in Jamaica versus the US, equal to 6.08%. Castalia was retained to advise JPS on the appropriate value for its cost of equity for the current 2014 rate review. The Consultant’s full report is presented in Annex A of this submission.

Castalia reports that recent developments in financial markets since the initial 2009 determination have serious implications for cost of equity faced by JPS investors. They indicate that the world is currently in the midst of its worst financial crisis in decades and it is uncertain whether a resolution is imminent in the near future. As financial markets will be characterized by greater uncertainties, and probably higher capital demands than in the recent past, Castalia believes these factors point to a higher required cost of equity for JPS.

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

Castalia recommended a real ROE for JPS of 19.8%. This recommendation is, in turn, founded on recommended values for the risk-free rate of return of 2.7%; an equity beta of 0.86; a market risk premium of 5.0%; and a country risk premium of 15.0%. All of these values support an increase in JPS’ cost of equity higher than determined in 2009. Castalia concludes this adjustment in JPS’ allowed ROE is reasonable given the most recently available data, ongoing uncertainties in the world’s capital markets, and the current credit condition of Jamaica. Table 7-4 summarizes the key aspects of the ROE with comparative information for 2004 and 2009.

Table 7-4: JPS ROE Calculation

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Risk-free Rate</td>
<td>2.3%</td>
<td>3.4%</td>
<td>2.7%</td>
</tr>
<tr>
<td>Equity Risk Premium</td>
<td>8.2%</td>
<td>7.5%</td>
<td>5.0%</td>
</tr>
<tr>
<td>Equity Beta Relevered</td>
<td>0.87</td>
<td>0.87</td>
<td>0.86</td>
</tr>
<tr>
<td>Country Risk Premium</td>
<td>4.43%</td>
<td>6.08%</td>
<td>15.0%</td>
</tr>
<tr>
<td>Country Risk Premium*</td>
<td>4.43%</td>
<td>6.08%</td>
<td>12.9%</td>
</tr>
<tr>
<td>Return on Equity (ROE)</td>
<td>14.9%</td>
<td>16.0%</td>
<td>19.8%</td>
</tr>
</tbody>
</table>

JPS accepts Castalia’s recommendations and proposes that the OUR uses the above parameters in their calculation of the cost of equity in the determination of the WACC for JPS. The key difference in this period is JPS adopting the “synthetic” spread methodology discussed by Damodaran in Castalia’s full report in Annex A.
7.4.1 Risk Free Rate

The risk free rate is the return that an investor can expect on an investment without default risk. When estimating cost of equity in USD, we recommend using the yield to maturity on 10-year US Treasury bonds as an estimate of the risk free rate. This is standard practice, and the approach used by the OUR in the JPS 2009 Determination and the 2013 Determination for the National Water Commission (NWC).

There are a few options for selecting the time period for the analysis:

- Most recent risk-free rate
- 1 year of information
- A longer period of information, for example 5 years

We believe the best option is the **first one; this yields a risk-free rate of 2.7 percent**.

The risk-free rate should be estimated for a point in time and should be for the same time as the valuation date. In the case of a tariff application, the valuation date can be translated into the tariff application date—which in practical terms means the most recent date for which data is available. As a result the most recent risk-free rate would be the best estimate of the future risk-free rate. The risk-free rate as of January 31, 2014, the date closest to the preparation of this report, was 2.7 percent\(^1\) and that is the rate that JPS will use.

7.4.2 Risk Premium

The risk premium is the amount an investor would demand to move from an investment with no risk to one with risk. According to Damodaran (and supported by many other practitioners of corporate finance), there is more risk in investing in an emerging market country than in a country with a mature market, and, therefore, correct analysis “*should use higher equity risk premiums when investing in riskier emerging markets.*”\(^2\) Furthermore, the risk premium consists of three components: the equity beta, equity risk premium, and the country risk premium.

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

- Multiplying the company’s beta by the Equity Risk Premium
- Multiplying the company’s risk premium by the relative equity market standard deviations

We think the best approach is the **first approach**, multiplying the company’s beta by the Equity Risk Premium. Using this approach, we get a value of 17.2 percent for Risk Premium. We explain our reasoning below.

With the variables presented in Table 3.3 the Risk Premium for JPS is 17.2 percent:

\[
RP = 0.86 \times (5.0\% + 15.0\%) = 17.2\%
\]

---


We calculate this formula using the following conclusions:

- The ERP_{MM} is 5.0 percent
- The Equity Beta for JPS is 0.86
- The CRP is 15.0 percent

This approach works well when the beta that measures exposure to all other risk also measures exposure to country risk. The beta used represents the global power sector and is a good representation of the beta for a Jamaican power utility. Additionally, because all of JPS’ revenue is domestic it is fully exposed to the country risk and therefore we can apply the beta to the country risk.

7.4.3 Country Risk Premium

The Country Risk Premium (CRP) is the expected return above the ERP_{MM} that investors require for investing in a country (for example, Jamaica) that has higher risk than the country issuing the risk free currency. Two options are available to estimate the CRP for the approach that we choose for the RP above: multiplying the company’s beta by the Equity Risk Premium (ERP):

- The actual bond spread approach
- The “synthetic” spread.

We think the synthetic spread approach is better; it yields a result of 15.0 percent. This result is consistent with the actual risk of investing in Jamaica. In particular it is consistent if we consider that the OUR accepted a CRP of 6.08 percent in 2009 when the country was considered less risky by rating agencies and other country risk measures, which means that the CRP for this tariff period must be higher. Below, we explain our reasoning in more detail.

The actual bond spread approach

There are a couple of disadvantages to this approach. First the default spread is a volatile measure as it is reactive to current events. The spread will increase and decrease quickly due to events not necessarily correlated with the business. Figure 4.1 shows the month to month volatility of the country risk premium calculated with this approach. The figure shows that country risk premium can change drastically from one month to the other for reasons not correlated with JPS’ business. For example, at the end of 2008, when the global financial market started, the default spread between the 10-year Jamaican bond and 10-year US Treasury bond increased from 3 percent to 9 percent. However, this was not due to Jamaica’s country risk increasing but due to the global financial crisis.
Secondly, this approach is likely to understate the country risk premium because it only measures the premium for default risk. We would expect the country equity risk to be higher than the country’s default risk spread.\textsuperscript{21}

The problems with this approach are evident if we consider that default spread between the 10-year Jamaican bond and 10-year US Treasury bond has actually decreased from 6.1 percent in 2009\textsuperscript{22} to 3.3 percent in January 2014, while the risk of investing in the country has actually increased. The view that the country’s risk has increased is supported by different country risk measures relevant to investors in a company in Jamaica.

The country risk has increased according to risk measures relevant to an investor in a company in Jamaica, but the actual default spread—which only takes into account financial data, has decreased makes the problem inherent with the actual bond spread approach evident: This approach leads to a decrease in the CRP for Jamaica from 2009 to 2013 even though the country’s credit rating has been downgraded, its country risk has increased, and the 10-year US Treasury Bond rate has decreased (which would also lead to an increase in the CRP).

Because of the disadvantages of the actual bond spread approach as a general approach for estimating the CRP, as well as the particular disadvantages of the Nelson-Siegel method, we recommend not using this approach.

\begin{figure}
\centering
\includegraphics[width=\textwidth]{Figure7-1.pdf}
\caption{Actual Bond Spread, Jamaican Bonds v US Treasury Bonds}
\end{figure}

\begin{flushright}
Source: OUR Determination Notice for JPS 2009-2014
\end{flushright}


\textsuperscript{22} OUR Determination Notice for JPS 2009-2014
The “synthetic” spread

Instead of calculating the actual spread between the risk free rate and Jamaican bonds, the synthetic spread approach uses the same spread for all bonds that have the same default risk, according to the credit agencies. This way, the spread does not depend on market volatilities, but on the average risk of a certain bond.

An advantage of using this methodology is that country ratings agencies use information which is relevant to investors in a company in an emerging country. An investor in a company in an emerging country perceives risks that go beyond financial risks. These risks include economic instability, political risks, and other force majeure risks. Rating agencies take these factors into account when producing country ratings. The table shows that all factors are relevant to an investor in Jamaica, and that this measure of country rating takes into account factors other than financial, which makes it a better measure of the risk perceived by an investor investing in a company in Jamaica\(^{23}\).

\textit{Figure 7-2: Comparing the Actual Bond Spread with Jamaica’s Credit Ratings}

7.5 Weighted Average Cost of Capital

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

7.5.1 Post Tax WACC Methodology

The post-tax WACC formula is given by:

\[ \text{Post tax WACC} = g \cdot r_d \cdot (1-t) + (1-g) \cdot r_e \]

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

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

The problem with this method is the manner in which debt is treated. The tax shield on debt in the formula is intended to reduce the Company’s tax liability. However, under the current tariff regime debt is already deducted from income before taxes are calculated. The shield instead simply reduces cost of debt the Company is allowed to recover through tariffs to a level below the actual costs associated with debt. Since the Company incurs the actual cost of debt, the impact of the tax shield is to diminish the effective rate of return on equity allowed in the revenue requirement. This may be corrected by grossing up the return on equity to compensate for the tax shield.

7.5.2 Pre-Tax WACC Methodology

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

\[ \text{Pre tax WACC} = g \cdot r_d + (1-g) \cdot \frac{1}{(1-t)} \cdot r_e \]

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

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

JPS recommends that the pre-tax WACC methodology be used in the 2009 rate review to calculate JPS’ rate of return on investment in part to avoid the error that occurred in 2004 but
also to eliminate the risk of over or underestimating the level of taxation included in the revenue requirement.

7.5.3 Calculation of JPS WACC

Given the continued risks facing investors in JPS, the risk/return principle implies that investors should expect a higher rate of return to be authorised in the 2014 non-fuel tariff revenue requirement compared to 2009. In this context, JPS proposes that the following estimates of the components of the weighted average cost of capital be included in the calculation:

- A weighted average cost of debt of 8.07% - This is calculated using the actual cost of the long-term debt in the JPS 2013 audited financial statements;
- A cost of equity of 19.8% - This value recommended by Castalia represents an increase of 380 basis points over the ROE authorised in 2009 following the same methodology prescribed by the OUR then. This is due mainly to continued volatility and the negative medium-term outlook for the business environment in which JPS operates; and
- A gearing of 48% - This reflects an adjustment of the capital structure indicated in the 2008 audited financial statements to include additional debt and the issuance of preferred shares in an effort to reduce debt.

These parameters and the rate base determined should result in following calculation of the return on investment, as shown in the Table 7-5.

<table>
<thead>
<tr>
<th>Table 7-5: Return on Investment</th>
</tr>
</thead>
<tbody>
<tr>
<td>****</td>
</tr>
<tr>
<td>Cost of Debt</td>
</tr>
<tr>
<td>Rate of Return on Equity (ROE)</td>
</tr>
<tr>
<td>Tax Rate</td>
</tr>
<tr>
<td>Gearing Ratio</td>
</tr>
<tr>
<td>Rate Base (US$)</td>
</tr>
<tr>
<td>Post-tax WACC</td>
</tr>
<tr>
<td>Pre-tax WACC</td>
</tr>
<tr>
<td>Return on Equity (US$)</td>
</tr>
<tr>
<td>Taxation (US$)</td>
</tr>
<tr>
<td>Return on Investment (US$)</td>
</tr>
<tr>
<td>Interest Expense (US$)</td>
</tr>
</tbody>
</table>
Chapter 8: Tariff Design (Non-fuel)

8.1 Non-Fuel Revenue Requirement and Tariff Design Relationship

This section aims at determining the set of tariffs that will allow JPS to obtain the Revenue Requirement presented in Chapter 6: ___. Different approaches were carried out looking for a set of tariffs that balanced the interests of both the customer and the Company:

- Customer perspective: simple, fair, equitable and affordable rates; and
- Company perspective: cost reflective rates which when applied to the billing determinants will yield revenues equal to the Non-Fuel revenue requirement.

From the different approaches carried out to allocate costs by category, theAverage Cost approach is presented below as a starting point and the Two Part Tariff approach, which is the final basis of the present proposal.

The fundamental idea is to follow the principle of cost causality from the cost of service study. The “cost causer pays” rule says that costs should be assigned to customers so that the party that causes a cost to be incurred will pay for those costs. Failure to reflect cost causation in the tariff structure would result in cross-subsidies, whereby some customers would subsidize other customers. Perpetuating cross-subsidies undermines both competition and efficiency goals.

Figure 8.1 summarises the relationship between the Non-Fuel Revenue Requirement and the Tariff Design.

Figure 8.1: Allocation of the Non-Fuel Revenue Requirement into the Utility Tariff Structure
Non-Fuel Administrative Costs\(^1\) are allocated between the standard utility functions: generation, transmission, distribution, and commercial, with consideration to the number of employees working in each function.

The cost allocation by function is obtained from JPS’ accounting systems. Operating expenses (OPEX) are separated into the following functions:

1. Generation
2. Transmission
3. Distribution
   a. Low Voltage
   b. Medium Voltage
4. Customer Services
5. General Services

Distribution costs are allocated between voltage classes based on the type of network components deployed in each voltage level.

The utility rate base (net rate base and depreciations) is allocated by utility function:

1. Generation (Steam, Hydraulic, Other)
2. Transmission (High Voltage)
3. Distribution (Medium Voltage, Low Voltage and Customer Service)
4. General Property

The distribution rate base is allocated by voltage level based on the type of components deployed in each voltage class. The Table 8-1 presents the Test Year Non-Fuel Revenue Requirement elements allocated by function.

### Table 8-1: Test Year Non-Fuel Revenue Requirement by Function

<table>
<thead>
<tr>
<th>Function</th>
<th>Unit</th>
<th>Rate Base (USD 000)</th>
<th>Debt</th>
<th>Return on Investment</th>
<th>Income tax</th>
<th>Depreciation</th>
<th>Total Cost of Capital</th>
<th>OPEX</th>
<th>Revenue Requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generation</td>
<td>USD 000</td>
<td>177,133</td>
<td>6,864</td>
<td>18,264</td>
<td>9,132</td>
<td>26,241</td>
<td>60,500</td>
<td>129,277</td>
<td>189,777</td>
</tr>
<tr>
<td>Transmission</td>
<td>USD 000</td>
<td>57,338</td>
<td>2,222</td>
<td>5,912</td>
<td>2,956</td>
<td>7,516</td>
<td>18,606</td>
<td>5,350</td>
<td>23,956</td>
</tr>
<tr>
<td>MV Distribution</td>
<td>USD 000</td>
<td>156,848</td>
<td>6,078</td>
<td>16,172</td>
<td>8,086</td>
<td>9,381</td>
<td>39,717</td>
<td>17,022</td>
<td>56,739</td>
</tr>
<tr>
<td>LV Distribution</td>
<td>USD 000</td>
<td>49,531</td>
<td>1,919</td>
<td>5,107</td>
<td>2,554</td>
<td>2,962</td>
<td>12,542</td>
<td>12,326</td>
<td>24,868</td>
</tr>
<tr>
<td>Commercial</td>
<td>USD 000</td>
<td>44,040</td>
<td>1,706</td>
<td>4,541</td>
<td>2,270</td>
<td>3,664</td>
<td>12,182</td>
<td>29,755</td>
<td>41,936</td>
</tr>
<tr>
<td>General Services</td>
<td>USD 000</td>
<td>121,770</td>
<td>4,718</td>
<td>12,555</td>
<td>6,278</td>
<td>7,734</td>
<td>31,286</td>
<td>95,807</td>
<td>127,093</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>USD 000</td>
<td>606,660</td>
<td>23,507</td>
<td>62,552</td>
<td>31,276</td>
<td>57,498</td>
<td>174,833</td>
<td>289,536</td>
<td>464,369</td>
</tr>
</tbody>
</table>

**Note:**

1. Rate Base: Is the total net rate base allocated by function. General Services function includes net current rate base (working capital).
2. OPEX
   a. PPA expenses are included within the Generation function; and

\(^1\) Administrative costs are not directly related to production (i.e. overhead costs). Indirect costs are necessary for the completion of the different activities the company performs. Therefore these costs must be considered within the revenue requirement and have to be allocated to direct costs activities on some basis.
b. General Services function, beyond Operating Expenses (Payroll, Benefits & Training), includes:

<table>
<thead>
<tr>
<th>Other Income / Expenses</th>
<th>USD 000</th>
</tr>
</thead>
<tbody>
<tr>
<td>Foreign exchange losses</td>
<td>14,000</td>
</tr>
<tr>
<td>Interest on short-term loans</td>
<td>1,403</td>
</tr>
<tr>
<td>Loan finance fees</td>
<td>4,829</td>
</tr>
<tr>
<td>Bank Overdraft Expense and Other</td>
<td>5,721</td>
</tr>
<tr>
<td>Interest on customer deposits</td>
<td>549</td>
</tr>
<tr>
<td>Interest Income</td>
<td>-2,690</td>
</tr>
<tr>
<td>Other income</td>
<td>-2,822</td>
</tr>
<tr>
<td>Preference Dividend</td>
<td>1,075</td>
</tr>
<tr>
<td>Self insurance fund contribution</td>
<td>2,000</td>
</tr>
<tr>
<td>Gross up for taxes on SIF</td>
<td>1,000</td>
</tr>
<tr>
<td>Caribbean Cement Revenue</td>
<td>-4,936</td>
</tr>
<tr>
<td>Loss Reduction Fund</td>
<td>13,000</td>
</tr>
<tr>
<td>Allowance for Funds Used In Construction</td>
<td>1,450</td>
</tr>
<tr>
<td><strong>Total Other Income and Expenses</strong></td>
<td><strong>34,580</strong></td>
</tr>
</tbody>
</table>

Based on Table 8-1, the following charts illustrate the contribution of each function to the non-fuel costs components.

**Figure 8.2: Cost of Capital by Function**

As can be observed, more than 50% of JPS total cost of capital is related to Generation and General Services functions. General Services function includes the cost of capital derived from the Working Capital Rate Base component.
General Services and Generation functions gather about 80% of the JPS Operating Expenses. Generation includes PPA costs that represent 1/3 of JPS’ OPEX. Non-operating expenses (detailed above) impacts on General Services function costs.

The Non-fuel Revenue Requirement used for tariff design is assigned by the type of the costs. The JPS costs are allocated between fixed and variable costs, as shown below.
Fixed capacity costs are related to the maximum demand of each voltage class by time period: peak, partial peak, and off peak. Variable costs are related to energy consumption of each customer class, and commercial costs are related to the number of customers in each customer class.

Though, the part of variable costs that should be linked to energy charges is around 7.5% and has to do with:

- The cost of capital of the Woking Capital: mainly used for fuel purchases
- PPA variable costs (around 20% of total PPA costs)
- Generation variable costs related to plants maintenance

The revenue requirement of each cost component is multiplied by the allocation factors\(^2\) for each customer class to determine each class’ charges.

Sometimes, the ideal solution must be modified because of metering constraints. For example, residential customer meters cannot measure demand, therefore fixed capacity costs must be recovered through the energy and customer charges.

### 8.2 Load Characterisation Study

#### 8.2.1 Principles

Understanding the consumption pattern of each customer class is essential to develop a tariff design. Load characterisation studies are designed to obtain information on the market served, to identify the responsibility of each customer class for power delivery costs. Using the load characterisation methodology results in a fairer allocation of costs to individual customers, and across customer classes. The data required to determine cost responsibility is based on demand data and energy consumption of the each ratepayer. Sometimes the data is not available for all customer classes, because of their type of metering device. Given these restrictions on data availability, a load characterisation study gathers crucial data for an adequate allocation of costs of each of the functions involved in the operation of the utility: generation, transmission, and distribution.

\[^2\] Parameters calculated based on a Load Characterization Campaign
The data obtained from the load characterisation study are useful both for the tariff design, and for JPS’ business planning. So as to be able to estimate the need of future investments resulting from system expansion, the engineering, and investment planning departments require power and load flow demand forecasting of the different voltage levels and areas served by the Company. Therefore, it is critical to obtain representative parameters of the consumer patterns belonging to the different customer classes, such as load factors, internal and external coincidence factors, which are calculated through load characterisation studies.

8.2.2 Case Presentation

Our load characterisation study includes data from 2012 and 2013, collected for individual customers. The study carried out in 2013 allowed not only the classes’ patterns calculation but the construction of the energy balance for the last finished year (2012) at that time.

Generally, medium and large customers have electronic meters with memory and are accessed remotely; therefore, a complete census can be carried out with these customers.

The streetlighting customer class has a unique operational profile. The load profiles in this class have a flat profile with an instantaneous demand at sunset and a drop to zero at sunrise. Given the operational profile of this class, it does not justify its inclusion in a measurement campaign to estimate the typical consumption behaviour. The consumption pattern of this class is calculated by choosing a city as a geographic centre and downloading the relevant sunrise and sunset data. The streetlighting data, together with the annual energy from the base year, allows the calculation of the profile.

Small customers are sampled because of the number and the type of meters used to determine a consumption pattern.

In 2012, JPS’ demand was composed as follows:

**Table 8-2: 2012 Demand Structure by Customer Class**

<table>
<thead>
<tr>
<th>Category</th>
<th>Customers</th>
<th>Energy Sales (MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>RT 10 LV Res. Service</td>
<td>523,991</td>
<td>1,025,155</td>
</tr>
<tr>
<td>RT 20 LV Gen. Service</td>
<td>61,097</td>
<td>600,501</td>
</tr>
<tr>
<td>RT 60 LV Street Lighting</td>
<td>253</td>
<td>70,060</td>
</tr>
<tr>
<td>RT 40 LV Power Service (STD)</td>
<td>1,586</td>
<td>669,982</td>
</tr>
<tr>
<td>RT 40 LV Power Service (TOU)</td>
<td>124</td>
<td>128,089</td>
</tr>
<tr>
<td>RT 50 MV Power Service (STD)</td>
<td>122</td>
<td>408,237</td>
</tr>
<tr>
<td>RT 50 MV Power Service (TOU)</td>
<td>27</td>
<td>113,766</td>
</tr>
<tr>
<td>Caribbean Cement Company</td>
<td>1</td>
<td>87,173</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>587,201</strong></td>
<td><strong>3,102,964</strong></td>
</tr>
</tbody>
</table>

Considering the number of customers in each class, and the type of meter used by each class, the optimum sampling design for JPS is:

- RT 10: Stratified Sample
- RT 20: Stratified Sample
- RT40 STD: Stratified Sample
- RT40 TOU: Census
After a thorough analysis and allowing for diverse constraints (financial, manpower, and time), a methodology for achieving the initial analysis was developed. This methodology, combined with available data, allows the Company to estimate the behaviour of its customers with minimal statistical error.

The methodology described below considers the following data for calculating the parameters and load profiles for each voltage level and subcategory:

- Total energy generated and purchased
- Energy losses by voltage level (%)
- Energy sold by customer class
- System load profile
- Consumption data from AMI (advanced metering infrastructure) meters
  - RT20: 778 load profiles
  - RT40 STD: 360 load profiles
  - RT40 TOU: 118 load profiles
  - RT50 STD: 101 load profiles
  - RT50 TOU: 23 load profiles

Using 2012 data on total energy generated and purchased, energy losses by voltage level (%), and energy sold by customer class, we accounted for the end-use of all energy generated (Table 8-3).
Table 8-3: Electricity Flow and Losses by Voltage Level

<table>
<thead>
<tr>
<th>Unit</th>
<th>2012</th>
<th>Losses (% of Net Generation)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Generation</td>
<td>MWh</td>
<td>4,154,446</td>
</tr>
<tr>
<td>Transmission Losses</td>
<td>MWh</td>
<td>112,170</td>
</tr>
<tr>
<td>%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Caribbean Cement Company</td>
<td>MWh</td>
<td>87,173</td>
</tr>
<tr>
<td>Energy injected at MV</td>
<td>MWh</td>
<td>3,955,103</td>
</tr>
<tr>
<td>MV Losses</td>
<td>MWh</td>
<td>74,780</td>
</tr>
<tr>
<td>%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 50 MV Power Service (TOU)</td>
<td>MWh</td>
<td>113,766</td>
</tr>
<tr>
<td>RT 50 MV Power Service (Std)</td>
<td>MWh</td>
<td>408,237</td>
</tr>
<tr>
<td>Energy injected at MV/LV</td>
<td>MWh</td>
<td>3,358,319</td>
</tr>
<tr>
<td>MV/LV Losses</td>
<td>MWh</td>
<td>54,008</td>
</tr>
<tr>
<td>%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 40 LV Power Service (TOU)</td>
<td>MWh</td>
<td>128,089</td>
</tr>
<tr>
<td>RT 40 LV Power Service (Std)</td>
<td>MWh</td>
<td>669,982</td>
</tr>
<tr>
<td>Energy injected at LV</td>
<td>MWh</td>
<td>2,506,240</td>
</tr>
<tr>
<td>LV Technical Losses</td>
<td>MWh</td>
<td>166,178</td>
</tr>
<tr>
<td>%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Non Technical Losses</td>
<td>MWh</td>
<td>644,346</td>
</tr>
<tr>
<td>%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 60 LV Street Lighting</td>
<td>MWh</td>
<td>70,060</td>
</tr>
<tr>
<td>RT 20 LV General Service</td>
<td>MWh</td>
<td>600,501</td>
</tr>
<tr>
<td>RT 10 LV Residential Service</td>
<td>MWh</td>
<td>1,025,155</td>
</tr>
</tbody>
</table>

Electricity flow data is gathered for each hour and each day, to determine the load profile for the residential class (RT 10). The residential class was the only class lacking sufficient information to calculate its profile directly.

The electricity flow by hour is calculated with a top-down process starting with net generation. Net generation is determined by the subtraction of energy losses and corresponding sales of each customer class to determine the load profile of each customer class.

8.2.2.1 Study Groups

The definitions of study groups followed the customer classes, and were structured as follows:

- RT10 Residential Class LV: This customer class was analysed in composite, and its behaviour was obtained indirectly as explained above.

- RT20 General Class LV: A stratified sample was conducted, distinguishing each stratum by monthly energy consumption (kWh/month):
  - Stratum 1: Consumption between 0 – 300 kWh/month
  - Stratum 2: Consumption between 300 – 1,000 kWh/month
  - Stratum 3: Consumption between 1,000 – 3,000 kWh/month
  - Stratum 4: Consumption between 3000 – 6,500 kWh/month
  - Stratum 5: Consumption greater than 6,500 kWh/month
- RT40 Power Service LV – STD option: A stratified sample was conducted, distinguishing each stratum by maximum power demand (in kW):
  - Stratum 1: Maximum power between 0 – 60 kW
  - Stratum 2: Maximum power between 60 – 110 kW
  - Stratum 3: Maximum power between 110 – 190 kW
  - Stratum 4: Maximum power between 190 – 360 kW
  - Stratum 5: Maximum power greater than 360 kW
- RT40 Power Service LV – TOU option: A census was conducted for this category.
- RT50 Power Service MV – STD option: A census was conducted for this category.
- RT50 Power Service MV – TOU option: A census was conducted for this category.
- RT60 Street Lighting LV: This category was analysed with 366 daily load profiles, with each profile comprising 96 blocks of 15-minute intervals.
- Caribbean Cement Company (CCC): Special analysis was conducted for this customer.

1.1.1.1 Parameter Definitions

The study developed load profiles, and the consumption parameters will be estimated for each study group. The parameters are defined as follows:

- **KonPK**: is defined as the percentage of energy consumed by a typical customer in class \( k \) during the on-peak hour block. The total consumption of all class \( k \) customers multiplied by this factor determines the quantity of energy consumed by class \( k \) during the on-peak hour block.

- **KpaPK**: is defined as the percentage of energy consumed by a typical customer in class \( k \) during the partial-peak hour block. The total consumption of all class \( k \) customers multiplied by this factor determines the quantity of energy consumed by class \( k \) during the partial-peak hour block.

- **KoffPK**: is defined as the percentage of energy consumed by a typical customer in class \( k \) during the off-peak hour block. The total consumption of all class \( k \) customers multiplied by this factor determines the quantity of energy consumed by class \( k \) during the off-peak hour block.

- **LFK**: is defined as the load factor of a typical class \( k \) customer. It provides information concerning the existing relationship between the average demand of a customer for a certain period and the maximum demand in the same period.

\[
LF_k = \frac{\overline{et}_k}{T \times \overline{\rho}_k}
\]

\( LF_k \): Load factor of class \( k \)
\[ et_k : \] Average total energy consumption of customers that belong to class \( k \)

\[ T : \] Period of time of measurement of curves (hours)

\[ \bar{P}_k : \] Average maximum power of customers that belongs to the group \( k \)

- \( ICF_k : \) is defined as the internal coincidence factor of class \( k \). The internal coincidence factor is bound for each class; that is, only data pertaining to the class is required for its calculation. This factor is the ratio between the peak demand of class \( k \) and the sum of non-coincidental peak demand for all customers in class \( k \).

\[
ICF_k = \frac{\sum_{i=1}^{n_k} p_{i Coin k}}{n_k} \frac{\sum_{i=1}^{n_k} \rho_i}{n_k}
\]

\( \hat{ICF}_k : \) Internal Coincidence Factor of class \( k \)

\( p_{i Coin k} : \) Demand of customer \( i \) coincidental with the peak demand of the selected sample of class \( k \).

\( \rho_i : \) Peak demand of customer \( i \) of the selected sample of class \( k \).

\( n_k : \) sample size of class \( k \)

- \( ECF_{kJ}^i : \) is defined as the external coincidence factor of class \( k \) with the peak demand at voltage level \( J \) (J = LV, MV, Transmission or Generation). Given level \( J \), the factor is defined as the quotient between class \( k \) coincidental peak demand at voltage level \( J \) and the peak demand of class \( k \).

The formula of the ECF is:

\[
ECF_{kJ}^i = \frac{\sum_{i=1}^{n_k} p_{i CoinJ}}{\sum_{i=1}^{n_k} p_{i Coink}}
\]

\( ECF_{kJ}^i : \) External Coincidence Factor of the selected sample of class \( k \) with peak demand of voltage level \( J \)

\( p_{i CoinJ} : \) Demand of customer \( i \) coincidental with peak demand of voltage level \( J \)

\( p_{i Coink} : \) Demand of customer \( i \) coincidental with peak demand of the selected sample of class \( k \).
- **$TCF_k^J$:** is defined as the class $k$ total coincidence factor with the peak demand of voltage level $J$ ($J = \text{LV, MV, Transmission or Generation}$). It is the result of $ICF_k$ multiplied by the $ECF_k^J$. From the peak demand measured in each class $k$ customer, this factor allows us to determine the class contribution to the peak demand of voltage level $J$. The formula is:

$$
TCF_k^J \equiv \frac{\sum_{i=1}^{n_k} P_{i}^{\text{Coin},J}}{\sum_{i=1}^{m} \rho_i}
$$

- $TCF_k^J$: Total Coincidence Factor of class $k$ with the peak demand of voltage level $J$

- $P_{i}^{\text{Coin},J}$: Demand of customer $i$ coincidental with the peak demand of voltage level $J$

- $\rho_i$: Peak demand of customer $i$ from the selected sample of class $k$.

Currently, JPS only has time-of-use demand charges for two rate classes (RT40 TOU and RT50 TOU). Consequently, it is necessary to estimate the TCF for each of the three time-of-use blocks in both classes, to be able to calculate the responsibility of each class for the peak demand during each time-of-use block. If capacity costs are linked to the peak demand that occurs in each time-of-use block, then these parameters allow the determination of the portion of each charge to be paid by each class. In the time-of-use classes, demand charges are directly calculated; for the other rate classes, these charges are assigned according to the appropriate measured variable (that is, energy or peak demand).

According to the 2013 Rate Schedule, the current blocks are:

- **On-peak hours:** Monday-Friday 6:00 p.m. to 10:00 p.m.
- **Off-peak hours:** Monday-Friday 10:00 p.m. to 6:00 a.m.; weekends and public holidays, all hours except 6:00 p.m. to 10:00 p.m.
- **Partial-peak hours:** Monday-Friday 6:00 a.m. to 6:00 p.m.; weekends and public holidays, 6:00 p.m. to 10:00 p.m.
Figure 8.6: TCF Calculation

For customers facing standard demand charges (STD), the TCF by block and voltage level is:

\[
\begin{align*}
TCF_{OnP}^J &= \frac{\sum_{i=1}^{n_k} P_{OnPJ}^i}{\sum_{i=1}^{n_k} P_i} \\
TCF_{OffP}^J &= \frac{\sum_{i=1}^{n_k} P_{OffPJ}^i}{\sum_{i=1}^{n_k} P_i} \\
TCF_{PaP}^J &= \frac{\sum_{i=1}^{n_k} P_{PaPJ}^i}{\sum_{i=1}^{n_k} P_i}
\end{align*}
\]

- \(TCF_{OnP}^J\): Class \(k\) total coincidence factor with the peak demand of voltage level \(J\) during the On-Peak block.
- \(TCF_{OffP}^J\): Class \(k\) total coincidence factor with the peak demand of voltage level \(J\) during the Off-Peak block.
- \(TCF_{PaP}^J\): Class \(k\) total coincidence factor with the peak demand of voltage level \(J\) during the Partial-Peak block.

\(P_{OnPJ}^i\): Demand of customer \(i\) coincidental with the peak demand of voltage level \(J\) during the On-Peak block.

\(P_{OffPJ}^i\): Demand of customer \(i\) coincidental with the peak demand of voltage level \(J\) during the Off-Peak block.

\(P_{PaPJ}^i\): Demand of customer \(i\) coincidental with the peak demand of voltage level \(J\) during the Partial-Peak block.
\( \hat{\rho}_i \): Peak demand of customer \( i \) from the selected sample of class \( k \).

For customers of the Time-of-Use demand charge, the TCF by time block and voltage level is:

\[
\begin{align*}
TCF_{OnP}^J & \equiv \frac{\sum_{i=1}^{n_k} \hat{\rho}_{i,OnP}^J}{\sum_{i=1}^{n_k} \hat{\rho}_{i,OnP}} \\
TCF_{OffP}^J & \equiv \frac{\sum_{i=1}^{n_k} \hat{\rho}_{i,OffP}^J}{\sum_{i=1}^{n_k} \hat{\rho}_{i,OffP}} \\
TCF_{PaP}^J & \equiv \frac{\sum_{i=1}^{n_k} \hat{\rho}_{i,PaP}^J}{\sum_{i=1}^{n_k} \hat{\rho}_{i,PaP}} 
\end{align*}
\]

\( TCF_{OnP}^J \): On-Peak Total Coincidence Factor of class \( k \) given voltage level \( J \) during the On-Peak block.

\( TCF_{OffP}^J \): Off-Peak Total Coincidence Factor of class \( k \) given voltage level \( J \) during the Off-Peak block.

\( TCF_{PaP}^J \): Partial-Peak Total Coincidence Factor of class \( k \) given voltage level \( J \) during the Partial-Peak block.

\( \hat{\rho}_{i,OnP}^J \): Demand of customer \( i \) coincidental with the peak demand of voltage level \( J \) during the On-Peak block.

\( \hat{\rho}_{i,OffP}^J \): Demand of customer \( i \) coincidental with the peak demand of voltage level \( J \) during the Off-Peak block.

\( \hat{\rho}_{i,PaP}^J \): Demand of customer \( i \) coincidental with the peak demand of voltage level \( J \) during the Partial-Peak block.

\( \hat{\rho}_{i,OnP} \): Peak demand of customer \( i \) from class \( k \) during the On-Peak block.

\( \hat{\rho}_{i,OffP} \): Peak demand of customer \( i \) from class \( k \) during the Off-Peak block.

\( \hat{\rho}_{i,PaP} \): Peak demand of customer \( i \) from class \( k \) during the Partial-Peak block.

8.2.3 Load Profiles Received

The number of load profiles collected and validated by class is as follows:
Table 8-4: Load profiles received

<table>
<thead>
<tr>
<th>Rate</th>
<th>Stratum</th>
<th>Range</th>
<th>Sample size</th>
</tr>
</thead>
<tbody>
<tr>
<td>RT20</td>
<td>1</td>
<td>0 - 300 kWh/mo</td>
<td>63</td>
</tr>
<tr>
<td>RT20</td>
<td>2</td>
<td>300 - 1000 kWh/mo</td>
<td>102</td>
</tr>
<tr>
<td>RT20</td>
<td>3</td>
<td>1000 - 3000 kWh/mo</td>
<td>226</td>
</tr>
<tr>
<td>RT20</td>
<td>4</td>
<td>3000 - 6500 kWh/mo</td>
<td>180</td>
</tr>
<tr>
<td>RT20</td>
<td>5</td>
<td>&gt; 6500 kWh/mo</td>
<td>207</td>
</tr>
<tr>
<td>RT40STD</td>
<td>1</td>
<td>0 - 60 kW/mo</td>
<td>125</td>
</tr>
<tr>
<td>RT40STD</td>
<td>2</td>
<td>60 - 110 kW/mo</td>
<td>80</td>
</tr>
<tr>
<td>RT40STD</td>
<td>3</td>
<td>110 - 190 kW/mo</td>
<td>70</td>
</tr>
<tr>
<td>RT40STD</td>
<td>4</td>
<td>190 - 360 kW/mo</td>
<td>52</td>
</tr>
<tr>
<td>RT40STD</td>
<td>5</td>
<td>&gt; 360 kW/mo</td>
<td>33</td>
</tr>
<tr>
<td>RT40TOU</td>
<td>1</td>
<td></td>
<td>118</td>
</tr>
<tr>
<td>RT50STD</td>
<td>1</td>
<td></td>
<td>101</td>
</tr>
<tr>
<td>RT50TOU</td>
<td>1</td>
<td></td>
<td>23</td>
</tr>
<tr>
<td>CCC</td>
<td>1</td>
<td></td>
<td>1</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td><strong>1,381</strong></td>
</tr>
</tbody>
</table>

8.2.4 Load Profiles by Class

Based on the standardised load profile consisting of 96 blocks of 15-minute intervals for weekdays and weekends, the load profile of a typical customer in each class and stratum was determined.

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

- Standardisation of all the observed customers’ load profiles into 96 blocks of consumption during weekdays and weekends.
- The average consumption was calculated for each block by adding the consumption of the sample units and dividing by the size of the sample (this was done by stratum in those categories where the sample was stratified).
- The average profiles were extrapolated to the population multiplying by the number of customers in each class (and stratum, if applicable).
- The data allowed the estimation of two profiles:
  - Weekday profile
  - Weekend profile

The two profiles are presented below by class, using a standardised format to facilitate comparison and to show the behaviour of each category within the different hour blocks:

8.2.5 RT20 General Service

Class RT20 presents an important activity and consumption in the weekdays during Partial-Peak hours. The typical customer load factor is 50%.
8.2.5.1 RT60 Street Lighting

The streetlight class (RT60) has a distinctive profile. The profile in this class has a plateau or flat curve with instantaneous demand at sunset and a drop to zero at sunrise.

Given the uniqueness of this class, its consumption patterns were calculated by taking the data of sunrise and sunset hours of the capital city, the city with greatest demand. This data was used to distribute the annual street lighting energy for 2012, in order to obtain the curve of this category.

The category load profile was treated in the following way:

- Selection of the city considered as the geographic centre of the concession area. This city was Kingston, specifically its harbour, position: West longitude 76° 47' and North latitude 17° 57'. Time zone: 5 Hours West of Greenwich. (Consulted Source: USNO Astronomical Application Department)
- The total annual energy for 2012 (70,060 MWh) was calculated with the daily sunrise and sunset time for the year, resulting in 366 curves for street lighting.
8.2.5.2 RT40 Low Voltage Power Service

Class RT40 STD has a load profile similar to that shown for Class RT20, but manifests an improvement in the load factor (64%).

Figure 8.9: Load Profile for RT40 STD Low Voltage Power Service

Figure 8.10: Load Profile for RT40 TOU Low Voltage Power Service
8.2.5.3 RT50 Medium Voltage Power Service

Figure 8.11: Load Profile for RT50 STD Medium Voltage Power Service
Figure 8.12: Load Profile for RT50 TOU Medium Voltage Power Service

8.2.5.4 Caribbean Cement Company

Figure 8.13: Load Profile for Caribbean Cement Company
8.2.5.5 *RT10 Residential Service*

The last load profile calculated was RT10. As stated above, a lack of data required us to estimate the RT10 load profile by subtracting the known data (load profiles of the other classes, and losses) from JPS’ total system load profile.

**Figure 8.14: Load Profile for Rate 10 System Curve**

![Load Profile for Rate 10 System Curve](image)

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

**Table 8-5: Breakdown of System Losses**

<table>
<thead>
<tr>
<th>Voltage level</th>
<th>Unit</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission</td>
<td>%</td>
<td>2.70%</td>
</tr>
<tr>
<td>MV</td>
<td>%</td>
<td>1.80%</td>
</tr>
<tr>
<td>MV/LV</td>
<td>%</td>
<td>1.30%</td>
</tr>
<tr>
<td>LV Technical</td>
<td>%</td>
<td>4.00%</td>
</tr>
<tr>
<td>LV Non-technical</td>
<td>%</td>
<td>15.51%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>%</td>
<td><strong>25.31%</strong></td>
</tr>
</tbody>
</table>

The percentages of technical losses by voltage level were obtained from the Wheeling Framework Determination Notice\(^3\), while the levels of non-technical losses were calculated by difference between the total energy generated (or purchased), and the energy sold plus technical losses.

Figure 8.15 shows JPS’ total system load profile.

---
8.2.6 Parameter Calculation

The parameters $K_{onK}$, $K_{paK}$ and $K_{offK}$, which represent the percentages of energy consumed by each class $k$ during the peak, partial peak and off peak blocks respectively, were estimated using the data for each class. This is also the case for the parameter $LF_K$.

For calculating the Total Coincidence Factors, a profile of each voltage level was built to identify the moment of the day during which peak demand occurs.

The following graphs show the moments of peak demand during each time-of-use block, for each voltage level.
Figure 8.16: Low Voltage Load Profile

Figure 8.17: MV / LV Load Profile
After determining the peak demand interval, the coincident peak demand for each point of the sample was determined to estimate the Total Coincidence Factors.
8.2.7 Parameter Results

Based on the information processed, the parameters were estimated. The results of this estimation are shown in Table 8-6.

Table 8-6: Parameters

<table>
<thead>
<tr>
<th>Group</th>
<th>KonP</th>
<th>KpPA</th>
<th>KoffP</th>
<th>LF</th>
<th>ICF</th>
<th>TCF</th>
<th>TCF</th>
<th>TCF</th>
<th>TCF</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>LV onP</td>
<td>LV paP</td>
<td>LV offP</td>
<td>MV&amp;TR onP</td>
</tr>
<tr>
<td>RT10</td>
<td>15.0%</td>
<td>37.3%</td>
<td>47.7%</td>
<td>38.6%</td>
<td>51.5%</td>
<td>50.3%</td>
<td>51.5%</td>
<td>49.4%</td>
<td>50.3%</td>
</tr>
<tr>
<td>RT20</td>
<td>11.3%</td>
<td>52.2%</td>
<td>36.5%</td>
<td>50.2%</td>
<td>80.5%</td>
<td>50.2%</td>
<td>47.9%</td>
<td>43.0%</td>
<td>50.2%</td>
</tr>
<tr>
<td>RT60</td>
<td>22.8%</td>
<td>10.7%</td>
<td>66.5%</td>
<td>49.4%</td>
<td>100.0%</td>
<td>100.0%</td>
<td>100.0%</td>
<td>100.0%</td>
<td>100.0%</td>
</tr>
<tr>
<td>RT40 (STD)</td>
<td>11.8%</td>
<td>51.6%</td>
<td>36.6%</td>
<td>64.2%</td>
<td>95.0%</td>
<td>65.7%</td>
<td>94.3%</td>
<td>56.9%</td>
<td>65.7%</td>
</tr>
<tr>
<td>RT40 (TOU)</td>
<td>11.0%</td>
<td>45.1%</td>
<td>43.9%</td>
<td>76.1%</td>
<td>91.3%</td>
<td>93.7%</td>
<td>93.5%</td>
<td>78.7%</td>
<td>93.7%</td>
</tr>
<tr>
<td>RT50 (STD)</td>
<td>13.2%</td>
<td>46.0%</td>
<td>40.8%</td>
<td>75.2%</td>
<td>93.7%</td>
<td>85.0%</td>
<td>91.7%</td>
<td>78.5%</td>
<td>85.0%</td>
</tr>
<tr>
<td>RT50 (TOU)</td>
<td>12.0%</td>
<td>43.7%</td>
<td>44.3%</td>
<td>74.5%</td>
<td>89.9%</td>
<td>98.1%</td>
<td>95.9%</td>
<td>87.7%</td>
<td>98.1%</td>
</tr>
<tr>
<td>CCC</td>
<td>12.1%</td>
<td>38.8%</td>
<td>49.2%</td>
<td>91.6%</td>
<td>100.0%</td>
<td>92.7%</td>
<td>84.6%</td>
<td>95.4%</td>
<td>92.7%</td>
</tr>
</tbody>
</table>

Note: The peak demand of the 3 blocks in MV, TR and Generation occur at the same moment, therefore TCF MV&TR onP, TCF MV&TR paP and TCF MV&TR offP are the Total Coincidence Factors for the three voltage levels.

8.2.8 Load Profile Comparative Analysis

We then compared JPS’ load profiles between 2008 and 2012, to facilitate tariff design decisions to be made for the upcoming regulatory period (2014 – 2019). A comparison of JPS’ total system load profile in 2008 and 2012 is provided below.

Figure 8.20: System Load Profile Comparison
Next, we present a comparison of load profiles over the same time period, by customer class.

Figure 8.21: Rate 10 Load Curve Comparison

![Rate 10 Load Curve Comparison](image)

Figure 8.22: Rate 20 Load Curve Comparison

![Rate 20 Load Curve Comparison](image)

Figure 8.23: Rate 40 and 50 Load Curve Comparisons

![Rate 40 and 50 Load Curve Comparisons](image)
The previous illustrations indicate that:

1. In some classes, the load profile has experienced slight changes, while the total system load profile has not changed from 2008 to 2012. The most recent system load profile confirms the optimal load curve JPS achieved 5 years ago with double peaks very close to one another. The measures adopted regarding the price signals given by the tariff (TOU option) have been successful and should be kept for the next tariff period.

2. RT20’s profile shows an improvement for the rate class in terms of load factor, reducing its contribution to partial-peak demand.
3. The improvement observed in the RT20 class is offset mainly by a slight deterioration of the RT40STD profile. The behaviour observed in RT40STD is likely due to migration of large RT20 customers to the RT40STD rate class.

4. The RT40TOU, RT50STD, and RT50TOU load profiles show an improvement based on a shift of energy consumption from weekdays to weekends.

5. The decreases in on-peak demand shown by most of the load profiles are offset by an increase in RT10 consumption during the same time block. RT10 now represents 27% of the coincident peak.

The fuel charge is uniform for all STD customers. TOU customers pay the uniform fuel rate multiplied by a different factor for each hour block. In the study, the following parameters are calculated by class:

- % of on-peak energy consumption
- % of partial-peak energy consumption
- % of off-peak energy consumption.

These parameters are useful in determining a weighted fuel charge for each rate class with consideration for responsibility each class has in the total energy consumption by time block. For TOU customers, the unitary cost per kWh in each block should be a pass-through charge, prior to the heat rate and losses adjustment.

### 8.3 Billing Determinants

In this section, the billing determinants are presented. Billing determinants are defined as the energy/demand quantities (such as kWh, kW, and kVA) required to bill a customer according to the company rate schedule.

The test year billing determinants are as follows:

**Table 8-7: Test Year Billing Determinants**

<table>
<thead>
<tr>
<th>Customer Class</th>
<th>Customers</th>
<th>Energy (MWh)</th>
<th>Demand kVA/Month</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>STD and On-Peak</td>
</tr>
<tr>
<td>RT 10 LV Res. Service &lt; 100 kWh</td>
<td>222,531</td>
<td>118,508</td>
<td></td>
</tr>
<tr>
<td>RT 10 LV Res. Service 100-500 kWh</td>
<td>301,954</td>
<td>710,037</td>
<td></td>
</tr>
<tr>
<td>RT 10 LV Res. Service &gt; 500 kWh</td>
<td>14,116</td>
<td>157,095</td>
<td></td>
</tr>
<tr>
<td>RT 20 LV Gen. Service &lt; 100 kWh</td>
<td>24,842</td>
<td>11,145</td>
<td></td>
</tr>
<tr>
<td>RT 20 LV Gen. Service 100-1000 kWh</td>
<td>28,235</td>
<td>135,779</td>
<td></td>
</tr>
<tr>
<td>RT 20 LV Gen. Service 1000-7500 kWh</td>
<td>8,588</td>
<td>304,169</td>
<td></td>
</tr>
<tr>
<td>RT 20 LV Gen. Service &gt; 7500 kWh</td>
<td>992</td>
<td>201,647</td>
<td></td>
</tr>
<tr>
<td>RT 60 LV Street Lighting</td>
<td>236</td>
<td>44,715</td>
<td></td>
</tr>
<tr>
<td>RT 40 LV Power Service (Std)</td>
<td>1,601</td>
<td>645,804</td>
<td>187</td>
</tr>
<tr>
<td>RT 40 LV Power Service (TOU)</td>
<td>121</td>
<td>121,303</td>
<td>24 28 26</td>
</tr>
<tr>
<td>RT 50 MV Power Service (Std)</td>
<td>104</td>
<td>411,322</td>
<td>95</td>
</tr>
<tr>
<td>RT 50 MV Power Service (TOU)</td>
<td>27</td>
<td>105,893</td>
<td>23 26 25</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>603,346</strong></td>
<td><strong>2,967,417</strong></td>
<td><strong>328 54 51</strong></td>
</tr>
</tbody>
</table>

The billing determinants presented here differ from the actual figures from 2013, due to known and measurable parameters predicted for the next tariff period. Some categories are split in tiers for tariff design purposes, as we will discuss in Section 8.4.

The quantities by tier of consumption are based on the 2013 sales data.
In terms of energy sales, reductions are expected for streetlights because of LED technology replacement for current lamps.

JPS expects that 1/4 of all streetlights will be replaced each year beginning in 2014. Based on energy sales in 2013, the following table shows RT60 sales including the effects of LED retrofits.

### Table 8-8: Expected RT60 Energy Consumption

<table>
<thead>
<tr>
<th>Level of replacement</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>Average</th>
</tr>
</thead>
<tbody>
<tr>
<td>MWh</td>
<td>62,916</td>
<td>52,804</td>
<td>42,692</td>
<td>32,580</td>
<td>32,580</td>
<td>44,715</td>
</tr>
</tbody>
</table>

We used the average expected energy consumption for streetlights (presented above), as the energy billing determinant for RT60. To the extent that the actual billing determinants vary from the amount utilized above in setting the revenue requirement this would be corrected through the annual tariff adjustment mechanism under the proposed revenue cap approach.

### 8.4 Non-Fuel Tariffs

This section discusses the set of non-fuel tariffs that will permit JPS to recover the revenue requirement presented in Table 8-1. Different approaches analysed for the revised set of tariffs have balanced the interests of both the customer and the Company:

- **Customer perspective:** cost-reflective, simple, fair, equitable and affordable rates with more tariff options; and
- **Company perspective:** cost reflective rates which, when applied to the billing determinants, will yield revenues equal to the non-fuel revenue requirement.

Of the various tariff design approaches we considered, we first present the average cost approach. We will use this as the basis for introducing the two-part tariff approach, which was our final choice for the tariff design. The existing tariff structure (also a two-part tariff) was approved by the OUR in Tariff Determination Notice, 2009 (Ele 2009/4: Det/03). Under the two-part tariff design, tariff charges derive from marginal costs, along with a fixed monthly charge per customer, called the Network Access Charge (NAC). This mechanism ensures that the different types of users pay according to their willingness to pay.

The basic concept of a two-part tariff is to follow the principle of cost causality from our cost of service study. The “cost causation” principle says that costs should be assigned to those customers that cause a given cost to be incurred. Failure to reflect cost causation in the tariff structure would result in cross-subsidies, whereby some customers would subsidise other customers. Perpetuating cross-subsidies undermines both competition and efficiency goals. It is important to note that cost causality should always be analysed according to the marginal costs imposed on the system; that is, every additional customer contributing to the network by paying a tariff above caused costs (marginal costs) is reducing the burden levied over existing customers. Therefore, there are no cross subsidies in this case. The two-part tariffs design fulfils this principle.
8.4.1 Tariffs with the Average Cost Approach

The following section conceptually presents the average cost approach. The average cost approach is widely used; it is an easy-to-calculate tariff, based on criteria determining that each category should pay according to its responsibility on the cost of service. These rates, which are meant to recover the costs of providing the service, do not consider the socio-economic factors that ultimately constrain the actual set of tariffs that are implemented. Also, this cost allocation method focuses on costs but fails to consider if the demand, composed of different customer types will be able to—and willing to—consume and pay for the electricity service at the average cost. Based on these aspects, the two-part tariff approach is carried out in the next section, aiming to deal with the socio-economic factors facing demand and, simultaneously, allowing JPS to meet its non-fuel revenue requirement.

However, it is important to present this tariff design method to see how it works, because many calculations involving average costs are used while dealing with marginal costs used in the two-part tariff approach.

8.4.1.1 Variable Non-fuel Costs

The variable non-fuel costs (Generation variable non-fuel costs) are distributed between the different customer classes, based on the consumption function that each class \( k \) demands, adding the energy losses originated in the network from the connection level up to the generation level.

\[
E_{GEN} = \sum_k E_k \times LossF_{Con\_level}^{Gen}
\]

where:
- \( E_{GEN} \): Generated energy
- \( E_k \): Consumed energy by category \( k \)
- \( LossF_{Con\_level}^{Gen} \): Accumulated energy losses factor from the connection level of category \( k \) to the Generation level.

Therefore, the variable non-fuel Generation cost from which category \( k \) is responsible is:

\[
CostG_k = CostG \times \frac{E_k \times LossF_{Con\_level}^{Gen}}{E_{GEN}}
\]

where:
- \( CostG_k \): Generation Cost assigned to category \( k \)
- \( CostG \): Total variable cost of Generation

Finally the variable charge is as follows:

\[
VarCh\ arg\ e_k = \frac{CostG}{E_{GEN}} \times LossF_{Con\_level}^{Gen} \text{ [$/kWh]}
\]

8.4.1.2 Network Capacity Costs

For capacity costs, JPS must design its network to meet the maximum demand caused by each customer class successively downstream on the system. Therefore, it is logical to think about a
cost allocation criterion by voltage level based on the contribution that each class has to the maximum demand of the system.

Given a voltage level $J$, the peak demand is obtained from the variable energy and demand measured to the customers, the total coincidence factors obtained through the load characterisation study and the addition of the power losses.

$$P^J = \sum_{k=1}^{n} \frac{E_k}{8760 \times LF_k} \times RF^J_k + \sum_{k=n+1}^{K} \left( \sum_{i} \hat{P}_i \right) \times RF^J_k$$

where:

$P^J =$ Peak demand at voltage level $J$.

$k$: Category, where $k=1, \ldots, n$ corresponds to the classes that only have energy measurement, whereas $k=n+1, \ldots, K$ corresponds to the classes that have demand measurement.

$RF^J_k =$ Responsibility Factor of class $k$ with voltage level $J$. This is equal to the product of the $TCF^J_k$ and the total accumulated demand losses factor from class $k$ voltage level of connection up to voltage level $J$.

$E_k =$ Annual energy sold to class $k$’s customers

8,760 = Number of hours per year

$LF_k =$ Load Factor of class $k$.

$\hat{P}_i =$ Individual maximum registered demand of customer $i$ that belongs to class $k$ and has demand measurement.

The responsibility factors identify the contribution of each class to $\hat{P}^J$, and in this way allow the distribution of the costs linked to voltage level $J$.

From above, it can be determined that the contribution to the peak demand of voltage level $J$ of class $k$ is:

- If it is a category where customers have a demand measurement:
  $$P_{k}^{Coin.J} = \left( \sum_{i=1}^{N} \hat{P}_i \right) \times TCF^J_k \times AFP^J_{Conn.Level} = \left( \sum_{i=1}^{N} \hat{P}_i \right) \times RF^J_k$$

- If it is a category where customers only have an energy measurement:
  $$P_{k}^{Coin.J} = \sum_{i=1}^{N} \frac{E_i}{T \times LF_k} \times TCF^J_k \times AFP^J_{Conn.Level} = \sum_{i=1}^{N} \frac{E_i}{T \times LF_k} \times RF^J_k$$

where:

$P_{k}^{Coin.J} =$ Demand of class $k$ coincidental with the peak demand of voltage level $J$. 

**TCF}_{J,k}^{i}:** is defined as the total coincidence factor for class \( k \) for a given voltage level \( J \). From the peak demand measured in a class \( k \) customer, this factor allows us to know the contribution to the peak demand of voltage level \( J \).

**AFP}_{\text{Connection Level}}^{i}:** Accumulated factor of power losses from the connection level of class \( k \) to voltage level \( J \)

\[ T: \text{Time} \]
\[ LF_k = \text{Load factor of class } k. \]
\[ RF_k^{i} = TCF_{J,k}^{i} \times AFP_{\text{Connection Level}}^{i}: \text{Responsibility Factor of class } k \text{ with voltage level } J. \]

Then, the cost of level \( J \), assigned to the class \( k \) results:

\[ \text{Cost } _k^{i} = \text{Cost } ^{i} \times \frac{P_{\text{Coin},J}^k}{\hat{P}^J} \]

where:

- **Cost }^{i}:** Total capacity cost of the voltage level \( J \).
- \( \hat{P}^J: \) Peak demand of voltage level \( J \).

To find the capacity charge in the previous formula, we need to identify and remove the class \( k \) billing determinant.

- If it is a category where customers have power demand measurement:

\[ \text{Cost } _k^{i} = \text{Cost } ^{i} \times \frac{P_{\text{Coin},J}^k}{\hat{P}^J} = \text{Cost } ^{i} \times \left( \sum_{i=1}^{N} \hat{P}_i \right) \times RF_k^{i} = U\text{Cost } ^{i} \times RF_k^{i} \times \left( \sum_{i=1}^{N} \hat{P}_i \right) \]

In this category, the billing determinant is the sum of peak demand \( \left( \sum_{i=1}^{N} \hat{P}_i \right) \). Therefore, the capacity charge to recover level \( J \) costs comprises the unitary capacity cost multiplied by the responsibility factor.

\[ CC_{J}^{i} = U\text{Cost } ^{i} \times RF_k^{i} \quad [\$/\text{kW}] \]

- If it is a category where customers only have energy measurement:

\[ \text{Cost } _k^{i} = \text{Cost } ^{i} \times \frac{P_{\text{Coin},J}^k}{\hat{P}^J} = \text{Cost } ^{i} \times \frac{\sum_{i=1}^{N} E_i}{T \times LF_k} \times RF_k^{i} = \frac{U\text{Cost } ^{i}}{T \times LF_k} \times RF_k^{i} \times \sum_{i=1}^{N} E_i \]

In this category, the billing determinant is the sum of energy sales \( \sum_{i=1}^{N} E_i \). Therefore, the capacity charge to recover voltage level \( J \) costs is comprised by the unitary capacity cost divided by \( T \) (Time) and \( LF_k \) (Category k Load Factor), times the responsibility factor.
In the case of JPS, the consumption (energy and peak demand) is measured by time-of-use block (On-Peak, Partial-Peak and Off-Peak) for customers that apply to be in RT40 and RT50, where the time-of-use option is available. The allocation cost mechanism involved the assignment of a percentage of the total costs calculated for each voltage level to each of the three time-of-use blocks. The portion of these costs which each class is responsible for, was calculated considering the power demand of each class coincidental with the peak demand calculated per voltage level and per time-of-use block.

8.4.1.3 Commercial Costs

The Commercial Costs were separated into three groups:

- Residential Services
- General and Streetlight Services
- Power Services

The customers have been separated into these groups, and are assigned more costs for those groups that require a higher level of customer service from JPS, or to render more personalized service, which in the end translate into higher costs per customer.

Based on the above, a weighted percentage matrix was constructed in order to allocate total commercial costs.

8.4.1.4 Average Cost Approach Results

The table below presents the non-fuel revenue requirement by class according to the average cost approach.

**Table 8-9: Revenue Requirement by Customer Class**

<table>
<thead>
<tr>
<th>Customer Class</th>
<th>USD 000</th>
</tr>
</thead>
<tbody>
<tr>
<td>RT 10 LV Residential Service</td>
<td>200,671</td>
</tr>
<tr>
<td>RT 20 LV General Service</td>
<td>113,933</td>
</tr>
<tr>
<td>RT 60 LV Street Lighting</td>
<td>7,554</td>
</tr>
<tr>
<td>RT 40 LV Power Service</td>
<td>89,000</td>
</tr>
<tr>
<td>RT 50 MV Power Service</td>
<td>53,211</td>
</tr>
<tr>
<td><strong>Total Non-Fuel Revenue Requirement</strong></td>
<td><strong>464,369</strong></td>
</tr>
</tbody>
</table>
In the following section, an alternative to the average cost tariff design is developed aiming to improve the tariff design through an allocation cost criteria based on aspects linked to the market JPS is serving, such as:

- Socio-economic environment
- Non-technical losses recovery
- Willingness to pay by class or by tiers within the classes
- Risk of losing large customers that (for the time being) share part of the cost of service

8.4.2 Theory of Two-Part Tariff Design

According to the marginalist theory\(^4\),\(^5\),\(^6\),\(^7\), in the presence of cost sub-additivity, strictly marginalist tariffs produce lower revenues than required to sustain the utility company. The difference between the revenue requirements and revenue obtained if prices were set equal to marginal costs is known as the Revenue Deficiency. Consequently, the tariff design must ensure the Revenue Deficiency is met.

With the two-part tariff\(^8\) approach, a variable charge is established equal to the long-run marginal cost—and the revenue gap, to meet the utility’s total costs, is recovered through a fixed charge, known as Network Access Charge (NAC). Under this regime, there are no social welfare losses, and a “first best” situation is maintained.

For achieving this type of structure we have to start from the long-run marginal costs calculated for each function and voltage level and multiply them by the responsibility factors of each category of user. Then the revenue gap has to be recovered through a NAC.

---

\(^4\) Electricity Economics Regulation and Deregulation, Geoffrey Rothwell and Tomás Gómez, IEEE Series


\(^6\) Power System Economics, Designing Markets for Electricity, Steven Staff, IEEE Series.


The long-run marginal cost of each voltage level is calculated by applying the Average Incremental Cost formula to the Total Cost variations due to the demand growth. The formula for the Long-Run Incremental Cost of j level is presented below:

\[
LRAIC_j = \frac{\sum_{t=1}^{T} \frac{\Delta TC_j^t}{(1 + CCR)^t}}{\sum_{t=1}^{T} \frac{\Delta D_j^t}{(1 + CCR)^t}}
\]

where,

\[\Delta TC_j^t = \text{total cost increase of voltage level “j” due to the demand growth.}\]

\[\Delta D_j^t = \text{demand increase of voltage level “j”.}\]

\[CCR = \text{the CCR discount rate is the regulated rate of return and the period T corresponds to the period 2008-2013.}\]

The proposed tariff structure has tariff charges derived from marginal costs, to which a fixed monthly charge per customer (NAC) is added. This mechanism ensures that the different types of users pay according to their willingness to pay. This way, lower-income sectors classes will pay a lower rate because they have a lower NAC.

Further, analysis done per class can determine that instead of recovering the NAC through a fixed charge per customer, part of it may be recovered through another type of charge (energy or demand charge). This happens, for example, when the number of tiers within a class is insufficient to group a wide range of heterogeneous customers (Heterogeneity because of size of the customers, level of energy consumption, power demand, etc.).

Additionally, the two-part tariff design becomes a useful structure that will help JPS and the government to tackle the non-technical losses issue and ensure JPS revenues are equal to the revenue requirement, while mitigating the customers’ loss of welfare.

8.4.2.1 Optimal Two Part Tariff Theory

In this methodology, there is a fixed charge (independent of consumption) as a right to access the service, and a variable charge for each unit consumed. The bill paid by the consumer, B, can be expressed as follows:

\[B = F + p \cdot q\]
The choice of the fixed charge and the variable charge per unit deserves special attention because they affect the welfare of consumers and the company providing the service. An optimal two-part tariff consists of setting a variable charge for each unit sold equal to the long-run marginal cost and a NAC, which constitutes a fixed monthly charge despite consumption, to cover the portion of costs that are not possible to recover through the variable charge. For this NAC to be viable, it must not exceed the consumer surplus (CS); otherwise, the customer would choose not to connect to the network and the utility would lose this client, with the risk that the customer becomes an illegal consumer. This would increase non-technical losses.

**Figure 8.26: Consumer Surplus**

In Figure 8.26 above, it can be observed that for quantities below $q_0$, the individual is willing to pay prices above the long-run marginal cost, as the demand curve is above that price. The shaded area actually indicates the net CS considering the amount he pays for the $q_0$ units. Indeed, the area $0$-$A$-$B$-$q_0$ represents the maximum amount that the consumer is willing to pay for $q_0$ units, while the $0$-$LRMgc$-$B$-$q_0$ rectangle represents the amount actually paid, since each unit is charged the same price $LRMgc$. The shaded area is the CS.
As stated earlier, note that the NAC should not exceed the CS, in which case the consumer would have a negative net surplus. The amount that is required for consumption is higher than his willingness to pay, making it more advantageous for the individual not to buy any units. In this case, the welfare loss is equal to the CS. Thus, it is important to have at least a minimum estimate of the CS which is the upper limit of the NAC.

In the case of electricity supply, the consumer’s demand is closely related to the cost of the best alternative option (BAO). Indeed, electricity will be demanded only if its price is equal or less than the BAO, provided that this opportunity is an acceptable substitute. For example, JPS cannot charge a price higher than the cost of self-generation. Consequently, demand for electricity is as shown in the figure below. As it can be observed, the demand $d$ matches the BAO up to $q'$ units and then becomes downward-sloping.

**Figure 8.27: Consumer Surplus in Electricity**

8.4.2.2 NAC Introduction

As mentioned above, the NAC must not exceed the CS of each consumer so as not to encourage disconnection from the network. Moreover, the NAC charged to all users should be equal to the revenue gap.

Considering that different users have different CS, if JPS intends to charge a uniform NAC that is the same for all customers, it should be lower than the lowest CS for all consumers. This would substantially limit the value of the NAC since some customers (especially low-income customers) have a CS that is almost zero.

The universe of customers is divided into classes (k) and within these in sub-classes (sk), or ranges of consumption. For each range of consumption, the lower value of CS is estimated becoming the upper limit of NAC sk to apply only to this sub-class (sk).

Not all users have the same willingness to pay for electric service; that is, not all of them have the same demand curve. Rather, it depends in the case of residential users on the size of the household, the stock of appliances and socio-economic status. Total household income is a crucial determinant of willingness to pay. The poorest families will tend to spend a higher proportion of their income to pay for electricity than better-off families. For this reason, it is not possible to divide the revenue gap between the total number of customers; the customer base should be analysed separately in different classes and sub-classes, so that the willingness to pay of each sub-class (sk) can be taken into account. In addition, it must be considered that each subcategory might have different substitutes to electricity (that is, different avoided cost options).
To illustrate this, consider that self-generation could be a reasonable substitute to network electricity for families with medium or high income, while kerosene lamps, candles, and LPG or kerosene refrigerators could be reasonable substitutes for low income families.

### 8.4.2.3 NAC Calculation

The surplus in each category is determined by the costs of the best alternative option, the marginal cost, and the demand curve.

The BAO is based on the analysis of each customer class.

For Residential Service, the consumption ranges analysed are:

- **1st Tier**: 0 – 100 kWh/month
- **2nd Tier**: 100 – 500 kWh/month
- **3rd Tier**: over 500 kWh/month

For General Service, the consumption ranges analysed were:

- **1st Tier**: 0 – 100 kWh/month
- **2nd Tier**: 100 – 1000 kWh/month
- **3rd Tier**: 1000 – 7500 kWh/month
- **4th Tier**: over 7500 kWh/month

For Power Service categories, the groups of customers analysed were:

- **RT40**: STD option
- **RT40**: TOU option
- **RT50**: STD option
- **RT50**: TOU option

The selection of the BAO took into consideration the following determinants:

- Average energy consumption
- Load factor
- Reserve factor recommended by manufacturers of self-generators (The peak demand must be multiplied by 1.4 to get the kVA that at least should have the unit)

In the case of small demand groups choosing the most economical generator that meets their electricity demand mainly considers:

- Cost of capital
  - Generator
  - Charger
  - Batteries
  - Inverter
- Maintenance cost of the generator
- Cost of fuel consumption

Solar panels and internal combustion generators were analysed as possible BAO.
For medium and large customers, some considerations must be made to determine the BAO. The self-generators required for these levels of continuous consumption. The cost of capital and OPEX of each group is based on:

- Price of the generator
- Cost required for installation
- Minor overhauls
- Major overhauls
- Costs linked to the backup equipment
  - Price of alternative generator unit
  - Spare parts in stock

Generators’ technical characteristics and prices (FOB prices) were obtained from different suppliers' web sites. FOB prices were marked up 50% to reflect what these generators might cost in Jamaica. The list of generators, their capacities, and prices are presented below:

<table>
<thead>
<tr>
<th>Generator</th>
<th>Max output KVA</th>
<th>Rated output KVA</th>
<th>Price USD</th>
</tr>
</thead>
<tbody>
<tr>
<td>DeWalt Heavy-Duty 2900 Watt</td>
<td>2.9</td>
<td>2.4</td>
<td>1,703</td>
</tr>
<tr>
<td>Campbell Hausfeld 2500 Watt</td>
<td>2.5</td>
<td>2.5</td>
<td>915</td>
</tr>
<tr>
<td>Porter-Cable Corp. 3,500 Watt</td>
<td>7.5</td>
<td>3.5</td>
<td>1,605</td>
</tr>
<tr>
<td>DeWalt Heavy-Duty 4300 Watt</td>
<td>4.3</td>
<td>3.8</td>
<td>2,405</td>
</tr>
<tr>
<td>Porter-Cable Corp. 4,500 Watt Electric Generator</td>
<td>9.0</td>
<td>4.5</td>
<td>3,384</td>
</tr>
<tr>
<td>Makita USA 5800 Watt</td>
<td>5.8</td>
<td>4.8</td>
<td>3,000</td>
</tr>
<tr>
<td>DeWalt Heavy-Duty 6000 Watt</td>
<td>6.0</td>
<td>5.0</td>
<td>3,225</td>
</tr>
<tr>
<td>DeWalt Heavy-Duty 6000</td>
<td>6.0</td>
<td>5.0</td>
<td>2,952</td>
</tr>
<tr>
<td>Campbell Hausfeld 5000 Watt</td>
<td>5.0</td>
<td>5.0</td>
<td>1,650</td>
</tr>
<tr>
<td>Campbell Hausfeld 5500 Watt</td>
<td>5.5</td>
<td>5.5</td>
<td>1,245</td>
</tr>
<tr>
<td>DeWalt Heavy-Duty 7000 Watt Gas Generator</td>
<td>7.0</td>
<td>6.0</td>
<td>3,344</td>
</tr>
<tr>
<td>Campbell Hausfeld 6000 Watt</td>
<td>6.0</td>
<td>6.0</td>
<td>1,500</td>
</tr>
<tr>
<td>Campbell Hausfeld 6500 Watt</td>
<td>7.8</td>
<td>6.5</td>
<td>2,475</td>
</tr>
<tr>
<td>Campbell Hausfeld 10,000 Watt</td>
<td>12.0</td>
<td>10.0</td>
<td>3,300</td>
</tr>
<tr>
<td>Cummins 10 kVA</td>
<td>10.0</td>
<td>10.0</td>
<td>2,250</td>
</tr>
<tr>
<td>Cummins 16 kVA</td>
<td>16.0</td>
<td>16.0</td>
<td>7,290</td>
</tr>
<tr>
<td>Gelec - Phanter 20</td>
<td>20.0</td>
<td>16.0</td>
<td>12,288</td>
</tr>
<tr>
<td>Cummins 22.5 kVA</td>
<td>22.5</td>
<td>20.0</td>
<td>6,750</td>
</tr>
<tr>
<td>Gelec - Phanter 37</td>
<td>37.0</td>
<td>30.0</td>
<td>13,303</td>
</tr>
<tr>
<td>Cummins 40 kVA</td>
<td>40.0</td>
<td>30.0</td>
<td>10,500</td>
</tr>
<tr>
<td>Cummins 50 kVA</td>
<td>50.0</td>
<td>40.0</td>
<td>12,000</td>
</tr>
<tr>
<td>Gelec - Phanter 62</td>
<td>62.0</td>
<td>50.0</td>
<td>15,740</td>
</tr>
<tr>
<td>Gelec - Tiger 80 kVA</td>
<td>80.0</td>
<td>64.0</td>
<td>18,482</td>
</tr>
</tbody>
</table>
For solar panels, prices were marked up 30% to reflect Caribbean market conditions.
An estimation of long-run marginal cost is also necessary to complete the calculation of consumers’ surplus. This cost represents the cost of energy, and power purchases (generation) plus marginal costs (cost of capital + OPEX) required for the expansion of the network.

For all classes, we assume an inelastic demand.

**Figure 8.28: Customer’s Consumer Surpluses**

As a formula:
\[ CS_{i,k} = (VBAO_k - LRMgC_k) \times q0_k + (FBAO_k - LRMgCP_k) \times Pmax_k - LRMgCC_k \]

where:

- \( CS_{i,k} \): Is the customer \( i \) surplus that belongs to class \( k \) ($/Customer/month).
- \( q0_k \): Average consumption of a typical class \( k \) customer (kWh/month).
- \( VBAO_k \): Is the variable cost of the BAO ($/kWh).
- \( LRMgC_k \): Is the variable long run marginal cost linked to energy ($/kWh).
- \( FBAO_k \): Is the fixed cost of the BAO ($/kw/month).
- \( LRMgCP_k \): Is the capacity long run marginal cost ($/kW/month).
- \( Customers \): number of class \( k \) customers
- \( LRMgCC_k \): Is the commercial long run marginal cost ($/customer/month).
- \( Pmax_k \): peak demand of a typical class \( k \) customer (kW/month)

The surplus of each class is the result of multiplying the individual surplus by users in each class. Adding the surpluses of all classes, the total surplus of the market can be estimated.

As indicated above, the NAC must be equal to the deficit generated by the difference between the revenue requirement and the income derived from the application of the long-run marginal costs.

### 8.4.2.4 NAC Design Criteria

The following figures show the elements that need to be taken into consideration for designing a two part tariff where customers pay an energy charge equal to marginal cost (LRMC) for their energy consumption and an access charge (NAC).

If there were only two customer classes, 1 and 2, then the following figure would be:
In a simplified way, if the customer is paying only LRMC, consumer surplus (CS) can be calculated as:

\[ CS = (BAO - LRMC) \times q \]

Assume that NAC is designed so as to capture 50% of the CS. Then:

\[ NAC = \frac{CS}{2} \]

Also assume that all customers face the same best alternative option (BAO=BAO1=BAO2), that marginal cost is equal for both customer classes (LRMC=LRMC1=LRMC2) and that Customer Class 2 consumes twice as much energy as Customer Class 1 (q2=2q1)

Then:

\[ CS1 = (BAO - LRMC) \times q1 \]
\[ CS2 = (BAO - LRMC) \times q1 \]

Therefore

\[ CS2 = 2CS1 \]
\[ NAC1 = \frac{CS1}{2} = \frac{(BAO - LRMC) \times q1}{2} \]
\[ NAC2 = \frac{CS2}{2} = \frac{(BAO - LRMC) \times q1}{2} \]

Replacing q2=2q1

\[ NAC2 = \frac{CS2}{2} = \frac{(BAO - LRMC) \times 2q1}{2} \]
\[ NAC2 = (BAO - LRMC) \times q1 \]
\[ NAC2 = 2NAC1 \]

We can conclude that the NAC should be designed proportionally to the CS for no social welfare redistribution. For decreasing marginal welfare distribution (that is, giving more value of money to the poor) NAC should increase more than proportionally than CS.

Note that if NAC is the same for some (or all) customer classes or sub-classes, there is the risk of charging a NAC that might be too high of a burden on a low-consumption customer whose NAC could be higher than their consumer surplus. As a result, such a customer might leave as a customer, either to commit fraud, or to switch to an alternative source. Additionally, for high-consumers customers, the NAC could be too small, providing them with a higher net consumer surplus than what the low-consumption (poorer) customers are receiving.

8.4.3 Proposed Rate Structure by Class

In this section, the principles, rate structure, and bill impact by category are presented.
8.4.3.1 Residential Service—RT10

**Regular Tariff**

**Definition and proposed charges for non-fuel costs recovery**

Tariff designs based on the two-part tariff approach generally consider four or more tiers to be optimal to enable a better organization of the customers, taking advantage of their different willingness to pay for the service and simultaneously minimizing billing shocks for customers when they move from one tier to another.

For residential service, JPS proposes to present three tiers of consumption with the following charges.

- **RT10 – 1st Tier (Consumption levels between 0 – 100 kWh/month):**
  - NAC: applicable whether there is consumption. It covers the customer service marginal costs and a portion of non-fuel costs that are part of the gap between marginal cost of service and average cost of service (Revenue Gap) that needs to be recovered for the business to be sustainable.
  - Energy charge: paid for every kWh of consumption. It covers capacity marginal cost, and a portion of non-fuel costs that are part of the Revenue Gap.

- **RT10 – 2nd Tier (Consumption levels between 100 – 500 kWh/month)**
  - NAC: applicable whether there is consumption. It covers the customer service marginal costs and a portion of the Revenue Gap. This charge is different from the one paid by the first tier.
  - Energy charge 1: This charge is paid for the first 100 kWh and is equal to the one paid by the first tier.
  - Energy charge 2: This charge is paid for every kWh of consumption over 100 kWh and it covers the capacity marginal cost and a portion of the non-fuel costs that are part of the Revenue Gap.

- **RT10 – 3rd Tier (Consumption levels over 500 kWh/month)**
  - NAC: applicable whether there is consumption. It covers the customer service marginal costs and a portion of the Revenue Gap. This charge is different from the one paid by the first tier and the second tier.
  - Energy charge 1: This charge is paid for the first 100 kWh and is equal to the one paid by the first tier.
  - Energy charge 2: This charge is paid for the every consumption between 100 kWh and 500 kWh and is equal to Energy charge two paid by the second tier.
  - Energy charge 3: This charge is paid for every kWh of consumption over 500 kWh and it covers the capacity marginal cost and a portion of the Revenue Gap.

The customer’s twelve month moving average energy consumption will determine his/her tier for billing purposes.

**Rate schedule**

According to the proposed tariff design, the non-fuel rate schedule and its comparison with the adjusted current rate schedule is as follows:

**Table 8-10: RT10 Rate Schedule**
Billing impact

The rates proposed, applied to the average residential customer in each tier, yield the average tariff that is presented in the table below. A comparison with the adjusted present rates in force, and the boundaries established by marginal cost and the costs of the BAO are also shown.

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

**Figure 8.29: Average Tariff Impact for RT10**

In the table below, billing impacts for typical customers in each tier are presented.

**Table 8-11: Typical Customer Bill Impact for RT10**
Base exchange rate of JMD1:USD1

The bill impact simulation is carried out for typical customers who pay their bills before the due date, though JMD 250 discount is included.

The residential tariff increases, on average, by 21%. However, the first tier that includes mainly low-income families will receive an average tariff increase of 17%. The number of residential customers affected by this increase is about 220,000 customers, representing 41% of the residential class.

Customers whose consumption is within the second tier will see an average increase of 21%.

Finally, customers with consumption over 500 kWh / month are those with the highest rate increase within this category, although the vast majority of these customers belong to the population with highest income on the island.

Using data from the Jamaica Survey of Living Conditions 2010, the effect of the rate review on residential customers’ budget was analysed.

First, household annual consumption was estimated using mean per capita annual consumption for each decile of the Jamaican population and household size. Next, JPS customers per decile and their mean annual consumption were matched using the statistics of electricity use per decile and total population. Finally, average electricity bill was calculated for each decile.

In the following table, we show what portion of household consumption the electricity bill represents. Results are shown in the table below.
As can be seen, electricity represents 4% to 10% of household consumption. Notably, this proportion increases with household wealth. It follows from this that the proposed rates will maintain the increasing trend.

The effect on household consumption of the proposed tariffs ranges, from only 1.4% for customers living under more vulnerable conditions to 2% for the wealthiest households, in line with the guiding social principles embedded in the Licence and promoted by JPS and the OUR.

**Prepaid Tariff**

Taking into consideration a driver for change identified both by the OUR and customers - *the need for more tariff options* – and capitalizing on over 20 years of successful international experience, JPS proposes a permanent Prepaid Electric Service Program for its residential customers. This billing arrangement would provide Jamaicans more control over energy usage and by extension better management of their household budgets.

An OUR-approved Technical 5-month Pilot Program has been underway since October 2013. Under the program, customers may purchase electricity on a prepaid basis and top up supplies whenever required.

Some expected benefits to be derived by Consumers are:

- Control over their energy usage and budget: Customers can determine the maximum amount of electricity they wish to purchase monthly and the frequency of purchases.
- Point of Payment Flexibility to purchase top-up supplies.
- Potential for Energy Savings: Studies shows that prepaid customers consume less energy and have lower monthly bills than their post-paid counterparts.
- Avoid the payment of a security deposit.
- Avoid the payment of certain fees: Prepay customers will not be charged for disconnection or reconnection fees, nor will they ever have to pay a late payment fee.
Under our proposal, the program shall be available to all JPS residential customers on an opt-in basis, subject to the availability of STS\(^9\) prepaid meters. Customers in high losses areas needing an AMI prepaid meter will be provided so based on a schedule agreed with the OUR.

Customers will be permitted to return to postpaid service at any time, provided they place an adequate customer deposit in accordance with the standard contract terms, along with an administrative switching fee and subject to a transition period to be agreed with the OUR.

**Pre-paid Tariff Design**

The rate charged for prepaid energy services will be a flat rate that is made up of a base rate and an incremental transaction fee. The base rate represents the average kWh rate charged to Rate 10 (residential) customers under the post-paid tariffs currently in effect. The incremental transaction fee reflects the cost to develop the more elaborate and expensive payment infrastructure that is required to facilitate issuing of encrypted codes used to top up meters as well as the use of a more sophisticated payment network with a higher transaction cost.

The base rate for electricity charged to prepaid customers would be equal to the weighted average of the effective rates faced by customers in each of the consumption intervals. The prepaid tariff will be calculated using the formula below:

\[
Prepaid\ Tariff = \frac{\sum_i \text{Cons}_i \cdot ER_i}{\sum_i \text{Cons}_i}
\]

where:

\[
\text{Cons}_i: \text{ Total consumption of customers whose monthly consumption falls within consumption interval } i.
\]

\[
ER_i = \text{Effective J$/kWh tariff rate faced by customer whose monthly consumption is equal to the average consumption at each consumption interval } i.
\]

The base rate will be recalculated each month using the same weights, network access charge and energy charges but with a new monthly fuel/IPP charge and an updated foreign exchange rate factor. The weights would be updated once per year during the annual tariff adjustment. The new weights will be based on the consumption data from the preceding calendar year.

The initial weights based on the Test Year RT10 billing determinant are as follows:

---

\(^9\) STS (Standard Transfer Specification): STS is a secure message system for carrying information between a point-of-sale and a meter.
The new rate would come into effect on the 10th day of each month for all credit purchased as of 6 a.m. This 10-day lag is required given the short time lag required to update the various inputs, particularly the fuel rate and foreign exchange rate.

In addition to the prepaid tariff customers will also be required to pay a per transaction processing fee to third party vendors at the point of sale. The fee reflects the development and operating costs of the more elaborate and expensive payment infrastructure required to support the prepaid energy service to facilitate issuing of encrypted codes, etc. used to top up meters. Discussions with vendors indicate that this fee will be approximately $50 per transaction which is comparable with the fee currently charged by the external payment agencies.

**Update on Pilot- AMI Meter Technology**

JPS initiated a Prepaid Electric Service Programme in May 2013 and embarked on a Technical pilot in June using AMI metering technology. The technical pilot which was conducted for a period of three months involved the evaluation of the prepaid technology and resolution of technical and operational support issues. A commercial Pilot was initiated in in October 2013 which targeted customers in the communities of Stadium Gardens and Delacree Park/Palm Grove.

During the Commercial Pilot, Information regarding the service was communicated to residents in community meetings, distribution of brochures, flyers and Q & A booklets. A “how-to” video was also presented. Although, customers saw the service as a good move, they did not participate for one or more of the following reasons:

- Little or no incentive to switch (from postpaid to prepaid)
- Unavailability of online top-up options
- Prepaid rates deemed to be higher
- Fear of being without power when the credit is depleted and customer is strapped for cash

**Stand-Alone (STS) Meter Technology**

The programme is being revisited but will focus on stand-alone (STS) metering technology. This type of technology allows the user to purchase a “token” consisting of a series of numbers which are keyed into the CDU. The CDU displays the amount of funds remaining and alerts the user when funds are almost depleted so that they can recharge before the supply is disconnected.

**Target Audience**

JPS commissioned an independent market research in February 2014, as part of preparations to roll out the prepaid service in late 2014. Just over 500 household heads and/or persons responsible for paying the bills were interviewed to gauge their level of interest in prepaid electricity service. The results were as follows:

- Interested: 29%

<table>
<thead>
<tr>
<th>Class</th>
<th>Energy sales (MWh)</th>
<th>Initial Weights</th>
</tr>
</thead>
<tbody>
<tr>
<td>RT 10 LV Res. Service &lt; 100 kWh</td>
<td>118,508</td>
<td>12.02%</td>
</tr>
<tr>
<td>RT 10 LV Res. Service 100-500 kWh</td>
<td>710,037</td>
<td>72.04%</td>
</tr>
<tr>
<td>RT 10 LV Res. Service &gt; 500 kWh</td>
<td>157,095</td>
<td>15.94%</td>
</tr>
<tr>
<td>Total</td>
<td>985,639</td>
<td>100.00%</td>
</tr>
</tbody>
</table>
Unsure: 28%
Not interested: 43%

Of the 43% who were not interested, approximately 19% required additional information or need to observe the process to determine efficiency of the service.

A decision was made to initially introduce the service in Portmore due to the diversity of its residents.

Projected Timelines
The Prepaid Service Programme, using STS meters, over, will commence April 2014 and is expected to last for a period of six (6) months. During this period, a Technical and Commercial phase will be conducted to assess the performance of the system.

Community Renewal Program Tariff

Definition and proposed charges for non-fuel costs recovery
The OUR shares the notion that there are implicit costs associated with back billing of illicit electricity consumption that need to be taken into account. It is crucial for JPS to devise a successful total approach to the problem of system losses.

Through the Community Renewal project, communities currently not paying for electricity are invited to connect to the system under promotional conditions, paying just for Long Run Marginal Cost. This is a temporary program aimed at recovering non-technical losses.

The proposed tariff structure for this customer class is as follows:

- NAC: applicable whether there is consumption. It covers the customer service marginal costs.
- Energy charge: This charge is paid for every kWh of consumption and it covers capacity marginal cost.

This rate will only be applicable for the first 200 kWh/month. Any higher consumption amount will be charged at the normal rate.

Rate schedule
According to the proposed tariff design, the non-fuel rate schedule and its comparison with the adjusted current rate schedule is as follows:

Table 8-14: RT10 Community Renewal Rate Schedule

---

10 Jamaica Public Service Company Limited Tariff Review for Period 2009-2014, page 142
Since the community renewal program is new, the comparison in this table is against RT10 < 100 kWh/month, which is the current lifeline rate.

**Billing impact**

The rates proposed applied to a customer consuming 50 kWh/month is presented in the following table. Given the interest in showing the total average tariff variation, a fuel charge needs to be considered in the analysis. For our purposes, a fuel charge is added to current non-fuel rates (0.239 USD/kWh). This fuel charge is based on the same data used to determine the February 2014 fuel charge, but relies on the proposed losses target of 21.5%, and excludes the FCRA component that will end in June 2014. The resulting fuel charge is 0.232 USD/kWh.

Table 8-15: Typical Customer Bill Impact for RT10 Community Renewal

<table>
<thead>
<tr>
<th>Class</th>
<th>Customer Charge</th>
<th>Energy Charge (USD/kWh)</th>
<th>Current Rate Billing (USD/month)</th>
<th>Proposed Rate Billing (USD/month)</th>
<th>Variation (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>RT 10 Community Renewal Program</td>
<td>0.069</td>
<td>3.815</td>
<td>1.50</td>
<td>1.55</td>
<td>-22%</td>
</tr>
</tbody>
</table>

Base exchange rate of JMD112:USD1

### 8.4.3.2 General Service - RT20

**Definition and proposed charges for non-fuel costs recovery**

Four tiers in this category were established, introducing four different fixed charges and four energy charges.

- **RT20 – 1st Tier** (Consumption levels between 0 – 100 kWh/month)
  - NAC: applicable whether there is consumption. It covers the customer service marginal costs and a portion of the Revenue Gap.
  - Energy charge: This charge is paid for every kWh of consumption and it covers capacity marginal cost and a portion of the Revenue Gap. The latter is the cost that needs to be recovered for the business to be sustainable.

- **RT20 – 2nd Tier** (Consumption levels between 100 – 1000 kWh/month)
  - NAC: applicable whether there is consumption. It covers the customer service marginal costs and a portion of the Revenue Gap. This charge is different from the one paid by the first tier.
Energy charge: This charge is paid for every kWh of consumption and it covers capacity marginal cost and a portion of the Revenue Gap. The latter is the cost that needs to be recovered for the business to be sustainable. This charge is different from the one paid by the first tier.

**RT20 – 3rd Tier (Consumption levels between 1000 – 7500 kWh/month)**
- NAC: applicable whether there is consumption. It covers the customer service marginal costs and a portion of the Revenue Gap. This charge is different from the one paid by the first tier and the second tier.
- Energy charge: This charge is paid for every kWh of consumption and it covers capacity marginal cost and a portion of the Revenue Gap. The latter is the cost that needs to be recovered for the business to be sustainable. This charge is different from the one paid by the first tier and the second tier.

**RT20 – 4th Tier (Consumptions over 7500 kWh/month)**
- NAC: applicable whether there is consumption. It covers the customer service marginal costs and a portion of the Revenue Gap. This charge is different from the one paid by the 1st, second and third tier.
- Energy charge: This charge is paid for every kWh of consumption and it covers capacity marginal cost and a portion of the Revenue Gap. The latter is the cost that needs to be recovered for the business to be sustainable. This charge is different from the one paid by the first tier, the second tier, and the third tier.

The customer’s twelve month moving average energy consumption will determine his/her tier for billing purposes.

**Rate schedule**

According to the proposed tariff design, the non-fuel rate schedule and its comparison with the adjusted current rate schedule is as follows:

**Table 8-16: RT20 Rate Schedule**

<table>
<thead>
<tr>
<th>Class</th>
<th>Proposed Rates</th>
<th>Current Rates</th>
<th>Variation %</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Network Access Charge (USD/Cust./month)</td>
<td>Energy Charge (USD/kWh)</td>
<td>Customer Charge (USD/Cust./month)</td>
</tr>
<tr>
<td>RT 20 LV Gen. Service &lt; 100 kWh</td>
<td>9.000</td>
<td>0.201</td>
<td>8.394</td>
</tr>
<tr>
<td>RT 20 LV Gen. Service 100-1000 kWh</td>
<td>15.000</td>
<td>0.195</td>
<td>8.394</td>
</tr>
<tr>
<td>RT 20 LV Gen. Service 1000-7500 kWh</td>
<td>25.000</td>
<td>0.189</td>
<td>8.394</td>
</tr>
<tr>
<td>RT 20 LV Gen. Service &gt; 7500 kWh</td>
<td>40.000</td>
<td>0.117</td>
<td>8.394</td>
</tr>
</tbody>
</table>

As can be observed, declining rate blocks are proposed for the energy charge. This measure aims at encouraging efficient consumption and simultaneously incentivizing these customers to remain on the grid, thereby keeping downward pressure on per unit costs for all customers using the network. The higher the customer’s consumption is, the lower the BAO per unit consumed the customer will face. Therefore, a competitive rate should be offered yielding benefits for all customers sharing the electricity service.

**Billing impact**
The rates proposed, when applied to the average customer in each tier, yield the average tariff that is presented in the table below. A comparison with the adjusted actual rates in force, and the boundaries established by marginal cost and the cost of the BAO are also shown.

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

**Figure 8.30: Average Tariff Impact for RT20**

In the table below, billing impacts for typical customers in each tier are presented.

**Table 8-17: Typical Customer Bill Impact for RT20**

<table>
<thead>
<tr>
<th>Class</th>
<th>Customer</th>
<th>Energy (kWh/month)</th>
<th>Current Rate Billing (USD/month)</th>
<th>Proposed Rate Billing (USD/month)</th>
<th>Variation (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>RT 20 LV Gen. Service &lt; 100 kWh</td>
<td>1</td>
<td>52</td>
<td>28</td>
<td>31</td>
<td>13%</td>
</tr>
<tr>
<td>RT 20 LV Gen. Service 100-1000 kWh</td>
<td>1</td>
<td>401</td>
<td>158</td>
<td>186</td>
<td>18%</td>
</tr>
<tr>
<td>RT 20 LV Gen. Service 1000-7500 kWh</td>
<td>1</td>
<td>2,951</td>
<td>1,111</td>
<td>1,268</td>
<td>14%</td>
</tr>
<tr>
<td>RT 20 LV Gen. Service &gt; 7500 kWh</td>
<td>1</td>
<td>16,945</td>
<td>6,340</td>
<td>5,956</td>
<td>-6%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Class</th>
<th>Current Rate Billing (JMD/month)</th>
<th>Proposed Rate Billing (JMD/month)</th>
<th>Variation (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>RT 20 LV Gen. Service &lt; 100 kWh</td>
<td>3,103</td>
<td>3,514</td>
<td>13%</td>
</tr>
<tr>
<td>RT 20 LV Gen. Service 100-1000 kWh</td>
<td>17,712</td>
<td>20,838</td>
<td>18%</td>
</tr>
<tr>
<td>RT 20 LV Gen. Service 1000-7500 kWh</td>
<td>124,458</td>
<td>141,963</td>
<td>14%</td>
</tr>
<tr>
<td>RT 20 LV Gen. Service &gt; 7500 kWh</td>
<td>710,091</td>
<td>667,063</td>
<td>-6%</td>
</tr>
</tbody>
</table>
The General Service category has on average an increase of 9%.

8.4.3.3 Street Lights and Traffic Lights—RT60

**Definition and proposed charges for non-fuel costs recovery**

The Street Lighting category tariff structure remains the same:

- **NAC**: applicable whether there is consumption. It covers the customer service marginal costs and a portion of the Revenue Gap.
- **Energy charge**: This charge is paid for every kWh of consumption and it covers capacity marginal cost and a portion of non-fuel costs that are part of the revenue gap.

**Rate schedule**

According to the proposed tariff design, the non-fuel rate schedule and its comparison with the adjusted current rate schedule is as follows:

**Table 8-18: RT60 Rate Schedule**

<table>
<thead>
<tr>
<th>Class</th>
<th>Proposed Rates</th>
<th>Current Rates</th>
<th>Variation %</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Network Access Charge (USD/Cust./month)</td>
<td>Energy Charge (USD/kWh)</td>
<td>Customer Charge (USD/Cust./month)</td>
</tr>
<tr>
<td>RT 60 LV Street Lighting</td>
<td>40.000</td>
<td>0.210</td>
<td>22.892</td>
</tr>
</tbody>
</table>

**Billing impact**

The proposed rates, when applied to the average street lighting customer, yield the monthly bill presented in the table below. A comparison with the adjusted actual rates in force is also shown.

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

**Table 8-19: Typical Customer Bill Impact for RT60**
8.4.3.4 Large Commercial Customers—RT40 and RT50

Regular Tariff

**Definition and proposed charges for non-fuel costs recovery**

The Power Service Low Voltage category keeps the current tariff structure. These classes comprise users with a very wide range of energy and demand consumption. Because the surplus in these categories is based on the analysis of the average customer, implementing the NAC as a fixed charge per customer is inappropriate, mainly because of the influence of customers whose consumption is far below the class average. So, the second best solution is to state a charge expressed in terms of contracted capacity ($/kVA/month). At the same time, and based on the results obtained from the load characterisation study, the load profiles of these customers contribute positively to JPS’ total system load profile. This indicates that the signal price by time-of-use block facing these customers is satisfactory. In an attempt to minimise the possible changes to the existing tariff structure for these classes, the portion of the NAC that cannot remain as fixed charge is allocated in the demand charge ($/kVA) or is energised, to become part of the energy charge ($/kWh) to equalise charges between RT40 and RT50, and between the Standard and TOU options:

- NAC: applicable whether there is consumption and irrespective of consumption. It covers the customer service marginal costs and a portion of the Revenue Gap.
- Energy charge: This charge is paid for every kWh of consumption and it covers capacity marginal cost and a portion of non-fuel costs that are part of the revenue gap.
- Demand charge
  - Standard Option:
    1. One demand charge applicable on each kVA billing demand
    2. Billing demand: The kilovolt-ampere (kVA) Billing Demand for each month shall be the maximum demand for that month, or 80% of the maximum demand during the five-month period immediately preceding the month for which the bill is rendered, whichever is higher, but not less than 25 kilovolt-amperes.
  - TOU Option:
    1. One demand charge applicable on each kVA billing demand per hour block.
2. On-Peak Period Billing Demand: the billing demand for this period shall be the maximum demand for the On-Peak hours of that month. The minimum 25 kilovolt ampere (kVA) does not apply.

3. Partial-Peak Period Billing Demand: the billing demand in this period shall be the maximum demand for the on-peak and partial-peak hours of that month, or 80% of the maximum demand for the on-peak and partial-peak hours during the five-month period immediately preceding the month for which the bill is rendered, whichever is higher but not less than 25 kilovolt-amperes.

4. Off-Peak Period Billing Demand: The billing demand in this period shall be the maximum demand for that month (despite the time of use period it was registered in), or 80% of the maximum demand during the five-month period immediately preceding the month for which the bill is rendered, whichever is higher but not less than 25 kilovolt-amperes kVA).

The Power Service Medium Voltage category keeps the current tariff structure.

- NAC: applicable whether there is consumption and irrespective of consumption. It covers the customer service marginal costs and a portion of the Revenue Gap.
- Energy charge: This charge is paid for every kWh of consumption and it covers capacity marginal cost and a portion of the revenue gap.
- Demand charge
  - Standard Option:
    1. One demand charge applicable on each KVA billing demand
    2. Billing demand: The kilovolt-ampere (kVA) Billing Demand for each month shall be the maximum demand for that month, or 80% of the maximum demand during the five-month period immediately preceding the month for which the bill is rendered, whichever is higher, but not less than 25 kilovolt-amperes.
  - TOU Option:
    1. One demand charge applies on each KVA billing demand per hour block.
    2. On-Peak Period Billing Demand: the billing demand in this period shall be the maximum demand for the On-Peak hours of that month. The minimum 25 kilovolt ampere (kVA) does not apply.
    3. Partial-Peak Period Billing Demand: the billing demand in this period shall be the maximum demand for the on-peak and partial-peak hours of that month, or 80% of the maximum demand for the on-peak and partial-peak hours during the five-month period immediately preceding the month for which the bill is rendered, whichever is higher but not less than 25 kilovolt-amperes
    4. Off-Peak Period Billing Demand: The billing demand in this period shall be the maximum demand for that month (despite the time of use period it was registered in), or 80% of the maximum demand during the five-month period immediately preceding the month for which the bill is rendered, whichever is higher but not less than 25 kilovolt-amperes kVA)

**Rate schedule**

According to the proposed tariff design, the non-fuel rate schedule and its comparison with the adjusted actual rate schedule are as follows:
Table 8-20: RT40 and RT50 Rate Schedule

<table>
<thead>
<tr>
<th>Class</th>
<th>Network Access Charge (USD/Cust./month)</th>
<th>Energy Charge (USD/kWh)</th>
<th>Demand Charge STD and On-Peak (USD/kVA)</th>
<th>Demand Charge STD and Partial-Peak (USD/kVA)</th>
<th>Demand Charge STD and Off-Peak (USD/kVA)</th>
</tr>
</thead>
<tbody>
<tr>
<td>RT 40 LV Power Service (Std)</td>
<td>80.000</td>
<td>0.000</td>
<td>28.500</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 40 LV Power Service (TOU)</td>
<td>80.000</td>
<td>0.000</td>
<td>16.046</td>
<td>12.540</td>
<td>1.210</td>
</tr>
<tr>
<td>RT 50 MV Power Service (Std)</td>
<td>80.000</td>
<td>0.000</td>
<td>26.163</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 50 MV Power Service (TOU)</td>
<td>80.000</td>
<td>0.000</td>
<td>14.535</td>
<td>11.337</td>
<td>1.163</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Class</th>
<th>Customer Charge (USD/Cust./month)</th>
<th>Energy Charge (USD/kWh)</th>
<th>Demand Charge STD and On-Peak (USD/kVA)</th>
<th>Demand Charge STD and Partial-Peak (USD/kVA)</th>
<th>Demand Charge STD and Off-Peak (USD/kVA)</th>
</tr>
</thead>
<tbody>
<tr>
<td>RT 40 LV Power Service (Std)</td>
<td>61.044</td>
<td>0.038</td>
<td>14.454</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 40 LV Power Service (TOU)</td>
<td>61.044</td>
<td>0.038</td>
<td>8.138</td>
<td>6.360</td>
<td>0.614</td>
</tr>
<tr>
<td>RT 50 MV Power Service (Std)</td>
<td>61.044</td>
<td>0.036</td>
<td>13.009</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 50 MV Power Service (TOU)</td>
<td>61.044</td>
<td>0.036</td>
<td>7.227</td>
<td>5.637</td>
<td>0.578</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Class</th>
<th>NAC vs Customer Charge</th>
<th>Energy Charge</th>
<th>Demand Charge STD and On-Peak</th>
<th>Demand Charge Partial-Peak</th>
<th>Demand Charge Off-Peak</th>
</tr>
</thead>
<tbody>
<tr>
<td>RT 40 LV Power Service (Std)</td>
<td>31%</td>
<td>-100%</td>
<td>97%</td>
<td>97%</td>
<td>97%</td>
</tr>
<tr>
<td>RT 40 LV Power Service (TOU)</td>
<td>31%</td>
<td>-100%</td>
<td>97%</td>
<td>101%</td>
<td>101%</td>
</tr>
<tr>
<td>RT 50 MV Power Service (Std)</td>
<td>31%</td>
<td>-100%</td>
<td>101%</td>
<td>101%</td>
<td>101%</td>
</tr>
<tr>
<td>RT 50 MV Power Service (TOU)</td>
<td>31%</td>
<td>-100%</td>
<td>101%</td>
<td>101%</td>
<td>101%</td>
</tr>
</tbody>
</table>

**Billing impact**

The rates proposed, when applied to the average\(^{11}\) customer in each class, yield the average tariff presented in the table below. A comparison with the adjusted current rates in force, and the boundaries established by marginal cost and the costs of the BAO are also shown.

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

\(^{11}\) The average customer does not consider in its calculation Large Customers with a power demand above 1 MVA.
In the table below, billing impacts for typical customers in each category are presented.

**Table 8-21: Typical Customer Bill Impact for RT40 and RT50**

<table>
<thead>
<tr>
<th>Class</th>
<th>Customer</th>
<th>Energy (kWh/month)</th>
<th>Demand STD and On-Peak (kVA)</th>
<th>Demand Partial-Peak (kVA)</th>
<th>Demand Off-Peak (kVA)</th>
<th>Current Rate Billing (USD/month)</th>
<th>Proposed Rate Billing (USD/month)</th>
<th>Variation (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>RT 40 LV Power Service (Std) 1</td>
<td>33,616</td>
<td>117</td>
<td></td>
<td></td>
<td></td>
<td>10,763</td>
<td>10,896</td>
<td>1%</td>
</tr>
<tr>
<td>RT 40 LV Power Service (TOU) 1</td>
<td>80,256</td>
<td>187</td>
<td>233</td>
<td>242</td>
<td></td>
<td>24,830</td>
<td>24,256</td>
<td>-2%</td>
</tr>
<tr>
<td>RT 50 MV Power Service (Std) 1</td>
<td>122,290</td>
<td>347</td>
<td>37,119</td>
<td>36,385</td>
<td></td>
<td>37,119</td>
<td>36,385</td>
<td>-2%</td>
</tr>
<tr>
<td>RT 50 MV Power Service (TOU) 1</td>
<td>107,558</td>
<td>281</td>
<td>367</td>
<td>386</td>
<td></td>
<td>33,189</td>
<td>32,895</td>
<td>-1%</td>
</tr>
</tbody>
</table>

**Wholesale Tariff**

Back in 2013, JPS proposed the introduction of a new wholesale tariff (WT) class for qualifying rate 40 and 50 customers. The OUR response was that it was not timely adequate to introduce tariff restructuring then, and that the 2014 Rate Review Submission would be the correct moment to analyse the matter.

Consequently, in the present tariff submission JPS is proposing a WT for the largest users of energy and demand on the network. The WT is intended for customers with demand exceeding 1 MVA, and should be an incentive for these customers with the potential to self-generate to remain on the grid thereby keeping downward pressure on per unit cost for all customers using...
the network. The new WT shall have four declining blocks in recognition of the lower BAO for larger generation equipment.

Retail minus tariff (R-), Wholesale tariffs (WT) and Economic Development Tariffs (EDT) are analogous tariff design approaches that aim at efficiently using the system with global optimal cost minimisation criteria for the electricity sector as a whole.

The retail minus concept is simple and intuitive: it requires that for those customers who do not consume a service that is bundled into the retail tariff, the cost of that service is discounted from the retail tariff. This discount is increasing with energy consumption (decreasing blocks). It is also known as wholesale tariff because of its nature that will offer increasing discounts to higher volume consumers. Therefore, a minimum demand requirement to qualify as wholesale customer need to be determined.

This new tariff design is proposed in response to the OUR’s request for more tariff options, and weighing the public interest in introducing tariffs that provide economic benefits for the entire country. The wholesale tariff will be offered to the largest customers that opt not to wheel, which may substantially influence the decision of entities who may be considering whether to wheel. Failure to offer such a wholesale tariff could lead to JPS’ largest customers choosing to wheel out of their own self-interest, but which would eventually result in a sub-optimal outcome for the country, and which would distort the efficient regulated tariff structure. This is particularly true considering the 20 year PPA commitment to the next round of generation expansion and the risk of excess capacity demand should actually decline as a result of large customers opting to self generate.

The introduction of a wholesale tariff would provide a better solution for large customers seeking to obtain a lower energy cost—while also preserving the socially optimal tariff structure. In order to calculate the wholesale tariff, we consider the BAO for the largest customers (those who would be eligible for the new tariff).

Clearly for the same revenue requirement, any tariff rebalancing (as would be required with the wholesale tariff) entails increasing some customer class tariffs in order to reduce others. Adjusting price structures—or rebalancing, as it is often called—could, but does not necessarily, involve cross-subsidies. For example, if one generator may supply power to both residential and industrial customers, it is not possible to say exactly what part of the cost of the common rate base is attributable to each customer class. Therefore, one customer class can end up paying more than another, without necessarily subsidizing the other. A cross-subsidy exists if—and only if—the tariff charged to the residential rate class is greater than its stand-alone cost, and the benefits are passed to those customers who would qualify for the WT (and thus would pay less than their incremental costs).

**Rate schedule**

According to the proposed tariff design, the non-fuel rate schedule is as follows:
Table 8-22: RT40 and RT50 Wholesale Tariff Rate Schedule

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

The rates proposed, when applied to the average\(^{12}\) customer in each class and tier, yielded the average tariff presented in Figure 8.32.

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

---

\(^{12}\) We assume that the average customer has demand in the middle of the tier and energy consumption calculated with a load factor of 70%.
The number of current JPS customers, by demand tier, is as follows:

Table 8-23: RT40 and RT50 Customers by Demand Tier

<table>
<thead>
<tr>
<th>Class</th>
<th>Customers by power demand tier</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1 MVA to 2 MVA</td>
</tr>
<tr>
<td>RT 40 LV Power Service (Std)</td>
<td>5</td>
</tr>
<tr>
<td>RT 40 LV Power Service (TOU)</td>
<td>2</td>
</tr>
<tr>
<td>RT 50 MV Power Service (Std)</td>
<td>15</td>
</tr>
<tr>
<td>RT 50 MV Power Service (TOU)</td>
<td>6</td>
</tr>
<tr>
<td>Total</td>
<td>28</td>
</tr>
</tbody>
</table>

8.4.3.5 Wheeling Service for Large Customers—RT40 & RT50 Wheeling

Definition and proposed charges for non-fuel costs recovery

The cost causation principle requires that those large customers that choose to wheel power across JPS’ transmission and distribution network should pay for the costs incurred by JPS in providing power delivery service. These costs can be listed as:

1. Network capacity costs;
2. Commercial costs; and
3. Fuel and generation capacity costs associated with energy losses.

The wheeling tariffs have been designed to allow customers to generate their own energy, instead of purchasing it from JPS. These customers will be able to use the utility’s network but JPS will not be required to provide generation (energy and capacity) for them. If wheeling
customers desire to avoid investing in back up equipment, they may contract with JPS for standby service and pay the corresponding charges.

Under the current regulations, wheeling customers must be self-generators (that is, generate electricity for their own consumption). For these customers, wheeling service is necessary because the point of generation differs from the point of consumption, and therefore the customer desires to use JPS’ network to receive the energy and power at the point of consumption. Here, JPS provides the transmission and distribution capacity required by the customer.

Because wheeling customers self-generate, JPS’ generation and IPP costs are not recovered through the wheeling tariff.

However, for energy losses, although these customers do not consume the energy generated or purchased by JPS, they must take part and pay for the energy losses that are allocated to them in the tariff review process. The cost of losses includes fuel costs, and generation capacity costs associated with the approved losses level. This approach is consistent with the retail-minus principle previously described, which effectively gives a "discount" from the retail tariff for costs not incurred in providing service to wheeling customers. In this case, losses are not avoided by wheeling, and therefore cannot be excluded from the tariff paid by wheeling customers.

Similarly, and consistent with the retail-minus approach, wheeling customers must pay for the rest of the costs in the same way as full service customers do.

To determine the wheeling tariff, then, we identify and remove the cost components related to generation and IPP costs only. This adjustment is necessary to both the marginal cost charges and the NAC.

The Wheeling Power Service Low Voltage (RT40 Wheeling) class follows the Power Service Low Voltage (RT40) tariff structure:

- **NAC**: applicable irrespective of the level of consumption. It covers the customer service marginal costs and a portion of the Revenue Gap.
- **Energy charge**: This charge is paid for every kWh of consumption and it covers capacity marginal cost and a portion of the revenue gap.
- **Demand charge**
  - **Standard Option**:
    1. One demand charge applicable on each kVA billing demand
    2. Billing demand: The kilovolt-ampere (kVA) Billing Demand for each month shall be the maximum demand for that month, or 80% of the maximum demand during the five-month period immediately preceding the month for which the bill is rendered, whichever is higher, but not less than 25 kVA
  - **TOU Option**:
    1. One demand charge applies on each kVA billing demand per hour block.
    2. On-Peak Period Billing Demand: the billing demand in this period shall be the maximum demand for the On-Peak hours of that month. The minimum 25 kilovolt ampere (kVA) does not apply.
    3. Partial-Peak Period Billing Demand: the billing demand in this period shall be the maximum demand for the on-peak and partial-peak hours of that month, or 80% of the maximum demand for the on-peak and partial-
peak hours during the five-month period immediately preceding the month for which the bill is rendered, whichever is higher but not less than 25 kVA.

4. Off-Peak Period Billing Demand: The billing demand in this period shall be the maximum demand for that month (despite the time of use period it was registered in), or 80% of the maximum demand during the five-month period immediately preceding the month for which the bill is rendered, whichever is higher but not less than 25 kVA).

The Wheeling Power Service Medium Voltage (RT50 Wheeling) class follows the Power Service Medium Voltage (RT50) tariff structure.

- NAC: applicable irrespective of the level of consumption. It covers the customer service marginal costs and a portion the Revenue Gap.
- Energy charge: This charge is paid for every kWh of consumption and it covers capacity marginal cost and a portion of the revenue gap.
- Demand charge
  - Standard Option:
    1. One demand charge applicable on each kVA billing demand
    2. Billing demand: The kilovolt-ampere (kVA) Billing Demand for each month shall be the maximum demand for that month, or 80% of the maximum demand during the five-month period immediately preceding the month for which the bill is rendered, whichever is higher but not less than 25 kVA
  - TOU Option:
    1. One demand charge applies on each KVA billing demand per hour block.
    2. On-Peak Period Billing Demand: the billing demand in this period shall be the maximum demand for the On-Peak hours of that month. The minimum 25 kilovolt ampere (kVA) does not apply.
    3. Partial-Peak Period Billing Demand: the billing demand in this period shall be the maximum demand for the on-peak and partial-peak hours of that month, or 80% of the maximum demand for the on-peak and partial-peak hours during the five-month period immediately preceding the month for which the bill is rendered, whichever is higher but not less than 25 kVA
    4. Off-Peak Period Billing Demand: The billing demand in this period shall be the maximum demand for that month (regardless of the time of use period it was registered in), or 80% of the maximum demand during the five-month period immediately preceding the month for which the bill is rendered, whichever is higher but not less than 25 kVA).

**Rate schedule**

An essential element in setting this rate is that it has to be coherent and consistent with the criteria adopted in the definition of the rates for regular customers. Thus, the principles of equity and justice will not be affected, being an adequate signal for all electricity customers.

As previously discussed, in order to calculate the wheeling tariff using the retail-minus approach, we exclude the generation and IPP costs from each component of the current RT40 and RT50 tariffs. Table 8-24 shows the current RT40 and RT50 non-fuel charges, by function. Specifically, we separate the generation component from the NAC, the energy charge, and the demand charge.
Table 8-24: Disaggregation of the Current RT40 and RT50 Rate Schedule

<table>
<thead>
<tr>
<th>Class</th>
<th>NAC (USD/Cust./month)</th>
<th>STD or On-Peak</th>
<th>Partial-Peak</th>
<th>Off-Peak</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generation T&amp;D&amp;C</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 40 LV Power Service (Std)</td>
<td>80.000</td>
<td>17.783</td>
<td>10.717</td>
<td></td>
</tr>
<tr>
<td>RT 40 LV Power Service (TOU)</td>
<td>80.000</td>
<td>10.012</td>
<td>6.034</td>
<td>7.824</td>
</tr>
<tr>
<td>RT 50 MV Power Service (Std)</td>
<td>80.000</td>
<td>16.325</td>
<td>9.839</td>
<td>7.074</td>
</tr>
<tr>
<td>RT 50 MV Power Service (TOU)</td>
<td>80.000</td>
<td>9.069</td>
<td>5.466</td>
<td></td>
</tr>
</tbody>
</table>

According to the proposed tariff design, the non-fuel rate schedule and its comparison with retail (non-wheeling) customers is as follows:

Table 8-25: RT40 and RT50 Wheeling Rate Schedule

![Table 8-25: RT40 and RT50 Wheeling Rate Schedule](image)

Standby Rate\(^{13}\)

\(^{13}\) Baron, Stephen. "Standby Electric Rates". Public Utilities Fortnightly, Nov. 8, 1984
Under Jamaican regulation, customers generating their own electricity can either consume it on premises, or wheel part or all of the energy to consume it elsewhere (subject to minimum demand requirements).

As Jamaica’s economy has developed, JPS’ customers have grown to expect a high level of service reliability. Yet, generating facilities are prone to failure, and keeping back up units on customer premises is expensive. Therefore, customers generally rely on JPS to provide a standby service in case their generator fails, or when scheduled maintenance is needed.

For this reason, standby rates need to be designed and implemented. Unfortunately, traditional tariff design methodologies are not suitable for this service, given the fact that it is difficult to assign responsibility over the use of shared rate base to a demand that might need service only in the case of customer equipment failure. The “expected value of failure” is a more realistic approach to analysing the required level of standby capacity and to considering simultaneity; that is, the fact that not all generating units may fail simultaneously.

Regarding the rate that standby consumers will pay, we propose applying the standard demand monthly charges. However, the demand in kVA to be billed to these customers will be the expected value of failure of the consumer’s contracted demand. That is, consumers should only pay for the portion of the demand that represents the probability of failing to generate their own consumption.

The probability of failure needs to be related to the reliability of the installed generating equipment. It is expected that the manufacturer’s specifications will define the forced outage rate for each generating unit. Gathering statistics over time should help verify that the specifications are correctly determined, and if not, would trigger reliability adjustments for each generating plant model to be realistic.

Given the characteristics of the standby service, there is the issue of actual usage of the guaranteed demand for a period of time. Since this service is designed for limited usage only—such as in case of an outage and until the equipment is repaired—limitations on standby service usage should be determined to avoid abuse or gaming the system, and to incentivize a prompt solution to customer equipment failure. The period of time allowed for guaranteed demand usage will be 30 days per year.

The contracted standby capacity will be determined by the customer, and it may be different from the maximum installed generating capacity or the maximum demand of the customer premises. This standby capacity will represent the amount of power that the customer needs in case of failure of the private generation units and for which the customer is willing to pay for standby service. Penalties for excess consumption above contracted capacity should be put in place. These penalties should be set much above standard energy charges to discourage their usage.

For self-generating customers, the contracted capacity will be determined by the customer. In the case of wheeling customers, the contracted capacity will be the maximum registered demand for each month or 80% of the maximum demand during the five-month period immediately preceding the month for which the bill is rendered, whichever is higher.

Finally, we note that when standby service is actually used, all energy that is consumed will be paid at the standard rate according to the customer’s class. The standby rate includes the generation component present in the retail RT40 and RT50 rate schedule.
### Table 8-26: RT40 and RT50 Standby Rate Schedule

<table>
<thead>
<tr>
<th>Class</th>
<th>Proposed Standby Rates</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Demand Charge STD and On-Peak (USD/kVA)</td>
</tr>
<tr>
<td>RT 40 LV Power Service (Std)</td>
<td>13.959</td>
</tr>
<tr>
<td>RT 40 LV Power Service (TOU)</td>
<td>7.859</td>
</tr>
<tr>
<td>RT 50 MV Power Service (Std)</td>
<td>12.815</td>
</tr>
<tr>
<td>RT 50 MV Power Service (TOU)</td>
<td>7.119</td>
</tr>
</tbody>
</table>

#### 8.4.3.6 Net Billing—RT10, RT20, RT40, and RT50

**Definition and proposed charges for non-fuel costs recovery**

The Net Billing\(^{14}\) Standard Offer Program, as part of the Government of Jamaica’s Energy Policy, seeks to encourage electricity production by small intermittent sources of renewable energy of 100kW or less. These private installations require supplemental power from JPS for moments when the customer’s generation does not meet its own demand. Conversely, when the customer’s generation exceeds its own demand, the customer can sell excess electricity to the JPS—provided that the gross system output does not exceed 10kW AC for myHome facilities, or 100kW for myBusiness facilities. In addition, sale of electricity is subject to the terms and conditions of the Standard Offer Contract for the “Purchase of As-Available Intermittent Energy from Renewable Energy Facilities”.

Currently, facilities that sell electricity to JPS under the Net Billing Program are paid the prevailing short run avoided cost of generation, plus a premium of up to 15%. This rate is computed every month using the net generation of power plants on the grid for the applicable period and their related fuel costs, subject to approval by the OUR. There is no distinction between electricity purchased during the on-peak, off-peak, or partial-peak periods.

Costs differ according to facility types, size, and location. At a minimum, there will be the following initial costs, independent of equipment costs (for which customers are responsible):

- Non-refundable application fee (to OUR) of J$2,000.00 for myHome facilities and J$10,000.00 for myBusiness facilities.
- Impact study cost (if deemed to be necessary)

---


Botero, Sergio; “Regulatory Feasibility Analysis Of Policy Mechanisms To Foster Renewable Energy In The Colombian Power Sector”

VT Public Service Board Feed-in Tariff Workshop, “Renewable Energy Feed-In Tariffs: Lessons Learned From the U.S. And Abroad”, July 10th, 2009
Tariff Design (Non-fuel)

- Interconnection infrastructure cost (if deemed to be necessary)
- Meter cost, which can be paid for upfront or monthly over a 6-month or 12-month period.

After an application is accepted and approved by JPS, a standard licence should be issued by the Ministry of Energy on the recommendation of the OUR.

Settlements are based on electricity actually delivered to JPS, based on metered data, and not on the rated capacity of the project. Payments are made according to JPS’ normal billing schedule.

Essentially, the net billing program should provide a sufficient incentive for the customer to invest in renewable energy facilities (recovering such investment through fuel saving), while simultaneously keeping JPS neutral to the program.

**RT10 and RT20**

**Rate Structure**

The rate structure proposed for residential and general service with net billing is similar to the one stated for retail RT10 and RT20 classes.

- **NAC**: applicable irrespective of consumption. It covers the customer service marginal costs and a portion of non-fuel costs of the Revenue gap.
- **Energy charge**: This charge is paid for every kWh of consumption and it covers capacity marginal cost and a portion of the revenue gap.
- **Demand charge**: One demand charge applicable on each kVA billing demand.
- **Billing demand**: The kilovolt-ampere (kVA) Billing Demand for each month shall be the maximum demand for that month, or 80% of the maximum demand during the five-month period immediately preceding the month for which the bill is rendered, whichever is higher.

**Rate Schedule**

According to the proposed tariff design, the Non-fuel Rate Schedule is as follows:

**Table 8-27: R10 and R20 Net Billing Rate Schedule**

<table>
<thead>
<tr>
<th>Class</th>
<th>Network Access Charge (USD/Cust./month)</th>
<th>Energy Charge (USD/kWh)</th>
<th>Demand Charge (USD/kVA)</th>
</tr>
</thead>
<tbody>
<tr>
<td>RT 10 LV Res. Service - Net Billing</td>
<td>18.00</td>
<td>0.00</td>
<td>70.00</td>
</tr>
<tr>
<td>RT 20 LV Gen. Service - Net Billing</td>
<td>25.00</td>
<td>0.00</td>
<td>80.00</td>
</tr>
</tbody>
</table>

**RT40 and RT50**

**Rate Structure**

The rate structure proposed for low voltage and medium voltage power service (RT40 and RT50) is as follows:
• NAC: applicable irrespective of consumption. It covers the customer service marginal costs and a portion of non-fuel costs of the Revenue gap.
• Energy charge: This charge is paid for every kWh of consumption and it covers capacity marginal cost and a portion of the revenue gap.
• Demand charge: One demand charge applicable on each kVA billing demand.
• Billing demand: The kilovolt-ampere (kVA) Billing Demand for each month shall be the maximum demand for that month, or 80% of the maximum demand during the five-month period immediately preceding the month for which the bill is rendered, whichever is higher but not less than 25 kVA.

Rate Schedule

According to the proposed tariff design, the Non-fuel Rate Schedule is as follows:

Table 8-28: RT40 and RT50 Net Billing Rate Schedule

<table>
<thead>
<tr>
<th>Class</th>
<th>Network Access Charge (USD/Cust./month)</th>
<th>Energy Charge (USD/kWh)</th>
<th>Demand Charge (USD/kVA)</th>
</tr>
</thead>
<tbody>
<tr>
<td>RT 40 LV Power Service - Net Billing</td>
<td>80.000</td>
<td>0.000</td>
<td>28.000</td>
</tr>
<tr>
<td>RT 50 MV Power Service - Net Billing</td>
<td>80.000</td>
<td>0.000</td>
<td>27.000</td>
</tr>
</tbody>
</table>

8.4.4 Proposed Non-fuel Rate Schedules

According to the proposed tariff design just described, we now present the combined non-fuel rate schedule for the rate year 2014–2015. In we present the rate schedule in US dollars (USD), and in we present the rate schedule in Jamaican dollars (JMD). The rate schedules presented here assume a base exchange rate of JMD 112:USD 1.
### Table 8-29: Non-fuel Final Rate Schedule in USD

<table>
<thead>
<tr>
<th>Network Access</th>
<th>Energy Charge USD/kWh</th>
<th>Demand Charge USD/kVA</th>
<th>Standby Rate USD/kVA</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>STD and On-Peak</td>
<td>Partial-Peak</td>
<td>Off-Peak</td>
</tr>
<tr>
<td>RT 10 Prepaid Rate</td>
<td>0.22</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RT 10 Community Renewal Program</td>
<td>0.00</td>
<td>0.07</td>
<td></td>
</tr>
<tr>
<td>RT 10 LV Res. Service &lt; 100 kWh</td>
<td>6.00</td>
<td>0.09</td>
<td></td>
</tr>
<tr>
<td>RT 10 LV Res. Service 100-500 kWh</td>
<td>12.00</td>
<td>0.22</td>
<td></td>
</tr>
<tr>
<td>RT 10 LV Res. Service &gt; 500 kWh</td>
<td>18.00</td>
<td>0.28</td>
<td></td>
</tr>
<tr>
<td>RT 10 LV Res. Service - Net Billing</td>
<td>18.00</td>
<td>0.00</td>
<td>70.00</td>
</tr>
<tr>
<td>RT 20 LV Gen. Service &lt; 100 kWh</td>
<td>9.00</td>
<td>0.20</td>
<td></td>
</tr>
<tr>
<td>RT 20 LV Gen. Service 100-1000 kWh</td>
<td>15.00</td>
<td>0.19</td>
<td></td>
</tr>
<tr>
<td>RT 20 LV Gen. Service 1000-7500 kWh</td>
<td>25.00</td>
<td>0.19</td>
<td></td>
</tr>
<tr>
<td>RT 20 LV Gen. Service &gt; 7500 kWh</td>
<td>40.00</td>
<td>0.12</td>
<td></td>
</tr>
<tr>
<td>RT 20 LV Gen. Service - Net Billing</td>
<td>25.00</td>
<td>0.00</td>
<td>80.00</td>
</tr>
<tr>
<td>RT 60 LV Street Lighting</td>
<td>40.00</td>
<td>0.21</td>
<td></td>
</tr>
<tr>
<td>RT 40 (Std)&lt; 1 MVA</td>
<td>80.00</td>
<td>0.00</td>
<td>28.50</td>
</tr>
<tr>
<td>RT 40 (Std)- From 1 MVA to 2 MVA</td>
<td>80.00</td>
<td>0.00</td>
<td>27.65</td>
</tr>
<tr>
<td>RT 40 (Std)- From 2 MVA to 3 MVA</td>
<td>80.00</td>
<td>0.00</td>
<td>26.79</td>
</tr>
<tr>
<td>RT 40 (Std)- From 3 MVA to 4 MVA</td>
<td>80.00</td>
<td>0.00</td>
<td>25.94</td>
</tr>
<tr>
<td>RT 40 (Std)&gt; 4 MVA</td>
<td>80.00</td>
<td>0.00</td>
<td>25.08</td>
</tr>
<tr>
<td>RT 40 (Std) - Net Billing</td>
<td>80.00</td>
<td>0.00</td>
<td>28.00</td>
</tr>
<tr>
<td>RT 40 (Std) - Wheeling</td>
<td>80.00</td>
<td>0.00</td>
<td>14.54</td>
</tr>
<tr>
<td>RT 40 (TOU)&lt; 1 MVA</td>
<td>80.00</td>
<td>0.00</td>
<td>16.05</td>
</tr>
<tr>
<td>RT 40 (TOU)- From 1 MVA to 2 MVA</td>
<td>80.00</td>
<td>0.00</td>
<td>15.56</td>
</tr>
<tr>
<td>RT 40 (TOU)- From 2 MVA to 3 MVA</td>
<td>80.00</td>
<td>0.00</td>
<td>15.08</td>
</tr>
<tr>
<td>RT 40 (TOU)- From 3 MVA to 4 MVA</td>
<td>80.00</td>
<td>0.00</td>
<td>14.60</td>
</tr>
<tr>
<td>RT 40 (TOU)&gt; 4 MVA</td>
<td>80.00</td>
<td>0.00</td>
<td>14.12</td>
</tr>
<tr>
<td>RT 40 (TOU) - Wheeling</td>
<td>80.00</td>
<td>0.00</td>
<td>8.19</td>
</tr>
<tr>
<td>RT 50 (Std)&lt; 1 MVA</td>
<td>80.00</td>
<td>0.00</td>
<td>26.16</td>
</tr>
<tr>
<td>RT 50 (Std)- From 1 MVA to 2 MVA</td>
<td>80.00</td>
<td>0.00</td>
<td>25.38</td>
</tr>
<tr>
<td>RT 50 (Std)- From 2 MVA to 3 MVA</td>
<td>80.00</td>
<td>0.00</td>
<td>24.59</td>
</tr>
<tr>
<td>RT 50 (Std)- From 3 MVA to 4 MVA</td>
<td>80.00</td>
<td>0.00</td>
<td>23.81</td>
</tr>
<tr>
<td>RT 50 (Std)&gt; 4 MVA</td>
<td>80.00</td>
<td>0.00</td>
<td>23.02</td>
</tr>
<tr>
<td>RT 50 (Std) - Net Billing</td>
<td>80.00</td>
<td>0.00</td>
<td>27.00</td>
</tr>
<tr>
<td>RT 50 (Std) - Wheeling</td>
<td>80.00</td>
<td>0.00</td>
<td>13.35</td>
</tr>
<tr>
<td>RT 50 (TOU)&lt; 1 MVA</td>
<td>80.00</td>
<td>0.00</td>
<td>14.54</td>
</tr>
<tr>
<td>RT 50 (TOU)- From 1 MVA to 2 MVA</td>
<td>80.00</td>
<td>0.00</td>
<td>14.10</td>
</tr>
<tr>
<td>RT 50 (TOU)- From 2 MVA to 3 MVA</td>
<td>80.00</td>
<td>0.00</td>
<td>13.66</td>
</tr>
<tr>
<td>RT 50 (TOU)- From 3 MVA to 4 MVA</td>
<td>80.00</td>
<td>0.00</td>
<td>13.23</td>
</tr>
<tr>
<td>RT 50 (TOU)&gt; 4 MVA</td>
<td>80.00</td>
<td>0.00</td>
<td>12.79</td>
</tr>
<tr>
<td>RT 50 (TOU) - Wheeling</td>
<td>80.00</td>
<td>0.00</td>
<td>7.42</td>
</tr>
</tbody>
</table>
Table 8-30: Non-fuel Final Rate Schedule in JMD

<table>
<thead>
<tr>
<th>Network Access Charge USD/Month</th>
<th>Energy Charge JMD/kWh</th>
<th>Demand Charge JMD/kVA</th>
<th>Standby Rate (JMD/kVA)</th>
</tr>
</thead>
<tbody>
<tr>
<td>RT 10 Prepaid Rate</td>
<td></td>
<td>24.92</td>
<td></td>
</tr>
<tr>
<td>RT 10 Community Renewal Program</td>
<td>0.00</td>
<td>7.75</td>
<td></td>
</tr>
<tr>
<td>RT 10 LV Res. Service &lt; 100 kWh</td>
<td>672.00</td>
<td>10.30</td>
<td></td>
</tr>
<tr>
<td>RT 10 LV Res. Service 100-500 kWh</td>
<td>1,344.00</td>
<td>24.53</td>
<td></td>
</tr>
<tr>
<td>RT 10 LV Res. Service &gt; 500 kWh</td>
<td>2,016.00</td>
<td>30.84</td>
<td></td>
</tr>
<tr>
<td>RT 10 LV Res. Service - Net Billing</td>
<td>2,016.00</td>
<td>0.00</td>
<td>7,840.00</td>
</tr>
<tr>
<td>RT 20 LV Gen. Service &lt; 100 kWh</td>
<td>1,008.00</td>
<td>22.51</td>
<td></td>
</tr>
<tr>
<td>RT 20 LV Gen. Service 100-1000 kWh</td>
<td>1,680.00</td>
<td>21.84</td>
<td></td>
</tr>
<tr>
<td>RT 20 LV Gen. Service 1000-7500 kWh</td>
<td>2,800.00</td>
<td>21.18</td>
<td></td>
</tr>
<tr>
<td>RT 20 LV Gen. Service &gt; 7500 kWh</td>
<td>4,480.00</td>
<td>13.13</td>
<td></td>
</tr>
<tr>
<td>RT 20 LV Gen. Service - Net Billing</td>
<td>2,800.00</td>
<td>0.00</td>
<td>8,960.00</td>
</tr>
<tr>
<td>RT 60 LV Street Lighting</td>
<td>4,480.00</td>
<td>23.52</td>
<td></td>
</tr>
<tr>
<td>RT 40 (Std)&lt; 1 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>3,192.00</td>
</tr>
<tr>
<td>RT 40 (Std)- From 1 MVA to 2 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>3,096.24</td>
</tr>
<tr>
<td>RT 40 (Std)- From 2 MVA to 3 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>3,000.48</td>
</tr>
<tr>
<td>RT 40 (Std)- From 3 MVA to 4 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>2,904.72</td>
</tr>
<tr>
<td>RT 40 (Std)&gt; 4 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>2,808.96</td>
</tr>
<tr>
<td>RT 40 (Std) - Net Billing</td>
<td>8,960.00</td>
<td>0.00</td>
<td>3,136.00</td>
</tr>
<tr>
<td>RT 40 (Std) - Wheeling</td>
<td>8,960.00</td>
<td>0.00</td>
<td>1,628.55</td>
</tr>
<tr>
<td>RT 40 (TOU)&lt; 1 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>1,797.15</td>
</tr>
<tr>
<td>RT 40 (TOU)- From 1 MVA to 2 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>1,743.23</td>
</tr>
<tr>
<td>RT 40 (TOU)- From 2 MVA to 3 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>1,689.32</td>
</tr>
<tr>
<td>RT 40 (TOU)- From 3 MVA to 4 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>1,635.41</td>
</tr>
<tr>
<td>RT 40 (TOU)&gt; 4 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>1,581.49</td>
</tr>
<tr>
<td>RT 40 (TOU) - Wheeling</td>
<td>8,960.00</td>
<td>0.00</td>
<td>916.90</td>
</tr>
<tr>
<td>RT 50 (Std)&lt; 1 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>2,930.28</td>
</tr>
<tr>
<td>RT 50 (Std)- From 1 MVA to 2 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>2,842.37</td>
</tr>
<tr>
<td>RT 50 (Std)- From 2 MVA to 3 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>2,754.47</td>
</tr>
<tr>
<td>RT 50 (Std)- From 3 MVA to 4 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>2,666.56</td>
</tr>
<tr>
<td>RT 50 (Std)&gt; 4 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>2,578.65</td>
</tr>
<tr>
<td>RT 50 (Std) - Net Billing</td>
<td>8,960.00</td>
<td>0.00</td>
<td>3,024.00</td>
</tr>
<tr>
<td>RT 50 (Std) - Wheeling</td>
<td>8,960.00</td>
<td>0.00</td>
<td>1,495.03</td>
</tr>
<tr>
<td>RT 50 (TOU)&lt; 1 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>1,627.92</td>
</tr>
<tr>
<td>RT 50 (TOU)- From 1 MVA to 2 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>1,579.08</td>
</tr>
<tr>
<td>RT 50 (TOU)- From 2 MVA to 3 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>1,530.24</td>
</tr>
<tr>
<td>RT 50 (TOU)- From 3 MVA to 4 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>1,481.41</td>
</tr>
<tr>
<td>RT 50 (TOU)&gt; 4 MVA</td>
<td>8,960.00</td>
<td>0.00</td>
<td>1,432.57</td>
</tr>
<tr>
<td>RT 50 (TOU) - Wheeling</td>
<td>8,960.00</td>
<td>0.00</td>
<td>830.56</td>
</tr>
</tbody>
</table>

Base exchange rate of JMD 112: USD 1

8.4.5 Fixed Revenues versus Fixed Costs

Proposed tariffs multiplied by the Test Year Billing Determinants yield the following revenue by customer class and type of charge.
Table 8-31: Revenues by Class and Charge

<table>
<thead>
<tr>
<th>Class</th>
<th>Unit</th>
<th>Network Access Charge</th>
<th>Energy Charge</th>
<th>STD and On-Peak</th>
<th>Partial-Peak</th>
<th>Off-Peak</th>
<th>Total Revenues</th>
</tr>
</thead>
<tbody>
<tr>
<td>RT 10 LV Res. Service &lt; 100 kWh</td>
<td>USD 000</td>
<td>16,022</td>
<td>10,903</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>26,925</td>
</tr>
<tr>
<td>RT 10 LV Res. Service 100-500 kWh</td>
<td>USD 000</td>
<td>43,481</td>
<td>109,480</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>152,962</td>
</tr>
<tr>
<td>RT 10 LV Res. Service &gt; 500 kWh</td>
<td>USD 000</td>
<td>3,049</td>
<td>36,332</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>39,381</td>
</tr>
<tr>
<td>RT 20 LV Gen. Service &lt; 100 kWh</td>
<td>USD 000</td>
<td>2,683</td>
<td>2,240</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>4,923</td>
</tr>
<tr>
<td>RT 20 LV Gen. Service 100-1000 kWh</td>
<td>USD 000</td>
<td>5,082</td>
<td>26,473</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>31,555</td>
</tr>
<tr>
<td>RT 20 LV Gen. Service 1000-7500 kWh</td>
<td>USD 000</td>
<td>2,577</td>
<td>57,525</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>60,101</td>
</tr>
<tr>
<td>RT 20 LV Gen. Service &gt; 7500 kWh</td>
<td>USD 000</td>
<td>476</td>
<td>23,644</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>24,120</td>
</tr>
<tr>
<td>RT 60 LV Street Lighting</td>
<td>USD 000</td>
<td>113</td>
<td>9,390</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>9,503</td>
</tr>
<tr>
<td>RT 40 LV Power Service (Std)</td>
<td>USD 000</td>
<td>1,537</td>
<td>66,197</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>67,734</td>
</tr>
<tr>
<td>RT 40 LV Power Service (TOU)</td>
<td>USD 000</td>
<td>116</td>
<td>4,524</td>
<td>4,396</td>
<td>441</td>
<td></td>
<td>9,477</td>
</tr>
<tr>
<td>RT 50 MV Power Service (Std)</td>
<td>USD 000</td>
<td>100</td>
<td>29,485</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>29,585</td>
</tr>
<tr>
<td>RT 50 MV Power Service (TOU)</td>
<td>USD 000</td>
<td>26</td>
<td>3,792</td>
<td>3,866</td>
<td>418</td>
<td></td>
<td>8,102</td>
</tr>
<tr>
<td><strong>Total Revenues</strong></td>
<td>USD 000</td>
<td>75,262</td>
<td>275,988</td>
<td>103,999</td>
<td>8,263</td>
<td>858</td>
<td>464,369</td>
</tr>
</tbody>
</table>

If we group in one column the revenue to be obtained from the Network Access charge and the Demand charges and in another one we group the revenue derived from the energy charges we have the following distribution of revenues:

Table 8-32: Fixed Revenues vs Variable Revenues

<table>
<thead>
<tr>
<th>Class</th>
<th>Unit</th>
<th>NAC and Demand Charges</th>
<th>Energy Charges</th>
</tr>
</thead>
<tbody>
<tr>
<td>RT 10 LV Res. Service &lt; 100 kWh</td>
<td>USD 000</td>
<td>16,022</td>
<td>10,903</td>
</tr>
<tr>
<td>RT 10 LV Res. Service 100-500 kWh</td>
<td>USD 000</td>
<td>43,481</td>
<td>109,480</td>
</tr>
<tr>
<td>RT 10 LV Res. Service &gt; 500 kWh</td>
<td>USD 000</td>
<td>3,049</td>
<td>36,332</td>
</tr>
<tr>
<td>RT 20 LV Gen. Service &lt; 100 kWh</td>
<td>USD 000</td>
<td>2,683</td>
<td>2,240</td>
</tr>
<tr>
<td>RT 20 LV Gen. Service 100-1000 kWh</td>
<td>USD 000</td>
<td>5,082</td>
<td>26,473</td>
</tr>
<tr>
<td>RT 20 LV Gen. Service 1000-7500 kWh</td>
<td>USD 000</td>
<td>2,577</td>
<td>57,525</td>
</tr>
<tr>
<td>RT 20 LV Gen. Service &gt; 7500 kWh</td>
<td>USD 000</td>
<td>476</td>
<td>23,644</td>
</tr>
<tr>
<td>RT 60 LV Street Lighting</td>
<td>USD 000</td>
<td>113</td>
<td>9,390</td>
</tr>
<tr>
<td>RT 40 LV Power Service (Std)</td>
<td>USD 000</td>
<td>67,734</td>
<td>0</td>
</tr>
<tr>
<td>RT 40 LV Power Service (TOU)</td>
<td>USD 000</td>
<td>9,477</td>
<td>0</td>
</tr>
<tr>
<td>RT 50 MV Power Service (Std)</td>
<td>USD 000</td>
<td>29,585</td>
<td>0</td>
</tr>
<tr>
<td>RT 50 MV Power Service (TOU)</td>
<td>USD 000</td>
<td>8,102</td>
<td>0</td>
</tr>
<tr>
<td><strong>Total Revenues</strong></td>
<td>USD 000</td>
<td>188,381</td>
<td>275,988</td>
</tr>
</tbody>
</table>

According to Figure 8.5: Allocation of Cost of Service—Fixed v. Variable Costs, fixed costs represent 89% of JPS’ total non-fuel costs, but the company expects to recover only 41% of the total revenue requirement through fixed charges. Even though the gap between fixed costs and fixed revenues is still high, there is an important improvement in fixed revenues allocation by means of the adopted tariff design. Improvements have to do with:

1. Increasing Network Access Charges by consumption tier for those classes that do not have demand measurement
2. The removal of the energy charge for RT40 and RT50. This measure is offset by an increase in the Demand charges. If the current rates for large customers were
analysed, it can be observed that 45% of the non-fuel revenue is collected with the Energy Charge. As shown in Figure 8.5: Allocation of Cost of Service—Fixed v. Variable Costs, only 11% of the revenue requirement is variable costs, and variable costs caused by energy consumption are just 7.5%. That means that the current energy charge allows JPS to collect not only variable costs but also fixed capacity costs. We know that many times capacity costs are “Energized” to meet metering limitations some classes have (i.e. Residential and Small Commercial), but for rate classes with meters with demand measurement the ideal design is to assign 100% of capacity costs to the Demand Charge since this is best way to send a price signal to customers that encourages (and rewards) them for having a good load factor. It is appropriate to use the cost of service study to correct distortions in price signalling and we believe the proposed changes in capacity charges for the commercial and industrial customers is important if the current tariff design deficiency is to be improved. The following basic case shows the billing impact for 2 customers with the introduction of changes to the energy and demand charges, being revenue neutral for the company.

Assume that the company has 2 hypothetical customers consuming the same quantity of energy, but customer A has a poor load factor (30%) in comparison with customer B’s load factor. Tariffs for alternatives 1 and 2 have been set in order to generate the same revenue for the company, but alternative 2 becomes a strong price signal that benefits those customers represented by customer B. Hopefully in the not too distant future, each customer (including residential and general services customers) will have access to a metre with demand measurement. This will enable demand charges for those classes, resulting important for both efficiency and equity. The correct tariffs encourage individuals to make efficient decisions on energy and power consumption, which directly impacts the network capacity the company must make available to the users and thus the costs of providing the service.

---

15 The other important driver that causes variable costs is the number of customers, due to the fact that new customers need customer service, reading, billing, etc.
Chapter 9: Performance Based Rate-Making Mechanism

9.1 X-Factor

JPS proposes that the X-Factor for the 2014–2019 tariff period be set at a value between 0 percent and 0.35 percent for the reasons given in this section.

This X-Factor is a key component of the Performance Based Ratemaking Mechanism (PBRM) design, as detailed in Schedule 3, Exhibit 1 of the All-Island Electricity Licence 2011 (“Licence”)—and summarized here.

Under the Licence, the maximum allowable Price Cap Increase (∆PCI) for JPS’ non-fuel base rates in a given year is equal to the change in inflation (∆I) less the X-Factor (a Q-Factor and Z-Factor are also applied, but not discussed here).

\[ ∆PCI = ∆I - X + Q + Z \]

As we discuss in Section 9.1.5 below, the X-Factor is defined in the licence as the difference in expected total factor productivity (TFP) growth of JPS and TFP growth of the general economy. The underlying assumption of the X-Factor is that JPS can become more productive than the general economy, and so these productivity gains should be shared with consumers.

\[ = ΔTFP_{Expected}^{JPS} - ΔTFP_{General} \]

With this understanding of the X-Factor, the key question is how quickly JPS can become more efficient in its non-fuel costs, compared to efficiency gains in the economy as a whole. In the past, the Office of Utilities Regulation (OUR) has set the X-Factor based on the assumption that JPS is inefficient and should be able to “catch up” to industry best practice. As we will demonstrate in this chapter, JPS has become more efficient—and is now at the efficiency frontier for the electric utility industry (see Section 1.1).

We will also show that for United States utilities, the long-term trend over 30 years has been for TFP gains in the utilities to occur at the same rate as for the economy as a whole. This means that for utilities that are efficient, the expected difference between utility TFP growth and economy-wide TFP growth is zero. Since JPS is now on the industry frontier for non-fuel cost efficiency, it cannot be expected to outperform the industry in this regard. Therefore, the X-Factor should be set to zero. We call this the “fundamentals approach” because it is based on an understanding of fundamental drivers of productivity gains for utilities (see Section 1.2).

For consistency with the approach used in the last tariff review, we also estimate the X-Factor using a “calculations approach.” This approach yields an X-Factor of 0.35 percent, obtained from estimates of expected TFP growth for JPS and actual TFP growth of the economy (see Section 9.1.6).

---

JPS retained Castalia to perform the TFP study and recommend an appropriate X-Factor. Additional details regarding Castalia’s study are available in Annex B to this tariff review application.

9.1.1 JPS is Efficient

JPS has increased efficiency at an annual rate of 1.27 percent from 2002-2011. This growth rate is roughly 50 percent higher than the observed TFP growth in the United States power sector over the last 35 years. As a result of these productivity gains, JPS is now at the efficiency frontier for its industry, as shown by these three efficiency analysis techniques:

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

In the following sections, we describe the methodology and results from each of these techniques. We conclude with a summary of the results, and a discussion of the implications of JPS being a demonstrated efficient performer. Annex B provides additional detail regarding the methodology and results of all three techniques.

9.1.1.1 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 electric utilities, 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.

JPS believes that the 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 non-fuel base rates, 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.

Productivity of Labour Operating Expense

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 9-1 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.\(^3\)

**Figure 9-1: 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 9-2), JPS is again among the top performers. Although it ranks third-best, JPS’ staff cost per customer are still well below 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. Therefore, we cannot expect to cut staff costs to the levels of these two companies.

**Figure 9-2: Productivity Benchmarking—Staff Cost**

When we measure labour productivity as staff cost per MWh sold, the United States utilities again outperform JPS. 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 9-3, 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 9-3: Productivity Benchmarking—Non-Fuel, Non-Staff Operating Expense

**Non-Fuel, Non-Staff OPEX (US$) / Customer**
*excl. IPP O&M for JPS*

- EDEESTE
- JPS 170.94
- DOMLEC
- GPL
- LUCELEC
- VINLEC
- Florida Power & Light Company
- Gulf Power Company
- Georgia Power Company

Average = 497.43

**Non-Fuel, Non-Staff OPEX (US$) / Customer**
*incl. IPP O&M for JPS*

- EDEESTE
- DOMLEC
- GPL
- LUCELEC
- VINLEC
- JPS 224.79
- Florida Power & Light Company
- Gulf Power Company
- Georgia Power Company

Average = 503.42

**Non-Fuel, Non-Staff OPEX (US$) / MWh Sold**
*excl. IPP O&M for JPS*

- JPS 30.60
- Gulf Power Company
- Florida Power & Light Company
- LUCELEC
- ANGLEC
- EDEESTE
- Georgia Power Company
- DOMLEC
- VINLEC
- GPL

Average = 45.49

**Non-Fuel, Non-Staff OPEX (US$) / MWh Sold**
*incl. IPP O&M for JPS*

- Gulf Power Company
- Florida Power & Light Company
- LUCELEC
- ANGLEC
- EDEESTE
- Georgia Power Company
- JPS 40.24
- DOMLEC
- VINLEC
- GPL

Average = 46.46
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 9-3), we provide a set of graphs including IPP O&M costs, as well as a set of graphs excluding IPP O&M costs. Figure 9-4 on the next page shows that we are again a strong performer when it comes to non-fuel operating expense.
Figure 9-4: Productivity Benchmarking—Non-Fuel Operating Expense

**Non-Fuel, Non-Staff OPEX (US$) / Customer**

*excl. IPP O&M for JPS*

- EDEESTE: 170.94
- JPS: 497.43
- DOMLEC
- GPL
- LUCELEC
- VINLEC

*Average = 497.43*

**Non-Fuel, Non-Staff OPEX (US$) / Customer**

*incl. IPP O&M for JPS*

- EDEESTE
- DOMLEC
- GPL
- LUCELEC
- VINLEC
- JPS: 224.79

*Average = 503.42*

---

**Non-Fuel, Non-Staff OPEX (US$) / MWh Sold**

*excl. IPP O&M for JPS*

- JPS: 30.60
- Gulf Power Company
- Florida Power & Light Company
- LUCELEC
- ANGLEC
- EDEESTE
- Georgia Power Company
- DOMLEC
- VINLEC
- GPL

*Average = 45.49*

**Non-Fuel, Non-Staff OPEX (US$) / MWh Sold**

*incl. IPP O&M for JPS*

- Gulf Power Company
- Florida Power & Light Company
- LUCELEC
- ANGLEC
- EDEESTE
- Georgia Power Company
- JPS: 40.24
- DOMLEC
- VINLEC
- GPL

*Average = 46.46*
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 our performance “bracket,” produced by excluding and including IPP O&M costs from non-fuel operating expense, we remain 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 our 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 our staff cost performance (see Figure 9-2) and understating our non-fuel, non-labour cost performance (see Figure 9-4).

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.

**Productivity of Capital Expense**

We also attempt to measure the relative productivity of our 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 9-5 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 9-5: Productivity Benchmarking—Capital Consumption

Capital Consumption (US$) / Customers
excl. IPP Capacity Payments for JPS

<table>
<thead>
<tr>
<th>Company</th>
<th>Capital Consumption (US$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDEESTE</td>
<td>217.00</td>
</tr>
<tr>
<td>GPL</td>
<td></td>
</tr>
<tr>
<td>GRENLEC</td>
<td></td>
</tr>
<tr>
<td>JPS</td>
<td></td>
</tr>
<tr>
<td>DOMLEC</td>
<td></td>
</tr>
<tr>
<td>LUCELEC</td>
<td></td>
</tr>
<tr>
<td>BEL</td>
<td></td>
</tr>
<tr>
<td>BL&amp;P</td>
<td></td>
</tr>
<tr>
<td>VINLEC</td>
<td></td>
</tr>
<tr>
<td>Florida Power &amp; Light Company</td>
<td></td>
</tr>
<tr>
<td>Gulf Power Company</td>
<td></td>
</tr>
<tr>
<td>Hawaiian Electric Company, Inc.</td>
<td></td>
</tr>
<tr>
<td>Maui Electric Company, Limited</td>
<td></td>
</tr>
<tr>
<td>Hawaii Electric Light Company, Inc.</td>
<td></td>
</tr>
<tr>
<td>Georgia Power Company</td>
<td></td>
</tr>
</tbody>
</table>

Average = 609.50

Capital Consumption (US$) / Customers
incl. IPP Capacity Payments for JPS

<table>
<thead>
<tr>
<th>Company</th>
<th>Capital Consumption (US$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDEESTE</td>
<td></td>
</tr>
<tr>
<td>GPL</td>
<td></td>
</tr>
<tr>
<td>GRENLEC</td>
<td></td>
</tr>
<tr>
<td>DOMLEC</td>
<td></td>
</tr>
<tr>
<td>JPS</td>
<td>302.09</td>
</tr>
<tr>
<td>LUCELEC</td>
<td></td>
</tr>
<tr>
<td>BEL</td>
<td></td>
</tr>
<tr>
<td>BL&amp;P</td>
<td></td>
</tr>
<tr>
<td>VINLEC</td>
<td></td>
</tr>
<tr>
<td>Florida Power &amp; Light Company</td>
<td></td>
</tr>
<tr>
<td>Gulf Power Company</td>
<td></td>
</tr>
<tr>
<td>Hawaiian Electric Company, Inc.</td>
<td></td>
</tr>
<tr>
<td>Maui Electric Company, Limited</td>
<td></td>
</tr>
<tr>
<td>Hawaii Electric Light Company, Inc.</td>
<td></td>
</tr>
<tr>
<td>Georgia Power Company</td>
<td></td>
</tr>
</tbody>
</table>

Average = 615.17

Capital Consumption (US$) / MWh Sold
excl. IPP Capacity Payments for JPS

<table>
<thead>
<tr>
<th>Company</th>
<th>Capital Consumption (US$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDEESTE</td>
<td></td>
</tr>
<tr>
<td>Gulf Power Company</td>
<td></td>
</tr>
<tr>
<td>Florida Power &amp; Light Company</td>
<td></td>
</tr>
<tr>
<td>Georgia Power Company</td>
<td>38.85</td>
</tr>
<tr>
<td>JPS</td>
<td></td>
</tr>
<tr>
<td>Hawaiian Electric Company, Inc.</td>
<td></td>
</tr>
<tr>
<td>GPL</td>
<td></td>
</tr>
<tr>
<td>GRENLEC</td>
<td></td>
</tr>
<tr>
<td>BL&amp;P</td>
<td></td>
</tr>
<tr>
<td>Maui Electric Company, Limited</td>
<td></td>
</tr>
<tr>
<td>ANGLEC</td>
<td></td>
</tr>
<tr>
<td>LUCELEC</td>
<td></td>
</tr>
<tr>
<td>BEL</td>
<td></td>
</tr>
<tr>
<td>Hawaii Electric Light Company, Inc.</td>
<td></td>
</tr>
<tr>
<td>DOMLEC</td>
<td></td>
</tr>
<tr>
<td>VINLEC</td>
<td></td>
</tr>
</tbody>
</table>

Average = 60.73

Capital Consumption (US$) / MWh Sold
incl. IPP Capacity Payments for JPS

<table>
<thead>
<tr>
<th>Company</th>
<th>Capital Consumption (US$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>EDEESTE</td>
<td></td>
</tr>
<tr>
<td>Gulf Power Company</td>
<td></td>
</tr>
<tr>
<td>Florida Power &amp; Light Company</td>
<td></td>
</tr>
<tr>
<td>Georgia Power Company</td>
<td></td>
</tr>
<tr>
<td>JPS</td>
<td></td>
</tr>
<tr>
<td>Hawaiian Electric Company, Inc.</td>
<td></td>
</tr>
<tr>
<td>GPL</td>
<td></td>
</tr>
<tr>
<td>GRENLEC</td>
<td></td>
</tr>
<tr>
<td>BL&amp;P</td>
<td></td>
</tr>
<tr>
<td>Maui Electric Company, Limited</td>
<td></td>
</tr>
<tr>
<td>ANGLEC</td>
<td></td>
</tr>
<tr>
<td>LUCELEC</td>
<td></td>
</tr>
<tr>
<td>BEL</td>
<td></td>
</tr>
<tr>
<td>Hawaii Electric Light Company, Inc.</td>
<td></td>
</tr>
<tr>
<td>DOMLEC</td>
<td></td>
</tr>
<tr>
<td>VINLEC</td>
<td></td>
</tr>
</tbody>
</table>

Average = 61.68
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 our own 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.

9.1.2 Efficient Frontier Analysis

As we have shown, 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 evaluate our 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 electricity regulator in the UK for its distribution utility price resets. 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 9-6 below illustrates the results of the EFA, with JPS highlighted in yellow, the efficiency frontier also marked in yellow, and the average efficiency score marked by a blue dashed line. We see that in 2011, JPS was both above average, and well above even the efficiency frontier. Put another way, JPS’ total expenditure was less than what the model expected—and even less than what is considered the efficiency frontier—and so is an efficient cost performer.

Figure 9-6: Efficiency Score of JPS Using Efficient Frontier Analysis

---

This EFA approach is robust and defensible, for the following reasons:

- It is based on an approach developed and used by the Office of Gas and Electricity Markets (Ofgem), the energy regulator in the UK, in resetting its price cap for electric distribution utilities
- The underlying data set represents a diverse set of relevant comparators, drawn from the Caribbean, the United States, and New Zealand. Utilities in the data set operate at varying levels of scale, and face differing operating environments and business structures
- The estimated model is based on sound economic intuition: that growth in total expenditure is primarily driven by growth in the length of the transmission and distribution network, with modest growth in total expenditure due to increases in customer density (customers per km of line) and energy density (energy sales per km of line)
- The estimated model exhibits outstanding statistical properties, including strong goodness-of-fit and statistically significant independent variables. It controls for variation in time and business structure. In addition, the model passes tests for omitted variables, multicollinearity, heteroskedasticity, and serial correlation
- The model was also the best of several econometric models fitted to the data.

More details regarding the methodology of our efficient frontier analysis, including a discussion of the derivation and testing of our econometric model, are provided in Annex B.

9.1.3 Data Envelopment Analysis

Having shown that we are 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).

The results of DEA (see Figure 9-7) show that our conclusion that JPS is an efficient cost performer is valid. JPS receives an efficiency score of 100 percent, which indicates that it is on the frontier of the utilities included in the DEA modelling.

**Figure 9-7: Data Envelopment Analysis**

These results are limited in one regard: it is not simple to control for differences in operating environment or time using DEA. For this reason, we limited the comparison to data on Caribbean utilities, as they are the most directly comparable peers to JPS.

Notably, DEA is commonly used by both Ofgem and the Australia Energy Regulator to validate the results of other benchmarking techniques\(^\text{43}\). That is, these regulators use it to check that their conclusions regarding relative efficiency of utilities are correct.

9.1.4 Interpreting the Benchmarking Results

The results of the three efficiency analysis techniques tell a story that is consistent with the OUR’s assertion that JPS has been inefficient historically. That is, performance-based regulation, with an aggressive X factor, was intended to induce JPS to increase its efficiency. Since the introduction of the PBRM, the regulatory regime has had its intended effect.

Notably, JPS has increased efficiency in non-fuel costs by an average of 1.27 percent per year from 2002–2011 (see Table 9-1). This rate of efficiency gain is nearly 50 percent higher than the United States industry average of 0.85 percent per year. In other words, JPS has been rapidly

---

catching up with the best performers in the industry. As a result of this sustained and rapid efficiency gain, JPS is now on the efficiency frontier for non-fuel costs.

In practical terms, this means there is no more room to cut costs. Whatever “fat” was in the business has been cut out. Any further cuts will be cutting into muscle, hindering the utility’s ability to deliver quality outputs. In fact, the low level of costs compared to other utilities—for example, in capital consumption relative to utilities with better quality of service levels—suggests, if anything, costs may have been cut too far. That is, more investment and expenditure might be required in the future compared to the past in order to allow quality of service to improve.

9.1.5 Fundamentals Approach to Setting the X-Factor

Fundamentally, the X-Factor is supposed to be the difference between the rate of productivity growth the utility can achieve, and the rate of productivity growth in the economy as a whole. If the X-Factor is positive, then JPS is expected to improve its productivity faster than the general rate of productivity gains across the Jamaican economy. Conversely, a negative X-Factor would result from an expectation of slower productivity gains at JPS than the economy as a whole.

\[ X = \Delta TFP_{JPS}^{\text{Expected}} - \Delta TFP_{\text{General}} \]

The available evidence shows that over the long run, productivity growth for the average utility is the same as, or lower than, the productivity growth of the economy as a whole\(^\text{44}\). This indicates that the X-Factor should be set to 0 percent.

In the remainder of this section, we explain the logic of our “fundamentals approach” to setting the X-Factor, which relies on a strong conceptual understanding of the X-Factor to reach our conclusion.

**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 core relationship of the X-Factor is clearly defined in the Licence\(^\text{45}\):

*The X-Factor is based on the expected productivity gains of the Licensed Business. The X-Factor is to be set to equal the difference in the expected total factor productivity growth of the Licensed Business and the general total factor productivity growth of firms whose price index of outputs reflect the price escalation measure ‘dI’.*

The X-Factor 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


\(^{45}\) Government of Jamaica, All-Island Electricity Licence 2011, Schedule 3, Exhibit 1
productivity faster than firms in the general economy generally are increasing their productivity\textsuperscript{46}.

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\textsuperscript{47}. 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 in lockstep with 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 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\textsuperscript{48}.

**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.\(^{49}\)

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.\(^{50}\)

**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
- JPS is now at the frontier of efficiency for electricity utilities, and so we 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 US and Jamaican economies. Accordingly, the X-Factor should be no more than zero.

### 9.1.6 Calculations Approach to Estimating the X-Factor

We also estimate the X-Factor using a “calculations approach” for consistency with the approach used in the last rate review. The following sections set out JPS’ expected growth rate and the TFP growth rate for the economy over the last 5 years. We combine these figures to arrive at a calculated X-Factor of 0.35 percent.

#### 9.1.6.1 JPS’ Expected TFP Growth Rate

The Licence requires that the calculation of the X-Factor include the expected TFP growth of JPS over the upcoming five-year tariff period. In the past, the OUR has interpreted this to mean that JPS’ expected TFP growth is equal to its historic TFP growth rate, plus a “stretch factor.”\(^{51}\)

This section sets out JPS’ productivity annual growth over the period 2006–2011, showing that it has been 0.5340 percent on average. It then shows that there are no grounds for expecting

---


JPS’ TFP growth to be faster than this in the future, and in fact, evidence suggests achievable TFP growth may well be slower.

**JPS’ Historic TFP Growth**

The average annual growth of JPS’ TFP over the period 2006–2011 was 0.5340 percent. This estimate is based on a TFP index calculated for JPS, and provided in Table 9-1.

**Table 9-1: JPS’ TFP Index (1991 = 1.0000)**

<table>
<thead>
<tr>
<th>Year</th>
<th>w/ IPP Capacity Payments</th>
<th>w/o IPP Capacity Payments</th>
</tr>
</thead>
<tbody>
<tr>
<td>1991</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>1992</td>
<td>0.932</td>
<td>1.0247</td>
</tr>
<tr>
<td>1993</td>
<td>0.828</td>
<td>0.7753</td>
</tr>
<tr>
<td>1994</td>
<td>0.9</td>
<td>0.8657</td>
</tr>
<tr>
<td>1995</td>
<td>0.764</td>
<td>0.7612</td>
</tr>
<tr>
<td>1996</td>
<td>0.834</td>
<td>0.7656</td>
</tr>
<tr>
<td>1997</td>
<td>0.834</td>
<td>0.7159</td>
</tr>
<tr>
<td>1998</td>
<td>0.833</td>
<td>0.8202</td>
</tr>
<tr>
<td>1999</td>
<td>0.907</td>
<td>0.9496</td>
</tr>
<tr>
<td>2000</td>
<td>0.909</td>
<td>0.9945</td>
</tr>
<tr>
<td>2001</td>
<td>1.001</td>
<td>1.0735</td>
</tr>
<tr>
<td>2002</td>
<td>1.013</td>
<td>1.0967</td>
</tr>
<tr>
<td>2003</td>
<td>0.998</td>
<td>1.1261</td>
</tr>
<tr>
<td>2004</td>
<td>1.022</td>
<td>1.1441</td>
</tr>
<tr>
<td>2005</td>
<td>1.096</td>
<td>1.132</td>
</tr>
<tr>
<td>2006</td>
<td>1.105</td>
<td>1.1306</td>
</tr>
<tr>
<td>2007</td>
<td>1.132</td>
<td>1.0867</td>
</tr>
<tr>
<td>2008</td>
<td>1.1549</td>
<td>1.0798</td>
</tr>
<tr>
<td>2009</td>
<td>1.2844</td>
<td>1.2379</td>
</tr>
<tr>
<td>2010</td>
<td>1.1823</td>
<td>1.1099</td>
</tr>
<tr>
<td>2011</td>
<td>1.1348</td>
<td>1.0546</td>
</tr>
<tr>
<td>2012</td>
<td>1.2094</td>
<td>1.1353</td>
</tr>
</tbody>
</table>

The TFP index in this table was calculated using a methodology consistent with our 2009–2014 Tariff Review Application. We calculated TFP as the ratio of an output quantity index to an input quantity index. In effect, this index measures the efficiency with which a firm converts inputs to outputs.

52 The TFP index that includes IPP capacity payments as a JPS capital input was constructed using historic values from 1991–2007 (from JPS’ 2009–2014 tariff review application), and “spliced” using annual growth rates of the TFP index as calculated by Castalia. See Appendix A for more details.
Growth in the TFP index is the difference between trends in the output and input quantity indexes. The output quantity index consists of trends in number of customers served, energy sales (MWh), and peak demand (MW). The input quantity index consists of trends in capital consumption and O&M activities. Because the X-Factor only applies to the Non-Fuel Base Rate, we excluded all fuel and purchased power costs from the calculation of these indexes.

We chose a five-year period (2006–2011) as the historical basis for JPS’ TFP calculation because the PBRM applies for a five year period, and should use the most recent five years of data. However, the time period used for JPS’ historic TFP growth estimate must be consistent with the time period used to calculate General TFP growth—in this case, a five-year period ending in 2011.

In addition, TFP growth over the last five years is a better predictor of future performance than TFP growth over the past 10 years. As JPS has caught up to the efficiency frontier, the rate of its productivity gains has slowed. Easier gains will have been made first, while remaining ones are harder and slower to achieve.

Moreover, as illustrated in Figure 9-8, JPS’ low demand growth has depressed TFP growth over the last five years. Since this demand trend is likely to continue in the next tariff period, it is reasonable to expect TFP growth to be suppressed as it has been over the past five years.

**Figure 9-8: JPS’ Demand Growth Has Stalled**

More details regarding the methodology used to calculate JPS’ TFP growth rate are included in Appendix A.

**JPS’ Expected TFP Growth**

The Licence does not specify that historic TFP growth forms the basis of the X-Factor calculation, but rather the expected growth of JPS’ TFP over the tariff period. As discussed in the previous section, the most reasonable expectation is that JPS’ TFP growth over the next five years would be no more than the observed growth over the five years from 2006–2011.

This is because, as we have demonstrated in our discussion of the efficiency analysis techniques, JPS is already operating at the industry efficiency frontier. Furthermore, our productivity benchmarking shows that there is little room to further reduce non-fuel costs. Lastly, we expect low demand growth. This, coupled with the loss of sales from net metering and wheeling, will eliminate another important source of productivity growth.
In the past, the OUR has added a stretch factor to JPS’ historic TFP growth, and has justified this on the basis that JPS is “inefficient” and therefore can “catch up” with other utilities\(^{53}\).

*JPS used the results of the benchmarking study to conclude that JPS is an average industry performer....JPS uses this argument to select the typical stretch factor for United States PBRM of 0% to 0.5% as appropriate for JPS....However it may be argued that given JPS’ low productivity growth compared with other utilities it is likely to be a below average performer.*

However, since JPS has now caught up to the efficiency frontier, this logic no longer holds. There is no longer a justification for adding a stretch factor to arrive at an expected TFP growth rate for JPS.

### 9.1.7 General Economy TFP Growth Rate

The general economy TFP growth rate to be used in setting the X-Factor is 0.1799 percent. This calculation is based on the weighted average prescribed in the Licence:

\[
\Delta TFP_{general} = (0.76 \times \Delta TFP_{US}) + (0.24 \times \Delta TFP_{Jamaica})
\]

The inputs to this calculation of general TFP growth are:

- 0.4207 percent for the United States economy, and
- \(-0.5827\) percent for the Jamaican economy.

We provide the respective United States and Jamaican TFP indexes used to calculate this general TFP growth rate in Table 9-2 below.

#### Table 9-2: General TFP Index

<table>
<thead>
<tr>
<th>Year</th>
<th>United States TFP Index</th>
<th>Jamaica TFP Index</th>
</tr>
</thead>
<tbody>
<tr>
<td>1991</td>
<td>82.653</td>
<td>1.0894</td>
</tr>
<tr>
<td>1992</td>
<td>84.592</td>
<td>1.1725</td>
</tr>
<tr>
<td>1993</td>
<td>84.84</td>
<td>1.1699</td>
</tr>
<tr>
<td>1994</td>
<td>85.471</td>
<td>1.146</td>
</tr>
<tr>
<td>1995</td>
<td>85.492</td>
<td>1.1144</td>
</tr>
<tr>
<td>1996</td>
<td>86.668</td>
<td>1.105</td>
</tr>
<tr>
<td>1997</td>
<td>87.179</td>
<td>1.0818</td>
</tr>
<tr>
<td>1998</td>
<td>88.446</td>
<td>1.0592</td>
</tr>
<tr>
<td>1999</td>
<td>89.909</td>
<td>1.0711</td>
</tr>
<tr>
<td>2000</td>
<td>91.354</td>
<td>1.0669</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Year</th>
<th>United States TFP Index</th>
<th>Jamaica TFP Index</th>
</tr>
</thead>
<tbody>
<tr>
<td>2001</td>
<td>92.032</td>
<td>1.0645</td>
</tr>
<tr>
<td>2002</td>
<td>94.229</td>
<td>1.0105</td>
</tr>
<tr>
<td>2003</td>
<td>96.627</td>
<td>1.0189</td>
</tr>
<tr>
<td>2004</td>
<td>98.926</td>
<td>1.0194</td>
</tr>
<tr>
<td>2005</td>
<td>100</td>
<td>1</td>
</tr>
<tr>
<td>2006</td>
<td>100.362</td>
<td>0.9989</td>
</tr>
<tr>
<td>2007</td>
<td>100.707</td>
<td>0.9856</td>
</tr>
<tr>
<td>2008</td>
<td>99.305</td>
<td>0.9742</td>
</tr>
<tr>
<td>2009</td>
<td>98.912</td>
<td>0.963</td>
</tr>
<tr>
<td>2010</td>
<td>101.465</td>
<td>0.9644</td>
</tr>
<tr>
<td>2011</td>
<td>102.491</td>
<td>0.9701</td>
</tr>
<tr>
<td>2012</td>
<td>103.417</td>
<td>1.0105</td>
</tr>
</tbody>
</table>

To arrive at 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.

Our TFP growth rate calculations for the Jamaican economy are based on the most recent data available from the Penn World Table. 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 our last tariff review application.

We note, however, that to be consistent in setting the X-Factor, the general economy TFP should also be a forecast of TFP over the upcoming tariff period. Although the Licence defines the X-Factor as \( X = \Delta TFP_{JPS}^{Expected} - \Delta TFP_{General} \), in order to be logically consistent, if JPS’ TFP growth is forecasted over the five-year tariff period, then the general TFP growth rate should also be forecasted.

---


55 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 tariff review application use 2011 as the ending year.
While estimates of the general economy TFP are not generally performed—and we have not attempted to do so—this point is important, since the X-Factor should be the difference between expected TFP growth for JPS and expected TFP growth for the economy as a whole. The “fundamentals approach” (see Section 9.1.5) may be a better guide than this “calculations approach,” since the fundamentals approach considers the long-run growth relationship between the utility’s TFP and economy-wide TFP.

9.1.8 Proposed X-Factor

To summarise our proposal, JPS believes that:

- Using the “fundamentals approach,” the X-Factor would be set at zero percent, since this is the difference between the expected TFP growth of JPS and the expected TFP growth of the economy.
- Using the “calculations approach,” the X-Factor would be set at 0.35 percent for the 2014–2019 tariff period. Additionally, because JPS is operating at the industry efficiency frontier, no stretch factor should apply.

JPS invites the OUR to determine an X-Factor in the range zero percent to 0.35 percent, and recommends that the number be in the lower half of this range, in light of JPS’ current, low non-fuel costs and expected low demand growth in the 2014–2019 tariff period.
9.2 Q-Factor – Quality of Service Standards

9.2.1 Introduction

The Q factor, as stipulated in the License, adjusts the annual price escalation rate to reflect changes in the quality of service provided to customers, specifically:

\[ \text{dPCI} = \text{dI} \pm X \pm Q \pm Z \]

It has been established by the OUR and JPS that the Q-factor should meet the following criteria:

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

In the application of the Q-factor mechanism, there is an annual reliability performance target measured in terms of the System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), and Customer Average Interruption Duration Index (CAIDI). The target is defined as an annual improvement on the baseline performance. This target was set at 2% for SAIFI and SAIDI during the period 2011-2014 in the last regulatory period. The baseline itself has however not yet been defined by the OUR due to concerns related to the quality of the reported data. The reliability indices are defined as follows:

- **SAIFI**—is the average number of interruptions that a customer faces and is described by the following equation:
  \[ \text{SAIFI} = \frac{\text{Total number of customer interruptions}}{\text{Total number of customers served}} \]
  SAIFI is expressed in number of interruptions per year.

- **SAIDI**—this index is commonly referred to as customer minutes of interruption and is designed to provide information about the average time that customers are interrupted. It is expressed in minutes.
  \[ \text{SAIDI} = \frac{\sum (\text{Customer interruption durations})}{\text{Total number of customers served}} \]

---

• CAIDI—this index represents the average time required to restore service to the average customer per sustained interruption. It is the result of dividing the duration of the average customer’s sustained outages (SAIDI) by the frequency of outages for that average customer (SAIFI).

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

The unit for CAIDI is minutes per interruption.

Additionally, in the 2009 Determination, the OUR proposed the addition of a fourth quality measure known as:

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

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

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

9.2.2 Calculation of the Q-Factor

In the 2009 Determination Notice, the OUR indicated that once it is satisfied that JPS’ calculation of the quality of service indices meet all the criteria of the data being properly captured, verified and auditable; the quality of service performance should be classified into three categories according to the following point system:

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

The financial incentive is based on the number of quality points and is set as follows. If the sum of Quality Points for:

- SAIFI, SAIDI, and CAIFI is 9, then Q = +0.50%
- SAIFI, SAIDI, and CAIFI is 6, then Q = +0.40%
- SAIFI, SAIDI, and CAIFI is 3, then Q = +0.25%
- SAIFI, SAIDI, and CAIFI is 0, then Q = 0.00%
- SAIFI, SAIDI, and CAIFI is -3, then Q = -0.25%
- SAIFI, SAIDI, and CAIFI is -6, then Q = -0.40%
- SAIFI, SAIDI, and CAIFI is -9, then Q = -0.50%
- SAIFI, SAIDI, and CAIFI is 0, then Q = 0.00%
The Q-factor may thus vary between a minimum of -0.5% to a maximum of +0.5%, is symmetric and all possible outcomes are properly defined based on PBRM point system. The design is also balanced as it provides equal opportunity for either a positive or negative adjustment to the PBRM.

Since the performance in each of the three performance measures can either be above target, below target or on target (dead band) there are twenty-five (25) possible outcomes as shown in Table 9-3 below:

<table>
<thead>
<tr>
<th>SAIDI</th>
<th>SAIFI</th>
<th>CAIDI</th>
<th>Total</th>
<th>Adjustment Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>3</td>
<td>3</td>
<td>9</td>
<td>0.50%</td>
</tr>
<tr>
<td>3</td>
<td>3</td>
<td>0</td>
<td>6</td>
<td>0.40%</td>
</tr>
<tr>
<td>3</td>
<td>0</td>
<td>3</td>
<td>6</td>
<td>0.40%</td>
</tr>
<tr>
<td>0</td>
<td>3</td>
<td>3</td>
<td>6</td>
<td>0.40%</td>
</tr>
<tr>
<td>3</td>
<td>0</td>
<td>0</td>
<td>3</td>
<td>0.25%</td>
</tr>
<tr>
<td>0</td>
<td>0</td>
<td>3</td>
<td>3</td>
<td>0.25%</td>
</tr>
<tr>
<td>0</td>
<td>3</td>
<td>0</td>
<td>3</td>
<td>0.25%</td>
</tr>
<tr>
<td>3</td>
<td>3</td>
<td>(3)</td>
<td>3</td>
<td>0.25%</td>
</tr>
<tr>
<td>(3)</td>
<td>3</td>
<td>3</td>
<td>3</td>
<td>0.25%</td>
</tr>
<tr>
<td>3</td>
<td>(3)</td>
<td>3</td>
<td>3</td>
<td>0.25%</td>
</tr>
<tr>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>3</td>
<td>0</td>
<td>(3)</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>(3)</td>
<td>3</td>
<td>0</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>0</td>
<td>(3)</td>
<td>3</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>(3)</td>
<td>0</td>
<td>3</td>
<td>0</td>
<td>0.00%</td>
</tr>
<tr>
<td>0</td>
<td>0</td>
<td>(3)</td>
<td>(3)</td>
<td>(0.25%)</td>
</tr>
<tr>
<td>0</td>
<td>(3)</td>
<td>0</td>
<td>(3)</td>
<td>(0.25%)</td>
</tr>
<tr>
<td>(3)</td>
<td>0</td>
<td>0</td>
<td>(3)</td>
<td>(0.25%)</td>
</tr>
<tr>
<td>3</td>
<td>(3)</td>
<td>(3)</td>
<td>(3)</td>
<td>(0.25%)</td>
</tr>
<tr>
<td>(3)</td>
<td>(3)</td>
<td>3</td>
<td>(3)</td>
<td>(0.25%)</td>
</tr>
<tr>
<td>(3)</td>
<td>3</td>
<td>(3)</td>
<td>(3)</td>
<td>(0.25%)</td>
</tr>
<tr>
<td>(3)</td>
<td>0</td>
<td>(3)</td>
<td>(6)</td>
<td>(0.40%)</td>
</tr>
<tr>
<td>0</td>
<td>(3)</td>
<td>(3)</td>
<td>(6)</td>
<td>(0.40%)</td>
</tr>
<tr>
<td>(3)</td>
<td>(3)</td>
<td>0</td>
<td>(6)</td>
<td>(0.40%)</td>
</tr>
<tr>
<td>(3)</td>
<td>(3)</td>
<td>(3)</td>
<td>(9)</td>
<td>(0.50%)</td>
</tr>
</tbody>
</table>

The OUR indicated that the weighting of MAIFI in the point score system will be assessed for its resultant tariff impact and a determination will be made by the OUR in a future tariff adjustment period.
9.2.3 Benchmarking of SAIDI, SAIFI and CAIDI

The OUR’s 2009 Determination Notice stated that due to countervailing circumstances the five year baseline data that was available then (2004 – 2008) was neither sufficient nor representative enough to ensure the optimum baseline for a robust Q factor and could have undermined the penalty and reward system that sought to incentivize JPS to provide quality electricity service. As a result, the Q factor was set to 0 in 2009. The OUR determined that once the baseline data is deemed reliable for SAIDI, SAIFI and CAIDI computation, the Q factor targets and penalty/reward scoring system would be revised during the 2010-2014 annual adjustment submissions. No revision of the targets or penalty scoring system was done during the 2009-2014 review period as the OUR had also stated that there was a need for the auditing of the data collection procedure and processes along with further analysis on the variability of the performance of the indices overtime before the Q factor baseline could be established. Subsequently, in 2012, the OUR engaged the international energy consulting firm, KEMA DNV, to “conduct a review of JPS’Q-factor performance indicators and data collection procedure and method.” The overarching goal of the audit according to the OUR and KEMA, was to inform regulatory decision on a suitable baseline for future reliability performance indices which will be used to determine the Q factor in the PBRM as described in the Licence.

9.2.4 Overview of the OUR/KEMA Q Factor Audit

KEMA completed its audit and submitted the final audit report to both the OUR and JPS in September 2012. The report identified some deficiencies in JPS’ Q factor processes and data collection methods and made a series of recommendations for improvement as well as identifies some key deliverables from JPS to ensure that it’s computed reliability performance indices may be used by the regulator to establish a baseline for future Q factor determination.

9.2.4.1 Audit Objectives

The objectives of the audit as identified by KEMA were to:

1. Establish the extent to which JPS’Q factor impacting data collection method and procedure was consistent with international best practices interruption data collection and was therefore, applicable for use in Q-factor determination.
2. Determine whether JPS’ data collection mechanism consistently provided accurate data for duration, frequency, and the number of customers affected by interruptions at the feeder and sub-feeder levels of the network.
3. Determine the accuracy of JPS submitted data for system average interruption duration index, the system average interruption frequency index and the continuous average interruption duration index for the period 2009-2011.

At the completion of the audit, KEMA was also to recommend to the OUR whether MAIFI should be included in the Q factor point scoring system.

---

57The countervailing factors were bad weather in 2004 and 2005, system shutdown in 2007 and 2008 and data collection issues relating to the integrity of the system.

58Momentary Interruption Duration Index (MAIFI) was also audited but although this number is reported to the OUR, it is not included in the Q factor computation.
9.2.4.2 Audit Recommendations

In carrying out its audit, KEMA identified two main areas of focus; business processes and data accuracy. The process audit sought to identify and understand the methods and procedures that were used by JPS to report the reliability data (SAIDI, SAIFI, CAIDI, and MAIFI). A key component of the process audit was to identify deficiencies in the processes that affected the acquisition and reporting of the reliability data. KEMA developed an evaluation criterion against which the process audit was conducted. The broad criteria, against which JPS was audited, were as follows:

- Organizational Structure, Responsibilities and competencies
  - Position, and roles
  - Responsibilities
  - Competencies needed
- Application of Data Collection Methods
  - Information Systems and Process Flow
  - Data Transfer
  - Data Trails
- Indicator Computations
  - Use of estimates and assumptions
  - Guidance on checks and reviews
  - Internal validation
  - Internal audit

Out of a maximum achievable score of 30, KEMA determined that JPS scored 19. This in KEMA’s view indicates that JPS has made “considerable efforts to set in place processes and software tools, but currently this is still with limitations and incomplete while there are no formal or written definitions of processes and process flows and no mechanisms for checks, reviews, validation of data, and internal auditing.” The key recommendations coming out of the process audit are as follows:

- Implementation of a process description and a process flow chart of the Q-factor process with the introduction of the new outage management system (OMS) which interfaces with GIS, SCADA, and the Call Centre Outage Log.
  - The OMS interfacing with GIS should allow accurate recording of staged restoration of interruptions with the corresponding number of customers restored in each stage of restoration.
- Identification and clear definitions of the roles, responsibilities, and accountabilities of employees involved in the Q factor process.
  - Responsibilities, accountability and competencies needed should be included in job descriptions of employees involved in the Q factor process
- Description and implementation of internal validation and internal audit processes.

59Details may be found in Chapter 2 of the KEMA Q Factor Audit Report

60KEMA had determined that JPS was not recording staged restoration and as a result, the computed value of SAIDI and SAIFI were more than they should have been.
9.2.4.3 The Data Audit

The aim of the data audit was to verify the accuracy of the reliability performance data reported to the OUR by JPS. KEMA also conducted a benchmarking exercise in which JPS’ reliability performance was measured against jurisdictions with similar power systems. In conducting the data audit, KEMA sought to verify whether the data used for the Q-factor mechanism; i.e., data in the Interruption List matched with the primary and secondary data sources within JPS. The primary Q-factor data sources identified were the Control Centre Outage Log, the JPS Reliability Management Log, SCADA Database and the Customer Number List. KEMA indicated that reliability levels at JPS are lower than other jurisdictions with similar characteristics and that generation accounted for over 50% of all interruptions because of low figures for generation reserve and availability. However, the key findings of the data audit allowed KEMA to conclude that “the current level of accuracy in the reported data by JPS does not allow it to be used for the purpose of setting a baseline or computing financial penalties/rewards.”

The deficiencies and inaccuracies in the data sources and computations as outlined in the audit report are summarized below:

- Errors were found in the randomly selected samples from the data sources.
- JPS does not currently record staged restoration of interruptions
- Double counts which were partly due to manual transfer of interruption start and end times from SCADA to the Control Centre Outage Log were identified and;
- Customer numbers when section interruptions were estimated instead of exactly determined.

With regards to the data submitted by JPS to OUR between 2009-2011, KEMA concluded, “that accuracy declined from a good level in 2009 to a low level in 2011, while still in all three years the issue of double counts and staged restoration has led to inaccuracy that cannot be exactly calculated or determined from outage logs, but based on the analysis is expected to be significant.”

KEMA believes that implementation of OMS in conjunction with GIS will improve the reliability of interruption data recording and that it will address the shortcomings of the current methods used for calculating affected customers for section interruptions and, customer and customer minutes count in staged restoration. The other weaknesses that would remain such as double counts and errors resulting from manual entry of data as reported out in the field could be corrected by adopting the proper data collection procedures such as implementation of a system within OMS for flagging double counts and by formalizing a system for validating manual entry. The Consultants provided a Reliability Data Collection and Reporting Manual which it recommended that JPS should adopt.

9.2.4.4 Treatment of MAIFI

With regards to including MAIFI in the computation of the Q factor, KEMA had recommended that MAIFI should be introduced in the Q factor but with no financial impact and

---

61Particularly the risk of double counting a feeder section interruption with an interruption of the same, entire feeder.
that JPS should set up additional data recording processes. The Consultants further recommended that the OUR not accede to JPS’ request for excluding a number of causes of momentary computations.

9.2.5 JPS Initiatives to Address Audit Recommendations

Following the submission of the Audit Report to JPS, the company formed a Q-factor working group whose members included several key stakeholders involved in the Q factor process across the company. The working group’s purpose was to identify initiatives and projects to be implemented in keeping with recommendations made by KEMA in its audit report. The working group identified the following major initiatives:

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

The remainder of this report will provide a brief description of the initiatives, and the progress and status of implementation of activities identified for each of the initiatives.

9.2.6 Adoption of Standardized Definitions

In keeping with international best practices, JPS has taken the decision to formally adopt the IEEE 1366-2012 definitions, applications, and calculations of reliability performance indices for electric distribution systems. The adoption of the IEEE 1366 not only allows standardization but will facilitate more accurate benchmarking comparison of JPS’ reliability performance against other utilities that have adopted the IEEE 1366. The IEEE 1366 incorporates a methodology that consistently defines, measures and identifies the impact of major events on reliability reporting. Major events are events that are outside the normal operating design and limits of the utility. By having a standard definition and method using the concept of “major event days” both utilities and regulators can clearly identify normal reliability trends and treat separately with major events. This also allows the OUR to do comparative benchmark assessment of JPS’ utility based on a common standard. A majority of major utilities and regulators in the United States have adopted the standard with the Energy Information Administration consulting on adopting it as the reliability reporting standard (see Lawrence Berkeley National Laboratory’s – supported by the US Department of Energy –recommendation to the EIA to adopt the standard.63

The definitions of CAIDI, SAIDI, SAIFI, and MAIFI as defined in the 2009 Determination Notice is not materially different from that in the IEEE 1366-2012 however, JPS is proposing the use of IEEE’s definition of major events as described below.

62IEEE 1366-2003 was introduced in 2003 and has been used by utilities and regulators since. It was revised in 2012 with clarifications to definitions but no modification of the definitions.

63http://www.eia.gov/survey/changes/electricity/comments/J_Eto_E_Fisher_LBNL.pdf
**Daily SAIDI = Σ sustained customer minutes interrupted (for the day)/Σ system customers served**

In order to evaluate trends during a year and to establish Major Event Thresholds, a daily SAIDI value is often used as a measure. This concept was introduced in IEEE Standard 1366-2012. This is the day’s total customer minutes out of service divided by the static customer count for the year. It is the total average outage duration customers experienced for that given day. When these daily values are accumulated through the year, it yields the year’s SAIDI results.

**Major Events**

A Major Event is defined as a 24-hour period where SAIDI exceeds a statistically derived threshold value, T_MED, (Reliability Standard IEEE 1366-2012) based on the 2.5 beta methodology.

- Daily SAIDI values for a period of time (usually five years) are used to calculate T_MED
- The natural log (ln) of each SAIDI value is found and the log-average (α) is found.
- The standard deviation of the logarithms is found (β).

From this data, T_MED is calculated as follows:

$$T_{MED} = e^{(\alpha + 2.5\beta)}$$

Where

- $T_{MED}$ = Major Event Threshold, minutes.
- $e$ = Exponential function, 2.718.
- $\alpha$ = Log-average of the data.
- $\beta$ = Log-standard deviation of the data.

In calculating the daily SAIDI, interruption durations that extend into subsequent days accrue to the day on which the interruption is initiated. The major event day identification threshold value, T_MED, is calculated at the end of each reporting period for use during the next reporting period as follows:

1. Collect values of daily SAIDI for five sequential years ending on the last day of the last complete reporting period. If fewer than five years of historical data are available, use all of the available historical data.
2. If any day in the data set has a value of zero for SAIDI, replace it with the lowest non-zero SAIDI value in the data set. (This permits taking the logarithm of every day.)

When computing the reliability indices for given reporting period, they will be corrected to account for separate reporting of major event days by assuming that the average daily value of the index would have resulted if a major event had not occurred, e.g. for a generic reliability index R (either SAIDI, SAIFI or CAIDI), with $D_{rp}$ days in the reporting period, which had $D_{MED}$ major event days, the corrected index will be calculated as follows:

$$R = \frac{D_{rp}}{D_{rp} - D_{MED}} R_{raw}$$
Where $R_{raw}$ is computed omitting all interruption events occurring on the major event days.

JPS is proposing that since five years of sequential data will not be available at the onset to compute $T_{MED}$ following the installation of the OMS system, that twelve (12) months of data be initially used to compute the indices in the next annual tariff adjustment submission in 2015 and that in subsequent reporting periods all available data up to that point be added until five sequential years of data becomes available by the end of the regulatory period.

9.2.7 Implementation of OMS

As identified by KEMA, implementation of the planned OMS was the centrepiece of the strategy to address the issues surrounding data integrity and veracity for reliability reporting. Due to initial reassessment of the procurement process, acquisition of the system was delayed for close to a year, setting back the Q-Factor remedial programme.

JPS commissioned its OMS and Service Suite (Mobile Work Dispatch System) on December 5, 2013 and has worked to quickly bring the associated Q Factor elements on track. The OMS was interfaced with JPS’ existing GIS system and at the launch of the system, all but 9000 customers were correctly mapped to their service transformers with full location data and phase of power serving them. The OMS in conjunction with GIS, SCADA, and Service Suite will provide the following:

- Manage all outage events island wide;
- Customer Service Reps (CSRs) in the Call Centre and Parishes will use a web based tool called NETCADOPs to log customer outage reports and view real-time updates on restoration activities;
- Collate customer reported outages received by customer service reps in the Customer Care Centre and parish offices where outages will be reported using the web based reporting tool, NETCADOPs;
- Receive directly from the SCADA system any outage events detected on the transmission and distribution network;
- Predict cause and location of outages and help the dispatchers in identifying such information;
- Create and dispatch mobile work orders directly to available crews, monitor the crew location and predict estimated time to restore;
- Update individual customer accounts;
- Field crews equipped with mobile handhelds will be able to accept and action emergency orders.

The OMS has been broadly meeting JPS’ expectations but as with all such major IT implementation is undergoing post cut-over monitoring, adjustments and data integrity verification that has delayed the immediate production and reporting of reliability indices. This evaluation period should conclude in March 2014.

It should be noted that the global experience with utilities and regulators is for reported reliability to worsen relatively after the implementation of OMS. This is because the information is considered more accurately because of the automation of the data capture and reporting process over the manual process that it generally replaces.
Therefore, it is JPS’ recommendation that the system be allowed to collect at least twelve (12) months of data for establishing a baseline for Q factor computations. JPS is also planning to install a business intelligence (BI) system in September 2014. The BI system will integrate with OMS to facilitate reporting of reliability indices directly from the OMS system.

9.2.8 Business Process Charts and Policy Documents

The Q factor working group identified several activities to be performed to enable the development of documentation for the Q factor related businesses processes. These include:

- Development of the Q factor Business Process Map – A Draft Business Process Map was developed by IT PMO, but further revisions will be done based on discussions with other members of the working group.
- Development of Q Factor Data Flow Chart – The drafting of the data flow chart is to be initiated post OMS implementation.
- Development of an Internal Audit Policy for Q Factor Process – The Internal Audit Department provided a framework to develop the policy for the Q factor process, but the finalization of the policy is dependent on the completion of the Business Process Map.
- Development of a GIS Update Policy – A draft GIS Update policy was developed in February 2014 and has been circulated. Finalization is in progress pending further comments from working group members.
- Development of an Outage and Data Collection and Maintenance Policy – This policy will include actions for dealing with manual entry reports from the field. This activity has not yet begun because it is dependent on data collection processes for OMS operations that are now being refined with the recent implementation of OMS.

9.2.9 Re-definitions of Organizational Roles and Functions

KEMA had identified that responsibilities, accountability and competencies needed should be in job descriptions of employees involved in the Q factor process. In keeping with this recommendation, the company has redefined the Reliability Department to ensure that the required competencies are in place. See Figure 9-9 for the draft organizational chart for the department. The Reliability Department will be responsible and accountable for ensuring full compliance with the Q factor processes and policies.

In addition, the working group will submit to the Human Resource department, recommendations for amendments to relevant job descriptions to reflect competencies and tasks required in the Q factor process.
9.2.10 Implementation of Data Collection and Recording Systems

JPS reviewed and modified where applicable, its data collection and recording systems prior to the implementation of OMS. These included the Customer Connected Database in GIS. The database was assessed, and corrections effected where necessary. Post-OMS customer mapping is being reinforced in Regions as part of work activities by Field Services and Operations teams. On-going updates are also being carried out from Banner CIS. Steps were also taken to ensure the outage database in OMS is in compliance with the Reliability Data Collection and Reporting Manual recommended by KEMA. This activity is primarily completed except for a few outstanding modifications that have been identified to ensure compliance.

Since the implementation of OMS, the manual entry of outage information from SCADA by system control personnel has been largely eliminated. The only manual entry that is being done is the input of switching and fault details. All the reliability computations are now done in OMS. An outstanding item to create a flag that can separate the initiating cause of an outage, for e.g., a generator trip is to be completed.

The following items were completed post implementation of OMS:

Figure 9-9: Reliability Department Organizational Chart
9.2.11 Validation of Sample Data Reports

There is an ongoing assessment of reliability reports. These assessments include validation of IPP outage exclusions; accurate representation of staged restoration; elimination of double counting of outages, accounting for manual entry reports from the field and; validation of MAIFI interruptions.

9.2.12 Status of JPS’ Q Factor Initiatives

The following table provides a summary and status of all initiatives that were described in the previous section. It also outlines the planned actions to be taken to ensure completion of the activities and the timeline for completion.

<table>
<thead>
<tr>
<th>ITEM</th>
<th>DESCRIPTION</th>
<th>% Complete</th>
<th>STATUS UPDATE</th>
<th>Action to be Taken</th>
<th>Projected Completion Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>#1</td>
<td>Business Process Charts and Policy Documents for the Q-Factor Process</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1a</td>
<td>Q-Factor Business Process Flow Map (Use KEMA Data Process Recording Process Flow as a baseline)</td>
<td>90%</td>
<td>Draft Reliability Business Process Map was developed by IT PMO (last version Oct. 22, 2013). Further, revisions to be done based on working group discussions post OMS implementation in December 2013.</td>
<td>Finalize the Business Process Map – IT PMO</td>
<td>April 30, 2014</td>
</tr>
<tr>
<td>1b</td>
<td>Q-Factor Data Flow Chart</td>
<td>60%</td>
<td>Drafting of data flow chart initiated.</td>
<td>Finalize the Q-Factor Data Flow Chart – IT PMO</td>
<td>April 30, 2014</td>
</tr>
<tr>
<td>1c</td>
<td>Internal Audit Policy for Q-Factor process</td>
<td>30%</td>
<td>Internal Audit provided a framework to develop the policy for the Q-Factor process. The finalization of the Audit Policy dependent on the completion of Business Process Map.</td>
<td>Develop Audit Policy – Engineering</td>
<td>June 30, 2014</td>
</tr>
<tr>
<td>1d</td>
<td>GIS Update Policy (focus on customer connections)</td>
<td>90%</td>
<td>A draft GIS Update Policy developed and circulated on February 2014.</td>
<td>Finalization in progress (pending further comments) – Engineering</td>
<td>May 30, 2014</td>
</tr>
<tr>
<td>1e</td>
<td>Outage Data Collection and Maintenance Policy (should include dealing with manual entry reports from the field)</td>
<td>0%</td>
<td>No activity. Dependent on data collection process for OMS operations (i.e. data capture from distribution and transmission)</td>
<td>Define data collection approaches for T&amp;D outages – System</td>
<td>July 30, 2014</td>
</tr>
<tr>
<td>ITEM</td>
<td>DESCRIPTION</td>
<td>% Complete</td>
<td>STATUS UPDATE</td>
<td>Action to be Taken</td>
<td>Projected Completion Date</td>
</tr>
<tr>
<td>------</td>
<td>-------------</td>
<td>------------</td>
<td>---------------</td>
<td>-------------------</td>
<td>--------------------------</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Complete</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>outages affecting customers)</td>
<td></td>
<td></td>
<td>Operations</td>
<td></td>
</tr>
<tr>
<td>#2</td>
<td>Recommendations for Re-definitions of Organisational Roles and Functions involved in Q-Factor Process</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Identification of organisational job functions involved in the Q-Factor process (Region Operations, System Control, IT, Strategy, Performance Management etc). Submission of recommendations to Human Resource department for amendments to relevant Job Descriptions to reflect competencies and tasks required in the Q-Factor process</td>
<td>10%</td>
<td>Reliability roles exist in the organization. Objective is to formalize in accordance with Report recommendation.</td>
<td>Reflect tasks, activities, competencies relevant to the Q-Factor process is included (at minimum) in Job Descriptions</td>
<td>June 30, 2014</td>
</tr>
<tr>
<td>#3</td>
<td>Implementation/Modification/Review of Data Collection and Recording Systems for Q-Factor Process in OMS/GIS/SCADA</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>3a</td>
<td>Customer Connected Database (feeder and sub feeder) in GIS</td>
<td>90%</td>
<td>Assessments completed pre-OMS implementation, and corrections effected that did not require field evaluation. Post-OMS customer mapping being reinforced in Regions as part of work activities by Field Services and Operations teams. On-going updates being done in GIS from Banner CIS. A draft GIS Update policy to be finalized to ensure accuracy of the GIS database with reference to connected customers.</td>
<td>(a) Complete RAMI customer mapping; (b) Customers identified as not mapped (pre-OMS) to be updated.</td>
<td>June 30, 2014</td>
</tr>
<tr>
<td>3b</td>
<td>Outage Database in OMS (in compliance with Reliability Data Collection and Reporting Manual)</td>
<td>95%</td>
<td></td>
<td>Completed outstanding modifications identified to ensure compliance - IT PMO</td>
<td>April 15, 2014</td>
</tr>
<tr>
<td>3c</td>
<td>Outage Database in SCADA</td>
<td>95%</td>
<td>There is no Outage Database in SCADA. There is an off-line and in-house application that was developed to capture outage information and produce fault outage reports. This application is hosted at System Control and also provided reliability and outage reporting to various users across the company via a website. The outage information input is a manual process that is done by the system controllers. Since the OMS was commissioned in December,</td>
<td>Assessment completed. Create a flag that can separate the initiating cause of the outage, for e.g., A generator trip resulting in Load Shedding, the dispatcher would need to add details to the interruption in the OMS to assign</td>
<td>September 30, 2014</td>
</tr>
</tbody>
</table>
they only input the switching and fault details, the Reliability Computations are now done in the OMS. All the reliability information is now in the OMS. The model that was integrated with the OMS will allow for the computation of Transmission and Generation related interruptions.

“Generation” as the cause, similar for Transmission and Distribution. IT PMO

3d Records of Customer Calls to Utility Reporting Interruptions in OMS 100% Completed with OMS/NetCadops Implementation in Dec 5, 2013 No further action required.

3e Records of Control Centre Logs indicating restoration actions and steps (staged restoration) 100% Staged restoration of customers is in Control Centre Logs. No further action required

#4 Validation of Sample Data Reports compliance with “Reliability Data Collection and Reporting Manual.”

4a Validate IPP outage exclusions, staged restoration represented, elimination of double counting of outages, accounting for manual entry reports from the field, MAIFI interruptions 70% On-going assessment of reliability reports in progress through joint effort between Engineering and IT PMO to ensure anomalies identified and resolved. On-going –IT PMO/Engineering September 30, 2014

9.2.13 Overview of Proposed Data Collection

As described previously, the Q factor data collection flow chart is being finalized following the implementation of OMS however, a brief overview of the data collection process with OMS is provided here. The OMS system interfaces and works in conjunction with the Banner CIS, GIS, SCADA and Service Suite systems.

The data collection on the start of an outage proceeds via two main routes as is described below:

- When a Customer calls reporting loss of service, the Customer Service Representative in the Call Centre logs the customer call and other customer information using the web based tool NETCADOPS which submits the outage data to the OMS system servers in which the islands entire distribution system is modeled. A trouble ticket is created within OMS and the outage start time is recorded as the ticket creation time. The OMS system automatically associates call with an existing outage if the call is potentially affected by the same device of the existing outage and received within 3 hours of first incident. NETCADOPS provides outage information to parish dispatch centers indicating the likely cause and the feeder and sub-feeders that are impacted. The Dispatch crew assigns priority based on outage type, number of customers affected and other parameters. Service Suite enables mobile work orders to be created and submitted to available field crews with mobile handheld devices.
When an electrical outage occurs, if a SCADA linked device on the transmission and distribution system is impacted, SCADA sends the signal to the OMS system which records an outage event. Since the systems are interfaced, the fault time in SCADA will be recorded as the outage creation time (the outage start time). If the outage is restored automatically by the system, the SCADA/OMS system records the restore time in the outage record and the Operator in the Dispatch Center marks the job as being completed. Based on the devices in SCADA which were impacted, the OMS system will use an inference system to determine the feeder or sub-feeder that was affected and from data in GIS and Banner, the number of customers affected can be determined. Otherwise, if the outage remains unresolved on the system, a trouble report ticket is created within the system which the Dispatch Department reviews, prioritizes and assigns field crews as described previously.

Once the job is acknowledged by a field crew, the outage log is updated by Dispatcher with time acknowledged and crew ID. The field crew verifies the outage and possible causes and contacts the Dispatcher regarding findings and steps to be taken. If stage restoration is required, the field crew maintains a constant dialogue with the Dispatcher and informs of items repaired and steps taken. The Dispatcher updates outage event with device restored and time of restoration. The job is marked as being restored and the restored time is automatically set as the outage end time.

All computation of reliability indices are done directly within the OMS system. Manual entry is limited to manual entry reports from the field.

9.2.14 SAIDI, SAIFI and CAIDI Performance - 2009-2014

Table 9-5 and Figure 9-10 provides an overview of the performance of the SAIDI, SAIFI and CAIDI indices between 2009 and 2012. Overall, JPS’ reliability improved between 2009 and 2013, SAIFI declined from 26.22 in 2009 to 10.53 in 2013 and SAIDI also trended downwards moving from 38 hours per customer to 22 hours per customer in 2013. This was the same trend that was seen for the customers minutes lost (CML). The CML for 2011 and 2012 were considerably less than for 2009 and 2010 indicating that generally there is a declining number of customers affected by interruptions. The CAIDI (despite the appearance of the graph) has been more or less consistent over the period although it moved to over 2 hours per interruption in 2013. The system outage in August 2012 contributed to the increase in SAIDI and CAIDI between 2012 and 2013. In addition, a major outage in March 2013 impacted the increase in CAIDI between 2012 and 2013. Under the IEEE 1366-2012 these major events as are all outages would continue to be recorded but separately identified so as to allow for a true and pure assessment of the normal reliability trend.
Table 9-5: Reliability Indicators 2009 – 2012

<table>
<thead>
<tr>
<th>Data</th>
<th>OutageClass</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>SAIDI</strong></td>
<td>Generation</td>
<td>5.71</td>
<td>10.56</td>
<td>5.14</td>
<td>4.03</td>
</tr>
<tr>
<td></td>
<td>Transmission</td>
<td>2.79</td>
<td>3.11</td>
<td>3.72</td>
<td>6.28</td>
</tr>
<tr>
<td></td>
<td>Distribution</td>
<td>29.27</td>
<td>32.11</td>
<td>20.04</td>
<td>23.93</td>
</tr>
<tr>
<td></td>
<td>Engineering</td>
<td>-</td>
<td>-</td>
<td>0.40</td>
<td>0.17</td>
</tr>
<tr>
<td></td>
<td>System Control</td>
<td>0.24</td>
<td>-</td>
<td>0.05</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total SAIDI</strong></td>
<td></td>
<td>38.01</td>
<td>45.78</td>
<td>29.35</td>
<td>34.42</td>
</tr>
<tr>
<td><strong>SAIFI</strong></td>
<td>Generation</td>
<td>11.79</td>
<td>15.24</td>
<td>10.48</td>
<td>8.55</td>
</tr>
<tr>
<td></td>
<td>Transmission</td>
<td>1.72</td>
<td>2.82</td>
<td>2.39</td>
<td>3.27</td>
</tr>
<tr>
<td></td>
<td>Distribution</td>
<td>12.65</td>
<td>11.80</td>
<td>9.01</td>
<td>10.09</td>
</tr>
<tr>
<td></td>
<td>Engineering</td>
<td>-</td>
<td>-</td>
<td>0.20</td>
<td>0.10</td>
</tr>
<tr>
<td></td>
<td>System Control</td>
<td>0.06</td>
<td>-</td>
<td>0.02</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total SAIFI</strong></td>
<td></td>
<td>26.22</td>
<td>29.87</td>
<td>22.11</td>
<td>22.00</td>
</tr>
<tr>
<td><strong>CAIDI</strong></td>
<td>Generation</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Transmission</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Distribution</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Engineering</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>System Control</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total CAIDI</strong></td>
<td></td>
<td>1.45</td>
<td>1.53</td>
<td>1.33</td>
<td>1.56</td>
</tr>
<tr>
<td><strong>CML</strong></td>
<td>Generation</td>
<td>201,078,238</td>
<td>377,800,081</td>
<td>176,779,059</td>
<td>138,714,923</td>
</tr>
<tr>
<td></td>
<td>Transmission</td>
<td>98,062,518</td>
<td>110,936,347</td>
<td>127,853,555</td>
<td>215,763,349</td>
</tr>
<tr>
<td></td>
<td>Distribution</td>
<td>1,028,602,577</td>
<td>1,147,427,181</td>
<td>688,968,760</td>
<td>822,785,623</td>
</tr>
<tr>
<td></td>
<td>Engineering</td>
<td>-</td>
<td>-</td>
<td>13,856,914</td>
<td>6,010,488</td>
</tr>
<tr>
<td></td>
<td>System Control</td>
<td>8,393,267</td>
<td>-</td>
<td>1,631,340</td>
<td>-</td>
</tr>
<tr>
<td><strong>Total CML</strong></td>
<td></td>
<td>1,336,136,600</td>
<td>1,636,163,609</td>
<td>1,009,089,628</td>
<td>1,183,274,383</td>
</tr>
<tr>
<td><strong># of Interruptions (&gt;5 mins)</strong></td>
<td>Generation</td>
<td>815</td>
<td>1,023</td>
<td>664</td>
<td>523</td>
</tr>
<tr>
<td></td>
<td>Transmission</td>
<td>189</td>
<td>263</td>
<td>256</td>
<td>359</td>
</tr>
<tr>
<td></td>
<td>Distribution</td>
<td>11,682</td>
<td>14,480</td>
<td>12,748</td>
<td>13,378</td>
</tr>
<tr>
<td></td>
<td>Engineering</td>
<td>0</td>
<td>0</td>
<td>53</td>
<td>6</td>
</tr>
<tr>
<td></td>
<td>System Control</td>
<td>5</td>
<td>0</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td><strong>Total Outages</strong></td>
<td></td>
<td>12691</td>
<td>15766</td>
<td>13722</td>
<td>14266</td>
</tr>
</tbody>
</table>
9.2.15 Recommendations for Implementation of Q Factor

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

The company is working to finalize outstanding issues with the OMS system and to validate the data from the system as described in Section 9.2.5 - 9.2.12. JPS has estimated that an additional twelve (12) months from March 31, 2014 is required to complete the gathering of accurate reliability indices data for the establishment of a baseline to be used in the computation of the Q factor in the tariff at the 2015 annual adjustment.

In that regard JPS proposes the following:

- That JPS will submit further quarterly reports to the OUR, beginning June 2014 to report on the completion of all outstanding items from the KEMA recommendations with all items scheduled to be completed by September 30, 2014.
- JPS will submit monthly, beginning April 2014, the reliability indices generated from the OMS. This data, after evaluation by the OUR will become the baseline data for the setting of the Q Factor as at the 2015 annual adjustment.
- In keeping with KEMA’s recommendation to move to international best practice JPS and the OUR will develop the framework around the IEEE 1366-2012 standard by December 30, 2014 to support the development of the baseline. The Reliability Data Collection...
and Reporting Manual has been adopted by JPS as the compliance standard and will be reviewed for conformity with IEEE 1366-2012 in the framework development.

- The OUR not proceed in keeping with the recommendation of KEMA that the baseline be set by way of benchmark rather than the actual data. This would require the OUR to conduct a benchmarking study to establish an appropriate set of comparators. As we have pointed out this would be most prudently and accurately done subsequent to JPS reporting its reliability using the now established standard of IEEE 366-2012. We therefore do not believe there is any advantage to be gained by proceeding with that recommendation.

- JPS maintains that MAIFI is an unnecessary overlay on the quality of service indices that is rarely used in far more mature electricity market’s than Jamaica and will only put upward pressure on already burdened tariffs to fund the investments to comply. Nevertheless, should the OUR not moderate its policy position JPS will propose by December 2014, a method of incorporation of MAIFI in the Q Factor with a non-financial impact, as recommended by KEMA.
Chapter 10: Revenue Cap

10.1 Introduction

Important structural changes are underway in Jamaica’s power sector. A new 381MW IPP means JPS will for the first time supply less than half of Jamaica’s peak demand. Three renewable IPPs are also being added. From early 2014 customers will be allowed to wheel power across JPS’ grid. At a smaller scale, more and more customers are generating their own power, and selling excess back to JPS. Energy efficiency is a national priority, and new technologies such as LED streetlights and solar cooling bring exciting opportunities to significantly reduce electricity bills.

The time has come to ask whether the price cap regime which has served Jamaica for the last 10 years is the best approach to support the power sector evolution now underway. International evidence and economic theory suggests it may not be. This chapter makes the case that Jamaica may be better served by a tariff control system in the form of a revenue cap, rather than a price cap, since it aligns incentives for diversity in generation and energy efficiency.

Revenue caps are now the preferred model for transmission regulation internationally, and are used successfully in small power systems (such as New Zealand, Scotland, and the Republic of Ireland), as well as in large systems including England and Wales, Germany, Australia and the Philippines. They are also used for distribution regulation in England and Wales, and in Scotland. Revenue caps are widely supported in the academic literature. They optimise risk allocation. Perhaps most importantly, revenue caps remove utilities’ incentive to sell more kilowatt hours (kWh). As a result, utilities can support energy efficiency programs and diversification of generation sources without having to worry that they will lose financially.

This chapter highlights the perverse incentives and the sub-optimal risk allocation that the current price cap regime could create (Section 10.2), and shows how a revenue cap could solve these problems (Section 10.3). Section 10.4 then describes how revenue caps have been applied in various international settings. In Section 10.5, we argue that on balance, adoption of an internationally-proven revenue cap regime would help Jamaica achieve its electricity sector objectives. In Section 10.6, we provide a focused discussion on the implementation of our revenue cap proposal. We illustrate the mechanics of the revenue true-up process, which is a core component of the revenue cap design. We conclude in Section 10.7 by showing how our revenue cap proposal results in an equitable sharing of demand risk, and how it is unlikely to result in rate shock for customers.

10.2 Price Caps, Incentives and Risks

JPS is currently regulated by a price cap framework. That is, its real tariff basket is fixed for the duration of a five-year regulatory period. This protects consumers from imprudent costs, and provides incentives for JPS to operate efficiently. However, it turns out to expose the utility to demand risk that is damaging and unnecessary.
10.2.1 The Theory of Price Caps

A price cap is an effective regulatory mechanism for incentivizing cost efficiency in regulated utilities. By limiting price growth, price caps simulate the incentive to control costs facing firms operating in a competitive market. Price caps have been successfully implemented by regulators around the world across a variety of regulated sectors, including electricity and water. However, as we will show, a price cap has some important drawbacks when a utility’s costs are largely fixed—as is the case with JPS’ non-fuel costs.

Price caps represent an evolution from the more traditional rate-of-return regulation, under which a utility is permitted to recover its cost of service plus a return on its investment. Price caps were first proposed by Stephen Littlechild, during the privatisation of public utilities in the UK. The underlying assumption at the time was that the cost structures of these utilities had become bloated under state ownership. Price caps were designed to drive out these inefficiencies by simulating the incentives under a competitive market. Since its introduction in 1983, the price cap framework has been adopted by public utilities regulators around the world—including in Jamaica.

A price cap creates a strong incentive for the utility to control costs. It does this by setting a path which a utility’s tariffs must follow for the duration of a regulatory period. The utility’s objective, then, is to restrain unit costs below the price set in each year of the regulatory period. Figure 10-1 illustrates how a price cap helps restrain cost growth. In year two, if the utility succeed in controlling costs, it is financially rewarded by keeping its profits. This is shown by the yellow shaded area beneath the price cap. Conversely, as shown in year three, if the utility is unable to control its costs, it must incur a financial loss (represented by the blue shaded area above the price cap).

---

10.2.2 How JPS’ Price Cap Works

As specified in its licence, JPS currently operates under a price cap framework, called the Performance Based Ratemaking Mechanism (PBRM). The PBRM only applies to the non-fuel base rate, which recovers the non-fuel portion of JPS’ cost of service.

The formula below describes how JPS’ real price level is fixed for the duration of the regulatory period. In practice, JPS’ price cap also includes an X-Factor to account for productivity gains, a Q-Factor to account for quality of service improvement, and a Z-Factor to account for exogenous factors. However, for illustrative purposes, we ignore these adjustments.

\[ P_t = P_{t-1} \times (1 + \Delta CPI) \]

This price cap is applied to the tariff basket as a whole. The tariff basket is defined as the sum of tariff revenues in the prior year. By applying the price cap to the tariff basket, JPS is free to allocate shares of the overall tariff adjustment to various rate classes (subject to regulatory approval).

Procedurally, JPS submits an annual tariff adjustment submission for each year during the five-year regulatory period. In its submission, JPS calculates a percentage adjustment to the overall tariff basket. This percentage adjustment is based on a weighted index of inflation in the United States and Jamaican economies. This submission also includes proposed adjustments for the X-Factor, the Q-Factor, and the Z-Factor.

10.2.3 Price Caps Create Demand Risk and Perverse Incentives

Despite price caps’ advantages, they can create demand risk and perverse incentives. These risks and perverse incentives arise when a utility’s tariff structure attempts to recover the fixed costs of transmission and distribution through a charge on energy sold. Such a tariff structure
leads to a mismatch between cost drivers and revenue drivers. Price caps lock in this mismatch for the regulatory control period. An unintended consequence is that utilities are given perverse incentives to boost demand and sell more energy, rather than to support energy efficiency and diversity of generation sources.

10.2.3.1 Demand Risk with Fixed Costs and a Variable Tariff Structure

Demand risk refers to the financial risk resulting from variations in demand. Demand risk arises because the costs of transmission and distribution infrastructure does not vary with the amount of electricity sold, while revenue does. The failure to match revenue drivers to cost drivers means that profits will vary simply because demand is higher or lower than forecast.

Table 10-1 illustrates how this demand risk arises. For simplicity, we assume that the utility’s tariff structure is entirely variable. If we assume that all the utility’s costs are also variable, then the profit margin remains constant despite variations in demand in years two and three. However, if fixed costs make up a large portion of total cost, then in years with strong demand (such as year two), the utility’s revenue grows, while its average total cost decreases. This yields supernormal profits for the utility, and means that customers pay higher tariffs than are needed to cover costs. Conversely, in years with weak demand (such as year three), the utility’s revenue declines while its average total cost increases. In this case, the utility’s profit margin erodes.

Table 10-1: Fixed Costs under a Price Cap Introduce Demand Risk

<table>
<thead>
<tr>
<th>0% Fixed Cost Structure</th>
<th>Units</th>
<th>Year 1</th>
<th>Year 2</th>
<th>Year 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand</td>
<td>kWh</td>
<td>100</td>
<td>110</td>
<td>80</td>
</tr>
<tr>
<td>x Allowed Price</td>
<td>JA$/kWh</td>
<td>$10</td>
<td>$10</td>
<td>$10</td>
</tr>
<tr>
<td>Total Revenue</td>
<td>JA$</td>
<td>$1,000</td>
<td>$1,100</td>
<td>$800</td>
</tr>
</tbody>
</table>

| Demand | kWh | 100 | 110 | 80 |
| x Average Variable Cost | JA$/kWh | $9 | $9 | $9 |
| Total Variable Cost | JA$ | $900 | $990 | $720 |
| + Total Fixed Cost | JA$ | - | - | - |
| Total Cost | JA$ | $900 | $990 | $720 |

| Profit | JA$ | $100 | $110 | $80 |
| Profit Margin | % | 10% | 10% | 10% |
This example is relevant for JPS because more than 80 percent of its non-fuel costs are fixed, while only 20 percent of these costs are variable. At the same time, only 22 percent of its non-fuel revenues are recovered through fixed customer and demand charges, while 78 percent of non-fuel revenues are recovered through a variable energy charge. This demonstrates a fundamental mismatch between JPS’ cost structure and its tariff structure.

### 10.2.3.2 Perverse Incentives to Oppose Energy Policy Goals

Under the price cap framework, JPS faces several perverse incentives that run counter to Jamaica’s broader energy policy goals. These include incentives to oppose:

- Customer energy efficiency programs
- Distributed generation by customers, and
- Wheeling of power by large customers.

In the case of customer energy efficiency programs, the perverse incentive is created by the revenue-maximising behaviour that the price cap encourages. That is, because the utility’s prices are capped, but its revenues are not, the utility is given every incentive to increase the quantity of energy sold (also called the “throughput” incentive). Under a price cap, then, the utility would not willingly participate in customer energy efficiency initiatives, because it would mean the utility would be working to reduce its own revenue. Although utilities are well positioned to support energy efficiency initiatives, such as serving as an energy services company (ESCO) or implementing ratepayer-funded energy efficiency programs, price caps do not properly align the utility’s incentives to do so. This is a common critique of price caps in jurisdictions where energy efficiency programs are being considered.

This “throughput” incentive created by price caps also prevents the utility from becoming a partner in customer adoption of distributed generation. Technical integration issues aside, the utility would face declining revenue if customers self-generate. Given the utility’s high fixed cost structure for non-fuel costs, declining revenue means the utility is unable to earn its approved, fair return on investment. Therefore, under a price cap, the utility faces an inherent conflict of interest: it is required to facilitate distributed generation through the net billing scheme, despite the fact that distributed generation would erode the utility’s financial viability.
Finally, under a price cap, the utility faces the prospect of being unable to recover embedded generation costs as large customers switch to the wheeling tariff—at least until the next rate reset. Under the price cap, the utility’s cost of service is considered every five years, using a historic test year. Tariffs are set on this basis, and are allowed to increase annually at the rate of inflation, plus adjustments for an X-Factor, a Q-Factor, and a Z-Factor. However, if large customers switch to the wheeling tariff in between rate resets, this means the share of fixed generation costs (such as capacity costs) that would otherwise be recovered from those customers is unrecoverable (or “stranded”). Until the next rate reset, the class cost of generation cannot be reallocated to the remaining customers in the rate class. For more a more detailed discussion of this issue, please refer to the companion Castalia report, “Designing an Appropriate Wheeling Tariff in Jamaica.”

10.2.3.3 Restructuring Tariffs to be Cost Reflective

A potential solution to these issues of demand risk and perverse incentives is to restructure JPS’ tariffs. Economic theory and regulatory best practices suggest that tariffs must be cost reflective. This suggests that a utility’s fixed costs should be recovered through fixed charges, while its variable costs should be recovered through variable charges.

JPS’ current tariff structure is not cost reflective in this way. For example, within the residential rate class, customers that are high energy consumers pay a disproportionate share of that rate class’ fixed cost allocation, since these costs are mostly recovered through the variable energy charge. As another example, large commercial and industrial consumers consume significant quantities of energy. Because of the existing tariff structure, these energy charge revenues pay more toward fixed costs than smaller residential and commercial customers do.

Table 10-2 provides an example of how a residential tariff (R10) could be restructured to reflect the large role that fixed, per-customer costs play in JPS’ non-fuel cost structure. In our example, the monthly customer charge increases from J$387.00 per month to J$1,634.08, for a 320 percent increase in this component of a customer’s bill. At the same time, the energy charge decreases from J$6.98 to J$1.24 per kWh for the first 100 kWh, and from J$15.96 to J$4.74 per kWh for monthly consumption over 100 kWh. This would represent a decrease in the energy charge of 82 percent and 70 percent for the two consumption blocks, respectively.

Table 10-2: Stylised Example of Residential Tariff Restructuring
The key point to understand here is that the fixed charges paid by a customer must increase, while the energy charge must decrease. This represents a rebalancing of cost causation with cost recovery, so that the utility’s fixed costs are recovered through a fixed charge, rather than through a volumetric energy charge.65

Yet, as our example shows, restructuring tariffs to be cost reflective cannot occur all at once. The impact on customers, particularly in the residential class, is too drastic to be implemented in the short term. Therefore, restructuring should occur more gradually, to avoid “rate shock.”

10.2.3.4 Looking Beyond Tariff Restructuring

The Jamaican power sector faces a key decision in its evolutionary path: how to resolve the issues of demand risk and perverse incentives in the face of rising power costs. While tariff restructuring is a possible solution, we have shown that there are significant challenges inherent in carrying out this out in the short-term. This signals the need for an alternative regulatory regime that achieves the same goals of tariff restructuring—mitigating demand risk and eliminating perverse incentives for the utility—while also being more achievable in the short-term. We introduce such an approach, a revenue cap, next.

---

65 To be fully cost reflective, each rate class should face three charges: a customer charge (fixed per customer), a demand charge (varies with customer peak demand), and an energy charge (varies with energy consumption). The demand charge is necessary to recover capacity costs incurred by the utility to serve peak load. However, because a demand charge requires specialised meters that residential customers do not typically have, implementing a demand charge would be too costly. Therefore, in our example, we assume that fixed costs for the residential class are recovered through the customer charge.
10.3 Understanding a Revenue Cap

If rate restructuring cannot solve the problems of demand risk and perverse incentives in the short term, what can be done? The good news is that moving from a price cap to a revenue cap would preserve all the efficiency incentives of the current system, while almost eliminating demand risk and perverse incentives.

10.3.1 The Theory of Revenue Caps

A revenue cap is a small variation to the price cap approach. Rather than capping prices, a utility’s revenues are capped for the duration of the regulatory period. Under a revenue cap, the utility’s objective remains the same as under a price cap: to restrain growth in costs below the prescribed path. As shown in year two of Figure 10-2, if the utility succeeds in controlling costs, it is financially rewarded by keeping its profits (shown as the yellow shaded areas below the revenue cap). However, if the utility is unable to control costs, it must bear the financial loss, as shown by the dark blue shaded area in year three.

Figure 10-2: A Stylised Diagram of a Revenue Cap

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

In contrast, under a revenue cap, revenue does not vary with changes in demand. If demand rises above expected level so that revenue is over-recovered in one year, the extra revenue is put into an account and rebated to customers in lower charges the following year. Conversely, if demand drops, leading to under-recovery of fixed costs, the shortfall in revenue is tracked and recovered through higher per unit charges the following year.
To summarise, a revenue cap maintains the same incentive as under a price cap to operate efficiently. As under a price cap, a revenue cap also protects customers from recovery of imprudent costs. However, revenue caps have the added benefits of minimizing demand risk for the utility and the consumer. Demand fluctuations do not lead to customers paying tariffs that lead to excess profits for the utility, nor do they lead to the utility under-recovering its fixed costs.

10.3.2 How a Revenue Cap Reduces Risks and Aligns Incentives

Like a price cap, a revenue cap provides the same strong incentive for utilities to operate as efficiently as possible. As a slight improvement over the price cap, a revenue cap protects ratepayers from the risk of revenue over-collection when demand growth is strong. Even better, a revenue cap can resolve many of the perverse incentives we identified under the existing price cap framework.

Crucially, a revenue cap eliminates the “throughput” incentive for a utility to maximise energy sales. As a result, the utility can become a full partner in implementing desirable energy policy goals, such as promoting energy efficiency and customer distributed generation. This is an important outcome, given the high cost of power in Jamaica, which is largely driven by fuel costs. Customers, then, become the primary beneficiaries of a revenue cap, because the utility is able to help them lower their monthly power bills by saving on fuel charges. Notably, the very issue of aligning utility incentives with energy policy goals has been driving the discussion of revenue caps, or “revenue decoupling,” in the United States.66 A 2009 fact sheet on decoupling from the National Renewable Energy Laboratory, an independent research unit of the U.S. Department of Energy confirms this trend: “While decoupling has been in practice for a few decades, interest in this policy option is on the rise….Decoupling can complement other policies that encourage energy efficiency, demand response, low-carbon resources, and supply-side resources.” Similar points are made by the National Association of Regulatory Utility Commissioners, an association of state utility regulators, and the Alliance to Save Energy, a pro-energy efficiency non-profit organization.67,68

With regard to aligning a utility’s incentives with wheeling, a revenue cap eliminates the stranded asset problem that might emerge from implementing wheeling under the existing price cap framework. This is because under a revenue cap approach, the retail tariffs would automatically be recalculated annually to reflect the true cost of service, including fixed generation costs that would otherwise go unrecovered as large customers switch to the wheeling tariff. Therefore, a revenue cap can also be pro-wheeling and pro-choice in generation.


10.3.3 Defining a Preferred Revenue Cap Design

There are several approaches to determining a revenue cap. JPS proposes adopting a pure (or fixed) revenue cap, based on a historic test year. This would be most consistent with the existing tariff setting methodology. As we will discuss in Section 10.6.3, the proposed approach would also minimise the revisions that would be necessary to Schedule 3 of the JPS Licence.

Under a pure revenue cap, the utility’s revenues are fixed based on a historic test year. In the first year of the regulatory period, allowed revenue equals earned revenue in the test year, plus an inflation adjustment (to keep revenue constant in real terms). In each subsequent year, allowed revenue equals the prior year’s allowed revenue plus inflation. The formula below shows the mechanics of a pure revenue cap based on a historic test year.

\[ \tilde{R}_t = \tilde{R}_{t-1} \times (1 + \Delta CPI) \]

Alternatively, the pure revenue cap can be set using a building blocks approach. Rather than relying on a revenue cap derived from a historic test year, the building blocks approach uses a forward-looking cost of service model to forecast the utility’s revenue requirement in each year of the regulatory period.

A key component of a revenue cap is that the utility must submit tariff adjustment submissions for each year in the regulatory period. This is similar to the process under a price cap. However, unlike with a price cap, a balancing account is established to reconcile the earned revenue in the prior year with the allowed revenue for that same year. If a utility earned more revenue in the prior year than what was allowed, it must refund customers the over-recovered amount. Conversely, if a utility earned less revenue than allowed, it is entitled to recover that amount from customers.

The amount that must be refunded to, or recovered from, customers is then rolled into the revenue requirement used to set tariffs in the next rate year. This balancing account is a critical component of the revenue cap, as it is what ensures that customers pay only for the approved cost of service, no more and no less.

10.4 International Precedent for a Revenue Cap

Revenue caps are considered good practice internationally, and were developed as an answer to some of the failures of price caps that we have already discussed. In this section, we will...
briefly discuss how revenue caps have been implemented around the world for electricity utilities. We first introduce the revenue caps in England and Wales, and Scotland. These jurisdictions are notable because they are where the price cap model was developed and later copied by other countries, such as Jamaica—and yet, transmission and distribution networks in England, Wales, and Scotland have now evolved to revenue cap regulation.

We also discuss the revenue cap models in similarly comparable countries, such as the Republic of Ireland, and New Zealand. We then include brief descriptions of revenue caps adopted elsewhere, including in Germany, Australia, Norway, and even in emerging markets like Trinidad and Tobago and the Philippines.

**England and Wales**

For distribution networks in England and Wales, from 1990 to 1995, a price cap on distribution tariffs applied, subject to RPI-X annual adjustments within the regulatory period. The RPI-X approach refers to annual adjustments to the price cap for inflation, a productivity measure (X-Factor), and other factors. At each periodic review, the economic regulator (Ofgem) reviews historic cost data and company business plans, in consultation with experts and industry stakeholders, to determine the applicable price cap in the next regulatory period. This was a model very similar to the price cap approach currently applied in Jamaica.

In 1995, as part of the reforms to enable retail competition, a revenue cap replaced the price cap for distribution networks, while still keeping the RPI-X adjustment process. This change was adopted by Ofgem because the price controls were no longer focused on controlling energy prices, but rather the price of distribution services. Under the revenue cap approach, the cap is set using a building blocks approach, and is in effect for the duration of a five-year regulatory period.73

Similar to the approach adopted for distribution networks, from 1990, the transmission network owner, National Grid, operated under a price cap. However, during the first price control review (in 1993), Ofgem replaced the price cap with a revenue cap, to remove the throughput incentive to maximise peak demand. While the second regulatory period lasted for four years, beginning with the third regulatory period, all future price controls lasted for five years.75

The British experience with revenue caps is particularly relevant to Jamaica, because the Jamaican price cap framework was modelled after the British RPI-X approach. Notably, 73

---


75 “Regulation of the UK Electricity Industry.” P. 69–71.

76 Beginning in 2013, Ofgem began replacing the RPI-X framework with the RIIO model, which stands for Revenue = Incentives + Innovation + Outputs. The new model maintains the revenue caps currently applied to transmission and distribution, but replaces the uniform RPI-X annual adjustments with customised annual adjustment allowances. The new model is designed to allow greater regulatory flexibility in incentivising utility activities that are consistent with public policy goals.
Jonathan Hedgecock of PPA Energy refers to the British model in his expert testimony to the All-Island Electricity Appeal Tribunal, in which he suggests that a revenue cap approach can be helpful in promoting efficient pricing for network services such as transmission and distribution.

**Scotland**

Scotland is another relevant comparator to Jamaica, because its electricity market is relatively small. Its population is approximately 5.3 million, while its system peak demand is approximately 6GW. Moreover, despite privatisation and sector restructuring, including some competitive generation, two vertically integrated utilities remain largely in control of the electricity market: Scottish Power and Scottish and Southern Energy.

A pure price cap was implemented from 1990 to 1995 for the distribution networks of both utilities, subject to annual RPI-X adjustments applied to distribution tariffs. From 1995, the distribution networks were transitioned from the price cap to a hybrid revenue cap. Under the new approach, 50 percent of total revenue was set as a function of number of customers, while the remaining 50 percent was set as a function of kWh energy sales. The hybrid revenue cap remains subject to RPI-X, and applies over a five-year regulatory period.

For the transmission networks, a pure price cap was applied from 1990 to 1994. However, to remove the throughput incentive, beginning in 1994, the Scottish transmission networks operated under a revenue cap. After the first regulatory period, which lasted only four years, each subsequent regulatory period was set for five years. The same RPI-X framework as applied to Scottish distribution networks also applied to transmission networks.

**Republic of Ireland**

Similar to the approaches in England, Wales, and Scotland, the energy regulator (CER) in the Republic of Ireland has adopted a revenue cap approach for the transmission operator and the transmission owner. The revenue caps, which apply for a five-year regulatory period, are set using a forward-looking building blocks approach, which are informed by submissions of historic cost data and business plans from the regulated companies. CER scrutinises the submitted data, and makes a determination on the maximum allowed revenue for each year of the regulatory period.

---

77 PPA Energy are the consultants hired by the OUR to develop the wheeling framework in Jamaica.


81 “Regulation of the UK Electricity Industry.” P. 76–78.

82 The Scottish transmission and distribution networks are also being transitioned from the RPI-X model to the RIIO model. See footnote 76.
regulatory period. Much like the British model, annual RPI-X adjustments are made to the revenue cap.\textsuperscript{83}

**New Zealand**

In New Zealand, the transmission network owner and operator, Transpower, is also subject to a revenue cap. The cap is set using a forward-looking building blocks approach, and applies for a four-year regulatory period.

The New Zealand model is unique in that it does not include an explicit X-Factor adjustment for the annual adjustment of the revenue cap. Rather, the regulator approves the revenue cap for each year of the regulatory period during the periodic tariff review. That is, the regulator and Transpower agree on achievable efficiencies at the beginning of the regulatory period. Then, in each year thereafter, Transpower may make adjustments to the revenue cap only to account for additional, approved capital expenditures not originally foreseen at the beginning of the regulatory period.\textsuperscript{84}

**United States**

In the United States, revenue caps have been widely discussed among regulators—and in limited cases, implemented—as a means of aligning utility incentives with public policy goals such as energy efficiency programs (we discuss this in Section 10.5). Known as “revenue decoupling” in the United States, the key barrier to the adoption of revenue caps has been a long tradition of conservatism among regulators.

As of 2012, 25 electric utilities in the United States operate under some form of revenue decoupling. Although this is a very small number compared to the 3,269 electric utilities in the United States\textsuperscript{85}, in the instances where implemented, decoupling has demonstrated minimal ratepayer impacts. Revenue decoupling mechanisms in the United States generally do not feature the RPI-X annual adjustment mechanism. A long-term study of revenue cap implementation in the United States has demonstrated two key results: (1) decoupling rate adjustments are mostly small (within plus or minus two percent of retail rates), and (2) these adjustments have yielded both refunds and surcharges.\textsuperscript{86}

**Germany**

Since 2009, the German energy regulator has implemented a pure revenue cap based on a historic test year.\textsuperscript{87} This cap applies to both transmission system operators and distribution

---


Revenue Cap

system operators, for the duration of each four-year regulatory period, and is adjusted annually for inflation. In line with the traditional incentive-based ratemaking model, the revenue cap is adjusted for expected productivity gains (an X-Factor), which is determined using efficiency benchmarking.

Australia

In Australia, a pure revenue cap has been applied to transmission companies, and to some distribution companies. The regulator applies the cap over a five-year regulatory period, with annual adjustments for inflation and an X-Factor. The revenue cap is set using a building blocks approach, which considers forecasts of energy consumption and customer numbers, expected O&M costs, plus a return on and of the regulatory asset base. Like the New Zealand model, the Australian revenue cap also allows for adjustments for approved capital expenditure not foreseen during the periodic review.

Norway

In Norway, the energy regulator (NVE) has applied revenue caps to the national transmission operator, 40–50 regional transmission utilities, and approximately 200 distribution utilities. Norway’s revenue cap applies over a five-year regulatory period. During the most recently concluded regulatory period, the revenue cap was determined using a test year lagging by two years. The revenue cap was equal to 40 percent of actual cost base, with the remaining 60 percent equal to “efficient costs.” To determine the value of efficient costs, NVE conducted efficiency benchmarking of all regulated utilities. Those utilities deemed to be operating at average efficiency were able to recover the remaining 60 percent of their cost base. Those operating below average efficiency were penalised by recovering less than actual cost base, while those operating above average efficiency were permitted to recover more than their actual cost base.

Trinidad and Tobago

Revenue caps are also being implemented in comparable small island markets, such as in Trinidad and Tobago. Since the first regulatory control period from 2006 to 2011, the electricity regulator in Trinidad and Tobago has adopted a pure (fixed) revenue cap, based on a building


blocks approach for forecasting revenue and expenditure.\textsuperscript{92} The revenue cap mechanism has been modified with several “secondary controls,” which are designed to mitigate the risk of rate shock. For example, the allowed revenue (including the revenue adjustment) cannot increase by more than 7.4 percent annually. The regulator has also adopted a profit sharing mechanism, which requires the utility (T&T EC) to refund customers if its profits were to exceed 10 percent of total revenue in a given year. In July 2011, the regulator agreed to renew the revenue cap mechanism for the second regulatory control period, from 2011 to 2016.

The Philippines

In the Philippines, the Energy Regulatory Commission has applied a pure revenue cap to the transmission operator, National Grid Corporation of the Philippines. Under the Filipino model, maximum allowed revenues are set using a forward-looking, building blocks approach. The revenue cap is fixed over a five-year regulatory period, but is adjusted annually for inflation, less an offset for expected productivity gains.\textsuperscript{93}

Summary of International Experience

As these examples show, revenue caps have been implemented in a range of operating environments. Moreover, these caps have replaced price caps in many jurisdictions—even in Great Britain, which was recognised for developing price cap regulation. In each case, regulators have customised the implementation to account for issues unique to the local power sector, such as expected productivity gains and quality of service improvements. However, the basic incentives and benefits under a revenue cap remain intact.

10.5 A Revenue Cap Creates Good Incentives

Beyond mitigating the demand risk for customers and the utility, a revenue cap can also ensure that JPS’ incentives are better aligned with Jamaica’s energy policy goals: competition, distributed generation, and energy efficiency. As we will describe, this is because JPS will recover exactly its approved cost of service—no more, no less—even if the success of these policy initiatives reduces demand for energy from JPS. In this way, JPS can fully embrace these initiatives without fear of financial penalties.

Under a revenue cap, JPS no longer faces a disincentive to assist customers in participating in distributed generation programs, such as its net billing scheme. Currently, customers that self-generate electricity are able to significantly lower their bill, for two reasons: (1) avoided fuel charges, and (2) avoided energy charges. The avoided fuel charges do not impact JPS because the fuel charge is a direct pass-through. However, the avoided energy charge suppresses JPS’ revenue without equally lowering its fixed cost of serving that customer. JPS, then, faces a disincentive to assist customers in interconnecting distributed generation to the grid. To contrast,
Revenue Cap

a revenue cap ensures that JPS is made whole for the approved cost of serving that customer, regardless of the customer’s energy demand.

For similar reasons, under a revenue cap, JPS can become a partner in implementing a wheeling tariff, without fear of losing financially when large customers participate in the program. Under the current price cap, large customers that shift demand to their own off-site generation via the wheeling tariff could reduce JPS’ ability to recover its cost of service.

In addition, one of the major criticisms of a price cap approach is that it creates a disincentive for utilities to promote energy efficiency and demand-side management. While these programs are socially desirable, under a price cap approach, the utility seeks to maximise its revenue by boosting sales. If the regulator caps the utility’s revenue at a cost-reflective level the utility can encourage energy efficiency and demand side conservation without fear of losing profits. Notably, in the United States, this potential benefit has been a key driver of discussions in some jurisdictions to transition to revenue decoupling.

10.6 Revenue Cap Mechanism

In this chapter, we have introduced the concept of a revenue cap and have demonstrated that it is both justified and commonly accepted in international jurisdictions. In this section, we describe exactly how the revenue cap would work in the Jamaican context. We first describe the precise mechanics of the true-up process, which is the central component of the rate design (Section 10.6.1). We then demonstrate the need to adjust the X-Factor approved under the price cap, should the revenue cap mechanism be accepted by the OUR (Section 10.6.2). We conclude in Section 10.6.3 by identifying the changes to the JPS Licence that would be necessary to implement our proposal.

10.6.1 Revenue True-Up Mechanism to Align Actual Revenue with the Target

To make a revenue cap work, the design must include a periodic true-up mechanism, which would be designed to bring actual revenue in line with the revenue target for each year of the regulatory period. This mechanism is necessary because actual demand is unpredictable, and so it would not be possible to set tariffs based on actual revenue. Instead, the revenue cap mechanism features a balancing account, which tracks the “overs” and “unders”—the variation from the revenue target—for each year in the regulatory period. Our revenue cap design relies on an annual true-up, which would occur as part of the annual tariff adjustment process already required under JPS’ Licence.\footnote{Amended and Restated All-Island Electric Licence 2011. Schedule 3, Section 4.}

In Table 10-3, we illustrate the simple mechanics of the revenue true-up process. Under the proposed revenue cap mechanism, the true-up occurs in the following year—that is, during the annual tariff adjustment for year t+1. The true-up adjustment (if any), would be applied as an adjustment to the tariff basket for the rates that would take effect in year t+1. For example, if the first year of the regulatory period is 2014–2015, then the revenue true-up would produce an adjustment to the tariff basket for rates taking effect in 2015–2016.
We note that our example here assumes that the foreign exchange (FX) losses true-up requested in this tariff review application is approved (see [insert section reference]). If the OUR does not approve this FX losses true-up, the underlying methodology of the revenue cap’s true-up mechanism would remain. The revenue cap true-up mechanism without the FX losses true-up would simply follow the same process in Table 10-3, excluding the items highlighted in blue text.

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

1. The revenue cap for year t is calculated by applying the Performance-Based Ratemaking Mechanism, such as the adjusted X-Factor, the Q-Factor, and the Z-Factor —line (a) is adjusted to arrive at line (b), a revenue cap of J$50,460,295,000

2. Actual earned revenue for year t, J$47,409,262,000, is populated on line (g)

3. The revenue shortage (or overage) is calculated by subtracting earned revenue from the revenue target—line (f) equals line (o) minus line (e), for an overage in year t of J$47,362,000

4. Interest is calculated on the revenue shortage (or overage) by multiplying half of the average shortage (or overage) times the authorized weighted average cost of capital. Line (g) shows that the interest on the overage is J$4,570,000

5. The total revenue shortage (or overage) in year t is equal to the actual revenue shortage (or overage), plus any interest —this total appears on line (h), for a total overage of J$51,932,000

6. The total revenue shortage (or overage) is carried forward as an addition to the balancing account in year t+1. In this example, the entire overage would be passed through to the tariffs in year t+1 —this appears on line (c), for a revenue reduction adjustment equal to J$51,932,000

7. Similar to the revenue true-up, a separate true-up is calculated for FX losses in year t. Actual FX losses for year t appear on line (i), equal to J$2,339,359,000

8. The FX losses shortage (or overage) is calculated by subtracting the FX losses embedded in the test year from actual FX losses in year t —line (m) equals line (k) minus line (j), for a shortage of J$211,688,000.

9. Interest is calculated on the FX losses shortage (or overage) by multiplying half of the average shortage (or overage) times the authorized weighted average cost of capital. Line (k) shows that the interest on the shortage is J$20,428,000

10. The total FX losses shortage (or overage) in year t is equal to the FX losses shortage (or overage), plus any interest —this total appears on line (l), for a total shortage of J$232,116,000

11. The total FX losses shortage (or overage) is carried forward as an addition to the balancing account in year t+1. In this example, the entire shortage would be passed through to the tariffs in year t+1 —this appears on line (d), for a revenue increase adjustment equal to J$232,116,000

12. The total revenue target that applies for tariff-setting purposes for year t+1 is then calculated. This is equal to the revenue target for year t+1, plus any revenue and FX
losses adjustments carried out of the balancing account—this total appears on line (o), for a total revenue target for year t+1 of J$50,640,479,000.

Table 10-3: Illustration of Revenue Cap True-up Mechanism

<table>
<thead>
<tr>
<th>Units</th>
<th>Year t 2014-2015</th>
<th>Year t+1 2015-2016</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Start</td>
<td>End</td>
</tr>
<tr>
<td>a</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Unadjusted Revenue Cap</td>
<td>J$’000</td>
<td>$47,361,900</td>
</tr>
<tr>
<td>Performance-Based Ratemaking Mechanism</td>
<td></td>
<td></td>
</tr>
<tr>
<td>+ Inflation Factor (dI)</td>
<td>J$’000</td>
<td>$2,845,536</td>
</tr>
<tr>
<td>+ X-Factor (X)</td>
<td>J$’000</td>
<td>$(165,767)</td>
</tr>
<tr>
<td>+ Revenue Cap Adjustment to X (X’)</td>
<td>J$’000</td>
<td>$418,626</td>
</tr>
<tr>
<td>+ Q-Factor (Q)</td>
<td>J$’000</td>
<td>$(165,767)</td>
</tr>
<tr>
<td>+ Z-Factor (Z)</td>
<td>J$’000</td>
<td>$(165,767)</td>
</tr>
<tr>
<td>b = Revenue Cap w/ PBRM</td>
<td>J$’000</td>
<td>$47,361,900</td>
</tr>
<tr>
<td>Revenue Balancing Account</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Opening Balance</td>
<td>J$’000</td>
<td>$165,767</td>
</tr>
<tr>
<td>+ Interest on Balance</td>
<td>J$’000</td>
<td>$418,626</td>
</tr>
<tr>
<td>+ Total Revenue Shortage / (Overage)</td>
<td>J$’000</td>
<td>$(51,932)</td>
</tr>
<tr>
<td>- Revenue Adjustment</td>
<td>J$’000</td>
<td>$-</td>
</tr>
<tr>
<td>+ Total FX Losses Shortage / (Overage)</td>
<td>J$’000</td>
<td>$(232,116)</td>
</tr>
<tr>
<td>c = Closing Balance</td>
<td>J$’000</td>
<td>$-</td>
</tr>
<tr>
<td>Revenue True-Up</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Revenue Target</td>
<td>J$’000</td>
<td>$47,361,900</td>
</tr>
<tr>
<td>- Revenue Adjustment</td>
<td>J$’000</td>
<td>$-</td>
</tr>
<tr>
<td>+ FX Losses Adjustment</td>
<td>J$’000</td>
<td>$(232,116)</td>
</tr>
<tr>
<td>d = Revenue Target</td>
<td>J$’000</td>
<td>$47,361,900</td>
</tr>
<tr>
<td>FX Losses True-Up</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Actual FX Losses</td>
<td>J$’000</td>
<td>$2,339,359</td>
</tr>
<tr>
<td>Test Year FX Losses</td>
<td>J$’000</td>
<td>$211,688</td>
</tr>
<tr>
<td>- Interest on Shortage / (Overage)</td>
<td>J$’000</td>
<td>$20,428</td>
</tr>
<tr>
<td>+ Total FX Losses Shortage / (Overage)</td>
<td>J$’000</td>
<td>$232,116</td>
</tr>
<tr>
<td>j = Total FX Losses Shortage / (Overage)</td>
<td>J$’000</td>
<td>$232,116</td>
</tr>
<tr>
<td>Revenue Target</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Revenue Cap w/ PBRM</td>
<td>J$’000</td>
<td>$47,361,900</td>
</tr>
<tr>
<td>+ Revenue Adjustment</td>
<td>J$’000</td>
<td>$-</td>
</tr>
<tr>
<td>+ FX Losses Adjustment</td>
<td>J$’000</td>
<td>$(232,116)</td>
</tr>
<tr>
<td>o = Revenue Target</td>
<td>J$’000</td>
<td>$47,361,900</td>
</tr>
<tr>
<td>Estimate of Average Tariffs</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energy Sales in Prior Year</td>
<td>MWh</td>
<td>3,089,826</td>
</tr>
<tr>
<td>Average Non-Fuel Tariff</td>
<td>J$/kWh</td>
<td>$15.33</td>
</tr>
<tr>
<td>+ Average Fuel Charge</td>
<td>J$/kWh</td>
<td>$27.10</td>
</tr>
<tr>
<td>= Average Tariff</td>
<td>J$/kWh</td>
<td>$42.43</td>
</tr>
</tbody>
</table>

Notes: This example assumes the inflation factor is 4.15%, the X-factor (after adjusting for the revenue cap) is -0.53%, the WACC is 19.30%, and earned revenue grows at the same rate as kWh sales growth in the base case demand scenario.

Average tariffs are provided for illustrative purposes. In practice, the tariff basket is calculated annually and distributed into the various rates charged to JPS customers, just as is currently done under the price cap mechanism.

In the example above, we assume that demand follows the Base Case with Natural Gas (“base case”) demand scenario from the demand forecast included in this tariff review application. The
The revenue adjustment applied to the tariff basket for year $t+1$ is a reduction of J$51.9$ million, or approximately $2$ percent of the total change in the tariff basket. As a reference point, if all tariffs were calculated on an energy-only basis, this tariff basket would yield an average tariff of J$16.37$ per kWh—and the revenue adjustment would only account for $0.10$ percent of the average non-fuel tariff.

10.6.2 The Revenue Cap Requires an Adjusted X-Factor

If the OUR accepts the proposed revenue cap mechanism, an “adjusted X-Factor” is needed as an input to the calculation above, so that the non-fuel tariff decreases in real terms at the rate of the approved X-Factor. In this section, we explain the rationale for adjusting the X-Factor under the revenue cap mechanism. We also specify the necessary adjustment, which would be an offset of $0.88$ percent to the approved X-Factor. As a reminder, in this tariff review application, we propose a price cap X-Factor of between zero percent and $0.35$ percent.

Under the proposed revenue cap mechanism, real revenue is based on a historic test year and is fixed for the duration of the regulatory period (ignoring any adjustments for the X-Factor, Q-Factor, or Z-Factor). At the same time, though, JPS expects demand to increase at a modest rate—especially once the $381$MW LNG plant comes online in mid 2016. The net result, then, is that the average non-fuel tariff (in real terms) must decrease over time as demand increases during the regulatory period.

To recall the conceptual discussion of the X-Factor calculation in this tariff review application, the very definition of productivity is the ratio of outputs for a given set of inputs. In the context of a revenue cap, inputs are constrained by the cap, but outputs (such as kWh sales) increase. Simply put, productivity gains are already embedded in the revenue cap design.

By comparison, the price cap alone does not drive productivity gains. Only by applying the X-Factor to the price cap does the average tariff (in real terms) decline during the regulatory period. Put another way, under the price cap mechanism, but for the application of the X-Factor, the average tariff (in real terms) would remain constant. Therefore, simply applying the price cap X-Factor under the revenue cap mechanism would not be appropriate, because it would “double count” for expected productivity gains.

There is a simple and reasonable way to calculate the X-Factor adjustment that would be necessary under the revenue cap: we can compare the average non-fuel tariff under the base case demand scenario to the average non-fuel tariff, if we assume that demand remains constant (that is, demand is the same as in the test year). Coincidentally, this constant demand scenario yields the same result as the existing price cap mechanism (without the X-Factor).

The compound annual growth rate (CAGR) of the difference between these two average non-fuel tariffs signals the approximate annual productivity gains that are embedded within the revenue cap mechanism. We illustrate this concept in Figure 10-3. In the illustration, at the end of the regulatory period, the average non-fuel tariffs under the two demand scenarios will have diverged by a CAGR of $0.88$ percent.

---

95 Please refer to the demand forecast prepared as part of this tariff review application for more details.
We then use this calculated value (0.88 percent) to adjust the X-Factor that would otherwise apply under the existing price cap mechanism. The adjustment we calculate here would apply as an offset to the X-Factor under the price cap mechanism, because it would be effectively “removing” the expected productivity gains that are already embedded in the revenue cap mechanism (to avoid double counting of expected productivity gains). Therefore, if the OUR approves a price cap X-Factor of zero percent, the revenue cap X-Factor would be 0−0.88 percent = -0.88 percent. Similarly, if the OUR approves a price cap X-Factor of 0.35 percent, the revenue cap X-Factor should be 0.35−0.88 = -0.53 percent.

A negative revenue cap X-Factor effectively means that real revenue, all else being equal, increases from year to year. This is logical, however. If we recall that the revenue cap design already embeds productivity gains, the net result of this adjustment is that the productivity gains targeted by the price cap X-Factor are achieved using this (“adjusted”) revenue cap X-Factor. In effect, this adjustment avoids “double counting” expected productivity gains, which would unfairly penalise JPS.

10.6.3 Revisions to the JPS Licence

In order to implement a revenue cap, the OUR would first need to make minor revisions to Schedule 3 of the JPS Licence, which governs the price controls. Effectively, these revisions simply replace any reference to the price cap with a reference to the revenue cap. The existing performance-based ratemaking mechanism and historic test year approach remains the same. The

---

96 Condition 30 of the JPS Licence indicates that the Conditions and Schedules relating to Standards and Price Controls may be modified by the OUR at any time, “after taking the views of the Licensee into consideration, without reference to the Minister.”
only addition is a provision for the revenue true-up process. If necessary, JPS can provide the required revisions in redline format.

10.7 Tariff Implications

The proposed revenue cap design may raise concerns about the implications for tariffs paid by JPS customers. Specifically, there may be concerns about the allocation of demand risk, as well as the potential for rate shock. We attempt to address these concerns in this section. In Section 10.7.1, we show how demand risk is shared under a revenue cap, instead of “shifted.” In Section 10.7.2, we show that the revenue cap mechanism is unlikely to cause rate shock, because of the interactions with the fuel and IPP component of customer bills.

10.7.1 Under a Revenue Cap, Demand Risk is shared – Not Shifted

A common critique of a revenue cap is that it “shifts” demand risk from the utility to customers. As we will show, this view is misinformed. Rather, the very nature of a revenue cap is that it shares the demand risk between the utility and the customer.

10.7.1.1 Revenue Cap Expected to Produce Lower Average Tariffs than Price Cap

As we illustrated in the previous section (see Figure 10-3), under the base case demand scenario with a revenue cap in place, JPS expects the real, average non-fuel tariff to decrease as demand increases over the duration of the regulatory period. This is an intuitive result, and one worth repeating: if real revenue is capped and demand remains constant, average non-fuel tariffs under the revenue cap would be identical to those produced under a price cap. However, if demand grows (as JPS forecasts) over the duration of the regulatory period, all else being equal, the average non-fuel tariff (in real terms) must decrease below what would be produced under a constant-demand revenue cap—and under a price cap.

We can also show that variations from the demand forecast produce divergent real, average non-fuel tariffs. To illustrate this point, in Figure 10-4 we consider three plausible demand scenarios: (1) the base case, (2) a low demand scenario, and (3) a high demand scenario. Our example shows that if actual demand deviates from the demand forecast, it can lead to lower tariffs (if demand is higher than forecasted) or lower tariffs (if demand is lower than forecasted). Simply put, the demand risk is equal for JPS and customers.

---

For simplicity, our low demand scenario is 2 percent below the base case demand forecast in each year of the regulatory period, while the high demand scenario assumes actual demand is 2 percent above the base case in each year.
As we discussed in Section 10.6.2, in the base case we can expect average non-fuel tariffs (in real terms) to decline over the duration of the regulatory period. This is because the revenue cap is set using a historic test year, which implicitly assumes that demand does not change over the regulatory period. Meanwhile, the base case demand forecast anticipates modest demand growth. The net result is a decrease in the real, average non-fuel tariff over time.

By comparison, in the low demand scenario, the average non-fuel tariff (in real terms) increases over the regulatory period. Meanwhile, in the high demand scenario, the average non-fuel tariff (in real terms) decreases over the regulatory period.
That the non-fuel average tariff (in real terms) varies depending on actual demand plainly contradicts the view that a revenue cap mechanism “shifts” risk to customers. Rather, our example shows that demand risk is shared: when demand rises, real prices decrease. This is because JPS must refund its customers for the value of any excess revenues collected above the revenue cap due to the higher demand. Conversely, when demand falls, real prices increase.

This plainly illustrates that the demand risk under a revenue cap is shared. Customers bear the “downside” demand risk, while JPS bears the “upside” demand risk—the likelihood that demand increases.

Using historic data, we can also show that it is unlikely that demand drops significantly in a given year. Rather, as we show in Figure 10-5, it is far more likely that demand continues to increase at a modest rate. We reach this conclusion by examining annual change in demand from 1993 to 2012.

**Figure 10-5: Demand is More Likely to Increase than Decrease**

![Bar chart showing annual growth in kWh sales.](image)

To summarise, under a revenue cap, demand risk is not fully shifted to JPS’ customers, but rather it is **shared**. If demand decreases in a given year, the non-fuel base rates would increase in the following period. In this regard, customers bear the downside demand risk. Conversely, though, if demand increases in a given year, the non-fuel base rates would decrease in the following period, as JPS must refund excess revenues to which it is not entitled.

JPS is willing to bear this “upside” demand risk because it means that if demand decreases, JPS still has a much better ability to recover the substantial fixed costs associated with its transmission and distribution network. This is an appropriate risk allocation because customers have a natural hedge against costs, while JPS does not. To illustrate the point, consider a customer that chooses to decrease consumption (whether through behaviour changes or energy efficient technologies). By decreasing consumption, this customer is able to save money on both the fuel and non-fuel components of his or her bill. While this customer’s demand reduction may
Revenue Cap

lead to a slight increase in the average non-fuel tariff he or she pays, the increase is more than offset by the savings realised on avoided fuel charges. To contrast, JPS’ cost structure for network services is largely fixed—and so, its costs do not decline when customers consume less energy.

10.7.2 A Revenue Cap is Unlikely to Cause Rate Shock

Plausible levels of upward movement in the non-fuel tariff would not be at all material—or even noticeable—to customers. For example, using our example in Section 10.6, in the low demand scenario for year t+1, the average tariff would increase by 3.1 percent (at most) over the prior year. As we will show next, this growth rate is well within the typical variance observed in JPS’ average tariffs.

If we examine the annual growth rate of the average tariff over the past 20 years, we see that customers’ bills have been just as likely to increase as they have been to decrease by the same magnitude. We base this conclusion on an analysis of real average tariffs over the 20-year period from 1993 to 2012. Figure 10-6 illustrates how this risk is distributed. Specifically, it is far more likely that real average tariffs increase by a modest percentage than it is that demand suddenly drops or spikes.

**Figure 10-6: Real Average Tariffs are Relatively Stable**

Moreover, even if the average non-fuel tariff were to spike—as a result of a sudden drop in demand—it would not have a significant impact on the average customer’s bill. This is because the non-fuel tariff makes up an increasingly minor part of the average tariff, which also includes the fuel and IPP charge. Put another way, the fuel and IPP charge, which is an increasingly large share of the average tariff, mutes much of the volatility that might occur due to year-to-year variation in demand.

98 However, because our estimate holds fuel costs constant, we could reasonably expect this change in the average tariff to be even lower, as fuel costs are far more volatile and likely to increase.
To illustrate this graphically, Figure 10-7 shows how the CAGR of the average non-fuel tariff is muted, once the fuel and IPP charge is accounted for in the average tariff calculation. This effect applies in all three of the demand scenarios described in this section.

Figure 10-7: Changes in Average Non-Fuel Tariff are Muted by Fuel and IPP Costs

From these examples, we can draw a very important conclusion: It is unlikely that implementing the revenue cap mechanism would subject our customers to rate shock. On a year-to-year basis it is nearly as likely that rates would decrease as it is likely that rates would increase. Furthermore, to the extent that the revenue cap causes rates to increase, the impact would be minimal when compared to the total customer’s bill.

10.8 Conclusion

As we have shown, there is an economically unjustifiable mismatch between JPS’ cost structure and its ability to recover these costs through its tariffs. Because JPS recovers a large share of its fixed costs through variable charges, the utility and customers face significant demand risk. This demand risk can be mitigated with a revenue cap, which ensures the utility can recover no more than the reasonable cost of service, regardless of demand fluctuations.

Electricity demand in Jamaica is entering a uniquely unpredictable and historically unprecedented phase. Demand growth has slowed as a result of macroeconomic conditions, net billing, and most recently, the proposed wheeling tariff. At the same time, it is highly likely that LNG generation will significantly reduce tariffs during the next regulatory period, and so boost demand for electricity.

This uncertainty means that JPS’ financial stability under the existing price cap lies in the balance between the factors suppressing demand and those that would potentially increase it. Rather than hope that these competing factors result in demand stable enough for JPS to recover the cost of service, a better solution would be to implement a revenue cap. This is particularly
necessary since the alternative—restructuring JPS’ tariffs to be truly cost reflective—cannot be implemented quickly, given the rate changes it would require.

Perhaps more importantly, a revenue cap aligns the utility’s incentives with those of the country. In particular, a revenue cap is pro-choice in generation and pro-energy efficiency. It changes the incentive structure so that JPS can become a champion for energy efficiency initiatives and distributed generation. It also enables choice in the power sector, such as wheeling. Moreover, it is telling that regulators in Great Britain—the pioneers of price cap regulation—have adopted revenue cap regulation for these very reasons.

A revenue cap would help stabilise JPS’ finances, which would make it a more appealing purchased power off-taker in the eyes of project financiers. This is a critical step to ensuring that the 381MW LNG plant can be financed. This same logic applies to JPS’ ability to purchase renewable energy from IPPs at the lowest possible cost. Put succinctly, the revenue cap is in the long-term national interest, because it would ultimately lead to lower power costs for Jamaican electricity consumers.

A revenue cap is a win-win solution. It maintains the desirable efficiency targets and customer protections under the existing price cap approach. It manages demand risk, avoids a tariff restructuring, and enables JPS to become a full partner in Jamaica’s energy policy goals of generation choice and energy efficiency.
Chapter 11: FX Losses

11.1 Introduction

Financial instruments, assets, and liabilities fluctuate unexpectedly due to the dynamics of the international currency markets in response to the underlying macro condition of each country in relation to its trading partners. These fluctuations are known as foreign exchange risk. Foreign exchange (FX) risk arises when a company’s revenues and costs are denominated in different currencies. Variability in the exchange rates may result in revenues being insufficient to cover costs. Generally these risks involve an upside as well as downside, however, in developing countries like Jamaica, the local currency mainly depreciates relative to more stable currencies such as the US dollar.

Most of JPS’ revenues are generated in Jamaican dollars, but over 90 percent of the company’s expenses are incurred in US dollars. This exposes the company to considerable foreign exchange risk due to potential large swings in exchange rates which impact the value of its US dollar related liabilities relative to Jamaican denominated revenues. Foreign exchange risk affects the company’s operations in a number of ways. Most important is the impact on Jamaican dollar denominated revenues generated from regulated tariff rates and the FX exposure faced on the settlement of business transactions.

The foreign exchange risk faced by the company is partially mitigated by a foreign exchange adjustment mechanism which indexes base tariff rates to exchange rates on a monthly basis. There are limitations inherent in this adjustment mechanism that results in only partial offset of the company’s exposure. The mechanism used is based on the currency composition of costs at the beginning of a regulatory period. Where the actual composition of costs differs from the composition implied by the indexation mechanism for the tariffs, the tariff adjustments may be insufficient to offset this foreign exchange exposure.

More important is the exposure faced by JPS to the actual settlement of business transactions denominated in currencies other than US dollars. The exposure arises because the company’s revenues are billed in Jamaican dollars at a particular month end FX rate and customers are generally provided 30 days credit to settle their bills in Jamaican dollars. During the period between the billing of invoices and the actual settlement of these transactions, the company remains exposed to the fluctuations in the Jamaican dollar relative to the US$. In addition the company also faces liquidity risk due to the limited availability of US dollars in the foreign exchange markets.

Settlement risk in this context refers to the exposure that JPS has when it collects Jamaican dollars from its customers after a 30 day credit period, given that it takes several days to actually convert the Jamaican dollar collections into US dollars in order to settle its US dollar denominated obligations. The result of billing customers at a particular month-end FX rate for services provided during a particular month, for example February 28, then having to wait thirty (30) days to collect those funds from customers, for example March 30, but then having to settle the related supplier obligations for that same month, February, at another FX rate thirty (30) days later, March 30, inevitably results in a foreign exchange loss for the company because of the fluctuation in the FX rate during the thirty (30) day period. This is the essence of the settlement risk which JPS faces in relation to movement in the FX rate between the date the billing FX rate
is set for revenues and the settlement date for the related expenses. During the 2013 financial year, as a result of the above noted settlement risk and the fourteen percent (14%) devaluation of the Jamaican dollar, the company incurred US$21M in foreign exchange losses. Currently this risk (and cost) is not adequately addressed in the tariffs, as this cost was not included in the revenue requirement which guided the establishment of the existing tariffs.

This paper reviews the company’s current exposure to foreign exchange risk due primarily to the settlement risk and limitations of the current tariff indexation mechanism to mitigating the exposure. Since JPS has insufficient control over this risk and there is no reasonable opportunity to hedge, JPS believes that this should be addressed through the regulatory tariffs through the inclusion of a line item in the revenue requirement to specifically cover the foreign exchange losses incurred by the company which is a prudently incurred cost in conducting its business.

11.2 Foreign Exchange Risk Exposure

JPS incurs foreign exchange risk primarily on the settlement of accounts receivables and payables and on purchases and borrowings that are denominated in currencies other than the United States dollar. The primary currencies giving rise to currency risk in JPS is the Jamaican dollar and to a lesser extent the Euro.

As at December 31, 2013, the company had US$391 million in outstanding indebtedness denominated in US dollars. A substantial portion of the machinery and equipment used in its operations is imported with prices indexed to US dollars. In addition JPS makes principal and interest payments on the notes in US dollars and settles substantially all of its fuel and Independent Power Producer (IPP) costs in US dollars. As a result, more than ninety percent (90%) of its total expenditure incurred US dollar denominated expenditure.

Revenues are billed and collected in Jamaican dollars and must be converted into US dollars on a routine basis to facilitate payments of US dollar denominated obligations; or, when concessions are made to settle these obligations in Jamaican dollars the applicable FX rate is the rate at the date of settlement. Therefore, when the Jamaica dollar depreciates in value relative to the US dollar the company must increase its Jamaican dollar revenues in order to meet existing US dollar denominated obligations.

The company manages its foreign exchange exposure by maintaining adequate liquid resources in appropriate currencies.

Table 11-1 shows JPS’s foreign currency exposure at the end of 2012 and 2013:

| Table 11-1: Exchange Rate Exposure for 2012-2013 |
|------------------|------------------|------------------|------------------|
|                  | 2012             |                  | 2013             |
|                  | J$ '000 | €$ '000 | US$ '000 | J$ '000 | €$ '000 | US$ '000 |
| Cash and Cash Equivalents | 1,844,642 | 19,840 | 431,802 | 431,802 | 4,059 |
| Trade and Other receivables | 25,708,716 | 276,504 | 27,339,904 | 489,976 | 4,606 |
| Other Assets | 538,991 | 5,797 | 4,606 |
| Long term Loans | 0 | (3,879) | 5,131 | 0 | (3,879) | (5,356) |
| Customer Deposits | (2,874,573) | (30,917) | (2,853,629) | (2,853,629) | (26,827) |
Foreign exchanges risks are worsened in environments where exchange rates are highly variable over a sustained period of time. Since 1992 the exchange rate in Jamaica has been determined by market conditions, and has fluctuated significantly over the period. From the beginning of 2008 through the end of 2013, the J$ has devalued approximately fifty-one (51%) percent relative the US$.

**Figure 11-1: J$ to US$ Exchange Rate**

![Exchange Rates – J$:$ US$](chart)

This variability is expected to continue in the medium term. The figure below provides evidence of the variability in exchange rates over the past 10 years.
While the company’s tariff structure permits monthly adjustments to billing rates to compensate for fluctuations in the exchange rate, the adjustments do not address the settlement risk which the company faces. The settlement risk (i.e. setting of monthly billing FX rate to collection) and conversion risk (from collection of Jamaican dollar billing until US dollar funds can be purchased on the local foreign exchange markets until US dollar denominated obligations have been paid) is manifested in the level of FX losses which the company incurs in its financial statements (see Table 11-2below). Any significant currency fluctuation or changes by regulator to restrict indexation of tariffs to exchange rates could adversely impact the company’s financial performance.

The company is currently facing significant foreign exchange exposure due to limitations in its non-fuel tariff indexation mechanism and on the settlement of business transactions. While the non-fuel index mechanism partially offsets the currency risk to billed revenues, there is no mechanism in place to adequately address the settlement risk or post billing exposure faced by JPS.

11.3 FX Risk on Non-Fuel Adjustment Mechanisms

JPS recovers revenues through tariffs set on an assumed Base Exchange rate which exposes the company to significant currency and settlement risks. Consequently, the Licence permits the company to adjust billing rates each month to account for movements in the exchange rate between the US dollar and Jamaican dollar.

Exhibit 3 of the Licence outlines the mechanism used to apply the monthly adjustments. It states that the total tariff, including the Non-Fuel Base Tariff, the Base Fuel Tariff, tariff adjustments for fuel cost variations and tariff adjustments under the Performance Based Related Mechanism (PBMR) will be adjusted for all consumer classes on a monthly basis using the following adjustment mechanism.

$$\text{Tariff}_m = \text{Tariff}_b \times \left[1 + 0.76 \left(\frac{EXC_{m-1} - EXC_b}{EXC_b}\right)\right]$$
Where:
- $\text{Tariff}_m = \text{Adjusted tariff for the month}$
- $\text{Tariff}_b = \text{Unadjusted tariff for the month calculated on Non-Fuel base rates}$
- $EXC_b = \text{Base Exchange rate for Jamaican Dollars into United States Dollars}$
- $EXC_{m-1} = \text{The Exchange Rate which is shown on the face of the bill that is the arithmetic mean of the daily weighted average of rates at which financial institutions in Jamaica sell United States Dollars for Jamaican Dollars on the Spot Market (the "Spot Market Weighted Average Selling Rate") issued by the Bank of Jamaica for the month two months preceding the month of billing. If no such rate is issued on any particular day by the Bank of Jamaica or, if the current system for determining the rate at which United States Dollars are exchanged for Jamaican Dollars shall have changed then, for the purpose of this provision, the rate for each such day shall be the weighted average of the rates at which Commercial Banks in Jamaica sell United States Dollars for Jamaican Dollars on each such day as determined by the Licensee. Where the billing period exceeds one month, that rate shall be the arithmetic mean of the monthly average exchange rates determined in accordance with the foregoing.}$
- $\text{The rate will be changed from time to time after consultation between the Office and the Licensee.}$

The mechanism includes a 76 percent foreign exchange adjustment factor which suggests that the formula indexes 76 percent of the non-fuel base tariffs to the foreign exchange. The factor was set in the 2004 Determination when at that time the currency composition of the company’s cost was 76 percent US dollar related and 24 percent local.

Regulatory policy dictates that the foreign exchange adjustment factor be set based on the currency composition of costs at the beginning of a tariff reset period and remain fixed for the duration of each tariff reset period. This assumes that the cost structure of JPS remains fixed during that period. Currently the tariff resset period is 5 years. This is a weakness in the indexation mechanism as to the extent that the actual composition of costs differ from the composition implied by the adjustment factor, the adjustments may be insufficient to mitigate foreign exchange risks. This results in the under recovery of revenues or slippage. In addition infrequent review and reset of the FX adjustment factor to reflect the actual currency composition of costs prolongs the under recovery.

The current foreign exchange adjustment factor has not been reset since 2004. In the 2009-2014 Tariff Submission JPS recommended that in accordance with the currency composition of expenses in the 2008 test year the formula should be modified to:

$$\text{Tariff}_m = \text{Tariff}_b \times \left[ 1 + 0.79 \left( \frac{EXC_{m-1} - EXC_b}{EXC_b} \right) \right]$$

This indicates an increase in the US$ denominated cost in the non-fuel rate base from the previously determined 76% to 79%. However, this proposal was not accepted by the OUR and this has resulted in significant under recovery of costs during the last 5 years.

Table 11-2 below summarizes the expenses incurred by JPS in 2013, the current test year. The table shows that 80% of all non-fuel costs incurred by JPS are denominated in US dollars. When the fuel expenses are included the table shows 92% of all of the Company’s costs were incurred in US dollars.
In light of the cost summary provided above JPS proposes that the foreign exchange factor in the indexation mechanism should be reset to:

\[
\text{Tariff}_m = \text{Tariff}_b \times \left[ 1 + 0.80 \left( \frac{\text{EXC}_{m-1} - \text{EXC}_b}{\text{EXC}_b} \right) \right]
\]

This reflects the currency composition of costs as at 2013, the price cap test year.

JPS also believes reviewing the adjustment factor every 5 years exposes the company to increased foreign exchange risk as the currency composition of the costs incurred by JPS fluctuates significantly between reviews. This is mainly because the proportion of US dollar related costs increases as the Jamaican dollar depreciates. While the company has made significant efforts to manage expenses to minimize its US dollar exposure, successive rounds of depreciation of the Jamaican dollar has resulted in an ever increasing proportion of costs being US dollar related. To adequately account for the impact to exchange rate variability on its

### Table 11-2: Currency Composition of Costs

<table>
<thead>
<tr>
<th>Expense</th>
<th>US$'000</th>
<th>% of Total Expense</th>
<th>2013 US$'000</th>
<th>US$ Equivalent</th>
<th>2008 %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Purchased Power (non-fuel)</td>
<td>104,111</td>
<td>9%</td>
<td>100%</td>
<td>104,111</td>
<td>100%</td>
</tr>
<tr>
<td>O&amp;M Expenses</td>
<td>143,265</td>
<td>12%</td>
<td>38%</td>
<td>54,081</td>
<td>39%</td>
</tr>
<tr>
<td>Payroll, benefits &amp; training</td>
<td>58,958</td>
<td>5%</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Third party services</td>
<td>25,830</td>
<td>2%</td>
<td>28%</td>
<td>7,232</td>
<td>35%</td>
</tr>
<tr>
<td>Materials &amp; equipment</td>
<td>8,544</td>
<td>1%</td>
<td>100%</td>
<td>8,544</td>
<td>100%</td>
</tr>
<tr>
<td>Office &amp; Other expenses</td>
<td>24,778</td>
<td>2%</td>
<td>60%</td>
<td>14,867</td>
<td>80%</td>
</tr>
<tr>
<td>Insurance expense</td>
<td>6,811</td>
<td>1%</td>
<td>100%</td>
<td>6,811</td>
<td>95%</td>
</tr>
<tr>
<td>Bad debt write-off</td>
<td>18,342</td>
<td>2%</td>
<td>91%</td>
<td>16,626</td>
<td>88%</td>
</tr>
<tr>
<td>Depreciation</td>
<td>49,168</td>
<td>4%</td>
<td>100%</td>
<td>49,168</td>
<td>100%</td>
</tr>
<tr>
<td>Net Finance Costs</td>
<td>61,777</td>
<td>5%</td>
<td>99%</td>
<td>61,228</td>
<td>100%</td>
</tr>
<tr>
<td>Finance Income</td>
<td>(3,065)</td>
<td>0%</td>
<td>100%</td>
<td>(3,065)</td>
<td>75%</td>
</tr>
<tr>
<td>Interest on customer Deposits</td>
<td>549</td>
<td>0%</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Interest on Short-term debt</td>
<td>1,403</td>
<td>0%</td>
<td>100%</td>
<td>1,403</td>
<td>100%</td>
</tr>
<tr>
<td>Interest on Long-term debt</td>
<td>31,383</td>
<td>3%</td>
<td>100%</td>
<td>31,383</td>
<td>100%</td>
</tr>
<tr>
<td>Other Net Financing costs</td>
<td>31,507</td>
<td>3%</td>
<td>100%</td>
<td>31,507</td>
<td>100%</td>
</tr>
<tr>
<td>Other Income</td>
<td>-4,425</td>
<td>0%</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Non-operational expenses</td>
<td>4,341</td>
<td>0%</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Sinking fund contribution</td>
<td>7,500</td>
<td>1%</td>
<td>100%</td>
<td>7,500</td>
<td>100%</td>
</tr>
<tr>
<td>Return On Rate Base</td>
<td>75,711</td>
<td>6%</td>
<td>100%</td>
<td>75,711</td>
<td>100%</td>
</tr>
<tr>
<td>Return on Equity</td>
<td>50,474</td>
<td>4%</td>
<td>100%</td>
<td>50,474</td>
<td>100%</td>
</tr>
<tr>
<td>Taxation</td>
<td>25,237</td>
<td>2%</td>
<td>100%</td>
<td>25,237</td>
<td>100%</td>
</tr>
<tr>
<td>Total Non-Fuel Expenses</td>
<td>441,448</td>
<td>38%</td>
<td>80%</td>
<td>351,798</td>
<td>79%</td>
</tr>
<tr>
<td>Total Fuel Expenses</td>
<td>728,745</td>
<td>62%</td>
<td>100%</td>
<td>728,745</td>
<td>100%</td>
</tr>
<tr>
<td>Total Expenses</td>
<td>1,170,193</td>
<td>100%</td>
<td>92%</td>
<td>1,080,543</td>
<td>91%</td>
</tr>
</tbody>
</table>
operations the company found it prudent to change its reporting currency to the US dollar in 2008.

JPS proposes that the regulator allow an annual review of the currency cost components of the company using the audited financial statements of the calendar year prior to each annual rate adjustment. The results of this review should be used to update the foreign exchange adjustment formula to reflect any changes in the relative proportion of US dollar related costs to local costs.

11.4 Foreign Exchange Losses / (Gains)

The previous result has implications for the annual inflation adjustment factor in the Performance Based Rate Making Mechanism (PBMR). Similar to the Foreign exchange adjustment factor the Inflation adjustment factor incorporates the relative proportion of the US dollar denominated and local currency denominated costs. The inflation adjustment is applied annually to base tariffs along with adjustments to account for productivity gains, the X-factor, and quality of service improvements, the Q-factor. The inflation adjustment formula in Schedule 2 of the 2011 Licence describes the inflation adjustment formula as follows:

\[ b_1 = b_0 (1 + dI) \]

Where

- \( dI = 0.76 \left( \frac{EX_n - EX_b}{EX_b} \right) (1 + 0.92INF_{US}) + (0.76)(0.92)INF_{US} + 0.24INF_I \)
- \( b_t = \text{Base non fuel tariff at time period } t = 1 \)
- \( b_0 = \text{Base non fuel tariff at time period } t = 0 \)
- \( EX_n = \text{New base exchange rate} \)
- \( EX_b = \text{Base exchange rate} \)
- \( INF_{US} = \text{US Inflation Rate} \)
- \( INF_I = \text{Jamaican Inflation Rate} \)

The above formula suggests that 76 percent of all costs incurred by JPS are US$ related and 24 percent are local Jamaican dollar costs. The equation also suggests that 8 percent\(^{99}\) of the US dollar related costs pertain to debt financing costs and hence should not be subject to US inflation adjustments. These parameters were determined in the 2004 Tariff Review and were retained in the 2009 Tariff Review Determination. The regulator opted to retain the parameters despite evidence included in the 2009 Tariff Submission that showed US dollar related costs to be 79 percent of all non-fuel costs.

To ensure that the inflation adjustment factor adequately reflects the currency composition of the company’s expenses for the 2013 test year JPS proposes that the formula be amended to adjusted to:

\[ b_1 = b_0 (1 + dI) \]

\[ \text{where} \]

\(^{99}\) Appendix 1 derives the Inflation adjustment formula from first principles and compares the parameters derived in the formula to the formula shown the Amended and Restated All Island Licence 2011.
The above formula indicate that 80 percent of all costs are US dollar related and 20 percent are local Jamaican dollar costs. In addition 12 percent of all US dollar related costs were related to debt financing as summarized below:

Table 11-3: Debt Factor Calculation

<table>
<thead>
<tr>
<th>Debt Financing Costs</th>
<th>US $</th>
</tr>
</thead>
<tbody>
<tr>
<td>Int on Customer Deposits</td>
<td>549</td>
</tr>
<tr>
<td>Net Financing Costs</td>
<td>9,965</td>
</tr>
<tr>
<td>Interest on LT Debt</td>
<td>31,383</td>
</tr>
<tr>
<td></td>
<td>41,897</td>
</tr>
<tr>
<td>Total Non Fuel US Costs</td>
<td>351,798</td>
</tr>
<tr>
<td>Debt factor</td>
<td>12%</td>
</tr>
</tbody>
</table>

11.5 FX Risk on the Settlement of Business Transactions

Foreign exchange risk on the settlement of business transactions is the risk that the amount of functional currency exchanged to settle a transaction will be different from its equivalent contract value. These transactions may be payments to JPS by customers for electricity services, receivables, or payments by JPS for goods and services, payables. The average settlement period for receivables, and for accounts payables, averages fifty-two (52) days, particularly due to the delinquency of the GOJ over the last three years. The fluctuation in exchange rate during this settlement period gives rise to significant FX exposure two percent (2%) in a single month. For the financial year 2013 JPS incurred US$21M in foreign exchange losses due to this exposure (as shown in Table 11-4).

JPS is specifically exposed to FX risk on accounts receivable that are denominated in Jamaican dollars while having to settle most of its obligations in US dollars. The company’s receivables are primarily from electricity sales transactions that are conducted on a postpaid basis. Customers are billed in Jamaican currency based on the exchange rate as at the end of the preceding month. Customers take on average fifty-two (52) days to remit payment after they have been billed. This implies that JPS has almost two (2) months of receivables on its books at any one time. It is the depreciation of the Jamaican dollar during this intervening credit period that fundamentally causes the settlement risk for JPS.

In 2013 JPS reported an average of over US$ 200M in receivables each month. The Jamaican dollar depreciated by one point two percent (1.2%) per month for the year. This resulted in in FX losses of approximately US$30M for the financial year.

On the accounts payables transactions JPS is exposed to foreign exchange risk on payables denominated in Jamaican dollars. JPS takes fifty-seven (57) days on average to settle its obligations. During that interval depreciation in FX rates will reduce the amount owing to local
suppliers in US$ functional currency terms. In the 2013 financial year JPS recorded a US$ 11M reduction in J$ denominated payables as a result of fluctuation in the foreign exchange rate.

The total foreign exchange losses recorded for the last 3 years are summarized in the table below:

**Table 11-4: Foreign Exchange Losses - 2011-2013**

<table>
<thead>
<tr>
<th></th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Receivables</td>
<td>2,349,326</td>
<td>15,579,331</td>
<td>30,223,586</td>
</tr>
<tr>
<td>Payables</td>
<td>1,175,521</td>
<td>(1,076,236)</td>
<td>(2,406,024)</td>
</tr>
<tr>
<td>Cash</td>
<td>(331,036)</td>
<td>(1,692,895)</td>
<td>(9,559,426)</td>
</tr>
<tr>
<td>Other</td>
<td>81,787</td>
<td>2,068,456</td>
<td>2,855,995</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>3,275,598</strong></td>
<td><strong>14,878,655</strong></td>
<td><strong>21,114,132</strong></td>
</tr>
</tbody>
</table>

FX losses were fifty percent (50%) higher than the US$14M incurred in 2012 due to the increased volatility in the foreign exchange rate. The Jamaican dollar lost 14.4% of its value in 2013 compared to 7.36% in 2012.

Currently there is no regulatory treatment for FX losses incurred on business transactions. The company manages the risk on these transactions by closely monitoring the foreign exchange market and maintaining adequate liquid resources in appropriate currencies. The company also tries to manage the timing of payments of foreign currency liabilities. JPS has little control over its exposure and no reasonable opportunity to hedge, due to illiquid markets. As a result, the company believes the exposure to this risk should be mitigated through the regulatory tariffs.

In light of this JPS proposes that a provision for the FX losses incurred on business transactions should be included as a separate revenue requirement item in the upcoming rate case. This amount should be based on the amount identified in the test year (2013) audited financials and adjusted for the 2014 estimate.

JPS also recommends the implementation of an annual “true-up” mechanism to reconcile the actual FX losses incurred compared to the amount embedded in the revenue requirement, similar in principle to the methodology currently used to “true up” PPA costs on a monthly basis. This would ensure the fair recovery of such costs in the tariffs and avoid any over or under recovery on an amount which can vary significantly from year to year over which the company has no control. JPS proposes that during annual PBRM tariff adjustments between rate reviews, the FX losses incurred in the preceding calendar year’s audited financial statements should be compared with the amount approved and embedded in the tariffs (i.e. the approved revenue requirement amount). If the actual FX losses are lower than the amount embedded in the tariffs then a negative adjustment should be incorporated into the annual PBRM tariff adjustment mechanism. If the actual amount of FX losses in the audited financial statements is higher than the amount allowed embedded in the tariffs then a positive adjustment should be incorporated into the annual PRBM tariff adjustment. below illustrates how the FX losses true-up mechanism could work. In each year, the tariff basket would be calculated in the following six steps:
1. The non-fuel base rate is populated in line (a). In our example, we refer to year t+1, where the unadjusted non-fuel base rate is carried over from the tariff basket in the prior year, J$47,361,900,000

2. We then apply the PBRM according to the approved rates for the inflation factor (dI), the X-Factor (X), the Q-Factor (Q), and the Z-Factor (Z). Line (b) shows that in year t+1, the non-fuel base rate with the PBRM adjustments (excl. FX losses) equals J$47,793,614,000

3. To calculate the true-up on FX losses, we subtract the FX losses in the test year from the actual FX losses in year t. This shortage (or overage) on FX losses appears on line (e), which is equal to line (c) minus line (d). In year t, this shortage equals J$211,688,000

4. We then calculate the interest on this shortage (or overage) in year t, which is equal to one half of the true-up times the approved weighted average cost of capital (WACC). This appears on line (f), which equals J$20,428,000

5. The total FX losses true-up amount is calculated on line (g), which is equal to the sum of the FX losses shortage (or overage) and the interest on this shortage (or overage). For year t, the total FX losses true-up equals J$232,116,000

6. To calculate the tariff basket, we sum the non-fuel base rate calculated on line (b) and the FX losses true-up calculated on line (g). The tariff basket appears on line (h), and for year t+1 equals J$50,273,786,000.
Table 11-5: FX Losses True-Up Mechanism

<table>
<thead>
<tr>
<th>Price Cap</th>
<th>Units</th>
<th>Start</th>
<th>End</th>
<th>Start</th>
<th>End</th>
</tr>
</thead>
<tbody>
<tr>
<td>a</td>
<td>Non-Fuel Base Rate</td>
<td>J$'000</td>
<td>$47,361,900</td>
<td>$47,361,900</td>
<td></td>
</tr>
<tr>
<td>Performance-Based Ratemaking Mechanism</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>+ Inflation Factor (dI)</td>
<td>J$'000</td>
<td>$ -</td>
<td>$2,845,536</td>
<td></td>
<td></td>
</tr>
<tr>
<td>+ X-Factor (X)</td>
<td>J$'000</td>
<td>$ -</td>
<td>$165,767</td>
<td></td>
<td></td>
</tr>
<tr>
<td>+ Q-Factor (Q)</td>
<td>J$'000</td>
<td>$ -</td>
<td>$ -</td>
<td></td>
<td></td>
</tr>
<tr>
<td>+ Z-Factor (Z)</td>
<td>J$'000</td>
<td>$ -</td>
<td>$ -</td>
<td></td>
<td></td>
</tr>
<tr>
<td>b</td>
<td>= Non-Fuel Base Rate w/PBRM</td>
<td>J$'000</td>
<td>$47,361,900</td>
<td>$50,041,670</td>
<td></td>
</tr>
<tr>
<td>FX Losses True-Up</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>c</td>
<td>Actual FX Losses</td>
<td>J$'000</td>
<td>$2,339,359</td>
<td>$2,479,909</td>
<td></td>
</tr>
<tr>
<td>d</td>
<td>Test Year FX Losses</td>
<td>J$'000</td>
<td>$2,127,671</td>
<td>$2,127,671</td>
<td></td>
</tr>
<tr>
<td>e</td>
<td>FX Losses Shortage / (Overage)</td>
<td>J$'000</td>
<td>$211,688</td>
<td>$352,238</td>
<td></td>
</tr>
<tr>
<td>f</td>
<td>= Interest on Shortage / (Overage)</td>
<td>J$'000</td>
<td>$20,428</td>
<td>$33,991</td>
<td></td>
</tr>
<tr>
<td>g</td>
<td>= FX Losses True-Up</td>
<td>J$'000</td>
<td>$232,116</td>
<td>$386,229</td>
<td></td>
</tr>
<tr>
<td>Tariff Basket</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>h</td>
<td>= Tariff Basket</td>
<td>J$'000</td>
<td>$47,361,900</td>
<td>$50,273,786</td>
<td></td>
</tr>
<tr>
<td>Estimate of Average Tariffs</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energy Sales in Prior Year</td>
<td>MWh</td>
<td>3,089,826</td>
<td>3,093,076</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average Non-Fuel Tariff</td>
<td>J$/kWh</td>
<td>$15.33</td>
<td>$16.25</td>
<td></td>
<td></td>
</tr>
<tr>
<td>+ Average Fuel Charge</td>
<td>J$/kWh</td>
<td>$27.10</td>
<td>$27.10</td>
<td></td>
<td></td>
</tr>
<tr>
<td>= Average Tariff</td>
<td>J$/kWh</td>
<td>$42.43</td>
<td>$43.36</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

11.6 Conclusion

JPS faces foreign exchange risk exposure due to limitations in the foreign exchange adjustment mechanism and transactions exposure on the settlement of its business transactions. The adjustment mechanism only partially mitigates risk on billed revenue while there is no regulatory treatment of settlement exposure. For this reason JPS makes the following proposals for the Office’s consideration and approval:

1. Updating the non-fuel foreign exchange adjustment factor to reflect the currency composition of costs as at 2013. The mechanism used to effect adjustments to index tariffs to exchange rate should apply the following formula to non-fuel base rates.

   \[
   \text{Tariff}_m = \text{Tariff}_b \times \left[ 1 + 0.80 \left( \frac{EXC_{m-1} - EXC_b}{EXC_b} \right) \right]
   \]

2. Updating the inflation adjustment formula to reflect actual inflation costs as at 2013. The formula applied annually to non-fuel base rates should be adjusted to:

   \[
   b_1 = b_0 (1 + dI)
   \]

Where
FX Losses

\[ dl = 0.80 \left( \frac{EX_n - EX_b}{EX_b} \right) (1 + 0.89INF_{US}) + (0.80)(0.89)INF_{US} + 0.20INF_j \]

3. Allowance for an annual review of the non-fuel foreign exchange adjustment factor to reflect changes in JPS’ currency composition of non-fuel costs.


5. The implementation of an annual “true-up” mechanism between rate reviews to reconcile the amount incurred for FX losses for the previous calendar year with the amount allowed in the revenue requirement. If FX losses incurred is less than the amount allowed then JPS must effectively refund the difference to customers. Conversely, if FX losses incurred is more than the amount allowed then the company should be allowed to recover the difference from customers.
11.7 Appendix: Derivation of Inflation Adjustment Factor

Base non fuel tariffs may be represented by the equation

\[ b_i = e_i C_i^f + C_i^n \]  

Equation 1

Where

- \( C_i^f \) – Foreign component of JPS costs
- \( C_i^n \) – Local component of JPS costs
- \( e_i \) – Exchange rate J$/US$
- \( i \in [0,4] \)

Note that all costs are either local or US based i.e. cost may be written as \( e_i C_i^f = \theta b_i \) and \( C_i^n = (1 - \theta) b_i \) where \( \theta \in [0,1] \) is the proportion of US dollar related costs.

Therefore the base non-fuel equation at period 1 may be written as

\[ b_1 = e_1 C_1^f + C_1^n \]

Please note the non-fuel US based costs contains debt financing costs and are affected by foreign exchange movements, but not US inflation rates. All other US based costs are impacted by both US inflation and foreign exchange movements. Let \( \delta \) be the portion of US costs dollar related to debt financing. We can rewrite the Equation 1 in terms of Period 0 costs and inflation rates.

\[ b_1 = (1 - \delta)(1 + \pi_U) \frac{e_1}{e_0} \theta b_0 + \delta \frac{e_1}{e_0} \theta b_0 + (1 + \pi_f)(1 - \theta) b_0 \]

Note that \( C_1^f = \frac{\theta b_0}{e_0} \)

Simplifying

\[ b_1 = [(1 - \delta)(1 + \pi_U) + \delta] \frac{e_1}{e_0} \theta b_0 + (1 + \pi_f)(1 - \theta) b_0 \]

\[ b_1 = b_0 \left[ [(1 - \delta)(1 + \pi_U) + \delta] \frac{e_1}{e_0} \theta + (1 + \pi_f)(1 - \theta) \right] \]

\[ b_1 = b_0 \left[ (1 + \pi_U - \delta - \delta \pi_U + \delta) \frac{e_1}{e_0} \theta + (1 + \pi_f)(1 - \theta) \right] \]

\[ b_1 = b_0 \left[ 1 + \pi_U - \delta \pi_U \right] \frac{e_1}{e_0} \theta + (1 + \pi_f)(1 - \theta) \]

Substituting \( \frac{e_1}{e_0} = (1 + \Delta e) \) and simplifying we get

\[ b_1 = b_0 \left[ (1 + \pi_U - \delta \pi_U)(1 + \Delta e) \theta + (1 + \pi_f)(1 - \theta) \right] \]

\[ b_1 = b_0 \left[ (1 + \pi_U(1 - \delta))(1 + \Delta e) \theta + (1 + \pi_f)(1 - \theta) \right] \]
Finally we get
\[
b_1 = b_0 \left[ \pi_U (1 - \delta) (1 + \Delta e) \theta + (1 + \Delta e) \theta + (1 + \pi_f) (1 - \theta) \right] \
\]
\[
b_1 = b_0 \left[ \pi_U (1 - \delta) (1 + \Delta e) \theta + \theta \Delta e + \theta + (1 - \theta) + (1 - \theta) \pi_f \right] \
\]
\[
b_1 = b_0 \left[ 1 + \theta (1 - \delta) (1 + \Delta e) \pi_U + \theta \Delta e + (1 - \theta) \pi_f \right] \
\]
\[
b_1 = b_0 \left[ 1 + \theta \Delta e (1 - \delta) \pi_U + \theta \Delta e + \theta (1 - \delta) \pi_U + (1 - \theta) \pi_f \right] \
\]

Therefore, letting \( DI \) be the inflation adjustment parameter, then the non-fuel base rate at Period 1 may be written as:
\[
b_1 = b_0 [1 + DI] \
\]

Where \( DI = \theta \Delta e (1 + (1 - \delta) \pi_U) + \theta (1 - \delta) \pi_U + (1 - \theta) \pi_f \)

Comparing this result to the Inflation adjustment factor stated in the Licence:
\[
dI = 0.76 \left( \frac{EX_n - EX_h}{EX_b} \right) (1 + 0.92 INF_{US}) + (0.76)(0.92)INF_{US} + 0.24INF_f \
\]

We may infer:
\[
\theta = 0.76 \text{ Is the proportion of foreign related costs used in the formula and } \delta = 0.08 \text{ is the portion of US cost used for debt financing (i.e. } 1 - \delta = 0.92).
Chapter 12: Fuel Recovery – Heat Rate Target

12.1 Introduction

In accordance with its Licence JPS is allowed to recover its fuel costs through a fuel tariff. The fuel tariff allows the Company to pass through its fuel costs to customers on a dollar for dollar basis subject to adjustments for efficiency factors relating to its system losses and heat rate. The efficiency adjustments are designed to incentivise JPS operate efficiently and operate as financial penalties to the extent that JPS fails to meet the regulatory determined efficiency targets, or as financial rewards to the extent that it exceeds the targets. The fuel tariff is recalculated each month based on the cost of fuel in the preceding month and after making allowance for the efficiency factors. The rates are also adjusted to account for movements in the exchange rate between the United Sates dollar and the Jamaican dollar.

The heat rate target focuses on the generation operations of the system and benchmarks how efficiently generators operated by JPS or its IPP partners convert fuel into electrical energy. Currently the heat rate target is set at 10,200 kj/kWh. To the extent, that the monthly heat rate exceeds this ceiling JPS is prevented from passing through a corresponding portion of its fuel costs to customers and must bear the costs themselves. To the extent, that the heat rate is better than the target then the company is permitted to pass through its fuel costs to customers on a dollar for dollar basis plus some additional revenues as a bonus for bettering the target.

The system losses target focuses primarily on the transmission and distribution (T&D) operations of the company. System losses are the difference between the energy generated by the system, and the energy sold to customers. Losses are generally because of technical causes and theft. The OUR has set a system loss target of 17.5 percent of the total electricity generated. To the extent that system losses exceed this target, JPS is prohibited from passing through a corresponding portion of its fuel costs to customers and must absorb the costs. To the extent that system losses are better than the target, JPS is permitted to pass through fuel costs on a dollar for dollar basis plus additional revenues as a bonus. As noted above, OUR’s determination to set the system loss target at 17.5% has unfairly imposed on JPS responsibility for theft losses which are beyond its control, and correction of this regulatory flaw is necessary for JPS financial stability.

The fuel rates are determined in accordance with Exhibit 2 of Schedule 3 of the Licence given below:

**Exhibit 2: Fuel Cost Adjustment Mechanism**

*The cost of fuel per kilowatt (net of efficiencies) shall be calculated each month on the basis of the total fuel computed to have been consumed by the Licensee and Independent Power Producers (IPPs) in the production of electricity as well as the Licensee's generating heat rate as determined by the Office at the adjustment date and the IPPs generating heat rate as per contract with the IPPs and system losses, as determined by the Office at the adjustment date of total net generation (the Licensee and IPPs).*
The fuel cost portion of the monthly bill computed under the applicable rate schedule will be calculated in the following manner:

\[ F = \frac{F_m}{S_m} \]

Where

Billing Period = The billing month during the effective period for which the adjusted fuel rates will be in effect as determined by the Office.

\[ F = \text{Monthly Adjustment Fuel Rate in J$ per kWh rounded to the nearest one-hundredth of a cent applicable to bills rendered during the current Billing Period.} \]

\[ F_m = \text{Total applicable energy cost for period} \]

The total applicable energy cost for the period is:

a. The cost of fuel adjusted for the determined heat rate and system losses and which fuel is consumed in the Licensee's generating units or burned in generating units on behalf of the Licensee for the calendar month that ended one month prior to the first day of the billing period plus;

b. The fuel portion of the cost of purchased power (including IPPs), adjusted for the determined system losses, for the calendar month that ended one month prior to the first day of the billing period; and

c. An amount to correct for the over-recovery or under-recovery of total reasonable and prudent fuel costs, such amount shall be determined as the difference between fuel costs billed, using estimated fuel costs, and actual reasonable and prudent fuel costs incurred during the month that ended one month prior to the first day of the billing period.

\[ S_m = \text{The kWh sales in the Billing Period} \]

The kWh sales in the billing period are the actual kWh sales occurring in the billing period, which ended one month prior to the first day of the applicable billing period.

The Fuel Rate Adjustment including the Schedule for application of the fuel charge to each rate class, shall be submitted by the Licensee to the Office ten (10) days prior to the end of the month just preceding the applicable billing month and shall become effective on the first billing cycle on the applicable billing month.
This chapter reviews the system’s heat rate performance during the previous regulatory period, presents the results of the heat rate forecast model for each of the next 5 years and outlines JPS’s proposals for the system heat rate target. The next chapter will present the company’s system losses initiatives and outline proposals for the system losses target for the next regulatory period.

Given the significant changes in the generation operations in the upcoming period the company is recommending that the system heat rate target be held at the current level of 10,200 kJ/kWh for the next year and that this be reviewed annually to the extent that new generation has been commissioned and the impact on the heat rate target has been determined. Additionally, we wish to note that when the next major round of generation is complete (381 MWs) in 2016/17 that more than 70% of net generation will be provided by IPPs. This event should trigger a comprehensive review of the entire industry generation assets and its consequent structure to determine whether the current mechanism of applying a system heat rate to JPS is still applicable within the context of the new industry dynamics.

Concomittantly, if the new generation capacity is not on-line by the end of 2016, the heat rate target should again be reviewed given the ageing status of JPS’s power plants and the fact that we cannot guarantee the heat rate performance of our power plants (292MW) that airmarked for retirement in 2016 beyond that date. These power plants will not be economical to keep running after that date and it will cost a substantial sum of money to keep them running. Accordingly, we would recommend a complete review of the heat rate target in such an event should the new generation project be completed by the end of 2016.

12.2 Heat Rate Target Objectives

The regulator’s stated objective for the heat rate target in the Fuel Adjustment Mechanism is to ensure that customers are provided with fair and reasonable rates by permitting the efficient pass through of fuel expenses. The target provides JPS with the incentives to minimize overall fuel expenses by improving the relative efficiency of converting chemical energy to electrical energy by its power generating system and by adherence to the economic dispatch of all available generation units.

JPS shares the overall objective of the regulator but believes that the following principles should be applied in setting the applicable heat rate target:

- The target should hold JPS accountable for only the factors which are under its direct control;
- The target should adequately and realistically reflect the available and future (within the rate-cap period) generating fleet’s capabilities and legitimate constraints;
- JPS should be provided with an adequate medium-term planning horizon with predictable targets, which is particularly important in the context of the price cap regime; and
- The target change interval should permit JPS the opportunity to harvest gains resulting from the capital, and effort invested in meeting and exceeding the agreed target.

In the following section, we review the system heat rate performance over the last 5 years and provide recommendations for the regulatory period 2014-2019.
12.3 System Heat Rate Performance – 2009 – 2013

The company’s heat rate improved annually during the regulatory period. The heat rate fell by an annual average of 72 kJ/kWh and a total of 287 kJ/KWh over the period. The major drivers of this improved efficiency was due to the addition of 18 MWs of wind from Wigton in 2010 and 65.5MW of efficient medium speed diesel technology from WKPP in 2012. Not to be discounted are the continuous efforts of JPS to improve and maintain its generation fleet through timely maintenance. The system-wide heat rate performance is illustrated in the figure below:

Figure 12-1: System Heat Rate Performance 2009 - 2013

The figure below shows the monthly performance in relation the target, and well as the impact of the major developments that occurred during the period.
Statistics for the monthly average system heat rate performance shown in Table 12-1 further illustrate the general trend of heat rate improvement over the tariff review period 2009 –2013.

Table 12-1: Descriptive Statistics - Heat Rate Performance (2009 – 2013)

<table>
<thead>
<tr>
<th>Year</th>
<th>N</th>
<th>Mean</th>
<th>St Dev</th>
<th>Min</th>
<th>Q1</th>
<th>Median</th>
<th>Q3</th>
<th>Max</th>
<th>Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>12</td>
<td>10,178</td>
<td>237</td>
<td>9,847</td>
<td>9,994</td>
<td>10,141</td>
<td>10,293</td>
<td>10,588</td>
<td>740</td>
</tr>
<tr>
<td>2010</td>
<td>12</td>
<td>10,187</td>
<td>194</td>
<td>9,867</td>
<td>10,090</td>
<td>10,196</td>
<td>10,269</td>
<td>10,513</td>
<td>645</td>
</tr>
<tr>
<td>2011</td>
<td>12</td>
<td>10,121</td>
<td>221</td>
<td>9,888</td>
<td>9,966</td>
<td>10,051</td>
<td>10,227</td>
<td>10,634</td>
<td>746</td>
</tr>
<tr>
<td>2012</td>
<td>12</td>
<td>9,964</td>
<td>287</td>
<td>9,369</td>
<td>9,803</td>
<td>9,918</td>
<td>10,226</td>
<td>10,360</td>
<td>991</td>
</tr>
<tr>
<td>2013</td>
<td>12</td>
<td>9,892</td>
<td>420</td>
<td>9,398</td>
<td>9,543</td>
<td>9,817</td>
<td>10,207</td>
<td>10,554</td>
<td>1,156</td>
</tr>
<tr>
<td>2009-2013</td>
<td>60</td>
<td>10,064</td>
<td>299</td>
<td>9,369</td>
<td>9,883</td>
<td>10,084</td>
<td>10,257</td>
<td>10,634</td>
<td>1,266</td>
</tr>
</tbody>
</table>

These are illustrated by the following box plots.
Both the average heat rate and the range (max – min) of heat rate variation has shown overall improvement comparing 2013’s performance to 2009. While there is a visibly stepped change in the system heat rate in 2012 with the inclusion of the new 65.5 MW WKPP plant, the trend has shown a constant decline over the last three years. Note that this monthly variation is a normal feature of the economic dispatch given that base load units must be routinely taken off-line for maintenance and there is a normal level of forced outage that would also be expected. This is the main reason why an availability factor of 85% is assumed for the JPS generation fleet and 90% for the IPP fleet.

The figure below shows the distribution of the monthly performances.
Figure 12-4: Heat Rate Performance for 2009 – 2013

While the mean heat rate over the five-year period was 10,064 kJ/kWh, the standard deviation of 229 kJ/kWh statistically indicates that 57% of the monthly average heat rate values ranged between 9,835kJ/kWh and 10,293kJ/kWh (one standard deviation). This is a 458kJ/kWh spread influenced by all usual which factors impact heat rate performance.

12.4 Factors Impacting System Heat Rate Forecast

12.4.1 Improvements to Existing Units

Changes to existing units to improve heat rate can be classified as either operating improvements or design improvements. JPS has invested significantly in the existing generating units over the past five years to effect such operating improvements. Generally, the heat rate performance of the existing fleet of units represents the best levels that will be achievable over the next five years. Greater levels of efficiency may be achieved with some design improvements or through fuel diversification but would require significant capital investment.

The current heat rate forecast model for 2014-19 includes the conversion of Bogue to natural gas that has been factored into the heat rate calculation. While this conversion will reduce the fuel bill substantially, it will have a small but noticeable effect on the heat rate of the Bogue CC plant.

12.4.2 Impact of New Generation on Economic Dispatch and Heat Rate

Since August 2007, the determination of the Least Cost Generation Expansion Plan and the required size and timing of new capacity addition is determined by the OUR. Further, the acquisition of new capacity is also under the control of the OUR.

The introduction of new generation units to the system during the 2014 –2019 rate cap period is expected to positively affect the heat rate and fuel cost. The effect of any new unit on the system heat rate can be determined by modelling the new unit in the system’s economic dispatch model reconciled with the expected growth in sales and demand during the period. The system heat rate
will progressively get worse in the near future given the age of JPS existing plant and the imminent need to retire 292 MWs of generation units. However, we anticipate a substantial improvement when the next round of new generating sets come online, whether from the 78 MW of renewable energy or from the completion of the 381 MW LNG project.

Note that since the last rate review the proportion of supply provided by the Independent Power producers has increased from 32 percent in 2009 to 43 percent last year. The figure below shows the changes throughout the period.

**Figure 12-5: IPP Production**

![Graph showing Contribution to Total Power Supply: JPS production vs IPP Production](image)

<table>
<thead>
<tr>
<th>Year</th>
<th>JPS Production</th>
<th>IPP Production</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>68%</td>
<td>32%</td>
</tr>
<tr>
<td>2010</td>
<td>68%</td>
<td>32%</td>
</tr>
<tr>
<td>2011</td>
<td>66%</td>
<td>34%</td>
</tr>
<tr>
<td>2012</td>
<td>63%</td>
<td>37%</td>
</tr>
<tr>
<td>2013</td>
<td>57%</td>
<td>43%</td>
</tr>
</tbody>
</table>

JPS’ economic dispatch model assumes that only renewables and baseload capacity will be added during the next five years, in the form of wind, hydro and combined cycle gas turbines on LNG.

12.4.3 Impact of Fuel Price on Economic Dispatch and Heat Rate

The variable cost of each generator is directly related to the price of fuel burned in the unit. Also, the relative delivered price of fuel at each plant will influence the merit order ranking of the generating units and hence the dispatch output. Note that the change in fuel prices for the two main fuel sources and projected LNG can be disproportionate.

When fuel prices are high generally, generating units with good heat rates will have a higher merit order ranking than units with a worse heat rate, subject to their variable operating and maintenance (O&M) costs. Good heat rate units will therefore deliver a substantial share of the energy required, all factors being normal. The system heat rate will therefore be good while the system fuel cost will be high.

Conversely, when fuel prices are low, the system fuel cost will be lower and the difference in the fuel component of merit order cost for good and bad heat rate units will be smaller. The merit order ranking of generators will be influenced a lot more by the value of the variable O&M than was the case in a high fuel price environment. The share of energy from units with relatively poor heat rates will also be greater, and hence system heat rate will deteriorate.
In either high or low fuel price scenarios, the differential price between JPS units and IPPs will influence the system heat rate. It is projected that the 381MW LNG CCGT plant will have a positive impact on the fuel component of the dispatch.

12.4.4 Impact of IPP Performance on Economic Dispatch and Heat Rate

The availability and reliability of IPPs has a direct effect on the overall system heat rate. Under the existing PPAs, the large IPPs provide either a guaranteed heat rate point or a curve. A similar PPA is expected to accompany the incoming 381MW LNG CCGT. This new IPP is projected to provide over 50% on average of the required energy demand, accordingly their performance will directly influence the resultant system heat rate.

The expected performance of IPPs is defined in their PPAs. Each IPP is allowed planned and forced outage hours and by extension is required to perform with a forecast level of availability and reliability. As much as the required IPP performance is not realized, more expensive and less fuel-efficient (worse heat rate) units have to be dispatched to provide for this energy shortfall. This negatively affects the expected system heat rate.

12.5 Heat Rate Forecast for Tariff Period

12.5.1 Model Assumptions

12.5.1.1 Projected Maximum Capacity Rating (MCR)

Rockfort’s maximum capacity rating is forecasted to remain at 20MW x 2 for the period 2014 to 2019.

Hunts Bay’s maximum capacity rating will remain at 122.5MW up to mid-2016 when the retirement of HB #B6 is forecasted to go offline. The stations MCR will be reduced by 68.5MW in 2016 to reflect a balance of 54MW. HB GT#5 (21.5MW), HB GT#10 (32.5 MW)

Old Harbour’s maximum capacity rating will remain at 223.5MW up to mid-2016 when the retirement of OH#2, OH#3 and OH#4 is forecasted to go offline. The station will be retired in its entirety by year end 2016.

Bogue’s maximum capacity rating is forecasted to remain at 222.5MW over the period 2014 to 2019.

JPS Renewables MCR is forecasted at 29.1MW over the period 2014 to 2019. This includes 3MW Munro wind farm and 6.3MW Maggotty “B” plant commissioned January 2014.

IPP’s MCR forecasted to grow by 78MW of renewable energy in 2015. This will take the IPP total from 298MW to 376.6MW in 2015. In 2016 the IPP MCR is forecasted to further grow by 381MW with the installation of EWI LNG CCGT plant. This will take the IPP total to 757.6MW
from 2016 to 2019. It must be noted that no existing IPP unit was forecasted to be retired from 2014 to 2019\(^{100}\).

The MCR assumptions for the 5 year period are shown in Figure 12-12: System Historical and Projected MCR (MW) at the end of the chapter.

### 12.5.1.2 Forecasted Capacity Factor

Rockfort’s capacity factor is forecasted to average 82% 2014 to 2015, upon arrival of EWI 381MW in 2016, the plant’s annual average capacity factor projected to fall to 57.5% 2016 to 2019. This is inclusive of major maintenance outages each year. Should the system demand grow at a rate >1% post EWI installation the capacity factor for this plant would increase.

Hunts Bay’s #B6 capacity factor is forecasted to average 53% 2014 to 2015, upon arrival of EWI 381MW in 2016, this unit will be retired. The capacity factor of Hunts Bay’s gas turbines projected to average 27%, 2014 to 2016. The average is forecasted to fall to 3% 2017 to 2019. Should the system demand grow at a rate >1% post EWI installation the capacity factor for these peaking units would increase.

Old Harbour’s capacity factor is forecasted to average 46% 2014 to 2015, upon arrival of EWI 381MW in 2016, all units will be retired. The station will be retired in its entirety by year end 2016.

Bogue’s capacity factor is forecasted to average 41% 2014 to 2019. Upon conversion of the CCGT at this site to use natural gas in 2016, the cap factor will remain constant over the period. Should the system demand grow at a rate >1% post EWI installation the capacity factor for Bogue’s peaking units would increase.

JPS Hydro Renewables capacity factor forecasted to average 71% 2014 to 2019. Capacity factor for Wind farms, Wigton 33% and Munro 15%.

IPP’s capacity factor forecasted to average 56% 2014 to 2015. With the installation of new capacity in 2016, the IPP average is forecasted at 44% 2016 to 2019.

The overall system capacity factor is forecasted to decrease over the period 2014 to 2019, largely in part due to the new installations expected online. To a lesser extent a <1% growth in demand is forecasted and will also have an impact on the system capacity factor.

The capacity factors of each plant for the 5 year period are provided in Figure 12-13 at the end of the chapter.

---

\(^{100}\) Although JPPC PPA is slated to expire in January 2018 its load was retained in the model under the assumption that plant is still available to provide power having not reached its useful life.
12.5.1.3 Forecasted Energy Production

Rockfort’s energy production is forecasted to average 265 GWh 2014 to 2016. 2017 to 2019 this numbers is projected to fall to 196 GWh average per year. Should the system demand grow at a rate >1% post EWI installation the energy production from this plant would increase, based on its standing on the merit order post EWI coming online.

Hunts Bay’s #B6 energy production forecasted to average 320 GWh annually 2014 to 2015. In its final year before retirement the unit is projected to produce 131 GWh of power for 2016. The gas turbines at Hunts Bay are forecasted to average annual production of 16 GWH 2014 to 2016. Post 2016 these GTS are projected to fall to annual production of 7 GWh. Should the system demand grow at a rate >1% post EWI installation the energy production from these peaking units would increase.

Old Harbour’s energy production is forecasted to average 911 GWh annually 2014 to 2015, upon arrival of EWI 381 MW in 2016, energy production from the Old Harbour plant is projected to fall to 243 GWh all units will be retired by year end 2016.

Bogue’s CCGT forecasted to average 794 GWH annually in energy production 2014 to 2019. Based on the CCGT being converted to natural gas in 2016. The other GTs at Bogue GT #3 – GT #11 are projected to average 2 GWH annually 2014 to 2019. Should the system demand grow at a rate >1% post EWI installation the energy from Bogue’s peaking units would increase.

JPS Hydro Renewables energy projection annually to average 138 GWh 2014 to 2019. Energy production from wind Wigton and Munro Blue Mountain and Solar, forecasted at 38 GWh annually 2014 to 2014.

IPP’s energy projection annually to average 413 GWh per site. JEP, JPPC, WKPP and EWI 2016 to 2019.

The overall system demand is forecasted to increase by 0.2% annually over the period 2014 to 2019, largely in part due to most new customers expected to come from small commercial and residential customers. Should demand grow by >1% post EWI installation and Bogue CCGT conversion to natural gas, the system production numbers will have the potential to grow.

The forecasted energy production of each plant for the 5 year period are shown in Figure 12-14 at the end of the chapter.

12.6 System Heat Rate Model Results

12.6.1 Heat Rate Forecast 2014

HFO #6 Fuel prices for 2014 was modelled at US$102.98/barrel average for JPS Plants. HFO #6 price average for the IPPs US$103.46/barrel was forecasted. For ADO #2 the average for 2014 was forecasted at US$138.51/barrel. 2014 VOM for the IPPs averaged US$15.81/MWh in
Fuel Recovery – Heat Rate Target

The merit order top ten units / plant from the above for 2014 RF#1, RF#2, JPPC, WKPP, JEP, HB #B6, OH#4, BG CCGT, OH #3, OH#2.

The forecasted heat rate by plant is as follows for 2014.

- Rockfort is forecasted at 9,274kj/kWh with planned major outage intervention on RF#2.
- Old Harbour plant heat rate is forecasted at 13,711kj/kWh, largely due to a forecasted lower capacity factor since the installation of WKPP, deteriorated performance of OH#2 with cycling duties now enabled, along with planned major maintenance of OH#3.
- Hunts Bay HB#B6 forecasted at 12,606kj/kWh with planned major intervention. Hunts Bay gas turbines forecasted at 15,891kj/kWh which is reflective of their peaking duties.
- Bogue gas turbine GT#3-GT#11 are forecasted at 18,395kj/kWh as per their peaking duties. Bogue CCGT is forecasted at 9,702kj/kWh with major outage intervention on CC GT#12.
- IPPs are forecasted at 8,391kj/kWh with major outage intervention forecasted for JEP Barge #1, major overhaul JPPC Engine#1, Major overhaul JPPC engine #2.

The 2014 System Thermal heat rate is forecasted at 10,390kj/kWh

**Figure 12-6: Heat Rate Forecast 2014**

12.6.2 Heat Rate Forecast 2015

HFO #6 Fuel prices for 2015 were modelled at US$105.04/barrel average for JPS Plants. HFO #6 price average for the IPPs US$105.53/barrel was forecasted. For ADO #2 the average for 2015 was forecasted at US$141.28/barrel. 2015 VOM for the IPPs averaged US$15.61/MWh
in the model. The merit order top ten units/plant from the above for 2015 RF#2, RF#1, JPPC, WKPP, JEP, HB #B6, OH#4, BG CCGT, OH #3, OH#2.

The forecasted heat rate by plant is as follows for 2015:

- Rockfort is forecasted at 9,261kJ/kWh with planned major outage intervention on RF#1.
- Old Harbour plant heat rate is forecasted at 13,307kJ/kWh, largely due to a forecasted lower capacity factor of OH#2 with cycling duties, along with the addition of 78MW of renewable capacity with forecasted 58GWh of production.
- Hunts Bay HB#B6 forecasted at 12,562kJ/kWh with routine maintenance. Hunts Bay gas turbines forecasted at 15,817kJ/kWh which is reflective of their peaking duties.
- Bogue gas turbine GT#3-GT#11 are forecasted at 18,709kJ/kWh as per their peaking duties along with 78MW of renewable capacity installation. Bogue CCGT is forecasted at 9,725kJ/kWh with major outage intervention on CC GT#13.
- IPPs are forecasted at 8,365kJ/kWh with major outage JEP Barge #2, major outages on single engines for WKPP.

The 2015 System Thermal heat rate is forecasted at 10,404kJ/kWh.

**Figure 12-7: Heat Rate Forecast 2015**

12.6.3 Heat Rate Forecast 2016

HFO #6 Fuel prices for 2016 were modelled at US$106.06/barrel average for JPS Plants. HFO #6 price average for the IPPs US$106.55/barrel was forecasted. For ADO #2 the average for 2016 was forecasted at US$142.30/barrel. The assumed LNG Fuel price for EWI was US$13.2/MMBTU and the assumed natural gas fuel price for Bogue CCGT was US$14.25/MMBTU. 2016 VOM for the IPPs averaged US$12.96/MWh in the model, inclusive
of EWI CCGT. The merit order top ten units / plant from the above for 2016 EWI CCGT, BG CCGT, RF#2, RF#1, JPPC, WKPP, JEP, GT#11, GT#10.

The forecasted heat rate by plant is as follows for 2016.

- Rockfort is forecasted at 9,569kj/kWh with planned major outage intervention on RF#2, driven largely by reduced capacity factor stemming from installation of EWI (3 blocks x 127MW LNG CCGT) and conversion of BG 120MW CCGT to compressed natural gas fuel.
- Old Harbour plant heat rate is forecasted at 13,165kj/kWh, largely due to a forecasted lower capacity factor with entire plant slated to retire between April to June 2016, with the installation of EWI (3 blocks x 127MW LNG CCGT).
- Hunts Bay HB#B6 forecasted at 12,616kj/kWh with unit slated to retire June 2016 with the installation of EWI (3 blocks x 127MW LNG CCGT). Hunts Bay gas turbines forecasted at 15,943kj/kWh which is reflective of their peaking duties.
- Bogue gas turbine GT#3-GT#11 are forecasted at 18,463kj/kWh as per their peaking duties with installation of EWI (3 blocks x 127MW LNG CCGT). Bogue CCGT is forecasted at 9,794kj/kWh with major outage intervention on CC GT#12.
- IPPs now including EWI 381MW (3 blocks of 127MW) are forecasted at 8,150kj/kWh with routine outage on EWI (3 blocks x 127MW LNG CCGT).

The 2016 System Thermal heat rate is forecasted at 9,150kj/kWh.

**Figure 12-8: Heat Rate Forecast 2016**

12.6.4 Heat Rate Forecast 2017

HFO #6 Fuel prices for 2017 were modelled at US$107.12/barrel average for JPS Plants, but not used. HFO #6 price average for the IPPs US$107.62/barrel was forecasted. For ADO #2 the average for 2017 was forecasted at US$143.72/barrel. The assumed LNG Fuel price for EWI was
US$13.2/MMBTU and the assumed natural gas fuel price for Bogue CCGT was US$14.25/MMBTU. 2017 VOM for the IPPs averaged US$12.99/MWh in the model, inclusive of EWI CCGT. The merit order top ten units / plant from the above for 2017 EWI CCGT, BG CCGT, RF#2, RF#1, JPPC, WKPP, JEP, GT#11, GT#10.

The forecasted heat rate by plant is as follows for 2017.

- Rockfort is forecasted at 9,687kj/kWh with planned major outage intervention on RF#1, driven largely by reduced capacity factor.
- Old Harbour plant retired.
- Hunts Bay HB#B6 retired. Hunts Bay gas turbines forecasted at 16,390kj/kWh which is reflective of their peaking duties.
- Bogue gas turbine GT#3-GT#11 are forecasted at 18,328kj/kWh as per their peaking duties. Bogue CCGT is forecasted at 9,884kj/kWh with major outage intervention on CC GT#13.
- IPPs now including EWI 381MW (3 blocks of 127MW) are forecasted at 8,135kj/kWh with routine outage on EWI (3 blocks x 127MW LNG CCGT).

The 2017 System Thermal heat rate is forecasted at 8,629kj/kWh.

**Figure 12-9: Heat Rate Forecast 2017**

12.6.5 Heat Rate Forecast 2018

HFO #6 Fuel prices for 2018 were modelled at US$107.66/barrel average for JPS Plants, but not used. HFO #6 price average for the IPPs US$108.16/barrel was forecasted. For ADO #2 the average for 2018 was forecasted at US$144.44/barrel. The assumed LNG Fuel price for EWI was US$13.2/MMBTU and the assumed natural gas fuel price for Bogue CCGT was US$14.25/MMBTU. 2018 VOM for the IPPs averaged US$13.03/MWh in the model, inclusive
of EWI CCGT. The merit order top ten units / plant from the above for 2018 EWI CCGT, BG CCGT, RF#2, RF#1, JPPC, WKPP, JEP, GT#11, GT#10.

The forecasted heat rate by plant is as follows for 2018.

- Rockfort is forecasted at 9,697kj/kWh with planned major outage intervention on RF#2, driven largely by reduced capacity factor.
- Old Harbour plant retired.
- Hunts Bay HB #B6 retired. Hunts Bay gas turbines forecasted at 16,381kj/kWh which is reflective of their peaking duties.
- Bogue gas turbine GT#3-GT#11 are forecasted at 18,325kj/kWh as per their peaking duties. Bogue CCGT is forecasted at 9,883kj/kWh with major outage intervention on CC GT#12.
- IPPs now including EWI 381MW (3 blocks of 127MW) are forecasted at 8,135kj/kWh with routine outage on EWI (3 blocks x 127MW LNG CCGT).

The 2018 System Thermal heat rate is forecasted at 8,629kj/kWh.

**Figure 12-10: Heat Rate Forecast 2018**

---

12.6.6  Heat Rate Forecast 2019

HFO #6 Fuel prices for 2019 were modelled at US$108.20/barrel average for JPS Plants, but not used. HFO #6 price average for the IPPs US$108.70/barrel was forecasted. For ADO #2 the average for 2019 was forecasted at US$145.16/barrel. The assumed LNG Fuel price for EWI was US$13.3/MMBTU and the assumed natural gas fuel price for Bogue CCGT US$14.25/MMBTU. 2019 VOM for the IPPs averaged US$13.07/MWh in the model, inclusive of EWI CCGT. The merit order top ten units / plant from the above for 2019 EWI CCGT, BG CCGT, RF#2, RF#1, JPPC, WKPP, JEP, GT#11, GT#10.
The forecasted heat rate by plant is as follows for 2019.

- Rockfort is forecasted at 9,687kJ/kWh with planned major outage intervention on RF#1, driven largely by reduced capacity factor.
- Old Harbour plant retired.
- Hunts Bay HB #B6 retired. Hunts Bay gas turbines forecasted at 16,346kJ/kWh which is reflective of their peaking duties.
- Bogue gas turbine GT#3-GT#11 are forecasted at 18,319kJ/kWh as per their peaking duties. Bogue CCGT is forecasted at 9,849kJ/kWh with major outage intervention on CC GT#12.
- IPPs now including EWI 381MW (3 blocks of 127MW) are forecasted at 8,099kJ/kWh with major outage on EWI (3 blocks x 127MW LNG CCGT).

The 2019 System Thermal heat rate is forecasted at 8,601kJ/kWh.

**Figure 12-11: Heat Rate Forecast 2019**

### 12.7 Proposal for Heat Rate Target

The system heat rate performance over the five-year price cap period will depend on several factors affecting the economic dispatch which include the:

1. Growth in system demand
2. The addition of new generating units and the installed reserve margin (OUR);
3. Heat rate improvements made to existing generating units (JPS);
4. Availability and reliability of JPS generators (JPS);
5. Availability and reliability of IPP generators (IPPs);
6. Absolute and relative fuel prices for JPS and the IPPs and the impact on economic dispatch;
7. Spinning reserve policy (JPS & OUR); and
8. Network constraints and contingencies (JPS).
Fuel Recovery – Heat Rate Target

While all the above factors influence the resultant system heat rate, JPS has sole direct control over only a few.

The mechanism used to calculate the pass-through Fuel Cost on a monthly basis under the current tariff operates according to the following formula:

\[
\text{Pass through Cost} = \text{Fuel Cost} \times \frac{\text{Heat Rate Target}}{\text{Heat Rate Actual}} \times \frac{(1 - \text{Losses Actual})}{(1 - \text{Losses Target})}
\]

The heat rate target should continue to be based on the total generating units throughout the system (both JPS and IPPs), since fuel optimization through economic dispatch seeks to optimize overall system variable cost. This is similar to the approach used in setting the 2009 –2014 heat rate target where average performance was considered indicative of future performance subject to the addition of new capacity or the retirement of existing ones. In this analysis, the effect of some of the heat rates influencing factors are not properly accounted for since average performance does not exactly mimic the cumulative effect of the actual monthly heat rate penalty/reward system. Average heat rate performance for a year does not fully capture the effect that a wide range of monthly heat rate values would have on a monthly penalty/reward calculation, especially given the monthly variation in fuel prices and foreign exchange rates throughout a given year. In this regard, it is JPS’ view that the heat rate target must consider the effect that the likely changes to the influencing factors, which are outside JPS’ control, would have on the actual monthly heat rate value.

JPS cannot influence the availability or reliability of the IPPs and should not be exposed to any additional penalties (fuel and heat rate) because of any failure to perform. JPS faces increased performance risk to the IPPs as their plants age over time and as they expand their generating capacity as a percentage of the system installed capacity. A failure to achieve the target level of availability and reliability by the IPPs has the largest negative effect on the system heat rate, all factors remaining constant. Since the performance guarantees (e.g. liquidated damages) that the IPPs provide for under performance is effectively refunded to the customer through the IPP fuel surcharge/adjustment, it is JPS that suffers the penalty when the system heat rate worsens because of the poor performance of IPPs.

Over the years, the OUR has set a heat rate target that requires continuous improvement by JPS, which is ultimately to the benefit of the customers. The system wide target (to include IPPs) was set at 11,900 kJ/kWh in 2002, then revised downwards to 11,600 kJ/kWh in 2003, to 11,200 kJ/kWh in 2004 and to finally to 10,200 kJ/kWh in 2012. This represents a required 14% improvement in the use of fuel over the last decade, which is meaningful by any standard. However, despite the system heat rate performance since 2009, the system is still prone to wide monthly variation as highlighted before. This has been so in the face of the relative stagnation in demand growth over the period, primarily on account of much needed maintenance to base load generation units.

Based on the planned mix of generating units, including IPPs, their projected availability and dispatch, and the foregoing discussion of heat rate affecting variables and the possible variation in heat rate performance for reasons beyond JPS’ control, JPS proposes the following heat rate target for the rate cap period 2014 –2019, as noted below:

- Maintaining the current Heat Rate target of 10,200 for the next year;
- Annual review of the Heat Rate target and adjustment for the known impact of new generation added to the grid;
An assessment of the total generation system, the structure of the system and the efficacy of a system heat rate target after the implementation of the 381MW LNG project in 2016; and

A review of the Heat Rate target for 2017, should the new 381MW project not be completed by 2016, given the fact that JPS’s existing power plants (292MW) slated for retirement in 2016 will not be able perform against a guaranteed heat rate target after 2016.
## Fuel Recovery – Heat Rate Target

### Table: Historical and Projected MCR (MW)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Average</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rockfort</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hunt's Bay</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Old Harbour</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bogue</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydro</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>JPS Co’s Total</td>
<td></td>
<td>623.69</td>
<td>625.89</td>
<td>625.89</td>
<td>625.89</td>
<td>625.89</td>
<td>625.89</td>
<td>633.89</td>
<td>634.89</td>
<td>603.89</td>
<td>341.89</td>
<td>341.89</td>
<td>452.89</td>
<td></td>
</tr>
<tr>
<td>EPC-50</td>
<td></td>
<td>74.16</td>
<td>74.16</td>
<td>74.16</td>
<td>74.16</td>
<td>74.16</td>
<td>74.16</td>
<td>74.16</td>
<td>74.16</td>
<td>74.16</td>
<td>74.16</td>
<td>74.16</td>
<td>74.16</td>
<td></td>
</tr>
<tr>
<td>IPPC</td>
<td></td>
<td>60.00</td>
<td>60.00</td>
<td>60.00</td>
<td>60.00</td>
<td>60.00</td>
<td>60.00</td>
<td>60.00</td>
<td>60.00</td>
<td>60.00</td>
<td>60.00</td>
<td>60.00</td>
<td>60.00</td>
<td></td>
</tr>
<tr>
<td>Jamaica #1</td>
<td></td>
<td>2.00</td>
<td>2.00</td>
<td>2.00</td>
<td>2.00</td>
<td>2.00</td>
<td>2.00</td>
<td>2.00</td>
<td>2.00</td>
<td>2.00</td>
<td>2.00</td>
<td>2.00</td>
<td>2.00</td>
<td></td>
</tr>
<tr>
<td>Jamaica #2</td>
<td></td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td></td>
</tr>
<tr>
<td>WPPT</td>
<td></td>
<td>18.00</td>
<td>18.00</td>
<td>18.00</td>
<td>18.00</td>
<td>18.00</td>
<td>18.00</td>
<td>18.00</td>
<td>18.00</td>
<td>18.00</td>
<td>18.00</td>
<td>18.00</td>
<td>18.00</td>
<td></td>
</tr>
<tr>
<td>New Peteque Plant</td>
<td></td>
<td>127.00</td>
<td>127.00</td>
<td>127.00</td>
<td>127.00</td>
<td>127.00</td>
<td>127.00</td>
<td>127.00</td>
<td>127.00</td>
<td>127.00</td>
<td>127.00</td>
<td>127.00</td>
<td>127.00</td>
<td></td>
</tr>
</tbody>
</table>

### Figure 12-13: Historical and Projected Capacity Factor

JPS Tariff Application 2014 – 2019  p. 278 of 412
### Fuel Recovery – Heat Rate Target

#### JPS Tariff Application 2014 – 2019

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
</tr>
<tr>
<td>Rockfort</td>
<td>1</td>
<td>83%</td>
<td>82%</td>
<td>80%</td>
<td>83%</td>
<td>81%</td>
<td>%</td>
<td>82%</td>
<td>86%</td>
<td>79%</td>
<td>66%</td>
<td>53%</td>
<td>59%</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>83%</td>
<td>79%</td>
<td>88%</td>
<td>80%</td>
<td>86%</td>
<td>%</td>
<td>83%</td>
<td>86%</td>
<td>86%</td>
<td>58%</td>
<td>59%</td>
<td>53%</td>
</tr>
<tr>
<td>Subtotal</td>
<td></td>
<td>77%</td>
<td>79%</td>
<td>83%</td>
<td>80%</td>
<td>82%</td>
<td>%</td>
<td>80%</td>
<td>82%</td>
<td>83%</td>
<td>62%</td>
<td>56%</td>
<td>56%</td>
</tr>
<tr>
<td>Hunt's Bay</td>
<td>H6</td>
<td>73%</td>
<td>72%</td>
<td>70%</td>
<td>67%</td>
<td>63%</td>
<td>%</td>
<td>69%</td>
<td>49%</td>
<td>57%</td>
<td>22%</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>GT #4</td>
<td>20%</td>
<td>17%</td>
<td>17%</td>
<td>18%</td>
<td>12%</td>
<td>%</td>
<td>17%</td>
<td>4%</td>
<td>3%</td>
<td>3%</td>
<td>2%</td>
<td>2%</td>
</tr>
<tr>
<td></td>
<td>GT #10</td>
<td>36%</td>
<td>29%</td>
<td>32%</td>
<td>28%</td>
<td>19%</td>
<td>%</td>
<td>29%</td>
<td>10%</td>
<td>7%</td>
<td>9%</td>
<td>4%</td>
<td>4%</td>
</tr>
<tr>
<td>Subtotal</td>
<td></td>
<td>51%</td>
<td>49%</td>
<td>48%</td>
<td>46%</td>
<td>40%</td>
<td>%</td>
<td>40%</td>
<td>47%</td>
<td>31%</td>
<td>34%</td>
<td>15%</td>
<td>3%</td>
</tr>
<tr>
<td>Old Harbour</td>
<td>OH #1</td>
<td>73%</td>
<td>62%</td>
<td>57%</td>
<td>51%</td>
<td>34%</td>
<td>%</td>
<td>55%</td>
<td>40%</td>
<td>42%</td>
<td>7%</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>OH #2</td>
<td>67%</td>
<td>63%</td>
<td>58%</td>
<td>59%</td>
<td>59%</td>
<td>%</td>
<td>60%</td>
<td>49%</td>
<td>58%</td>
<td>13%</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>OH #4</td>
<td>70%</td>
<td>66%</td>
<td>57%</td>
<td>49%</td>
<td>65%</td>
<td>%</td>
<td>66%</td>
<td>62%</td>
<td>68%</td>
<td>22%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Subtotal</td>
<td></td>
<td>54%</td>
<td>51%</td>
<td>47%</td>
<td>44%</td>
<td>44%</td>
<td>%</td>
<td>48%</td>
<td>44%</td>
<td>49%</td>
<td>14%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bogue</td>
<td>GT #3</td>
<td>21%</td>
<td>11%</td>
<td>10%</td>
<td>10%</td>
<td>6%</td>
<td>%</td>
<td>12%</td>
<td>4%</td>
<td>2%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>GT #6</td>
<td>9%</td>
<td>8%</td>
<td>4%</td>
<td>4%</td>
<td>2%</td>
<td>%</td>
<td>5%</td>
<td>2%</td>
<td>1%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>GT #7</td>
<td>12%</td>
<td>12%</td>
<td>5%</td>
<td>0%</td>
<td></td>
<td></td>
<td>6%</td>
<td>5%</td>
<td>0%</td>
<td>1%</td>
<td>1%</td>
<td>1%</td>
</tr>
<tr>
<td></td>
<td>GT #9</td>
<td>11%</td>
<td>4%</td>
<td>10%</td>
<td>5%</td>
<td>6%</td>
<td>%</td>
<td>5%</td>
<td>0%</td>
<td>1%</td>
<td>1%</td>
<td>1%</td>
<td>1%</td>
</tr>
<tr>
<td>Subtotal</td>
<td></td>
<td>54%</td>
<td>51%</td>
<td>47%</td>
<td>44%</td>
<td>44%</td>
<td>%</td>
<td>48%</td>
<td>44%</td>
<td>49%</td>
<td>14%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydro</td>
<td>GT #12</td>
<td>85%</td>
<td>74%</td>
<td>78%</td>
<td>75%</td>
<td>65%</td>
<td>%</td>
<td>75%</td>
<td>83%</td>
<td>77%</td>
<td>80%</td>
<td>78%</td>
<td>78%</td>
</tr>
<tr>
<td></td>
<td>GT #13</td>
<td>71%</td>
<td>84%</td>
<td>84%</td>
<td>81%</td>
<td>72%</td>
<td>%</td>
<td>78%</td>
<td>83%</td>
<td>77%</td>
<td>80%</td>
<td>78%</td>
<td>78%</td>
</tr>
<tr>
<td>Subtotal</td>
<td></td>
<td>45%</td>
<td>45%</td>
<td>46%</td>
<td>44%</td>
<td>34%</td>
<td>%</td>
<td>43%</td>
<td>43%</td>
<td>39%</td>
<td>40%</td>
<td>40%</td>
<td>40%</td>
</tr>
<tr>
<td>JPSCo’s</td>
<td>Subtotal</td>
<td>72%</td>
<td>69%</td>
<td>68%</td>
<td>67%</td>
<td>55%</td>
<td>%</td>
<td>72%</td>
<td>74%</td>
<td>68%</td>
<td>70%</td>
<td>70%</td>
<td>70%</td>
</tr>
<tr>
<td>JEP 124MW 2012</td>
<td>73%</td>
<td>71%</td>
<td>76%</td>
<td>86%</td>
<td>68%</td>
<td>%</td>
<td>75%</td>
<td>50%</td>
<td>42%</td>
<td>17%</td>
<td>7%</td>
<td>7%</td>
<td>7%</td>
</tr>
<tr>
<td>IPP 50</td>
<td>81%</td>
<td>84%</td>
<td>84%</td>
<td>84%</td>
<td>80%</td>
<td>%</td>
<td>80%</td>
<td>88%</td>
<td>89%</td>
<td>65%</td>
<td>55%</td>
<td>55%</td>
<td>55%</td>
</tr>
<tr>
<td>JPCC</td>
<td></td>
<td>81%</td>
<td>81%</td>
<td>80%</td>
<td>78%</td>
<td>80%</td>
<td>%</td>
<td>85%</td>
<td>79%</td>
<td>24%</td>
<td>3%</td>
<td>3%</td>
<td>4%</td>
</tr>
<tr>
<td>JWFF</td>
<td></td>
<td>79%</td>
<td>86%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>54%</td>
<td>67%</td>
<td>68%</td>
<td>68%</td>
<td>68%</td>
<td>68%</td>
</tr>
<tr>
<td>EW1 CC #1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>47%</td>
<td>69%</td>
<td>69%</td>
<td>66%</td>
<td>63%</td>
<td></td>
</tr>
<tr>
<td>EW1 CC #2</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>47%</td>
<td>69%</td>
<td>69%</td>
<td>66%</td>
<td>63%</td>
<td></td>
</tr>
<tr>
<td>EW1 CC #3</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>41%</td>
<td>70%</td>
<td>70%</td>
<td>70%</td>
<td>70%</td>
<td>63%</td>
</tr>
<tr>
<td>Jamaica</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Jamaica Broilers</td>
<td>12%</td>
<td>20%</td>
<td>25%</td>
<td>13%</td>
<td>18%</td>
<td></td>
<td></td>
<td>17%</td>
<td>17%</td>
<td>17%</td>
<td>17%</td>
<td>17%</td>
<td>17%</td>
</tr>
<tr>
<td>Wigton I</td>
<td>33%</td>
<td>30%</td>
<td>27%</td>
<td>33%</td>
<td>35%</td>
<td></td>
<td></td>
<td>30%</td>
<td>32%</td>
<td>31%</td>
<td>31%</td>
<td>31%</td>
<td>31%</td>
</tr>
<tr>
<td>Wigton H</td>
<td>28%</td>
<td>32%</td>
<td>39%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>30%</td>
<td>30%</td>
<td>30%</td>
<td>30%</td>
<td>30%</td>
<td>30%</td>
</tr>
<tr>
<td>Wigton H</td>
<td>11%</td>
<td>31%</td>
<td>31%</td>
<td>31%</td>
<td>31%</td>
<td></td>
<td></td>
<td>11%</td>
<td>31%</td>
<td>31%</td>
<td>31%</td>
<td>31%</td>
<td>31%</td>
</tr>
<tr>
<td>WRG Solar</td>
<td>7%</td>
<td>18%</td>
<td>18%</td>
<td>18%</td>
<td>18%</td>
<td>18%</td>
<td></td>
<td>7%</td>
<td>18%</td>
<td>18%</td>
<td>18%</td>
<td>18%</td>
<td>18%</td>
</tr>
<tr>
<td>JPS Manro</td>
<td>9%</td>
<td>13%</td>
<td>9%</td>
<td>13%</td>
<td></td>
<td></td>
<td></td>
<td>5%</td>
<td>3%</td>
<td>3%</td>
<td>3%</td>
<td>3%</td>
<td>3%</td>
</tr>
<tr>
<td>Maggotty B</td>
<td></td>
<td>48%</td>
<td>70%</td>
<td>61%</td>
<td>61%</td>
<td>61%</td>
<td></td>
<td>48%</td>
<td>70%</td>
<td>61%</td>
<td>61%</td>
<td>61%</td>
<td>61%</td>
</tr>
<tr>
<td>Brigade Capacity 3 – 60MW Diesel</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>IPP</td>
<td>74%</td>
<td>67%</td>
<td>71%</td>
<td>57%</td>
<td>70%</td>
<td>68%</td>
<td>%</td>
<td>63%</td>
<td>49%</td>
<td>39%</td>
<td>45%</td>
<td>45%</td>
<td>45%</td>
</tr>
<tr>
<td>System</td>
<td>58%</td>
<td>55%</td>
<td>56%</td>
<td>51%</td>
<td>52%</td>
<td>%</td>
<td>54%</td>
<td>50%</td>
<td>47%</td>
<td>35%</td>
<td>43%</td>
<td>43%</td>
<td>43%</td>
</tr>
</tbody>
</table>

**JPS Tariff Application 2014 – 2019 p. 279 of 412**
Fuel Recovery – Heat Rate Target

Figure 12-14: Historical and Projected Unit Energy (MWh)
Plant
Rockfort

Hunt's Bay

Old Harbour

Bogue

Unit
1
2
Subtotal
B6
GT #4
GT #5
GT #10
Subtotal
OH #1
OH #2
OH #3
OH #4
Subtotal
GT #3
GT #6
GT #7
GT #8
GT #9
GT #11
GT #12
GT #13 CCGT
ST #14
Subtotal

2009

2010

2011

2012

2013

Average

2014

2015

2016

2017

2018

2019

Average

MWh

MWh

MWh

MWh

MWh

MWh

MWh

MWh

MWh

MWh

MWh

MWh

MWh

142,117
113,387
255,503
411,486
37,620
100,285
549,391
336,172
332,939
396,681
1,065,791
39,700
13,978
18,158
18,332
24,501
279,892
235,273
233,478
863,313

140,272
135,821
276,094
408,318
32,438
81,286
522,043
309,606
344,485
342,272
996,362
21,132
1,360
12,472
19,339
(21)
14,644
243,577
277,511
265,014
855,028

137,715
151,827
289,541
395,128
32,668
89,806
517,602
284,358
319,185
322,577
926,120
18,056
16,723
5,909
7,600
7,430
1,722
258,215
277,010
274,987
867,652

143,060
137,217
280,277
378,742
32,904
78,239
489,885
258,656
321,497
276,978
857,131
19,445
9,530
5,929
(59)
17,471
1,275
248,159
268,275
261,236
831,260

138,942
147,908
286,850
357,582
22,555
52,838
432,975
171,323
320,617
372,519
864,458
11,487
4,937
2,970
8,845
216,658
236,884
161,959
643,741

140,421
137,232
277,653
390,251
31,637
80,491
502,379
272,023
327,745
342,205
941,973
21,964
6,510
8,251
9,008
10,411
8,428
249,300
258,991
572,864

150,291
137,057
287,348
296,992
7,901
27,398
332,291
211,639
279,281
370,840
861,760
7,164
747
3,918
9,429
277,680
277,680
277,680
854,298

138,625
151,356
289,981
343,579

115,258
101,489
216,747
131,499

93,724
102,737
196,461

102,917
93,553
196,470

93,749
102,757
196,506

5,247
21,020
369,846

6,534
25,002
163,035

218,285
333,040
410,828
962,153
3,290
866
1,718

35,532
75,874
131,661
243,067
400
40
180

3,760
10,263
14,023
470

3,760
10,279
14,039
470

3,760
10,357
14,117
470

255

255

255

647

1,235

2,053

2,054

2,056

257,334
257,334
257,334
778,523

265,825
265,825
265,825
799,329

261,245
261,245
261,245
786,512

261,286
261,286
261,286
786,638

265,467
265,467
265,467
799,181

134,040
2,534,543
456,434

137,950
1,560,128
186,770

137,629
1,134,625
76,259

137,629
1,134,776
76,205

137,629
1,147,433
77,046

468,370
452,018

344,941
138,800
603,396
526,656
461,276
4,392
17,568
54,890
61,761
64,863
58,949
32,184
741
38,353
2,595,540
4,155,668

290,499
17,670
750,632
765,817
782,120
4,380
17,520
54,755
61,628
64,707
58,804
32,088
590
38,278
3,015,747
4,150,372

289,723
17,685
751,235
766,411
782,728
4,380
17,520
54,755
61,628
64,707
58,804
32,088
590
38,278
3,016,737
4,151,513

296,381
24,370
757,694
737,722
781,654
4,380
17,520
54,755
61,628
64,707
58,804
32,088
590
38,278
3,007,617
4,155,050

115,761
114,825
230,586
257,357
5,160
17,387
279,904
77,576
114,699
152,222
344,497
2,044
551
1,097
2,912
264,806
264,806
264,806
801,022

Hydro
Subtotal
JPSCo's Total
JEP 124MW 2012
JEP-50
JPPC
WKPP
EWI CC #1
EWI CC #2
EWI CC #3
Jamalco
Jamaica Broilers
Wigton I
Wigton II
Wigton II
Blue Mountain Wind
WRG Solar
JPS Munro
Maggotty B
Brigde Capacity 3 - 60MW Diesel
Import Sub Total
Total

140,073
2,874,071
476,657
357,391
437,590

151,564
2,801,091
463,475
370,246
433,444

149,526
2,750,441
492,262
369,625
418,268

148,448
2,607,002
557,418
209,046
388,393
181,189

120,309
2,348,333
736,308
431,512
491,594

141,984
2,436,853
545,224
261,262
421,841

3,158
13,064
58,565
-

2,325
20,847
53,162
-

3,645
26,970
46,892
44,334

3,605
13,810
57,159
50,305

3,768
19,202
54,763
61,606

3,300
18,779
54,108

1,346,425
4,220,496

564
1,344,062
4,145,153

2,560
1,404,557
4,154,998

2,241
1,463,167
4,070,169

3,406
1,802,158
4,150,491

Growth Rate (%)

JPS Tariff Application 2014 – 2019

6.9%

-1.8%

0.2%

-2.0%

2.0%

1,472,074
4,148,261

144,987
2,480,684
543,121
463,606
484,866
4,380
17,520
52,560
47,307
1,317
26,207
1,640,884
4,121,568
-0.6%

4,380
17,520
55,755
60,613
24,160
21,597
12,480
792
38,278
1,612,397
4,146,940
0.6%

p. 280 of 412

0.2%

-0.1%

0.0%

0.1%

138,311
1,794,319
235,973
358,920
189,235
572,591
559,321
561,556
4,382
17,528
54,578
59,094
47,191
42,826
23,488
770
36,279
2,649,608
4,151,909


## Figure 12-15: JPS Thermal Heat Rate

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
</tr>
<tr>
<td>Rockfort</td>
<td>1</td>
<td>9,207</td>
<td>9,148</td>
<td>9,211</td>
<td>9,253</td>
<td>9,121</td>
<td>9,188</td>
<td>9,293</td>
<td>9,282</td>
<td>9,626</td>
<td>9,799</td>
<td>9,799</td>
<td>9,799</td>
<td>9,600</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>9,495</td>
<td>9,092</td>
<td>9,195</td>
<td>9,240</td>
<td>9,141</td>
<td>9,233</td>
<td>9,254</td>
<td>9,242</td>
<td>9,503</td>
<td>9,585</td>
<td>9,585</td>
<td>9,585</td>
<td>9,459</td>
</tr>
<tr>
<td></td>
<td>Subtotal</td>
<td>9,335</td>
<td>9,121</td>
<td>9,203</td>
<td>9,246</td>
<td>9,132</td>
<td>9,207</td>
<td>9,274</td>
<td>9,261</td>
<td>9,569</td>
<td>9,687</td>
<td>9,697</td>
<td>9,687</td>
<td>9,580</td>
</tr>
<tr>
<td></td>
<td>B6</td>
<td>12,819</td>
<td>12,669</td>
<td>12,518</td>
<td>12,550</td>
<td>12,774</td>
<td>12,666</td>
<td>12,606</td>
<td>12,562</td>
<td>12,616</td>
<td>12,595</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>GT #4</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>GT #5</td>
<td>16,410</td>
<td>16,915</td>
<td>16,894</td>
<td>16,825</td>
<td>17,010</td>
<td>16,811</td>
<td>17,932</td>
<td>17,788</td>
<td>18,044</td>
<td>18,011</td>
<td>18,011</td>
<td>18,012</td>
<td>17,966</td>
</tr>
<tr>
<td></td>
<td>GT #10</td>
<td>14,490</td>
<td>14,703</td>
<td>14,668</td>
<td>14,695</td>
<td>15,019</td>
<td>14,715</td>
<td>15,302</td>
<td>15,325</td>
<td>15,394</td>
<td>15,796</td>
<td>15,784</td>
<td>15,741</td>
<td>15,557</td>
</tr>
<tr>
<td></td>
<td>Subtotal</td>
<td>13,370</td>
<td>13,249</td>
<td>13,167</td>
<td>13,180</td>
<td>13,268</td>
<td>13,247</td>
<td>12,955</td>
<td>12,793</td>
<td>13,260</td>
<td>13,380</td>
<td>13,381</td>
<td>13,346</td>
<td>13,034</td>
</tr>
<tr>
<td></td>
<td>OH #1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>OH #2</td>
<td>13,606</td>
<td>14,442</td>
<td>14,296</td>
<td>14,525</td>
<td>14,438</td>
<td>14,261</td>
<td>14,734</td>
<td>14,237</td>
<td>14,298</td>
<td>14,423</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>OH #3</td>
<td>12,635</td>
<td>13,406</td>
<td>12,847</td>
<td>13,311</td>
<td>13,294</td>
<td>13,099</td>
<td>13,808</td>
<td>13,723</td>
<td>13,734</td>
<td>13,755</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>OH #4</td>
<td>12,646</td>
<td>12,920</td>
<td>13,829</td>
<td>12,692</td>
<td>12,393</td>
<td>12,896</td>
<td>13,053</td>
<td>12,476</td>
<td>12,532</td>
<td>12,687</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Subtotal</td>
<td>12,945</td>
<td>13,561</td>
<td>13,634</td>
<td>13,477</td>
<td>13,133</td>
<td>13,350</td>
<td>13,711</td>
<td>13,307</td>
<td>13,165</td>
<td>13,165</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>GT #3</td>
<td>17,814</td>
<td>18,214</td>
<td>18,941</td>
<td>18,017</td>
<td>18,250</td>
<td>18,247</td>
<td>18,642</td>
<td>18,716</td>
<td>18,906</td>
<td>18,633</td>
<td>18,638</td>
<td>18,634</td>
<td>18,695</td>
</tr>
<tr>
<td></td>
<td>GT #6</td>
<td>0</td>
<td>23,183</td>
<td>18,037</td>
<td>18,616</td>
<td>18,764</td>
<td>15,720</td>
<td>19,195</td>
<td>19,279</td>
<td>19,342</td>
<td>19,272</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>GT #7</td>
<td>17,690</td>
<td>19,076</td>
<td>19,426</td>
<td>18,633</td>
<td>19,139</td>
<td>18,793</td>
<td>18,573</td>
<td>18,610</td>
<td>18,657</td>
<td>18,578</td>
<td>18,572</td>
<td>18,595</td>
<td>18,595</td>
</tr>
<tr>
<td></td>
<td>GT #8</td>
<td>17,672</td>
<td>17,923</td>
<td>18,389</td>
<td>0</td>
<td>13,496</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>GT #9</td>
<td>16,976</td>
<td>0</td>
<td>17,561</td>
<td>18,279</td>
<td>18,035</td>
<td>14,170</td>
<td>18,070</td>
<td>18,178</td>
<td>18,222</td>
<td>18,222</td>
<td>18,222</td>
<td>18,215</td>
<td>18,189</td>
</tr>
<tr>
<td></td>
<td>GT #11</td>
<td>12,568</td>
<td>13,963</td>
<td>18,610</td>
<td>19,349</td>
<td>16,122</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>GT #12</td>
<td>13,539</td>
<td>14,801</td>
<td>14,991</td>
<td>14,708</td>
<td>14,524</td>
<td>14,476</td>
<td>14,476</td>
<td>14,476</td>
<td>14,476</td>
<td>14,476</td>
<td>14,476</td>
<td>14,476</td>
<td>14,476</td>
</tr>
<tr>
<td></td>
<td>CCGT GT #13</td>
<td>13,623</td>
<td>13,909</td>
<td>13,754</td>
<td>14,222</td>
<td>13,974</td>
<td>13,896</td>
<td>13,896</td>
<td>13,896</td>
<td>13,896</td>
<td>13,896</td>
<td>13,896</td>
<td>13,896</td>
<td>13,896</td>
</tr>
<tr>
<td></td>
<td>ST #14</td>
<td>9,269</td>
<td>9,494</td>
<td>9,479</td>
<td>9,581</td>
<td>10,491</td>
<td>9,663</td>
<td>9,702</td>
<td>9,649</td>
<td>9,794</td>
<td>9,884</td>
<td>9,883</td>
<td>9,849</td>
<td>9,793</td>
</tr>
<tr>
<td></td>
<td>Subtotal</td>
<td>10,238</td>
<td>10,140</td>
<td>10,075</td>
<td>10,162</td>
<td>10,836</td>
<td>10,290</td>
<td>9,918</td>
<td>9,725</td>
<td>9,814</td>
<td>9,913</td>
<td>9,879</td>
<td>9,860</td>
<td></td>
</tr>
<tr>
<td>JPSCo's Heat Rate</td>
<td>11,261</td>
<td>11,287</td>
<td>11,216</td>
<td>11,142</td>
<td>11,367</td>
<td>11,255</td>
<td>11,670</td>
<td>11,577</td>
<td>10,744</td>
<td>9,960</td>
<td>9,961</td>
<td>9,932</td>
<td>10,641</td>
<td></td>
</tr>
</tbody>
</table>
### Fuel Recovery – Heat Rate Target

#### Figure 12-16: Total System Thermal Heat Rate

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
<td></td>
<td>%</td>
<td>%</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>%</td>
</tr>
<tr>
<td>JPSCo's Heat Rate</td>
<td>11,261</td>
<td>11,287</td>
<td>11,216</td>
<td>11,142</td>
<td>11,367</td>
<td>= 11,255</td>
<td>11,670</td>
<td>11,577</td>
<td>10,744</td>
<td>9,960</td>
<td>9,961</td>
<td>9,932</td>
<td>10,641</td>
</tr>
<tr>
<td>JEP 124MW 2012</td>
<td>8,166</td>
<td>8,166</td>
<td>8,416</td>
<td>8,615</td>
<td>8,615</td>
<td>8,396</td>
<td>8,615</td>
<td>8,615</td>
<td>8,615</td>
<td>8,615</td>
<td>8,615</td>
<td>8,615</td>
<td>8,615</td>
</tr>
<tr>
<td>JEP-50</td>
<td>8,166</td>
<td>8,166</td>
<td>8,416</td>
<td>8,615</td>
<td>8,615</td>
<td>8,396</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>JPPC</td>
<td>8,106</td>
<td>8,049</td>
<td>8,076</td>
<td>8,104</td>
<td>8,072</td>
<td></td>
<td>7,935</td>
<td>7,917</td>
<td>8,391</td>
<td>8,779</td>
<td>8,790</td>
<td>8,729</td>
<td>8,424</td>
</tr>
<tr>
<td>WPP</td>
<td>8,569</td>
<td>8,569</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>8,569</td>
<td>8,569</td>
<td>8,569</td>
<td>8,569</td>
<td>8,569</td>
<td>8,569</td>
<td>8,569</td>
</tr>
<tr>
<td>EWI CC #1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>8,000</td>
<td>8,057</td>
<td>8,056</td>
<td>8,012</td>
<td>8,031</td>
</tr>
<tr>
<td>EWI CC #2</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>8,010</td>
<td>8,032</td>
<td>8,031</td>
<td>7,992</td>
<td>8,016</td>
</tr>
<tr>
<td>EWI CC #3</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>8,001</td>
<td>8,007</td>
<td>8,006</td>
<td>7,974</td>
<td>7,997</td>
</tr>
<tr>
<td>Jamalco</td>
<td>9,500</td>
<td>9,500</td>
<td>9,500</td>
<td></td>
<td>9,500</td>
<td></td>
<td>9,500</td>
<td>9,500</td>
<td>9,500</td>
<td>9,500</td>
<td>9,500</td>
<td>9,500</td>
<td>9,500</td>
</tr>
<tr>
<td>Jamaica Broilers</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wigton</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Munro</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Renewable Projects</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Brigde Capacity 3 - 60MW Diesel</td>
<td>8,500</td>
<td>8,500</td>
<td>8,500</td>
<td>8,500</td>
<td></td>
<td>8,500</td>
<td>8,501</td>
<td>8,502</td>
<td>8,503</td>
<td>8,504</td>
<td>8,505</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>8,149</td>
<td>8,128</td>
<td>8,308</td>
<td>8,446</td>
<td>8,418</td>
<td>8,290</td>
<td>8,391</td>
<td>8,365</td>
<td>8,150</td>
<td>8,135</td>
<td>8,135</td>
<td>8,099</td>
<td>8,213</td>
</tr>
<tr>
<td>System Heat Rate kJ/kWh thermal</td>
<td>10,273</td>
<td>10,250</td>
<td>10,222</td>
<td>10,275</td>
<td>10,329</td>
<td>10,270</td>
<td>10,390</td>
<td>10,404</td>
<td>9,150</td>
<td>8,629</td>
<td>8,629</td>
<td>8,601</td>
<td>9,467</td>
</tr>
</tbody>
</table>
Chapter 13: Fuel Recovery - System Losses Target

13.1 Introduction

The system Losses target focuses primarily on the transmission and distribution (T&D) operations of the company. System losses are the difference between the energy generated by the system and the energy sold to customers. Losses are generally because of technical causes and theft. The OUR has set a system loss target of 17.5 percent\(^1\) of the total electricity generated. To the extent that system losses exceed this target, JPS is prohibited from passing through a corresponding portion of its fuel costs to customers and must absorb the costs. To the extent, that system losses are better than the target JPS is permitted to pass through fuel costs on a dollar for dollar basis plus additional revenues as a bonus. As noted above, the OUR’s Determination to set the system loss target at 17.5% has unfairly imposed on JPS responsibility for theft losses which are beyond its control.. Correction to this target setting regime is critical for JPS financial stability..

Similar to the system heat rate discussion in the previous chapter, this chapter looks at the system losses efficiency target in the Fuel Cost Adjustment Mechanism. The first section reviews the initiatives over the 2009 – 14 regulatory period and details the results. The report then describes the Company’s new system losses programs for the regulatory period 2014 – 19 and introduces a new initiative, the Community Renewal Program, aimed at regularizing consumers in communities where high incidences of non-technical losses have been identified. Finally, the chapter outlines JPS’ proposals for modifications to the system losses target.

13.2 System Losses Initiatives

The objective of this section is to provide a summary of the system loss initiatives the Company has undertaken during the review period, as well as the challenges that it faces in managing the system losses, and to offer proposals as it relates to a sustainable program to effectively reduce energy losses.

13.3 The JPS Losses Situation – vs. - Challenges

JPS’s system energy loss at the end of December 2013 was 26.6%. Technical losses were estimated as 8.6% and non-technical losses at 18.0% or 67% of total system losses. Both the technical and non-technical energy loss situation comes with their own challenges due primarily to the existing T&D infrastructure; customer distribution across the network and socio-economic conditions coupled with the volatility of fuel price and foreign exchange movements in Jamaica.

With regards to non-technical energy loss, there is a strong correlation between system losses and fuel prices with a correlation coefficient of 73% as seen in the graph below.

\(^{101}\) Recall the target was increased to 19.5% in October 2009, reduced to 17.5% in July 2011 and effectively increased to 19.5% in July 2013 when the effect of the FCRA is taken into consideration.
System losses have been a longstanding problem for JPS and specifically electricity theft (which is a crime). This loss is primarily driven by social and economic conditions that exist in Jamaica and, just like any other crime, this problem is substantially outside of the control of JPS. It is unjust and unreasonable to punish JPS for third-party crime, beyond JPS control and where the penalties fail to address or help resolve the socio-economic issues underlying that system loss problem. In looking at Jamaica’s economic condition, while the total system heat rate has improved by 14% over the past 10 years, unfortunately the price of fuel per KWh has increased by over 300% for the same period and, as such, the price of electricity has increased substantially over the period as well. Fuel now represents approximately 70 percent of the total cost of electricity. In response to the high cost of energy and the generally challenging economic conditions in Jamaica, we have seen increased incidences of the theft of electricity and there are now an estimated 180,000 households with illegal access to electricity. This has occurred despite the significant amounts of capital and human expenditures by JPS to reduce system losses on every front possible. JPS is proposing revisions to implementation of the system loss to help address the regulatory implementation failures that have been unfairly and pointlessly harming JPS by punishing it for losses beyond JPS's control.

13.3.1 Technical Energy Loss

Technical energy loss is an inherent part of any electric utilities operation and it is considered unavoidable, however there is an optimal level to which each should operate. This optimal level is dependent on the topography, network configuration; T&D standardized voltage levels, customer distribution across the network, etc. These factors along with the economics surrounding technical energy loss reduction programs must be considered before an optimal level or comparison is made with other electric utilities.

When a comparison is done between JPS’ Technical losses and that of other utilities with similar network size and structure, there were both better and worse than JPS existing in
countries of similar size. JPS continues steadfastly in its endeavours to reduce Technical losses, as explained in this document.

13.3.2 Non-Technical Energy Loss

Non-technical energy loss, unlike that of technical energy loss is primarily due to a myriad of socio-economic challenges within the country. These situations and conditions include general macro-economic challenges impacting the affordability of electricity, governance, crime rate, unemployment, accessibility, etc.

When a comparison is done with JPS’ non-technical energy losses to other utilities, though it is discovered that the Company is much better than many utilities that exist in countries with similar socio-economic conditions, JPS commits a vast amount of its business resources to reducing losses. System losses especially jeopardize the viability of the business given that the existing regulated fuel tariff recognizes only 17.5% of the total system losses, which leaves JPS absorbing all the losses above this threshold – including those from theft. It is for this reason that the basis for setting the target must be fair and objective.

In many countries, the percentage of system losses recognition by the energy tariff is dependent on the socio-economic structure of the country. A vivid example is the Dominican Republic, which has broadly similar socioeconomic conditions when compared to Jamaica. One difference is that in the Dominican Republic, the country’s energy sector is unbundled and there are several generation companies (both Government and Private owned), one transmission company (Government owned) and three Distribution companies (both Government and Private owned). The distribution companies have system losses of 33% and higher. Though the loss figure sounds very high, it was agreed that to reduce losses substantially under the present socio-economic structure of the country, the companies would require extremely high investment during next 10 years but possibly with very little tangible return. As this could cause an unbalance in the country’s economy through over investment in a particular sector, the Government and the Regulatory Commission decided to recognize the Distribution Companies’ system losses through a direct Subsidy to the Distribution companies along with implementation of strict Laws to restrain illegal abstraction of electrical energy from the distribution network. The Distribution companies nevertheless remained with the responsibility to continuously try and reduce system losses.

Similarly, in Brazil, where there are more than four (400) million inhabitants, they have sixty-three (63) distribution utilities in over fifty (50) main municipalities. The level of non-technical losses varies greatly across these utilities, primarily dependent on the socio-economic conditions of each municipality. Accordingly, the regulator in Brazil has turned to looking at the socio-economic conditions in each territory as a means to deciding what level of system losses should be recovered through the tariffs.

The major factors impacting Non-technical energy Loss are internal bleeds and electricity theft. Electricity theft primarily comes from socio-economic factors that are outside JPS control. Quantum (2013) looked at the socio-economic situation of Jamaica and how this affects system losses. To benchmark non-technical energy loss or electricity theft, electric utilities or

---

102 Effectively 19.5% when the impact of the US$20 million p.a. FCRA is included.
countries with similar socio-economic conditions were considered. The objective of the study was to demonstrate there is a strong relationship between non-technical losses (NTL) and the social conditions of the population living in the area supplied by JPS. To confirm the hypothesis that NTL are higher in those utilities operating in regions that have living conditions that are less favourable, data about utilities of Argentina, Bolivia, Brazil, Guatemala, El Salvador and the Dominican Republic corresponding to the years 2004 –2011 was used. These socio-economic conditions can be broken down by:

- Demographic characteristics, violence, schooling, income, inequality, infrastructure, labour informality, temperature, market characteristics (% of residential customers) of the electric utility and electricity price.

In looking at fifty-three (53) distribution companies, the model considered the NTL to low voltage index, poverty index, the average residential rate based on GDP per capita index and the violence index (murder rate per 100,000). The study (2013) has clearly demonstrated a very strong correlation between electricity theft, and the socio-economic and political conditions within which the utility operates. Hence, the following was concluded:

- 90% of the variability in the NTL are explained by socio-economic variables.
- NTL depend positively on the poverty level, on the payment capabilities of the population and the degree of violence present in the environment.
- For each 1% increase in the proportion of the population that lives in conditions of poverty, the NTL level increases by 0.63%.
- The result confirms the importance of the social dimension on the performance of the electric utilities.
- This task cannot be performed by JPS alone, but requires the joint efforts of the Regulator, GOJ, customers and other stakeholders.

A breakdown of the energy losses island wide can be seen in

**Figure 13-2** below, which highlights energy losses in parishes with a high population density of inner city and squatter settlements.
13.4 Overview of Loss Reduction Activities 2009 – 2013
The chart below illustrates the Company’s System Losses Trend:

Figure 13-3: JPS 10 year System Losses Trend
Just as it is evident from the graph above, there has been a noticeable increase in system losses since the last tariff review. However, despite the efforts of several initiatives implemented by the Company, system loss has continued to increase. It is also important to note that the growth in system losses is also impacted by the 2% annual reduction in sales over the last three consecutive years. In the table below are highlights of some major activities undertaken from 2009 to 2013.

### Table 13-1: Loss Reduction Activities 2009 - 2013

<table>
<thead>
<tr>
<th>Loss Reduction Activities</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>CAMI Installations(^{104})</td>
<td>762</td>
<td>1,306</td>
<td>1,752</td>
<td>476</td>
<td>880</td>
<td>5,176</td>
</tr>
<tr>
<td>RAMI Installations</td>
<td>-</td>
<td>8,500</td>
<td>6,146</td>
<td>8,155</td>
<td>7,609</td>
<td>30,410</td>
</tr>
<tr>
<td>Audits</td>
<td>33,843</td>
<td>136,873</td>
<td>141,295</td>
<td>115,841</td>
<td>113,733</td>
<td>541,585</td>
</tr>
<tr>
<td>Strike Force</td>
<td>-</td>
<td>-</td>
<td>35,773</td>
<td>98,714</td>
<td>198,000</td>
<td>332,847</td>
</tr>
<tr>
<td>Arrests</td>
<td>45</td>
<td>63</td>
<td>65</td>
<td>76</td>
<td>1,200</td>
<td>1,341</td>
</tr>
<tr>
<td>House Wiring(^{105})</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>12,327</td>
<td>-</td>
<td>12,327</td>
</tr>
<tr>
<td>Joint Street Light Audit</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>108,339</td>
<td>108,339</td>
</tr>
</tbody>
</table>

In summary despite the above achievement over the past 5 years it is evident that inner-city, squatter settlements and similar type communities (low-income communities) in Jamaica often do not pay for electricity. This significantly jeopardizes the ability of JPS to invest in providing better, cheaper service for all communities, and pushes up tariffs for other customers. The illegal users, utilizes the electricity services that they receive indiscriminately since they are not paying. This further pushes up cost or worsens service for other customers. Law

---

\(^{103}\) This is the first time in recent history (certainly the last 30 years) that JPS has experienced a reduction in sales for three consecutive years. This is primarily the result of energy conservation efforts of legitimate customers who are responding to the increasing cost of electricity. This will necessarily impact system losses which are reported as a percentage of sales vs net generation.

\(^{104}\) The CAMI project started in 2007. A total of 147 were installed in 2007 and 1,179 meters were installed in 2008

\(^{105}\) The 12,327 house wired represent from the start of the program in 2009 up to 2012.
enforcement by the police is generally very low to non-existent in these communities which is why residents are able to survive in the manner that they do and why JPS cannot prevent them from stealing. It also renders the efforts of removing illegal connections futile since the consumers often reconnect themselves within 24 hours after being raided and disconnected time and time again. The prosecution rate is also very low (partly due to a lack of resources on the part of the police and the low priority given to electricity theft on their part) as JPS removed more than 1980,000 illegal connections in 2013 but the police were only willing to make 1,200 arrests during the same period.

The energy loss directly related to the category of (non-customers) theft is 9.85% of net generation or over 50% of total non-technical energy loss. It must be noted also that among JPS 600,000 customers, electricity theft contributes to a significant portion of non-technical loss to the extent that 44% of the irregularities found in 2013 are customer related with a further 37% categorised as meter defects are related to tampering of the meter. In 2013 a total of 133,733 customers were investigated and 31,413 irregularities were identified.

Lastly, the penalties, even if persons are prosecuted, are quite weak and are not a real deterrent to persons who are bent on stealing the electricity supply or who deem it necessary for their survival but simply cannot afford the product.

Set out below is a summary of the activities the Company has undertaken since the last tariff review in 2009.

13.4.1 Loss Reduction Program 2009-2010

Given the threat of a mushrooming in losses and the debilitating effect of this on the Company’s revenues, from its inability to achieve the regulatory target, JPS proposed a fresh approach to loss reduction in its 2009-14 Tariff Review Application.

This multi-prong plan involved:

1. The commissioning of the first study on the factors driving losses included with the application.
2. A commitment to investing unprecedented levels of capital expenditure on losses.
3. Deployment of a technology-led strategy supported by the largest mobilization of staff and third party agents dedicated to loss reduction.
4. Revision of the regulatory target for system losses to better reflect the intransigent and pervasive nature of this crime as well as to ensure JPS remains focused and motivated to reduce losses.
5. Introduction of punitive fines and penalties to strengthen both deterrence and punishment for an offence.

13.4.1.1 Loss Reduction Activities 2009

In November 2009, JPS established a Division dedicated to the identification and reduction of system losses. The Division headed by a Vice President with approximately 260 staff, and a budget of US$30M for 2010 focused on the following priorities:
1. Achieve a comprehensive and precise system for improved Identification and Measurement of Losses;
2. Identify the drivers negatively impacting commercial electricity losses and coordinate the development of intelligence to support targeted inspection and investigation of irregularities;
3. Dedicate significant resources to the actual investigation and regularization of suspected irregularities;
4. Achieve significant growth in incremental consumption and/or reduction in unregistered consumption;
5. Establish sustainable Commercial Processes that results in reduction of Non-Technical losses.

13.4.1.2 Loss Reduction Activities 2010

The main activities for 2010 are outlined below:

Energy Balance Project

The priority for 2010 was the completion of the Energy Balance Project; this initiative was integrated as part of JPS’ routine operation to reduce energy loss. The following was achieved during the year:

1. Completion of the metering of all twenty-six Net Generation points;
2. Alignment of all distribution feeders’ energy loss with commercial parish boundaries (Frontier Metering)
3. Completion of the metering of all 110-distribution feeders island-wide.

Central Intelligence Unit

The primary focus of the Intelligence unit is the identification of both internal and external factors negatively affecting billed sales and the development of intelligence to support targeted inspection and investigation of irregularities. The key activities of this unit include:

a. Desktop and Data Mining - data analysis to determine which accounts/locations will be targeted for investigations.

b. Develop and implement analytical tools utilizing feeder balance metering to support targeted inspection of irregularities and improve strike rate through the use of intelligence.

c. Monitoring and controlling the various internal processes that can negatively affect bill sales.

Other major activities carried out in 2010 were:

1. Monitoring of Large customers
   a. Prioritizing top 60k revenue customers (75% of revenues)
   b. Analysis of consumption trends to identify marked drop in consumption.
   c. Assign Standard Industrial Codes (SIC) to monitor consistency of consumption of similar enterprises.
2. Feeder Based Initiative  
   a. To produce a replicable standard operating procedure for loss reduction based on high loss feeders. Allowing us to quantify losses at specific circuits on the feeder especially in the Red Zones.

3. Process Control Initiatives  
   a. Review of Meter Inventory Management  
   b. Review and Modification of Applications to support Loss Reduction Initiative. Applications cover the Meter Reading, Service Order Management and Billing processes that would cause accounts not to bill or bill properly.

4. Residential Anti-Theft Advanced Metering Infrastructure (RAMI)  
   This was aimed at “sustainable” loss reduction efforts where anti-theft networks such as RAMI are utilized and once completed should show an immediate and long term reduction in overall losses. These projects aggressively targeted informal residential/inner city communities and clusters of informal commercial districts across the three largest “loss” parishes in Jamaica -Kingston, St. Catherine and St. James. Results in 2010 showed that once these projects were completed they showed a pronounced and immediate reduction in energy losses within the communities. The completed RAMI projects were Seaview Gardens, Old Harbour, Pitfour, Retirement, Hurlock and Tivoli Gardens and 30% of Denham Town equating to 8,500 customers. Meter centre projects (non-AMI) included Ocho Rios Market, Village Green, Faith’s Pen, Ambrook Lane, Belair, Dam Head, Top Town, Tarrant Drive, Jobs Lane and Port Henderson Road. Collectively the projects contributed to approximately 12.5 GWh of additional sales and/or reduction in net generation or 0.39% contribution to the overall loss reduction effort at a cost of almost US$8M.

5. Analysis and Investigation of Accounts with Suspected Irregularities  
   This involves the analysis of accounts to identify those with potential irregularities and then conduct field investigation of these accounts. Suspected irregularities include meter tampering, direct connections, meter bypasses, etc. The work was divided and organized around customer groups based on monthly billed sales:
   1. Large accounts –8,732 accounts investigated; 1,028 identified irregularities with effective strike rate of 11.77% and recovery of 16.94 GWh.  
   2. Small commercial accounts–14,661 accounts investigated; 1,653 identified irregularities with an effective strike rate of 11.27% and recovery of 18.120 GWh.  
   3. Residential accounts - 113,480 accounts investigated; 22,185 identified irregularities with effective strike rate of 19.6% and recovery of 54 GWh.  

The above approach, while necessary, was costly, and labour intensive work that utilized approximately 200 personnel and cost over US$11M in O&M expense. As this work is not considered “sustainable” loss reduction, this recovery must be replicated year after year. Obviously, the same level of financial and labour commitment will result in a diminishing return year over year as it becomes more and more difficult to find irregularities.

Challenges experienced  
   JPS through its corporate social responsibility outreach has expended significant amount of resources in augmenting its loss reduction activities with very limited social intervention
projects, but the Company is neither equipped nor has the resources to take on this challenge. JPS projected a reduction in system losses of 2% and therefore did not achieve its target by 0.5%. The Company experienced several challenges that affected the success of the Loss reduction efforts. These included:

1. Increase in the price of electricity driven by rising fuel prices;
   a. Average fuel prices rose by 25.5% in 2010 compared to 2009 and resulted in electricity prices increasing by approximately 20% despite the revaluation of the Jamaican dollar. Historically, the increase in electricity price results in a rise in system loss. This has increased our exposure, and vulnerability to irregularities beyond our control and the loss reduction team has seen many innovative attempts to illegally extract electricity from the network.

2. Reduction in energy sales especially among the low loss customers
   a. The combined large customer group (Rate40/50) experienced energy sales reduction of 20 GWh in 2010. During 2010, fifty-seven (57) RT40/50 customers were rendered inactive and this contributed to a decline in consumption of 10.1 GWh in 2010 (compared to 3.1 GWh in 2009). Large accounts RT40/50 accounted for 46% (58 GWh of 126 GWh) of the reduction in billed sales for 2010.

3. Increased hostility towards the JPS loss reduction team in the execution of their job function

4. Socio-political conditions in areas where the greatest level of loss are being incurred.

   In 2009, JPS Energy Loss was 982.5 GWh or 23.3%, the results of the 2010 was Energy Loss of 902.1 GWh or 21.8% JPS therefore achieved a reduction of 80.5 GWh or 1.5%. Despite this improvement, JPS incurred fuel penalty of US$13.0M in 2010 due primarily to a system loss penalty of US$24.8M.

13.4.2 Loss Reduction Activities 2011

   Over a three (3) year period 2009 –2011 the reduction in system losses has continued on a positive path. However, the assessment of the environment for 2010 and 2011 suggested that the original targets for the 5-year plan 2009 –2014 would not have been achievable but would have to be contended in subsequent years. It was sufficient to summarize the challenge as being socio-economic and outside of the control of JPS, as the theft of electricity is in fact, a crime, and a national problem that occurs all across the island. Additionally, this challenge was increasing in a recessionary environment where energy prices are increasing primarily because of rising oil prices and the continued devaluation of the Jamaican Dollar.

   In 2011, the second year of its medium term loss reduction initiative, a reduction of 0.7 percentage points of net generation was realized. This was due mainly to a cessation of losses activities in August, September and December 2011, and the effect of conservation efforts by customers in response to the 30% increase in fuel prices during the year. The cessation of activities in the months mentioned were considered absolutely necessary to ensure the safety of our work crews because of the significant customer outcry pertaining to the installation of digital meters (which affected our efforts in August –September) and the effect of the national elections in December (recall elections were not constitutionally due until 2012) which meant our usual security detail (including police support) was not available in December and there
was the fear of escalated violence during this election period. Using the 2010 net generation of 4,137 GWh, a 2% reduction in losses was targeted. This equated to approximately 83 GWh. Actual recovery arising from account audits resulted the recovery of 70 GWh, representing 1.7% of net generation. The performance for the last quarter of 2011 was significantly affected by numerous external challenges, as mentioned briefly above.

13.4.2.1 Account Investigations

Investigation of 134,621 customer accounts yielded an overall recovery of 70 GWh. The work was organized around customer groups based on their consumption patterns:

1. Large Accounts – A total of 5,211 accounts were investigated, 636 of these accounts were discovered with irregularities, representing a strike rate of 12.2% and an overall recovery of 16 GWh.
2. Small Commercial Accounts – A total of 6,082 accounts were investigated, 1,146 of these accounts were discovered with irregularities, representing a strike rate of 18.8% and a recovery of 15 GWh.
3. Residential Customer Accounts – A total of 128,878 accounts were investigated, 23,877 of these accounts were discovered with irregularities, representing a strike rate of 18.5% and an overall recovery of 38 GWh.
4. Central Intelligence Unit – A total of 1,124 accounts were investigated, 300 of these accounts were discovered with irregularities, represents a strike rate of 23.6% and recovery of 1 GWh.

The above approach, while necessary, is costly, and labour intensive work that utilized approximately 200 personnel and cost over US$14M in O&M expenses in 2011. In carrying out these investigations, the LCD made significant adjustments each month that contributed to billed sales positively and this can be seen in Figure 13-4. However, despite these efforts, this method was not sustainable as the policy was reviewed at the end of 2011 resulting in fewer adjustments depending on the magnitude of the offense committed by the customer. Once this policy was in place losses showed an increase in 2012.

Figure 13-4: LCD Contribution to Billed Sales 2008 to 2011

![LCD Contribution to Billed Sales 2008-December 2011](image)
13.4.2.2 Meter Replacement Project

JPS embarked on an initiative to replace approximately 30,000 electro-mechanical meters (or 5% of the population of meters) in 2011 that were originally installed prior to 1995. The average life of an electro-mechanical meter is typically 15 years after which it is expected to start degrading. Annual replacement of outdated meters is a normal mode of business for most utilities to help ensure overall metering accuracy over time. Replacement priority was given to those electro-mechanical meters along the highest loss feeders and concentrated urban areas in each parish. This was intended to aid in the losses imitative through improved billing accuracy after defected or degraded meters were replaced. During 2011, 23,613-meter changes were completed, representing approximately 79% of the planned replacements. The remaining meters were planned to be changed during 2012. The targeted meter changes in 2011 were not met because of the public outcry between August and September 2011 regarding high bills and adjustments. The OUR and JPS Board initiated an audit of the project as well as the suspension of the meter change project during that period. While this work stoppage lasted for a period of approximately two (2) months, upon resumption we observed many customers resisting to have their meters changed, which greatly hindered our effectiveness in this regard since the public outcry. It was observed that irregularities immediately subsided for these accounts, as it gave customers the opportunity to remove illegal abstractions before allowing JPS access.

13.4.2.3 Residential Automated Metering Infrastructure (RAMI)

Results in 2011 confirm the RAMI projects are successful, once implemented, in reducing commercial losses within the specific communities. Unfortunately, these initiatives are very time-consuming and capital intensive, because of the high level of planning, community intervention, home rewiring and certification, and network construction required; but appeared to offer the best return over the long-term. As at December 2011, the overall completed RAMI areas include Sea View Gardens, Old Harbour, Pitfour, Retirement, Hurlock, Tivoli Gardens, Denham Town, Rose Town, and section of the Mid Town Project. Areas including Payne Land, Delacree, Whitfield Town, Greenwich Farm, Central Village, Rema, Trench Town and Flankers/Providence Heights were all scheduled to be completed by December 31, 2011; however, because of several external challenges experienced which were beyond JPS’s control, they were rescheduled to be completed during 2012.

13.4.2.4 Energy Balance Project

The priority for 2011 was the completion of the energy balance project and remote links with locations where relays presently exist. The following was achieved in 2011:

1. Energy balance - Remote energy balance communication link
   a. The total JPS net generation metered locations is twenty-seven of which twenty-six have remote communication.
   b. There are thirty-eight metered transformer locations of which twenty-eight presently have remote links;
   c. There are 111 metered feeder locations island-wide of these eighty-five have remote links.
2. Substation feeder metering
a. The transformer at Martha Brae was replaced, and another feeder added;
b. 22 sub-feeder metering links were completed to facilitate RAMI projects;
c. 18 circuits for secondary total metering were completed in 2011.

3. CAMI (C & I) meter replacement/installation
   a. 1,752 commercial meters were replaced in 2011 with AMI enabled meters to facilitate remote data acquisition.

13.4.2.5 Meter Centre Projects

As part of our efforts to reduce losses, JPS committed to investing J$1.3 billion over the period 2010 –2015 in the implementation of meter centres island-wide. Under the meter centre project, areas in which JPS has traditionally faced operational challenges are identified and the overhead low voltage power lines (which persons usually throw up wires) were replaced with high voltage tamper-proof power lines. The meters were also removed from residences and installed in tamper-proof cabinets (or meter centres) mounted on light poles. Customers are then connected directly from the meter centre thus eliminating the incidence of 'throw-ups' or illegal connections. During 2011, J$52 million was spent on installation of commercial and residential meter centres. The meter centres installed included:

- The implementation of 272 commercial meter centres in downtown Kingston, Montego Bay, and St. Catherine.
- The installation of residential tamper resistant meter centres covering 1,000 customers Island-wide.

13.4.3 Loss Reduction Activities 2012

13.4.3.1 System Losses Target

In 2012, JPS expressed in its annual tariff submission that it would be near to impossible for it to substantially reduce system losses from the levels of 25% in the near future and without a complete redesign in the approach to addressing crime. However, despite this challenge JPS continued efforts to reduce system losses. The activities carried out in 2012 are outlined below:

13.4.3.2 Technical Losses

JPS recommended that an independent study was critical to confirming the existing level of technical losses (to the satisfaction of the regulator) that were evaluated to be approximately 9 - 10%. Additionally, the study would help to design a credible agreed programme to achieve an optimal level of technical losses. The T&D system configuration and voltage levels are critical to determining the actual level of technical losses. Further, reduction in technical losses will typically be because of capital intensive programmes such as building more sub-stations or increasing the voltage level at which we transmit and distribute electricity. Because of the high capital cost, a proper engineering study would have to be conducted to determine the applicable reconfiguration cost and expected benefits. Additionally, this study would identify other low cost corrective measures, which could be taken to improve technical losses. This would form the basis for a credible work program, which the regulator could then use as a
basis for setting regulatory targets for desired levels of technical losses, while also giving consideration to the required funding to achieve the specified targets.

### 13.4.3.3 Independent Third Party Evaluation

On the instruction of the OUR, an international firm of consultants (KEMA) was engaged to conduct an engineering study and were expected to submit the results of this study to the OUR by April 15, 2013 to help guide establishing a credible technical loss reduction campaign. Then, the OUR could indicate a clear path going forward for achieving a reasonable regulatory target for technical losses. This could be embedded in a five-year business plan, which could be implemented as part of the 2014-19-tariff application process. This was applicable given the substantial resources that would likely be involved and the long planning horizon for reconfiguration of a T&D network that also needs to be synchronized with future generation expansion plans. Additionally, given the level of actual losses relative to the regulatory target, the US$30 million penalty experienced in 2012 was a substantial financial setback for JPS, severely impacting the viability of the business and its ability to raise much needed capital to continue investing in the business. Additionally, there was generally the need for a greater provision of capital expenditure in the tariffs to accomplish this feat (particularly as it relates to reducing technical losses) but it was believed that the engineering study would objectively confirm the best way forward.

### 13.4.3.4 Non-Technical Losses

JPS took numerous strategies and activities in its efforts to reduce non-technical losses. However, despite these efforts the fuel penalty being experienced by JPS continued to grow. In 2012, JPS could not prevent the rising trend in losses over the decade and sharply accelerated over the prior two years, despite best efforts. The theft of electricity was costing the country approximately US$60 million per annum in wasted fuel, another US$30 million in fuel penalties for JPS and an annual budgetary expenditure of approximately US$30 million to try to prevent/reduce this criminal act. In 2012, the main measures implemented to reduce theft were:

1. There were approximately 476 CAMI installations.
2. The strike force removed a total of 98,714 illegal throw ups and made seventy-six (76) arrests.
3. There were a total of 8,155 RAMI installations.
4. A total of 98,714 audits island wide.

### 13.4.3.5 Social Intervention

It was proposed that there should be a joint force with the relevant government authorities under the direction of the PIOJ, and by including the NWC into this programme, a pool of US$25 million per annum from existing funds between the two utilities could be available, subject to regulatory approval, to implement a more holistic approach to regularizing the estimated 150,000 households which exist in informal settlements across Jamaica. This programme would have elements of incentive, as well as enforcement, inducement, and empowerment but supported by strong deterrents and sanctions. This programme would be
funded to ensure a systematic approach was taken to regularizing impoverished communities all across the country, where one of their main constraints is a lack of basic infrastructure. There is also clearly a need for a structured social intervention programme to provide skills and jobs training, customer education and financial assistance to help persons to be able to afford the utility services in the short-term.

13.4.4 Loss Reduction Activities 2013

In addition to a continuation and intensification of several energy loss reduction initiatives (both technical and non-technical) the decision was taken to conduct a review of the programs. In summary, the following was done:

1. Contract the services of an independent international consultant (KEMA) to review and make recommendations of JPS existing programs, energy loss spectrum and areas of opportunities to effectively reduce energy loss on a sustained basis. The 2014 energy loss spectrum is revised consistently with KEMA’s recommendation.
2. With the decentralization of the energy loss reduction management and programs in 2012 to the parishes and regions, a centralized unit was established in August 2013 to provide the necessary leadership and directives to the Company.
3. Based on KEMA recommendations and further review and developments the Company established a strategic and systematic approach to better manage and reduce system energy loss on a sustained basis.
4. A review of the RAMI program, which clearly highlighted the challenges being experienced within the communities where over US$30M was invested. The results and conclusion clearly demonstrated the significant effect of the socio-economic conditions in these communities.
5. The implementation of several pilot projects to demonstrate the effectiveness of the 2014 proposed energy loss reduction initiatives.

13.4.4.1 Non-Technical Energy Loss

Managing and reducing system loss continues to be a significant challenge, which is threatening the viability of the Company. Several initiatives have been undertaken to reduce non-technical losses. These initiatives are Commercial Anti-theft AMI (CAAMI), RAMI, and audits, strike force activities, house wiring and the Joint Street Light Audit with the GOJ.

13.4.4.2 Technical Energy Loss

Unlike the non-technical losses, the technical energy losses generally can be positively identified, quantified and even measured. When a technical loss reduction solution is proved to be economical, implementing the solution will bring in the desired results. JPS has continued its efforts to identify areas of the T&D network through its system planning, engineering designs and operations for further technical energy loss reductions.

JPS’s existing technical energy loss is estimated at 8.6% of net generation. This is based on a revision in 2014 consistent with recommendations from KEMA presented in June 2013.
13.4.4.3 JPS 2014 Revised System Energy Loss Spectrum

The accurate measurement and estimation of energy loss across the T&D network are the first step in the fight against energy loss. That is to establish the energy loss sources across the T&D network for both technical and non-technical energy loss. Because of advanced metering technology, specifically Advance Metering Infrastructure (AMI), the accurate and timely measurement of energy loss across the network is now practical. Transmission energy loss is now measured at JPS using AMI meters, which is a key part of JPS monthly monitoring and reporting mechanism.

The loss spectrum is the term used to define the categorization and quantification of energy loss as shown in System energy loss at the end of January 2014 was calculated at 26.51% of net generation with technical and non-technical energy loss estimated at 8.6% and 17.91%. With this information coupled with the solution to reduce energy loss will guide JPS with the prioritizing of the necessary investment to economically reduce energy loss on a sustained basis.
Loss Reduction Improvements

To continue to improve system losses, major initiatives, and programs were undertaken in 2013. Despite the socio-economic conditions in Jamaica JPS continues to intensify its effort to reduce energy loss as outlined below.

1. Field audits  
   a. Over 6,000 large accounts  
   b. Over 106,000 small accounts
2. Replaced over 13,000 Nansen meters with digital meters. The Nansen meters are meters identified with an internal defect (plastic gears).
3. Strike Force team removed over 192,000 illegal connections
4. Over 1,200 arrests (compared to 250 arrests in previous years)
5. Technical Energy Loss  
   a. Improvement in feeder phase imbalance for twelve feeders  
   b. Improvement in feeder power factor for twenty feeders  
   c. Installation and commissioning of two bulk capacitor banks.

Technical Loss – Review, Analysis and Activities

Technical losses were divided into four groups and were reviewed. The following gives a description of the four technical loss groups:

- Technical losses in the transmission system, which are, measured losses. JPS determines the amount of transmission system technical losses based on measurements of Net
Generation Meters, Feeder Meters, and energy measured as delivered to customers who are supplied directly from the transmission system and this loss is currently 2.6%.

- Technical losses in distribution feeder lines are calculated losses. JPS is using SynerGEE to calculate kW losses in peak load condition and then convert the peak kW losses to kWh energy losses by applying a system loss factor. The loss on the distribution feeder lines is currently 1.8%.

- Technical losses in distribution transformers are calculated losses. The method utilized to determine the energy losses from distribution transformers is based on the manufacturer’s power loss specification for each transformer size along with JPS’s operating parameters of the year. The loss on the distribution transformers is currently 1.3%.

- Technical losses in low voltage networks are calculated losses. JPS estimates low voltage network losses in three portions: secondary line losses, service drop losses, and meter coil losses. The loss on the low voltage networks is currently 2.9%.

To be more efficient at our business, JPS has looked at other utilities to benchmark an optimal level for each of the four technical loss categories. In doing so we have found the following:

- One island in the Pacific, where the maximum load is around 300 MW, technical losses is 6.5%, but this island utility is less mountainous, is smaller, and has shorter line lengths with relatively high transmission voltages to their customers.

- In another similar island – with similar size and geographic characteristics but with most of the load concentrated in two regions – technical loss is 8%.

- Suriname, with some 500,000 people and a maximum load climbing to 200 MW, technical loss is around 8%.

- In a developing country like Nigeria, with a maximum load seven times higher than in Jamaica, technical losses are 10% and similar figures exist for other larger developing countries.

- **CARILEC** average technical loss is 8.36% (excluding JPS)

- “We cannot compare with smaller islands like Aruba and Grand Cayman, where all loads are very concentrated, where the transmission voltage to the load centers is quite high and where distances are very short. Here, they reach technical loss figures between 4% and 5% which is not possible in the Jamaican power system and which is not even possible in large countries in Europe. Going back to the relatively comparable island systems, it looks like best practices are between 6.5 to 8% (KEMA-April 12, 2013).

Once the actual level of technical loss was established, the next step is to move towards achieving the optimal level of losses in the categories that we can be more efficient. A breakdown along with the necessary investment and time of this can be seen below:
Table 13-2: Technical Losses Initiatives

<table>
<thead>
<tr>
<th></th>
<th>Existing Loss (%)</th>
<th>Optimal Loss (%)</th>
<th>Investment (US$M)</th>
<th>Years</th>
<th>Loss Reduction Activities</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power System</td>
<td>2.6</td>
<td>2.4</td>
<td>1.8</td>
<td>5</td>
<td>Installations of Substation Capacitor Banks (0.2%)</td>
</tr>
<tr>
<td>Primary Distribution</td>
<td>1.8</td>
<td>1.0</td>
<td>85/0.8/0.2</td>
<td>15/5/5</td>
<td>VSP (0.3%) / Var Mgmt; (0.3)/ Phase balancing (0.2%)</td>
</tr>
<tr>
<td>Pole and Pad Mounted Transformers</td>
<td>1.3</td>
<td>1.3</td>
<td>0</td>
<td>0</td>
<td>Low Loss Transformers</td>
</tr>
<tr>
<td>Secondary and Service</td>
<td>2.9</td>
<td>2.7</td>
<td></td>
<td>5</td>
<td>Secondary Rehabilitation</td>
</tr>
<tr>
<td>Total</td>
<td>8.6</td>
<td>7.4</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

13.4.4.5 Non-Technical Loss – Review, Analysis and Activities

Street Lights

A Joint Street Light Audit with the Ministry of Local Government (MLG) consistent with a MOU was completed in September 2013. The audit revealed that an additional 12,102 street lights exist on JPS grid that are not billed on a monthly basis. This translates to approximately 0.2% of net generation each month.

Large Accounts

This group, the Priority Industrial and Commercial Group (PIC Group), consists of large rate 20 customers, rate 40 and 50 customers, giving a total of 6,197 customers with AMI meters. This group is estimated to contribute to 1.64% of net generation. This group represents 1% of our customer population and contributes to over 50% of sales.

Small Accounts

Outside of illegal/un-metered users of electricity, R10 and R20 are the highest contributor of non-technical system losses with 86% resulting from electricity theft and defective meters. The R10 and R20 groups are a significant non-technical loss driver as they account for over 90% of the customer base. In 2013 over 106,000 investigations were done within these groups. A total of 31,413 irregularities were identified with over 63% of them being customer related and 44% of irregularities found were directly related to electricity theft. It was also reported that 36% of irregularities were resulting from meter defects that can also be theft related. A breakdown of the irregularities found within these groups is shown in Figure 13-6 below:
**Figure 13-6: Irregularities Found on Investigations**

![Figure 13-6: Irregularities Found on Investigations](image)

**Internal Bleeds/Unquantified**

Internal bleeds/Unquantified energy loss is based on the difference between total system loss and the sum of the respective categories of energy loss computed within the spectrum. This contributes to approximately 1.56% of system losses. In estimating this aspect of system losses, JPS has acknowledged the presence of internal inefficiencies. Internal bleeds stem from inefficiencies in a utility’s internal operations. One main driver identified in 2013 was billing adjustments. It was found that adjustments were mainly due to human error; e.g., meter reading errors, estimation errors, etc. Human errors driven by current weaknesses in Customer Information System and process weaknesses contributed to these internal bleeds that ultimately contribute to system losses. JPS continues to review its internal process to reduce inefficiencies. A major investment in the improvement in billing processes is the upgrade of our current billing system (i.e. Banner) which will be launched in August 2014. Other improvements include increased efficiency in billing processes to reduce estimated accounts per month. Some of the other areas being monitored and actioned are:

1. **Found Meters** - these are meters found within route that is not in our billing database. As at December 2013 there were over 4,000 “Found Meters” that were reported.
2. **Days of Service** - this is the number of days billed within any given month. The aim is to be able to bill the same number of days equalling the number of days of energy generated.
3. **Idle Advancing Meters** - these are meters that were disconnected for non-payment of bill, but subsequent checks found them illegally reconnected. Since the end of June there has been a steady reduction in reported cases, as each month planned actions are taken to correct the breach of our system; however, the total the end of December has shown an increase in the cases over the previous month.
4. **Loss Impacting Comment Codes** – This represents data inputs from our Field Contractors that initiate an investigation.
Unmetered Customers

Unmetered customers are primarily found in the residential class and with the current socio-economic conditions existing this is a significant challenge for JPS. It is estimated that over 180,000 illegally connected households island-wide and this contributes to approximately 54% of non-technical energy loss. This figure is based on estimation from STATIN and JPS’s computation of the average use per consumer.

The primary solution that has been used for this problem is RAMI, and this has been funded through the assistance of the Electricity Efficiency Improvement Fund (EEIF). Since the implementation of RAMI, over 21,000 illegal users have been regularized through RAMI and at an investment of over US$34M in twenty-two communities.

Before the RAMI intervention, there was an average of 75% energy loss in the red zone communities. After the RAMI intervention the energy loss reduced to below 6%, however, after a period of 8 to 12 months the average energy loss per community increased to 40%. This reflects the persistence of persons who are intent to steal, the fact that RAMI is not ‘full proof’ and the general difficulty in monitoring and policing these very challenging communities.

The annual contributions since the EEIF was established can be seen in Table 13-3:

<table>
<thead>
<tr>
<th>(US$ millions)</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net Losses Fund Reserve for AMI</td>
<td>1.365</td>
<td>8.446</td>
<td>8.643</td>
<td>8.209</td>
<td>8.236</td>
</tr>
<tr>
<td>Budgeted AMI</td>
<td>-</td>
<td>-</td>
<td>12.980</td>
<td>12.147</td>
<td>9.448</td>
</tr>
<tr>
<td>Actual AMI</td>
<td>-</td>
<td>-</td>
<td>15.256</td>
<td>8.792</td>
<td>5.846</td>
</tr>
</tbody>
</table>

13.4.4.6 Non-Technical Loss Initiatives

Audit and Investigation

In 2013, a total of 113,733 accounts were audited yielding a recovery of over 6 GWH of energy. The type of irregularities found include metering tampering, meter bypass, and direct connection to our distribution network. However, the identification of losses has become increasingly difficult because of several factors including:

- Significant change in consumption pattern resulting from conservation or utilization of alternative sources of energy. This is evident in the low strike rate in 2013, which is also attributed to more complex methods of illegal abstraction and the fact that persons know JPS’ schedule for investigation and will schedule their illegal activities, accordingly.

Given the low strike rate, additional strategies have to be employed including greater utilization of technology, to provide the improvement of intelligence and capabilities. Some of the methods we now employ are:

- The incorporation of a Business Intelligence tool, which utilizes data from internal reports and management data to analyze meter activity.
- Flexible Audit Schedules i.e., night audits and audits outside normal (business) hours.
- Group Investigation: Blitz & Block Audit: the identification and analysis of suspected areas and the subsequent high intensity investigations conducted within a given day.
Strike force

JPS launched the “Take Back JPS” campaign. This initiative involved various stakeholders, including the constabulary force and residents within these communities. It focused on our top eleven (11) highest loss feeders and a very aggressive daily removal of illegal connections to our network. The operation started in January 2013. The plan was to conduct extensive raids and remove at least 200,000 throw-ups island wide between 2013 and 2014. Through coordinated Strike Force Activities (Strike Force teams including linemen, technicians, and the security force (police)) approximately 198,000 illegal throw ups were removed from the grid, over 8,000 idle service meters removed and over 1,200 persons were arrested for “Illegal Abstraction of Electricity.”

Sub-Feeder Metering

This is a loss reduction strategy aimed at improving the Company’s measurement of energy losses and will enable greater understanding of the areas of high losses on the feeder for targeted and planned action. This involves the installation of primary metering facilities on feeder line sections of the worst loss feeders. A total of sixty-four locations were identified where sub-feeder metering facilities could be utilized in performing greater feeder intelligence and at the end of 2013 a total of sixty-two (98%) meters were installed across the three regions on selected feeder line sections.

Meter change

JPS is replacing old meters with aging technology. These were identified to be the Nansen meters; the operational reliability of these meters has been characterized by low consumption measurements over time. Studies conducted revealed that approximately 50% of these meters in the sample were defective. For 2013, the Company replaced approximately 7,200 meters yielding a total recovery of over 200 MWH. A total of 932MW were gained from the project for the period July to December 2013.

Social Intervention

JPS has engaged the PIOJ, STATIN, and other stakeholders in consultation to form social partnerships. JPS has reviewed and conducted some analysis on the data published in the 2011 Census. This analysis includes understanding the variance in persons whose primary source of lighting is electricity as reported by STATIN relative to our residential customer base. We are in the process of acquiring additional details from STATIN to further our analysis and to assist us in our engagement of the PIOJ as we explore partnering in its Community Renewal Programme. JPS continuously promotes its Customer Education Programmes by hosting various workshops/forums on topics that affect our customers. These include topics such as electrical safety, conservation, and electricity theft etc.

Prepaid Metering

While not directly a project to combat non-technical electricity losses, it was expected to give greater control to customers over the usage of electricity and ultimately their monthly expenditure on for the service. The company has commissioned and completed a “Pre-Paid” pilot project, which has been successful. All technical aspects have been completed and reviewed resulting in the project receiving a positive report card. The launch included a
customer education campaign via community meetings and workshops. These meetings were held in the Delacree and Palm Grove communities. Unfortunately, customers have been slow to sign prepaid contracts. JPS is now looking at strategies to review and revamp the programme to boost the take up of the prepaid solution including a wider geographic offering.

**Recloser Energy Limiting Initiative (RELI)**

This involves implementing a strategic cap on the amount of energy delivered to specified communities where electricity losses are notably high especially during times of generation shortfall where load-shedding is necessary. These communities have more than 50% losses on a monthly basis, and although this initiative is only implemented on a very short term basis, it underscores the unconventional measures JPS has had to undertake to limit the incessant climb in non-technical electricity losses. These communities also span several parishes and across varying feeders. JPS has commissioned a total load of 12.74 MW in eleven communities. In 2013, a total of approximately 40 MWh were recovered from limiting power to these communities. JPS’ use of this method is however very limited and primarily restricted to load-shedding opportunities. However, we would like to discuss with the OUR how this methodology could be proactively applied as a peak shaving strategy thereby reducing the fuel bill overall for customers in good standing (i.e. we would avoid turning on peaking units because of the energy demand of illegal users on the system).

**13.5 Loss Reduction Initiatives 2014 – 2019**

A strategic, systematic, and analytical approach is now being taken to reduce system energy loss on a sustained basis. The lessons learnt and experience gained over the years have clearly demonstrated that until the necessary measurements, process control and management systems are in place and functional, there is no guarantee to the sustainability of the program. It is because of this requirement that investments are being made by JPS to put in place the energy balance infrastructure from the net generation meters through individual feeder meters to customer pole-mounted transformer aggregate meters.

The diagram below depicts the strategic direction for the next 5 years.
In moving forward into 2014, the use of measurements and empirical data in decision-making will be critical for JPS. It is through the use of measurement that it was decided to change the focus of the demographic from the red zones to target yellow zone communities and identified high loss circuits through a targeted feeder approach. A pilot project was successfully carried out in the third quarter of 2013 to demonstrate that opportunities exist in the yellow zones as the average energy loss on feeders are 1.52GWh and this translates to 4MWh per transformer each month.

Aside from technical loss initiatives, social intervention is a critical part of the strategy by JPS and with the necessary support from the Government of Jamaica (GOJ) to address the socio-economic challenges that currently exist. In this regard JPS is requesting regulatory approval to introduce a Community Renewal Programme aimed at low income communities such as squatter settlements, rural villages and inner city areas. The program will provide assistance to residents of these areas with wiring their households in order to facilitate the safe consumption of electricity. It will also fund a subsidized billing program to help these persons who are currently illegal consumers of electricity transition to legitimate paying customers. Details on the program is provided in the next section. JPS will also be lobbying the GOJ for legislative reform to be introduced quickliesomething which they have indicated they are willing to pursue.

A summary of the 5-year plan for both technical and non-technical energy losses is shown below in Table 13-4.

**Table 13-4: JPS 5 Year Loss Reduction Program (Summary)**

<table>
<thead>
<tr>
<th>Category</th>
<th>Initiatives</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Illegal (Users) Non-customers</td>
<td>Strike Force, RAMI, CAAMI, Community Renewal Program</td>
<td>0.14%</td>
<td>0.25%</td>
<td>0.43%</td>
<td>0.43%</td>
<td>0.43%</td>
<td>1.68%</td>
</tr>
<tr>
<td>Residential</td>
<td>Field Audit</td>
<td>0.13%</td>
<td>0.15%</td>
<td>0.10%</td>
<td>0.10%</td>
<td>0.10%</td>
<td>0.58%</td>
</tr>
<tr>
<td>Small Commercial</td>
<td>Field Audit</td>
<td>0.07%</td>
<td>0.07%</td>
<td>0.10%</td>
<td>0.10%</td>
<td>0.10%</td>
<td>0.44%</td>
</tr>
<tr>
<td>Large Commercial &amp; Industrial</td>
<td>Field Audit</td>
<td>0.24%</td>
<td>0.10%</td>
<td>0.10%</td>
<td>0.10%</td>
<td>0.10%</td>
<td>0.64%</td>
</tr>
<tr>
<td>Technical Energy Loss</td>
<td>Feeder PF &amp; PB, S/s Capacitor Banks, Secondary Rehabilitation</td>
<td>0.18%</td>
<td>0.23%</td>
<td>0.24%</td>
<td>0.15%</td>
<td>0.10%</td>
<td>0.90%</td>
</tr>
<tr>
<td>Targeted Feeder Energy Balance Sol.</td>
<td>RAMI, CAAMI, Field Audit &amp; Aggregate meters</td>
<td>0.33%</td>
<td>0.50%</td>
<td>0.60%</td>
<td>0.70%</td>
<td>0.80%</td>
<td>2.93%</td>
</tr>
<tr>
<td>Impact on Losses</td>
<td></td>
<td>1.09%</td>
<td>1.30%</td>
<td>1.57%</td>
<td>1.58%</td>
<td>1.63%</td>
<td>7.17%</td>
</tr>
</tbody>
</table>

This reflects the expected impact (reduction) on the quantum of losses (GWh) being experienced by JPS. A more detailed breakdown of the cost/benefit, and the programs for each group can be seen in Table 13-6 at the end this section and JPS’s expectation to the impact on the system losses rolling average is shown in Table 13-12.
13.5.1 Non-Technical

The following activities and projects will be carried out to aid in the reduction of non-technical losses:

13.5.1.1 Targeted Energy Balance Project

This project is the primary 2014 System Energy Loss Reduction initiative to effectively measure and provide energy loss sources/information at the distribution transformer level. The top 2 energy loss feeders have been identified for each region and will be targeted for 2014. A total of 1,800 aggregate meters are scheduled for installation on these six (6) feeders island-wide. The loss associated with the feeders targeted for 2014 can be seen in Table 13-5 below.

Table 13-5: Top Loss Feeders Targeted for 2014

<table>
<thead>
<tr>
<th>Feeders</th>
<th>Monthly Losses (MWh)</th>
<th>No. of Customers</th>
<th>Losses %</th>
<th>Avg. KWh loss per customer</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bogue 310</td>
<td>2,031.20</td>
<td>13,255</td>
<td>36.90%</td>
<td>153.24</td>
</tr>
<tr>
<td>Paradise 110</td>
<td>1,320.40</td>
<td>10,560</td>
<td>38.10%</td>
<td>125.04</td>
</tr>
<tr>
<td>Tredgar 410</td>
<td>2,725.70</td>
<td>9,475</td>
<td>45.90%</td>
<td>287.67</td>
</tr>
<tr>
<td>MonyMusk 410</td>
<td>558.1</td>
<td>2,523</td>
<td>32.30%</td>
<td>221.21</td>
</tr>
<tr>
<td>Constant Spring 410</td>
<td>1,944.20</td>
<td>9,066</td>
<td>46.70%</td>
<td>214.46</td>
</tr>
<tr>
<td>Washington Blvd 310</td>
<td>1,361.20</td>
<td>5,817</td>
<td>34.50%</td>
<td>234.03</td>
</tr>
</tbody>
</table>

This approach targets approximately 1,800 transformer locations supplying over 40,000 customers island-wide. The average loss on these feeders was found to be 1.52 GWh per month. This translates to an average of 4MWh monthly energy loss per transformer circuit. The objective is to target and prioritize high loss transformer circuits for corrective action. This project is expected to rollout on a wider scale across the island from 2014 – 2018. It is intended that each year the top 6 worst performing feeders will be targeted. The project will be used to effectively guide the reduction of energy losses on a sustainable basis.

13.5.1.2 RAMI Installation

RAMI will be continuing in 2014 and a total of 7,000 RAMI installations will be done. These installations will be on the high loss feeders and will be guided by measurement of losses primarily in the yellow zones. This project will be driven by the targeted feeder energy balance project. RAMI will be deployed on circuits in which the calculated energy losses are above 100kWh per customer per month or 2.5MWh loss per transformer circuit.

The targeted installation of 7000 RAMI solutions is expected to have a projected impact of 11.3GWh in reduced net generation/increased sales or approximately 0.27 percentage point. In yellow zones, the average cost for installation of RAMI solutions is approximately half the cost when compared to installation in red zones. In addition, there will be opportunities for reduced operational and maintenance costs in yellow zones.
The RAMI project will be an annual initiative focused on achieving JPS’s overall strategy of automating the read-to-bill cycle for all customers. It will be deployed strategically on areas where measurement and analysis shows that it is cost effective.

13.5.1.3 **CAAMI Installation**

This project involves the procurement and installation of a CAAMI metering solution as part of 2014 energy loss reduction strategy. This will primarily be installed on the 2014 targeted energy balance feeders where high energy loss associated with small and medium size commercial customers. This project will be done in parallel with RAMI solutions on high loss feeders and consistent with 2014-2018 overall loss reduction strategy.

A total of 3,000 CAAMI solutions are targeted for 2014. The estimated recovery from the CAAMI installation is 2.65GWh or 0.06 percentage points in the first year. This project dovetails the Targeted Feeder and RAMI projects and supports the revised strategy of focusing on JPS’s Priority Industrial and Commercial (PIC) customer group. This group accounts for approximately 1% of JPS customer base and contribute to over 50% of billed sales.

13.5.1.4 **Audits**

This involves the analysis of accounts to identify those with potential irregularities and then to conduct field investigations of these accounts. Suspected irregularities include meter tampering, direct connections, meter by-pass, etc. This will be a continuation to investigate large and small accounts guided by data and intelligence. With the loss initiatives mentioned above, the success of the process is expected to increase as JPS will be guided by measurement at the transformer level resulting in an improved strike rate.

13.5.1.5 **Strike Force Operations**

Illegal ‘throw-up’ connections are an on-going problem that has been difficult for JPS to eradicate. JPS’s plan aims to frustrate these consumers to the point where they will regularize their supply. Strike Force teams comprising of linemen, technicians and police, work collaboratively to remove illegal ‘throw-ups’ and arrest guilty parties in these areas, through consistent raids over an extended period. The areas targeted are communities within the highest loss feeders (red zones) in the island. The strike force operations within the parishes will continue throughout 2014 to 2018 to help deter energy theft and reinforce physical presence. JPS plans to be more aggressive each year to frustrate these illegal users by reinforcing JPS physical presence (along with the appropriate police detail) and encourage these users to regularize their supply.

13.5.2 **Technical**

The following provides the details of the technical energy loss reduction activities and initiatives that will be undertaken in 2014-2018 to achieve optimal technical energy loss on a sustained and economical basis.
13.5.2.1 Transmission System

Incremental reduction in energy loss on the transmission network can be economically realized through the following 3 activities:

1. *Generation Expansion/Replacement* - This is driven by the need to serve increasing load or the replacement of existing generating plants (e.g. 381MW), which is related to the optimal placement of additional generation facilities. The major load centers are Kingston, Spanish Town and Montego Bay accounting for approximately 60% of the system load.

2. *Transmission Expansion* - This is driven by the need to improve network reliability, security and to serve increasing load primarily during generation expansion. During normal operating conditions the transmission lines are loaded on average of less than 40% of their respective capacity.

3. *Substation Bulk Capacitor Banks* – Any short term (1-2 years) realistic reduction in technical energy loss on the transmission system is in the area of VAR Management or the optimal placement of bulk capacitor banks at substations island-wide. It was recommended that JPS change its present objective of utilizing voltage improvement as the determining factor for investments in bulk capacitor to that of energy loss reduction. JPS has since installed bulk capacitor banks at the Constant Spring (5.0 MVAR Unit) and Lyssons Substations (2.5 MVAR). For 2014, JPS will install four (4) additional Bulk Capacitor Banks.

13.5.2.2 Primary Distribution Network

Incremental reduction in energy loss on the primary distribution network can be economically realized through the following initiatives:

1. *Continuation of the 24kV Standardization Program (VSP)* – To date 73% or 80 of the 110 feeders are at 24kV which represents 68% of the technical energy loss on the primary distribution network. The remaining feeders are at 12kV and 13.8kV representing 31% and 2% of primary distribution losses respectively. Converting the remaining 27% or 30 feeders to 24kV is estimated to yield a 0.3% reduction in energy loss at a projected cost of US$85M. This cost is mainly driven by the non-standard equipment such as pole and pad-mounted transformers, underground cables and pole line insulators.

2. *Feeder Power Factor Correction*: 240MVARs or 400 pole-mounted capacitor banks are presently installed on the 110 distribution feeders island-wide. These are monitored with the aim of maintaining a power factor of 0.95 and above. The PF of 0.95 is the optimal point at which the greatest return on investment and losses is achieved. For 2014, 47 feeders will be targeted.

3. *Feeder Phase Balancing*: Feeder phase balancing is essential in maintaining good voltage quality and reliability of supply by ensuring the neutral current for the 3 phase system to be less than 10% of the feeder average current.

A proper assessment of the number of feeders with phase imbalance above 20% and analysis is required to more accurately determine the level of energy loss the present feeders contribute.
However, based on preliminary analysis it is estimated that feeder phase imbalance contributes to approximately 0.2% of net generation. For 2014, a total of 40 feeder will be targeted island wide for phase balancing. These feeders will be chosen based on the study done on existing feeders that was completed in January 2014.

**13.5.2.3 Pole and Pad Mounted Distributed Transformers**

A total of 41,202 pole and pad-mounted transformers exist. In 2008 JPS completed the re-mapping of its distribution transformer assets to establish the total number and size of transformer installed across all feeders. The loss reduction solution is the replacement of high loss transformers with low loss ones. This program commenced as early as 1992 with the establishment of new specifications and standards, which dictates the maximum allowable energy loss per transformer size.

To date over 95% of the existing transformers are low loss transformers with little or no meaningful energy loss reduction to be gained by aggressively replacing the remaining 5%. The remaining less than 5% will be replaced through routine and emergency maintenance.

**13.5.2.4 Secondary and Service Wire Network**

This section of the electric network is estimated to contribute to the highest level of energy loss because of the lowest voltage and higher currents per circuit. The main factor contributing to this level of energy loss is the non-standard secondary circuit lengths and defective joints. The solution involves the rehabilitation of secondary circuits to correct non-standard joints and secondary circuit lengths.

**13.5.3 Financing System Losses Program**

As indicated, JPS is committing almost US$90M in capital expenditure over the next 5 years to combat system losses. This is evidence of the Company’s determination to do everything within its control to minimize losses. This becomes more and more important as the company’s core function shifts towards the transmission and distribution operations of the business. In order to help facilitate this level of expenditure JPS is requesting that the EEIF embedded in the current tariffs be retained to partially fund these initiatives especially the Community Renewal Program.
### Table 13-6: JPS 5 Year Loss Reduction Program Breakdown

<table>
<thead>
<tr>
<th>Program</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Impact</td>
<td>Capex</td>
<td>Impact</td>
<td>Capex</td>
<td>Impact</td>
<td>Capex</td>
</tr>
<tr>
<td>Illegal (Users) Non-Customers</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Theft Resistant CAMI (CAAMI)</td>
<td>0.04%</td>
<td>0.5</td>
<td>0.10%</td>
<td>1</td>
<td>0.10%</td>
<td>1</td>
</tr>
<tr>
<td>Residential Anti-Theft AMI System</td>
<td>0.10%</td>
<td>0.5</td>
<td>0.10%</td>
<td>0.3</td>
<td>0.15%</td>
<td>0.3</td>
</tr>
<tr>
<td>Community Renewal Program</td>
<td>0.00%</td>
<td>1</td>
<td>0.05%</td>
<td>1</td>
<td>0.18%</td>
<td>1</td>
</tr>
<tr>
<td>Residential Auditing Rate 10 Customers</td>
<td>0.13%</td>
<td>0.24</td>
<td>0.15%</td>
<td>0.24</td>
<td>0.10%</td>
<td>0.26</td>
</tr>
<tr>
<td>Small Commercial Auditing of Small Commercial Customers</td>
<td>0.07%</td>
<td>0.12</td>
<td>0.07%</td>
<td>0.12</td>
<td>0.10%</td>
<td>0.12</td>
</tr>
<tr>
<td>Large C&amp;I</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Large Account Audit</td>
<td>0.24%</td>
<td>0.05</td>
<td>0.10%</td>
<td>0.1</td>
<td>0.10%</td>
<td>0.11</td>
</tr>
<tr>
<td>Technical Energy Loss</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Feeder Phase Balancing</td>
<td>0.03%</td>
<td>0</td>
<td>0.03%</td>
<td>0</td>
<td>0.04%</td>
<td>1</td>
</tr>
<tr>
<td>Distribution Feeder P F Correction</td>
<td>0.10%</td>
<td>0.25</td>
<td>0.10%</td>
<td>0.3</td>
<td>0.10%</td>
<td>0.05</td>
</tr>
<tr>
<td>Secondary Rehabilitation</td>
<td>0.00%</td>
<td>0</td>
<td>0.05%</td>
<td>2.5</td>
<td>0.05%</td>
<td>2.5</td>
</tr>
<tr>
<td>Substation VAR Management</td>
<td>0.05%</td>
<td>0.6</td>
<td>0.05%</td>
<td>0.3</td>
<td>0.05%</td>
<td>0.3</td>
</tr>
<tr>
<td>Targeted Feeder Energy Balance Solution</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sub-feeder &amp; aggregate transformer Energy Balance Metering</td>
<td>0.00%</td>
<td>1.8</td>
<td>0.00%</td>
<td>2.5</td>
<td>0.00%</td>
<td>3</td>
</tr>
<tr>
<td>New CAAMI Installation</td>
<td>0.06%</td>
<td>3.5</td>
<td>0.15%</td>
<td>3</td>
<td>0.20%</td>
<td>3</td>
</tr>
<tr>
<td>New RAMI Installation</td>
<td>0.27%</td>
<td>7</td>
<td>0.35%</td>
<td>7</td>
<td>0.40%</td>
<td>7</td>
</tr>
<tr>
<td>Total impact on Losses</td>
<td>1.09%</td>
<td>15.56</td>
<td>1.30%</td>
<td>18.36</td>
<td>1.57%</td>
<td>19.64</td>
</tr>
</tbody>
</table>
13.6 Community Renewal Program

13.6.1 Introduction

This section outlines an integrated Community Renewal Program in which JPS, NWC, and Government agencies can come together to improve services to low-income communities island-wide, in an integrated way that emphasizes community responsibility and payment as the *quid pro quo* for service upliftment.

Jamaica needs to move beyond an ‘enforcement’ approach to the problem of service theft and non-payment, to one which emphasizes reciprocity. International and Jamaican evidence shows that if communities are involved in decision making, treated with respect and provided good service, they will be willing to pay at least some amount for electricity and piped water supply. Experience also shows that the most effective approaches treat communities holistically, addressing a broad set of basic needs, community organization, and community responsibility.

First, the Paper describes the problem of electricity and water theft in low-income communities (Section 4.1). This problem endangers the financial health of Jamaican utilities. JPS loses about US$75 million in revenue from theft, and NWC loses about US$49 million.

Communities that steal electricity and water face many barriers that exclude them from the modern economy, including lack of formal land title, and limited access to credit, among others (Section 13.6.3). The three main types of low-income communities that steal electricity and water in Jamaica are rural areas, squatter settlements, and inner-city areas. While every community is unique, common features across these areas allow a basic community framework to address utility theft and uplift the community.

International and Jamaican experience demonstrates that a holistic approach can reduce electricity and water theft, if done correctly (Section 4.4). Communities must be involved in the process. Tariffs, financing, and collection mechanisms must be designed to meet community needs. Finally, successful programs often offer community members additional services that only the utility can provide, such as access to credit and life insurance.

Applying this experience to Jamaica leads to a strategy with a good chance of success. JPS should partner with NWC, the Housing Authority of Jamaica (HAJ) and other Government agencies to offer a comprehensive Community Upliftment Program (Section 4.13.6.5). Residents in low-income communities would be offered improved roads and footpaths, land title regularization, and access to micro credit, as well as reliable electricity and water supply. In return for these services, residents would need to agree to pay for electricity and water service. To establish mutual trust, benefits must be provided step-by-step, emphasizing reciprocity and establishing mutual trust between community members and the program.

Utilities, the Government, and donors should collaborate in organizing and funding this program. Utilities will see a financial return on their investments in this program through getting some revenue for services which they currently provide without any revenue. Donors and the Government should fund the non-utility aspects of the program, which aligns well with their priorities.
13.6.2 The Problem

Low-income communities in Jamaica often do not pay for the electricity or piped water supply that they receive. This jeopardizes the ability of the service providers to invest in providing better, cheaper service for all communities, and pushes up tariffs for other customers. Often, residents waste the utility services that they receive, since they are not paying for them. This further pushes up cost or worsens service for other customers. Law enforcement by the police is generally low to non-existent in these communities which is why the inhabitants are able to survive in the manner that they do and why the utility companies cannot prevent them from stealing. It also renders the efforts of removing illegal connections futile since the consumers often reconnect themselves in a matter of days after being raided by a utility and disconnected time and time again. The prosecution rate is also very low (partly due to a lack of resources on the part of the police and the low priority given to electricity theft on their part) as JPS removed more than 180,000 illegal connections in 2013 but the police were only willing to make 1,200 arrests during the same period. Lastly, the penalties, even if persons are prosecuted, are quite weak and are not a real deterrent to persons who are bent on stealing the electricity supply or who deem it necessary for their survival but simply cannot afford the product.

Table 13-7 shows access to electricity and piped water service island-wide, along with theft. The table also provides estimates on the financial effect of unauthorized household connections on JPS and NWC.

**Table 13-7: Access to Electricity and Piped Water and Theft**

<table>
<thead>
<tr>
<th></th>
<th>Electricity</th>
<th>Piped Water</th>
</tr>
</thead>
<tbody>
<tr>
<td>Access to service</td>
<td>92.9 percent</td>
<td>70.3 percent</td>
</tr>
<tr>
<td>Estimated households with service (including authorized and unauthorized connections)</td>
<td>720,000</td>
<td>540,000</td>
</tr>
<tr>
<td>Estimated number of households with unauthorized connections</td>
<td>180,000</td>
<td>220,000</td>
</tr>
<tr>
<td>Estimated annual financial impact of consumption from unauthorized accounts for JPS and NWC</td>
<td>US$75 million</td>
<td>US$49 million</td>
</tr>
</tbody>
</table>

Notes: Figures on access to service come from the Survey of Living Conditions (2010). Estimated households with service are calculated by multiplying the total number of households in Jamaica (773,935) times the percentage of households with service. The estimated number of households with unauthorized connections was calculated as the total number of households with service – the utility’s reported number of active residential customers.

For NWC, estimated households with service - NWC’s residential customers (544,076 - 320,585 = 223,492). This is close to NWC’s estimate of 166,000 customers with unauthorized connections, including customers with inactive accounts that are receiving service. The estimate of households with unauthorized connections includes some households that receive piped water supply from Parish Councils or private service providers, but these are very few.

For JPS, estimated households with service - JPS’ residential customers (718,985 - 531,827 = 187,158). This is consistent with JPS’ estimates. JPS estimates that it has 180,000 customers with unauthorized connections from all rate classes.

For NWC, the estimated annual financial impact of providing service to these customers is based on the monthly bill for average monthly consumption for a residential consumer (J$1,951.30 for 3,600 imperial gallons per month) x 12 months x the number of unauthorized customers (223,492) = US$49 million.

In 2013, JPS’ financial loss due to losses, including to residential, commercial, and industrial customers, was US$75 million. The OUR’s approved losses target for JPS is 17.5 percent as a percentage of net generation. Losses up to this target are priced into the
Fuel Recovery - System Losses Target

JPS provides service to about 180,000 unauthorized residential customers. The total financial effect on JPS for all unauthorized connections is about US$75 million. The combined cost of residential unauthorized consumption to JPS and authorized consumers may be as high as US$143 million. If unauthorized consumers consume at the same level as the average household, and paid a bill for the amount they consumed, then the increase in revenue from regularizing them all could be US$143 million. Of this, about US$75 million would flow to JPS as increased profit, while the remainder would go do benefit other customers through lower fuel charges. These estimates are far from exact, but they correctly indicate the scale of the problem.

JPS’ estimated annual losses from theft of US$75 million has contributed to putting the company into a position of default on its financing agreements in 2012. That in turn imperils further investment in the electricity system. Particularly, it puts at risk the ability to secure financing for the planned addition of 381MW of natural gas-fired generation capacity or the ability of JPS to refinance its existing debt.

Illegal connections also endanger lives in the community. Households are connected although their interior wiring without proper breaker panels and this creates fire and electric shock hazards. This is indeed a significant contributor to the many fires which are heard on the news each week which destroy homes in informal settlements all across the island and sometimes causes the death of children.

NWC provides service to about 220,000 unauthorized residential customers. NWC loses about US$49 million in tariff revenue annually because of these unauthorized residential connections. This deprives NWC of funds needed to rehabilitate infrastructure and expand access. Illegal connections damage the water pipes creating additional leaks. Leaks and unbilled consumption combine to give NWC non-revenue water at around 70 percent. Moreover, leaks and wastage deprives NWC of scarce water resources, resulting in lock-offs for many customers. This in turn contributes substantially to NWC’s own energy bill (which now represents approximately 25% of its total revenue requirement according to the last OUR Determination for water rates), as they are literally paying for electricity to pump water down the drain. NWC in turn is the largest customer of JPS, primarily as a result of the severe problem they are having for non-revenue water.

This demonstrates how the problem of theft severely impacts both utilities and the interconnectedness of this problem which is costing the country tens of millions of US$ per annum in wasted fuel. Needless to say, the total fuel bill of the country last year exceeded
US$2 billion and represents the single largest import item of the country, which by itself exceeds the total exports of the country.

### 13.6.3 Type of Communities

The problem of electricity theft is related to the issue of social exclusion. Low-income communities where people steal electricity and water are often communities that lack basic services, secure land tenure, and a voice in the development of the country. These communities suffer from inadequate water and sanitation services, and poor local roads, and paths. Many residents in these communities do not have titles to their land, even if generations of their family have lived there. Some entire communities have been established illegally, often on land owned by the Government. These informal settlements often foster a spirit of corruption and deceit as these poor inhabitants are ‘forced’ to do whatever they deem necessary in order to survive in very difficult economic conditions.

Problems are different in each community, but low-income communities can reasonably be grouped into the following three types:

- Rural villages
- Squatter settlements
- Inner-city areas.

Key characteristics are summarized in Table 13-8.

### Table 13-8: Characteristics of Low-income Communities in Jamaica

<table>
<thead>
<tr>
<th></th>
<th>Rural village</th>
<th>Squatter settlement</th>
<th>Inner-city area</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Electricity</strong></td>
<td>JPS Distribution network is in the village, and most households at one point had an authorized connection; Some or all households were cut-off by JPS, others self-disconnected; All non-JPS customers have illegal connections</td>
<td>No JPS network in the community; All households have illegal connections</td>
<td>Full urban style distribution network; Most households have unauthorized connections</td>
</tr>
<tr>
<td><strong>Water</strong></td>
<td>Many do not have NWC connection; Use a communal spring or catchment tank, and individual rainwater tanks, as well as buy water from vendors</td>
<td>No NWC system in the community; Many households have an unauthorized connection; In some settlements, vendors illegally take water from NWC facilities and sell into the community</td>
<td>Full urban-style distribution network; Most customers do not pay for water and NWC does not collect</td>
</tr>
<tr>
<td><strong>Sanitation</strong></td>
<td>Pit latrines and septic tanks</td>
<td>Pit latrines, septic tank, ‘bag and throw’</td>
<td>Many have toilets connected to sewer systems, but systems are in poor repair and may contaminate community</td>
</tr>
<tr>
<td><strong>Local roads and paths</strong></td>
<td>Village built around small country road in poor repair; Informal paths run back from road</td>
<td>No roads; Informal paths and lanes</td>
<td>Normal urban roads and lanes</td>
</tr>
</tbody>
</table>
From an electricity service perspective, these communities have key features in common:
- Almost everyone receives electricity from JPS’ network
- In many communities, almost no one is paying for electricity
- JPS’ traditional approaches to controlling unauthorized connections are not working.

Traditional approaches involving removing unauthorized connections, and arresting people. When JPS removes ‘throw-ups’—wires that residents attach to distribution lines to illegally tap into the electricity network—they are quickly put back. JPS’s repeated and increasing attempts at enforcement has not been effective at reducing electricity theft. While JPS stepped up enforcement efforts significantly in 2013 compared to 2012, carrying out about 60,000 more audits and removing about 100,000 more throw ups, it actually recovered only 17 percent of the electricity that it did 2012. This reflects the diminishing returns from these efforts in terms of recoverability.

The cost of patrolling and removing throw-ups exceeds the revenue saved. In 2013, JPS lost an estimated US$11.1 million from enforcement efforts, slightly less than the US$11.5 million it lost in 2012 (see Table 13-9). Additionally, while arresting and prosecuting people has a deterrent effect, arresting entire communities is not possible due to resource constraints on the part of the police and the judicial system. A new sustainable approach is clearly needed.

**Table 13-9: JPS Enforcement Indicators for Losses**

<table>
<thead>
<tr>
<th></th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of audits</td>
<td>121,672</td>
<td>115,841</td>
<td>113,733</td>
</tr>
<tr>
<td>Number of throw-ups removed</td>
<td>35,773</td>
<td>98,714</td>
<td>197,999</td>
</tr>
<tr>
<td>Number of arrests</td>
<td>65</td>
<td>76</td>
<td>1,200</td>
</tr>
<tr>
<td>Number of mechanical meters replaced with electronic meters</td>
<td>23,613</td>
<td>29,480</td>
<td>54,144</td>
</tr>
<tr>
<td>Number of RAMI Installations</td>
<td>6,500</td>
<td>6,700</td>
<td>6,000</td>
</tr>
<tr>
<td>GWh recovered</td>
<td>70.08</td>
<td>46.84</td>
<td>7.99</td>
</tr>
</tbody>
</table>
Note: Revenue saved is the average residential tariff x GWh recovered.
For 2013, the 2012 average residential tariff was used to calculate revenue saved.
Net benefit (loss) is Revenue saved – Total cost of enforcement.

The differences between the communities mean that each has its own problems and opportunities, and each needs its own approach. In squatter settlements, the need to put in infrastructure is greatest—and sometimes the solution is to offer people elsewhere to live. In inner-city communities, much of the infrastructure is there, so factors other than infrastructure upgrading will need to be offered to bring communities into a program in which they agree to pay.

However, there are sufficient similarities that strategies for one type of community may with some adaptation work in another. This suggests a unified organizational approach may be worth considering, with a single set of institutions addressing all communities, using strategies that differ according to the community being assisted. However, there is clearly the need to engage the relevant GOJ agencies which have the appropriate social intervention skills required to make this venture successful. It is also important that any community renewal program which is developed for the utility sector be developed to augment and complement the existing GOJ programs to ensure its effectiveness.

13.6.4 International and Jamaican Experience

Utilities in other countries—and other sectors in Jamaica—have found ways to work more closely with communities to increase payment for service. Three clear lessons emerge from these experiences:

- Involve communities in service design and management
- Tailor tariffs, financing, and collection mechanisms to community needs
- Offer additional services that the utility is in a unique position to provide.

Each of these lessons is expanded on below.

13.6.4.1 Involve Communities in Service Design and Management

Communities are more likely to pay for services if they are involved in decisions on how service is provided. Other countries and utilities have done this through distribution cooperatives, the use of community members in billing and collection, and meaningful consultation with communities over service and payment arrangements.

Distribution cooperatives

In Bangladesh, consumer involvement through cooperatives is linked to higher payment rates. While the Power Development Board (PDB), which supplies most of the country has high system losses and poor collections, electricity cooperatives perform much better. Cooperatives’ aggregate system and collection losses are one third lower than those of the

---

106 PDB has system losses of 23% and collection rates of 89% in 2003. Source: “Integrity in Bangladesh’s Rural Electrification”. USAID. April 2006, for aggregate losses of 34 percent.
main utility, although the cooperatives serve poor rural areas and charge higher tariffs. (Box 5.1).

**Use of community members in billing and collection**

The Philippines also has numerous rural electrification cooperatives which work with communities to ensure payment. To help with billing and collection in rural areas, these Filipino cooperatives generally use a member of the community as a billing and collection agent. Each agent is responsible for service to a small group of houses or ‘sitio’—possibly as few as twenty households. The agent is always a member of the community, and provides a liaison between the community and the cooperative utility. The agent not only ensures that bills are delivered, and money collected, she or he (they are often women) works with families to assist them in managing consumption and budgeting. Being an agent is a part-time role, for which a modest stipend is paid.

Similarly in Delhi, India, Tata Power Delhi Distribution (TPDDL) involved community members as franchisees to meter and collect bills in slum clusters, improving overall collections. This was a key component in a comprehensive loss reduction project that reduced Aggregate Technical and Commercial line losses from 53 percent in 2002 to 15 percent in 2009 (Box 5.2).

In Ahmedabad, India, the Ahmedabad Electricity Company (AEC) worked with community-based organizations to educate customers about the slum electrification program and used these organizations as bill collection points (Box 5.4).

**Meaningful consultation with communities over service and payment arrangements**

Involving the community has also worked well in Jamaica for the National Water Commission (NWC). As part of a comprehensive system loss reduction project for the Stony Hill area of Kingston, a team of contractors and utility staff developed an innovative approach to regularize service to the Rocky Gully squatter community. This community had grown up on steep lands with no roads or utility services. Almost all households in the community had made illegal connections to the NWC pipeline in the road, which ran along the edge of the community.

The contractors and utility staff consulted with the community to see what could be done. The community indicated that they would be willing to pay for service, if they would be provided with an official connection. A workable technical solution to provide formal service was developed and discussed with the community. Authorized connection points were installed at central locations in the community (see Table 13-7). Households run their own flexible pipe from their connection to their home.

A combination of design features and community initiatives has prevented theft on the customer side of the meter. There is a valve allowing the householder to turn off supply to his home when he is out. Many householders have gone further and installed lock boxes over their valve, to ensure that no one else in the community can draw water from the connection when they are away.

Once they agreed, the solution was implemented using labour from the community. Since the solution was installed, NWC has been receiving payment from most households every month.
In other words, households that earlier got piped water for free through illegal connections are now happy to pay for the water, thanks to this consultative approach.

**Figure 13-7: NWC Meter Bank in Rocky Gully Squatter Settlement**

---

**Box 13.1: The Use of Cooperatives in Bangladesh**

Bangladesh has been able to provide electricity to over 9 million of its rural citizens through the use of rural electricity cooperatives. These cooperatives, known as Palli Bidyut Samities (PBSs), are consumer-owned and organized for the distribution of electric power to its members. These cooperatives are managed by the Rural Electrification Board (REB), an agency of the Ministry of Energy and Hydrocarbons.

One of the reasons for the success of PBSs is local participation. Community leaders are engaged early and lead the process of board elections. Local industries, farming groups, and commercial leaders are engaged to ensure their interests are addressed. A village advisory program allows community leaders access to PBS management to voice customer concerns.

PBSs have proven to run very effective commercial practices. System losses are around 23 percent. Collection rates average above 95 percent throughout the REB system. PBSs manage their own billings and collections. Energy bills are calculated by the accounting staff and delivered by employees. Payments can be made to local banks or directly to PBS’ headquarters office. Customers are given 30 days to pay their bills or assessed a fine. Service is disconnected if payment is not received in 60 days and membership is revoked if payment is received in 90 days. Reconnection is possible but only after a fine. Meter readers are fixed-term employees of PBS and rotated among service territories to reduce the risk of customer fraud. Meter readers’ contracts are limited to three years to further reduce the risk of fraud and administrative losses.

Annual performance targets for 21 indicators are agreed upon by the REB management and PBS managers. Indicators include benchmarks for system losses, sales, and collection rates. Annual bonuses for PBS employees are based on the performance against these targets and senior PBS staff are responsible for monitoring progress. The REB provides monthly summaries of operational and financial characteristics to help PBSs monitor performance.

13.6.4.2 Tailor Tariffs, Financing, and Collection Mechanisms to Community Needs

Low-income customers have shown a willingness to pay for reliable electricity service, but have unique financial challenges that require tailored tariffs, financing, and collection mechanisms to encourage payment. Useful options are discussed below.

Avoid upfront connection fees

Customers have shown the ability to pay monthly utility bills but are often unable to afford the initial connection fee. Utilities have found ways reduce the burden of this fee. A local utility in the Cagayan province in the Philippines waives the fee (Box 5.3) while the AEC allows customers to pay in instalments. NWC took a similar approach in Rocky Gully.

Provide facilities to accept small, irregular payments during the month

Utilities have also found ways to meet the irregular cash flows of local communities. AEC provides monthly billings for slum communities to match customers’ cash flows, instead of its usual billing every two months. Some agents in the Philippines collect irregular payments from customers toward their monthly bills.

Prepaid meters are a great way to make it easier for customers to pay for a small amount of electricity and avoid a large bill at the end of the month. Another benefit of prepaid meters is that there is no disconnection or reconnection fee if customers cannot pay for electricity. Further, customers with prepaid meters typically reduce the electricity they consume by 10 to 15 percent, as they are more consistently aware of how much they are spending on electricity. DOMLEC, Dominica’s electricity utility, offers prepaid meters and have found that this increases revenue and collection rates. It has been observed that most customers are purchasing electricity on a weekly basis to help manage their cash flows.

Provide convenient local customer service and collection points

Utilities have increased bill collection points to help increase customer payment rates. AEC has partnered with local organizations such as post offices and community-based organizations to provide additional bill collection units. It also offers a mobile bill collection centre that periodically visits slum communities to increase convenience for bill payment. TPDDL provides multiple payment options including collection centres, online payment options, and drop boxes (see Box 13.2).

Offer lower tariffs

Sometimes, utilities can benefit by charging low-income communities less than the full cost of providing service. Charging lower tariffs can increase collection rates and overall revenues from these communities. For utilities, this is better than not collecting any money at all, and tariffs can be raised gradually to cover the full cost of providing service. It also allows communities to establish a habit of paying utility bills, which they will continue as tariffs rise. This makes good economic sense as long as the tariffs charged exceed the marginal cost (i.e. MR > MC) even if the tariff does not recover the full cost of service.

For example, PSBs in Bangladesh and TPDDL in Delhi, India charge tariffs to residents of low-income communities that are below the cost of service. In Bangladesh, cross-subsidies
from high-consuming industrial customers make up the difference between the full costs of providing service. In Delhi, the Government subsidizes tariffs.

**Box 13.2: Focusing on Customer Service in Delhi**

Tata Power Delhi Distribution (TPDDL) has reduced Aggregate Technical and Commercial line losses from 53 percent at its inception in 2002 to 15 percent in 2009. This reduction comes from focusing on customer service in various ways and has no doubt been aided by the fact that India has been able to reduce its cost of electricity over the last decade through the implementation of several key large-scale low cost generation facilities. TPDDL focused particularly in slum clusters.

As a first step, the company partnered with a local consultancy to survey local residents in an effort to find incentives to encourage customers to sign up for legal connections. From the results of these surveys, TPDDL partnered with local NGOs to provide free medical facilities, vocational training, and educational support to anyone in the community. In the first year, 1,200 community members took advantage of vocational training courses for electricians, plumbers, beauticians, tailors, and computer literacy. 750 children benefited from scholarships to government schools. 4,600 people benefitted from 30 drug de-addiction camps. TPDDL also worked with local organizations to work with the government to provide authorized connections in homes without titles. TPDDL then partnered with NGOs to create incentives for regular bill payments, including the provision of life insurance.

Additionally, TPDDL involved community members as franchisees for metering and bill collection in slum clusters. This has not only provided employment in the communities, but strengthened the connection with customers. This model has encouraged customers to get legal connections, improve collections, and provide easier access for customers to TPDDL officials.

Lastly, TPDDL has focused on revenue collection. It established a Revenue Recovery Group whose sole responsibility is to recover defaulted payments from current and disconnected customers. This included providing multiple payment options, such as collection centres, online payment options, and drop boxes. It also included doorstep services, spot billing, and accepting various forms of payment, such as multiple payments, debit/credit cards, and Electronic Clearing Systems.

Finding ways to bridge the gap with its customer has paid substantial dividends for TPDDL. The utility added 100,000 new connections in the slum clusters within three years. Its collection rate today is more than 90 percent, and customer satisfaction rates have increased.


“Afghanistan Executives Examine India Strategies to Improve Electricity Distribution Customer Service & Commercial Operations”. USAID and USEA.

### 13.6.4.3 Offer Additional Services that the Utility is in a Unique Position to Provide

People in low-income areas have service needs that differ from the needs of the middle-class consumers. Utilities that respond to these needs have been rewarded with high payment
rates. Types of services that have worked to increase payments include financial services, security of land ownership, and livelihood training.

JPS could fund some services for communities, especially micro-loans, and school-improvement projects, out of the tariff revenue from that community. This would directly link payment for electricity with benefits to the community. Communities with good payment records would receive extra benefits (typically calculated on a commission basis), providing a further incentive for community members to pay for electricity.

**Financial services**

Utilities are in a unique position to either provide financial services or tools which can help customers access financial services. A private utility in Bogota, Colombia used its customer information and utility bill payment records to offer credit cards to its customers. Sixty percent of customers who used this service did not have a bank account, and 35 percent lived on $2 or less per day (Box 13.3). NWC has found that simply providing a utility bill can help low-income consumers access credit, and is a reason consumers welcome regularization. TPDDL partnered with local organizations to offer accidental death insurance to regularized customers in slums. The value of the insurance ensures that customers continue to meet their monthly payments.

**Box 13.3: Innovative Consumer Finance Practices**

Utilities around the world have found innovative ways to use consumer finance to increase their consumer bases or create new revenue streams.

Many households are able to afford a monthly power bill, but cannot afford the large up-front connection fee which ultimately prohibits them from becoming connected to the grid. In response, Cagayan Electric Power and Light Company (CEPALCO), based in the Philippines, waives connection fees for its customers. CEPALCO recovers the cost of the connection through the sale of power to customers. CEPALCO has grown from 750 customers in 1952 to 100,000 in 2012. Its tariffs are based on a cost-plus model, which allows CEPALCO to take advantage of economies of scale from a growing customer base. While this policy has increased the required capital needed to be invested in the company, CEPALCO has been able to attract private equity and debt financing due to its overall performance, which includes consistent profitability.

Codensa, the private utility serving Bogota, Colombia, was able to use its customer information and utility bill payment records to provide consumer financing to its customers. This separate financing arm, called Codensa Hogar, offered credit cards to its customers, 60 percent of whom had no bank account and 35 percent of whom lived on $2 or less per person per day. Clients often used this financing to purchase electrical appliances which, in turn, increased their demand for electricity. Codensa not only had the infrastructure in place for sending bills but it also had the relevant information for credit-scoring. Additionally, it had the financial strength and brand recognition to encourage merchants to accept the card. Lastly, enforcement was credible because Codensa had the ability to cut off power in the event of non-payment. Codensa Hogar eventually became more profitable than Codensa’s core business and was sold off.

Security of land ownership

Many low-income people with unauthorized connections lack secure titles to their land. Country people often have a legitimate ownership based on traditional occupation, but lack a formal title. Squatters on Government land have no title, but in established communities their *de facto* ownership is recognized by the Government. The Government regularizes ownership or offers plots of land or houses elsewhere in exchange for releasing the occupied land, through the Housing Agency of Jamaica.

Just having a legal connection and a utility bill are taken culturally as a signal of legitimate ownership. While in truth it has no legal effect, it is still valuable to people. For example, a utility bill is a basic proof of residence document that is required by financial institutions (or providers of credit) when creating an account for a new customer. By partnering with Government, utilities can turn this cultural perception into reality, if the program of regularizing connections is accompanied by a program of regularizing title. Title regularization projects are now recognized as very important for development, and are widely supported by donor agencies. Additionally, basic access to credit is an important development opportunity for low-income people.

Local NGOs in Ahmedabad, India worked with AEC and the local government to successfully address this issue. The local government agreed to grant “non-eviction” certificates to slum dwellers, which ensure that dwellers would not get evicted for 10 years. Despite not being formal titles, AEC accepted these certificates as proof of residence and granted electricity connections.
Box 13.4: Ahmedabad Slum Electrification Project

By 2008 all the slums in Ahmedabad had been electrified, adding legal connections to over 200,000 households in a span of six years. The municipal authority (AMC), electricity utility (AEC), and local NGOs (SAATH and MHT) in Ahmedabad, India worked in partnership to achieve these milestones. This project succeeded because it was able to address three major challenges: communities’ lack of trust in the electricity utility, limited access to finance/loans to pay for connection fees, and slum dwellers’ lack of legal status and security of tenure.

To address the first challenge, AEC relied on local NGOs to represent slum communities and help build trust between these communities and the utility. SAATH and MHT helped market the electrification program, educate consumers, and train community-based organizations (CBOs) to facilitate the program.

AEC also needed to find creative solutions to meet the needs of slum communities. It offered monthly billing instead of the standard billing—every two months—to meet the cash flows of these local communities. In addition to partnering with CBOs, AEC set up multiple bill collection units in places such as CBO offices, post offices, civic centres, and even mobile billing collection centres—vans that visited slum communities and collected payment. AEC provided onsite services to receive applications and answer consumer inquiries. All of these locations offered space free-of-charge to AEC. AEC also used social techniques such as offering gifts to girls’ schools, distributing gifts during important holidays (such as Diwali), and organizing road shows to raise awareness to encourage people to get legal connections.

AEC also effectively addressed the second challenge of financing connection fees. To arrive at an optimal connection fee, SAATH conducted an analysis to determine the optimal price at which households would be willing to connect. AEC also learned that households were more willing to pay connection fees if they had the option to pay in instalments. In response, local banks and cooperatives began to offer loans for these connection fees.

Lastly, NGOs worked with AEC and AMC to address the legal challenges of getting an electricity connection. In 2002, it was mandatory to obtain building permission in order to gain electricity. SAATH filed a public interest litigation to the High Court, which clarified that slums did not have to obtain building permission. Second, AEC had certain prerequisites for obtaining a new electricity connection, including a record demonstrating legal ownership of the land, the latest copy of property tax bill, and ration cards as proof of residence. Slum dwellers were not able to meet these requirements, as most slums were not authorized and dwellers did not have security of tenure. The NGOs worked with AEC to relax these requirements, and they requested that AMC not evict slum dwellers for a period of 10 years. Because of the trust the NGOs had developed with the community and government, both organizations agreed. AMC began granting non-eviction certificates to slum dwellers, which could be used to obtain electricity connections.


Livelihood training

In the poorest communities, utilities have offered livelihood training as a type of corporate social responsibility. TPDDL offers free vocational training, education support, and medical facilities to its customers. Additionally, TPDDL employs community members for metering and bill collection. Similarly, NWC in Rocky Gully employed community members, which
increased local support for the project and community members’ skills. JPS could partner with the established GOJ vocational training centres to offer jobs and skills training to members of the communities which it is targeting to regularize. All efforts to improve education and reduce unemployment will redound to the benefit of the utility and the wider society and certainly increase the success rate of the regularization program.

**Impact of the service**

As discussed above, the provision of additional services increases the likelihood of payment in three ways:

- Consumers are more likely to sign up for regularization of utility connections, since they want to access the other services. These are services that they typically cannot get in any way other than through regularizing their utility connections
- Customers are more likely to keep paying, since they want to retain access to the services. For instance, TPDDL cites the desire of very low-income families in Delhi to retain life insurance coverage as a key reason they remain current on their bills
- Increased earning power and access to credit makes it easier for customers to pay. With livelihood skills, customers can earn more money. With insurance, tragedies such as the death of the income earner in the family do not necessarily mean a default in payment. With access to credit and banking services, customers can manage fluctuations in income and expenditure while remaining current with their bills. Finally, secure title provides a method to offer security, increases access to credit, and provides the opportunity to recover against the property in the event of serious default.

13.6.5 Strategies for Community Renewal

JPS should also partner with NWC and the Ministry of Transport, Works, and Housing to launch a program that phases in community services in exchange for a commitment from the community to pay for the power and water services they receive. This program would be piloted in squatter settlements and eventually rolled out to rural communities and inner-city communities. The program would be funded by the Government, JPS, NWC, and the donor community. Given the multi-dimensional nature of the project, it is likely that the donor community would be a major source of funding and JPS has confirmed this in initial discussions with the SDC and World Bank.

13.6.5.1 The Program

This program would be designed to offer infrastructure improvements and other benefits to communities. Infrastructure improvements would include:

- Reliable access to water, sanitation, and electricity (including house wiring)
- Fixing local roads and footpaths
- Wireless broadband access (if there is demand).

Additional benefits would depend on community needs, and would be decided in consultation with the community. Some examples of additional benefits that have proven successful in encouraging payment in the past include:
Fuel Recovery - System Losses Target

- Land title regularization
- Housing improvements or resettlement options for squatters
- Provision of utility bills to be used for credit checks and access to finance
- Skills and job training
- Employment for community members (job placement and apprenticeship programs)
- Option to purchase life insurance.

Payment

This program would offer improved payment options. First, it would offer transitional “community upliftment tariffs.” These tariffs would be discounted and gradually increased as services levels increase and customers’ ability to pay increases. Additionally, there would not be any initial connection charge. Instead, customers would be able to pay for the cost of connection in instalments, added on to their monthly bills.

Customers that cannot make payments will not be disconnected automatically. Instead, they will be offered credit arrangements with interest. Alternatively, prepayment meters can be provided as a means of helping persons to manage their budget more efficiently and to “pay as they go” avoiding large monthly bills at the end of each month which they did not properly budget to address.

Community involvement

The community would be consulted to determine its priorities for the upliftment plan. This will ensure that the community agrees to the services it will receive and understands that the program will only be sustainable if the whole community participates and pays. A representative from each community would be selected as a liaison between the community and the relevant GOJ agency working alongside JPS and the NWC. This representative would help to canvas the needs of the community, respond in person to service problems, and provide other support, such as advice to customers on how to limit consumption levels. There will also be other opportunities for community responsibility, such as contracting out management of the billing and collections to a community-based organization.

Implementation process

The first step of this program will need to be taken by the team of JPS, NWC, and the Government. The exact scope of works and initial project cites for the first year of the program could be finalized within 90 days. The existing EEIF funds would be used to fund these projects after the project cost is developed for the first year and approved by the OUR. Utility rates initially would be discounted as mentioned under the tariff chapter but would gradually increase as benefits to the community increase. We estimate the graduation period to be five (5) years but the success of each project would be reviewed annually and modifications sought from the OUR each year.

Service providers and community members would establish mutual trust and gradually work together to improve services and cost recovery. If payments were to stop at any point, community meetings would be organized to create social pressure to pay. If non-payment continued, any additional upgrades would cease and non-payers would be aggressively pursued. If, after project implementation, losses in such communities exceeded excepted
standards then community based load-shedding could be utilised through our Recloser Energy Limiting Initiative (RELI) as a general strategy towards ensuring overall compliance and limiting the impact of losses to all other JPS customers. Load shedding during certain hours of the day would ensure the community still had access to electricity during certain agreed critical hours of the day but not provide that community with access 24 hours per day based on their unacceptably high level of energy losses. An appropriate schedule and scale would be communicated and agreed with the OUR prior to implementation. This could in fact be communicated to the community as a means of ensuring overall compliance and ensuring they understand clearly the consequence for non-compliance.

The communities that benefited from the program and the improvements that they received would be publicized to create demand for the program throughout the country. However, we are confident that with the World Bank funding and additional services that would likely be provided (credit support, life insurance, access to education, etc.) to such customers that the community renewal project would like be a huge success.

13.6.5.2 Organization

This project should be run by a unit that is led and coordinated by the GOJ in conjunction with the JPS and NWC. The Unit would employ contractors and JPS and NWC staff. Community interaction would be handled by the staff and contractors of the Unit, accompanied by the relevant utility representatives.

After a community plan is agreed upon, actual work would be contracted by the Unit to various service providers, including Rural Electrification Company and Rural Water Company. As service is regularized, relationships with the community would be mainstreamed back into utility operations. However, community representatives working for the relevant GOJ agency on behalf of both JPS and NWC would be retained, utility staff would continue to visit the community, and the Unit would monitor progress until full regularization is achieved, including a steady record of payment at regular tariffs. The continuous involvement of the GOJ monitoring unit would also facilitate World Bank funding for the aspects of the community renewal that the GOJ would directly fund, e.g. infrastructure improvement.

13.6.5.3 Phasing

This project should be rolled out in a three major phases. The program for squatter settlements would be first piloted in two areas, then evaluated, adapted, and scaled up. These communities have the most to gain in terms of legal connections, land titles, and other benefits. The next two phases would be adapting the program and extending it to rural communities and inner-city areas.

13.6.5.4 Funding

This is a large-scale program, and multiple sources of funding will be needed:

- **Government.** All improvements related to land, housing, roads, paths need to be funded by the Government. There are existing budgets that can be used to fund the project initially, but a longer-term commitment to the project will be required.
• **JPS.** JPS must pay for all the parts related to electricity infrastructure, financing the cost for house-wrign and for project organization. JPS and the NWC would jointly contribute towards the social intervention costs which are designed to ensure the sustainability of the program. This would include contributions towards the cost for jobs and skills training, customer education and security and law enforcement. The program should be able to prove its financial viability within 12 months. By this time it should be clear that communities engaged in the program are paying for service they earlier took without paying. From this, it will be possible to validate ROI calculations and we would encourage that this analysis is conducted annually by a relevant GOJ agency (such as STATIN).

• **JPS** will also reinvest a portion of the electricity revenue generated from communities with good payment records back into the community, by providing extra benefits, such as school electrification and micro-finance, or other programs that community members want such as access to life insurance benefits. This will provide further encouragement for community members to pay for electricity, because it directly links electricity payment with benefits.

• **NWC.** NWC will need to pay for everything related to water, and contribute to the costs of running the program and like JPS make a contribution towards social intervention costs. This program will also be financially positive for NWC. NWC is on a drive to expand and improve services, and to reduce NRW, meaning that the program will fit very well with the priorities of the government.

• **Donors.** If donor relations are well-handled, substantial concessional loans and grants will be coming from IADB, CIDA, DFID, the EU, and others to support social intervention and community renewal. These funds should be managed by the GOJ Unit to ensure proper monitoring and reporting is maintained to the donor’s satisfaction. There are numerous existing programs today that are managed by JCIF and the SDC.
13.7 Proposals for System Losses Target

The original intent of the separation of Fuel and Non fuel tariffs was to facilitate the pass-through of fuel cost with JPS being incentivized to become more efficient through the application of reasonable heat rate and system losses targets. The tariffs were designed to allow JPS to focus on earning its core profits from the Non-Fuel Tariffs, while leaving the Fuel tariffs to be primarily cost reflective. This is standard practice with price cap regimes.

In the last 5 years fuel prices have skyrocketed and due to the existing target for System Losses since July 2012 the fuel incentive framework has simply become a constant fuel penalty framework, and has risen to levels which threaten the very viability of the business, with a US$18M net penalty in 2011, US$32M in 2012 and a US$43M net penalty for 2013. This situation if not corrected threatens the solvency of the company. This was confirmed by an independent consultant’s report (KEMA) in 2013 that indicated that the current basis for setting the System Losses target by the OUR was not sustainable and likely to bankrupt the utility.

JPS believes that for the company to remain viable the basis for setting the system losses target must be changed. For any incentive mechanism to work it must be fair (i.e. grounded in some reality), practical and objectively determined. JPS strongly believes that using historical averages is a fair basis for setting the losses target and proposes that the Losses target be based on the last 3 years actual Losses with a stretch target of 2 percent. The JPS has added a stretch target of 2% on the basis that in addition to JPS’ best effort of the Government, OUR and other key stakeholders will work in partnership to ensure that the appropriate supporting legislation and social intervention programmes are implemented in a timely and effective manner. If this support is not implemented it should be appreciated that this stretch target will unlikely to be met. To avoid severe financial penalties which would impact the viability of the business and therefore its own ability to fund the loss reduction activities themselves and maintain a reliable power service for the country, there should also be a cap on the fuel penalty or gain of US$1M (or 1.5% of the cost of fuel) per month. This would result in an upper limit of US$12M in fuel penalties which would provide enough incentive to the company to fight system losses without putting it at risk of being completely wiped out. It should be noted that US$12M represents more than 20% of the target ROE of the Company.

This proposal is consistent with losses incentive mechanisms used in a number of jurisdictions. Table 13-10 below retrieved from the KEMA Losses study shows the number of countries with similar penalty reward mechanisms setting their losses targets based on historical performance. JPS was the only jurisdiction that had their target subjectively set by the regulator.
### Table 13-10: International experiences with losses incentive mechanisms

<table>
<thead>
<tr>
<th>Country</th>
<th>System losses level</th>
<th>Scope</th>
<th>General properties</th>
<th>Target setting basis</th>
<th>Sales Risks from not meeting losses target</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jamaica</td>
<td>24.3%</td>
<td>Heat rate + System Losses</td>
<td>Explicit system. Target and penalty/reward.</td>
<td>Set by regulator</td>
<td>Yes</td>
</tr>
<tr>
<td>Saint Lucia</td>
<td>9%</td>
<td>Heat rate + System Losses</td>
<td>Implicit. Adjustment of next year’s targets based on historical losses efficiency</td>
<td>Based on last year’s performance</td>
<td>In principle yes, but non-technical losses are relatively low so impact is limited</td>
</tr>
<tr>
<td>Grand Bahamas</td>
<td>9%</td>
<td>Heat rate + System Losses</td>
<td>Implicit. Adjustment of next year’s targets based on historical losses efficiency</td>
<td>Based on fixed heat rate and system losses target</td>
<td>In principle yes, but non-technical losses are relatively low so impact is limited</td>
</tr>
<tr>
<td>United Kingdom</td>
<td>5%</td>
<td>System Losses</td>
<td>Explicit system. Target and penalty/reward.</td>
<td>Historical basis</td>
<td>In principle yes, but non-technical losses are very low so impact is negligible</td>
</tr>
<tr>
<td>Trinidad &amp; Tobago</td>
<td>9.4%</td>
<td>System Losses</td>
<td>Explicit system. Target and penalty/reward.</td>
<td>Historical basis / Benchmarking</td>
<td>In principle yes, but non-technical losses are very low so impact is negligible</td>
</tr>
<tr>
<td>Oman</td>
<td>Varies per utility between 12% and 20%</td>
<td>System Losses</td>
<td>Explicit system. Target and penalty/reward.</td>
<td>Annual adjustment based on observed convergence speed</td>
<td>No, revenue-yield system is applied</td>
</tr>
<tr>
<td>Jordan</td>
<td>Varies per utility, around 10%</td>
<td>System Losses</td>
<td>Explicit system. Target and penalty/reward.</td>
<td>Reduction based on observed improvements.</td>
<td>No, rate-of-return system is applied</td>
</tr>
<tr>
<td>Philippines</td>
<td>9.5%</td>
<td>System losses</td>
<td>Explicit system. Target and penalty/reward.</td>
<td>Fixed at 9.5%</td>
<td>In principle yes, but non-technical losses are relatively low so impact is limited</td>
</tr>
<tr>
<td>Australia</td>
<td>6.5%</td>
<td>System losses</td>
<td>Explicit system. Target and penalty/reward.</td>
<td>Average of last 5 years</td>
<td>In principle yes, but non-technical losses are very low so impact is negligible</td>
</tr>
<tr>
<td>Norway</td>
<td>7.6%</td>
<td>System losses</td>
<td>Explicit system. Target and penalty/reward.</td>
<td>Actual of previous year</td>
<td>In principle yes, but non-technical losses are very low so impact is negligible</td>
</tr>
</tbody>
</table>
As noted by KEMA, JPS was the only country on the list where sales risks is also present. The countries that do in principle have sales risks, did so due to non-technical losses but these are very low in these countries and thus immaterial. In cases such as Oman and Jordan the regulator has made separate arrangements within the price control formula to correct for not meeting the losses reduction targets.

The proposed losses target for 2014 -2018 is outlined in Table 13-11:

**Table 13-11: Proposed System Losses Target**

<table>
<thead>
<tr>
<th></th>
<th>Actual</th>
<th>Forecast</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2013 2014</td>
<td>2015 2016 2017 2018</td>
</tr>
<tr>
<td>System Losses - 3 Yr Rolling Average</td>
<td>23.34% 24.95%</td>
<td>25.98% 26.22% 25.63% 22.88%</td>
</tr>
<tr>
<td>Stretch Target</td>
<td>2.00%</td>
<td>2.00% 2.00% 2.00% 2.00%</td>
</tr>
<tr>
<td>Proposed System Losses Target</td>
<td>22.95%</td>
<td>23.98% 24.22% 26.63% 22.88%</td>
</tr>
</tbody>
</table>

The forecasts were calculated from 3 year rolling averages of system losses based on the impact of the proposed initiatives detailed in Table 13-6 of the current chapter. A summary of the calculations is provided below:

**Table 13-12: 3yr Rolling Average**

<table>
<thead>
<tr>
<th></th>
<th>Actual (%)</th>
<th>Forecast (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Losses - Beginning of the Year</td>
<td>23.32 21.80 23.24 24.97</td>
<td>26.64 26.34 25.69 24.86 24.08</td>
</tr>
<tr>
<td>Impact of Proposed Initiatives</td>
<td>0.30 0.65 0.83 0.78</td>
<td>0.78 0.86</td>
</tr>
<tr>
<td>System Losses - 3 Yr. Rolling Average</td>
<td>23.30 23.1 22.79 23.34</td>
<td>24.95 25.98 26.22 25.63 24.88</td>
</tr>
</tbody>
</table>

Though the energy loss reduction programs, initiatives and investments over the next 5 years are aimed at realizing an energy loss recovery equivalent to 7.17% (in terms of the reduction in the quantum of Losses as measured in GWh, the impact on the total system losses will be 3.1 percentage points. This reflects our expectation in terms of sales growth as reflected in our demand forecast in Chapter 17. If the sales growth outturn is stronger than we anticipate then overall system losses would be expected to lower than shown above..

JPS experience over the past decade and based on a recent study clearly demonstrate a very strong correlation between electricity theft, and the socio-economic and political conditions within which we operate. Hence, the following was concluded:

- 90% of the variability in the NTL are explained by socio-economic variables.
- NTL depend positively on the poverty level, on the payment capabilities of the population and the degree of violence present in the environment.
- For each 1% increase in the proportion of the population that lives in conditions of poverty, the NTL level increases by 0.63%.
- The result confirms the importance of the social dimension on the performance of the electric utilities.
Fuel Recovery - System Losses Target

The forecast reflects the fact that this task cannot be performed by JPS alone, but requires the joint efforts of the Regulator, GOJ, customers and other stakeholders. The stretch target implies that there will be full support from the GOJ in addition to JPS best effort to get the target indicated.
Chapter 14: Other Fees

14.1 Interest on Accounts Receivables for Commercial Customers

Currently, JPS’ accounts receivable is collected over a 52 day period on average. This occurs primarily on account of a mix of customers in all rate classes paying their bills well after the due date which manifests itself in approximately 20,000 to 30,000 disconnections per month. However, there is also a group of customers in the essential services (primarily Government accounts) which cannot be disconnected and as a result we have seen there average outstanding balance well above the norm. As a result of these factors, JPS suffers significant interest costs on the additional working capital requirement to fund the business, and FX losses on the outstanding balances due from those customers. JPS does not have an interest rate clause in its standard offer contract and as such the interest paid on additional funding required to maintain operations while these amounts receivable remain outstanding is absorbed by the Company. The Company suffers significant foreign exchange losses on these balances while they remain unpaid especially during periods of rapid devaluation of the Jamaican dollar against the US Dollar. As indicated in Table 14-1 below, during 2013 the Company suffered FX losses of over $30M in relation to the settlement risk. This is primarily due to the significant devaluation of the Jamaican Dollar during 2013 when the dollar devalued by 14.3%. Commensurate with the FX losses for 2012 being 7.4%, the level of FX losses experienced in 2012 was half that incurred in 2013.

Table 14-1: Foreign Exchange Losses 2011-2013

<table>
<thead>
<tr>
<th></th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Receivables</td>
<td>2,349,326</td>
<td>15,579,331</td>
<td>30,223,586</td>
</tr>
<tr>
<td>Payables</td>
<td>1,175,521</td>
<td>(1,076,236)</td>
<td>(2,406,024)</td>
</tr>
<tr>
<td>Cash</td>
<td>(331,036)</td>
<td>(1,692,895)</td>
<td>(9,559,426)</td>
</tr>
<tr>
<td>Other</td>
<td>81,787</td>
<td>2,068,456</td>
<td>2,855,995</td>
</tr>
<tr>
<td></td>
<td>3,275,598</td>
<td>14,878,655</td>
<td>21,114,132</td>
</tr>
</tbody>
</table>

Since the implementation of the early payment incentive and late payment fee for residential customers the number of customers who pay their bills on a timely basis has increased from 35% to 44% on average. Whilst we would not refer to this level of response as a resounding success, the initiative has proven to be somewhat effective in motivating residential customers to pay on a timelier basis. Notwithstanding this level of success, residential customers do contribute to the losses suffered by the company and when the interest costs are taken into consideration the total cost outweigh the benefit of the late payment fee when residential customer bills begin to trend upwards of $18,000 per month. The late payment fee proves to be a more effective hedge against interest and FX cost when the average monthly customer bill is below this level.

Unfortunately, there isn’t a similar mechanism in place for treating with commercial and industrial customers. By virtue of this, the payment experience on those accounts is markedly worse than residential customers with approximately 30% of commercial customers paying their bills within the prescribed due date. Government receivables including NWC and other public...
sector agencies account for just under a third of total receivables and on average they are settling their bills in the 120 day time frame. Other industrial customers tend to pay within periods in excess of 30 days.

As indicated in Chapter 6, JPS’ average cost of debt at December 2013 is 8.07%. Additionally, while the 14.3% rate of devaluation experienced in 2013 resulted in a US$21 million FX loss for the year only US$14 million was included in the revenue requirement to adjust for a normal year’s expectation. JPS therefore considers it reasonable that the rate of interest to be charged on commercial customer bills should be set at such a level that recovers the approximate FX loss that is suffered during the period the debt remains outstanding, which this includes the normal 30 day settlement period.

Based on the foregoing, it is JPS’ proposal that the rate of interest on outstanding debt be set at the rate of 15% per annum for commercial customers. By setting the rate at this level, the 7% increment over and above the 8% average cost of debt will act as an FX recovery proxy. This is required since the customers are settling their bills in J$ but JPS in turn requires this money to settle its US$ obligations, whereby 85% alone relates to Fuel (Petrojam) and the IPPs. The 7% portion of the interest rate charge will be used at the end of each financial year as a offset to the FX loss recovery (i.e. the annual ‘true-up’) proposed in section five of Chapter 11 of this filing. Practically, this will require that a proportion equivalent to 7/15 of the total interest charged to commercial customers under this program be separated and offset against the US$14 million FX recovery included in the revenue requirement. The inclusion of the US $14 million in this assessment of the recovery of FX losses will be limited to the extent that these amounts are billed to customers. Any over or under recovery of FX losses will, as indicated in Chapter 11, be adjusted as a part of the annual rate reset proposed in Chapter 11.

JPS further proposes that commercial customers be given a three (3) day grace period during which no interest would apply to the outstanding balance. The grace period will commence the day following the due date on the customer’s bill and will terminate on day three following the due date. Interest accrual will therefore commence on the first day following the due date on the customer’s bill but would be waived where the customer pays within 3 days of the due date.
Chapter 15: Decommissioning

15.1 Description

JPS has executed a purchased power agreement (PPA) with Energy World International (EWI) to construct a new 381 MW generation facility, which will begin commercial operation in 2016. When the EWI plant begins commercial operation in 2016, it will be necessary to retire the existing Old Harbour Power Plant (Old Harbour) the same year, and potentially Hunts Bay Unit B6 (Hunts Bay) in 2017. The EWI plant necessitates the retirement of Old Harbour (292 MW) with the Hunts Bay (89 MW) remaining in operation to facilitate load growth, however, the current load forecast shows little to no growth in the near term. The EWI plant when begins operation will displace the existing resources; both the Old Harbour units and the Hunts Bay facility. As directed by the OUR, it is now necessary for JPS to prepare a decommissioning and closure cost report for submission to the National Environmental Planning Agency (NEPA). JPS will also be required to include these costs in the 2014 rate case submission.

Additionally, for Hunts Bay JPS has looked at two options:

- Closure\(^1\) of the unit as per OUR requirement
- Repowering of the unit by converting the fuel source to LNG.

Recommendations

Old Harbour

The Old Harbor Power Plant units have exceeded their lifetime and a significant investment would need to be made in order to bring them close to the required environmental standards and efficiency levels. This is not economically or operationally 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 381 MW of generation. 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 accurate cost estimates for environmental clean up, dismantling of equipment and site clearance. As such early soils investigation and asbestos identification are recommended by mid-2014. It is recommended that an independent demolition consultant be engaged approximately 12 - 18 months before

\(^1\) “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: Resource Conservation and Recovery Act).
Decommissioning

decommissioning to prepare the detail RFP for construction works and environmental remediation.

Hunts Bay

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. 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.

Decommissioning Cost Treatment

The decommissioning of Old Harbour and Hunts Bay will cost JPS an estimated US$10.353 million with associated severance costs ranging from US$7.5 million to US$9.8 million. Once the EWI facility achieves commercial operation, these costs become a liability for JPS and need to be recovered through the rate setting mechanism. It is typical practice for these “stranded costs” to be recovered through rates until these costs are fully recovered.

California and Texas are two markets in the United States, which transitioned from vertically integrated utilities to unbundled operations, generation, transmission, and local distribution companies. In each of these market deregulation regimes, the cost of stranded and retired generation assets were recovered through rate mechanism to ensure financial and operational viability of the utility provider. Independent evaluations were conducted either by independent auditors or through market-based approaches, such as auctions.

JPS considered the following approaches for decommissioning:

1. Option 1: Adding the projected decommissioning and severance costs as a separate revenue requirement item in the upcoming rate case (2014-2019) with the costs allocated to each rate class based upon generation cost allocators. These revenues would be placed into an escrow or trust account until OUR deems Old Harbour and Hunts Bay retired. Any residual funds would be returned to ratepayers through a one-time credit once the plants decommissioning is completed.

2. Option 2: The introduction of the EWI plant into the JPS grid triggers a special out-of-cycle rate case in the 2016/2017 time-frame, in order to deal with the new system dynamics associated with replacing over half of system peak capacity along with changing the dominant fuel source from HFO to natural gas, along any transmission upgrades required for system reliability. The decommissioning and severance costs for Old Harbour and Hunts Bay can be addressed in the out-of-cycle rate case.

JPS recommends Option 2 for Old Harbour Power plant upon commercial operation of the new power plant and the repowering of Hunts Bay Unit B6, which can be reviewed once natural gas becomes the primary fuel source for Jamaica.
15.2 Decommissioning Strategy

15.2.1 Old Harbour

The closure of Old Harbour is required in accordance to the OUR Generation Expansion Plan of October 2010, the latest available. Given JPS has executed a PPA for the EWI facility scheduled for completion by June 2016, 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; subject to final approval by the OUR.

Table 15-1: Old Harbour Decommissioning Timeline

<table>
<thead>
<tr>
<th>OH Units</th>
<th>Shutting Down</th>
<th>Decommissioning Start</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit 1</td>
<td>Before December 2010</td>
<td>June 2016</td>
</tr>
<tr>
<td>Unit 2</td>
<td>Before June 2016</td>
<td>June 2016</td>
</tr>
<tr>
<td>Unit 3</td>
<td>Before December 2016</td>
<td>March 2017</td>
</tr>
<tr>
<td>Unit 4</td>
<td>Before June 2017</td>
<td>September 2017</td>
</tr>
</tbody>
</table>

The decommissioning consists of several phases, strategic preparation, engineering and planning, delineation of decommissioning and demolition work with an agreed time schedule and coordination with the remaining generation capacity to ensure a continued safely balanced national power supply.

The demolition process starts with in-depth planning to determine the necessary budget for the process along with obtain the necessary permission from the OUR. The preparation of a back-up plan for continued operation in the event the new generation is delayed. An external demolition contractor with the support of external consultants will decommission Old Harbour.

Figure 15-1: Old Harbour Decommissioning Chart
15.2.2 Hunts Bay

Hunts Bay (68.5 MW) was commissioned in 1976 and is still operationally sound. The retirement of Hunts Bay in 2017 would result in JPS losing a viable asset. As a result, Hunts Bay is under consideration for repowering.

The closure of Hunts Bay is being planned in accordance with the OUR Generation Least Cost Expansion Plan Oct 2010. Hunts Bay B6 was recommended for closure 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 demolition process starts with in-depth planning to determine the necessary budget for the process along with obtaining the necessary permission from the OUR. The preparation of a back-up plan for continued operation in the event the new generation is delayed. An external demolition contractor with the support of external consultants will decommission Hunts Bay.

15.2.3 Decommissioning Plan

This Decommissioning and Closure Plan (DCP) for both Old Harbour and Hunts Bay will document the process JPS will undertake to decommission equipment when it becomes necessary at the end-life of the plants 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.

The conceptual DCP, presented herein, outlines the general process and consideration that will be employed to decommission any equipment or facility and closure of the Old Harbour and Hunts Bay at the appropriate times.

The Decommissioning and/or Closure Plans should be finalized and submitted to the National Environment Planning Agency, Kingston and St. Andrew Corporation (KSAC) 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.

15.2.4 Environmental Clean-up Plan & Implementation

Some areas at the Old Harbour and Hunts Bay sites have been identified as potentially containing asbestos, mineral fibers and mineral oils, which will require special attention before dismantling and disposal.

15.2.5 Decommissioning Time Schedule

15.2.5.1 Old Harbour

Decommissioning and dismantling of Old Harbour Power Plant will require five (5) years starting in January 2015. The tasks are presented below.
15.2.5.2 Hunts Bay

A total period of five (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 Table 15-3.

Table 15-3: Hunts Bay Summary Schedule
15.2.6 Decommissioning & Dismantling Cost Estimate

15.2.6.1 Old Harbour

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

This estimate includes the cost for dismantling and demolition works at the site, the preparation of the demolished materials, transportation and disposal, as well as a preliminary estimate for asbestos removal and revitalization cost for contaminated soils. Early soil tests 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 known and measurable adjustments 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.

15.2.6.2 Hunts Bay

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 known and measurable adjustments 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 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 staff2.

---

2 Detailed cost estimate provided in Appendix B
15.2.7 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, conversion from one fuel source to another, upgrading of boiler plant, life extension of turbine and generator and, replacement of main auxiliary equipment.

The proposed 381MW power plant includes the installation of an LNG land based conversion facility. The availability of natural 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$13.2/MBTU 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$0.151/kWh. The all-in electricity would be US$0.1655/kWh\(^3\).

15.2.8 Mothballing Power Plants

15.2.8.1 Old Harbour

In order to reduce the initial cost of decommissioning in 2016, the OUR has suggested considering implications for mothballing of viable Old Harbour Units. This will only be applicable for Units 3 & 4 because Units 1 is already closed and Unit 2 will be officially closed by end of 2014.

The main costs associated with mothballing of Units 3 & 4 will be costs associated with staff reduction to staff the plant to enable re-opening. This will include O&M costs associated with maintaining the plant to prevent rusting and unsafe conditions in a potentially corrosive environment.

It is recommended that a minimum staff of approximately ten persons on an eight hour shift is retained along with twenty-four hour security. The asset value would be retained with normal depreciation annually.

15.2.8.2 Hunts Bay

Mothballing Hunts Bay B6 is a third option to reduce the initial decommissioning expenditures. Minimum staff would be retained with no extra cost for security.

15.2.8.3 Summary of Options

The various options are summaries for a quick overview as follows:

\(^3\) Details of assumptions and costing provided in Appendix C
### Table 15-4: Option Summary

<table>
<thead>
<tr>
<th>PLANT DESCRIPTION</th>
<th>Dismantle Cost</th>
<th>Salvage Cost</th>
<th>Project Cost</th>
<th>Staff No.</th>
<th>Redundancy Cost</th>
<th>Asset Value</th>
<th>O&amp;M Cost/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>Options</td>
<td>US$'000</td>
<td>US$'000</td>
<td>US$'000</td>
<td>#</td>
<td>US$'000</td>
<td>US$'000</td>
<td>US$000/yr</td>
</tr>
<tr>
<td>Non Fuel</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>OLD HARBOUR</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Existing Old Harbour</td>
<td>78</td>
<td>30,337</td>
<td>9,500</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>A Decommission Units 1-4</td>
<td>9,270</td>
<td>(1,619)</td>
<td>7,651</td>
<td>0</td>
<td>7,420</td>
<td>to 0</td>
<td>-</td>
</tr>
<tr>
<td>B Mothball Units 3 &amp; 4*</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
<td>10</td>
<td>6,469</td>
<td>held</td>
<td>750</td>
</tr>
<tr>
<td>(Units 1 &amp; 2 Closed)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>HUNTS BAY</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Existing Hunts Bay</td>
<td>51</td>
<td>2,947</td>
<td>2,500</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>A Decommission Unit B6</td>
<td>3,100</td>
<td>(398)</td>
<td>2,702</td>
<td>26</td>
<td>2,419</td>
<td>to 0</td>
<td>-</td>
</tr>
<tr>
<td>B Repowering Unit B6</td>
<td>NA</td>
<td>NA</td>
<td>18,000</td>
<td>51</td>
<td>NA</td>
<td>20,947</td>
<td>2,000</td>
</tr>
<tr>
<td>C Mothball Unit B6*</td>
<td>NA</td>
<td>NA</td>
<td>500</td>
<td>36</td>
<td>1,396</td>
<td>held</td>
<td>250</td>
</tr>
</tbody>
</table>

* Decommissioning cost Deferred
15.3 Appendix A: Old Harbour - Decommissioning Costs

The initial estimate was done using parametric estimating technique. See Table 15-5. 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 15-5: Decommissioning Costs

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

For further details, see Appendix E of original report for detail materials listing for each plant. The JPS budgetary engineer’s estimated cost of US$7.651M was derived from the Burns McDonnell sample estimates along with the detailed material listings and weight calculations, included in Appendix G.

Costs for asbestos and soil remediation estimates are based on plant size and medium levels of contamination. The summary estimate is presented in Table 15-6 below:
### Table 15-6: OH Summary Decommissioning Estimate

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

<table>
<thead>
<tr>
<th>No.</th>
<th>Description</th>
<th>Unit</th>
<th>Quan.</th>
<th>Labour</th>
<th>Material /Equip</th>
<th>Disposal</th>
<th>Environ.</th>
<th>Total Cost</th>
<th>Salvage</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Fuel Oil Facilities</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>No. 1 Heavy Oil Tank</td>
<td>CF</td>
<td>144218</td>
<td>30,000</td>
<td>30,000</td>
<td></td>
<td></td>
<td>60,000</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>No. 2 Heavy Oil Tank</td>
<td>CF</td>
<td>144218</td>
<td>30,000</td>
<td>30,000</td>
<td></td>
<td></td>
<td>60,000</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>No. 3 Heavy Oil Tank</td>
<td>CF</td>
<td>282289</td>
<td>40,000</td>
<td>40,000</td>
<td></td>
<td></td>
<td>80,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Unit # 3 Day Oil Tank (HFO)</td>
<td>CF</td>
<td>9180</td>
<td>5,000</td>
<td>5,000</td>
<td></td>
<td></td>
<td>10,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Unit # 4 Day Oil Tank (HFO)</td>
<td>CF</td>
<td>9180</td>
<td>5,000</td>
<td>5,000</td>
<td></td>
<td></td>
<td>10,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Unit # 1 Light Oil Tank</td>
<td>CF</td>
<td>1964</td>
<td>1,000</td>
<td>1,000</td>
<td></td>
<td></td>
<td>2,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Unit # 3 Light Oil Tank</td>
<td>CF</td>
<td>3928</td>
<td>2,000</td>
<td>2,000</td>
<td></td>
<td></td>
<td>4,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Diesel Oil Tank #1</td>
<td>CF</td>
<td>1595</td>
<td>1,000</td>
<td>1,000</td>
<td></td>
<td></td>
<td>2,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Diesel Oil Tank #2</td>
<td>CF</td>
<td>101</td>
<td>3,000</td>
<td></td>
<td></td>
<td></td>
<td>3,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Oil Room</td>
<td>SF</td>
<td></td>
<td></td>
<td></td>
<td>3,000</td>
<td></td>
<td>3,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Scrap Steel</td>
<td>TN</td>
<td></td>
<td></td>
<td></td>
<td>(220,000)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Sub-total</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>114,000</td>
<td>114,000</td>
<td>6,000</td>
<td>(220,000)</td>
</tr>
<tr>
<td></td>
<td><strong>Common Plant Facilities</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Laboratory and Chemistry Building</td>
<td>SF</td>
<td>35,000</td>
<td>25,000</td>
<td></td>
<td></td>
<td></td>
<td>60,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Demineralization Plant</td>
<td>LS</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>38,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Raw Water Storage Tank # 1</td>
<td>CF</td>
<td>28209</td>
<td>20,000</td>
<td>20,000</td>
<td></td>
<td></td>
<td>40,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Raw Water Storage Tank # 2</td>
<td>CF</td>
<td>28209</td>
<td>20,000</td>
<td>20,000</td>
<td></td>
<td></td>
<td>40,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Raw Water Storage Tank # 3</td>
<td>CF</td>
<td>28209</td>
<td>20,000</td>
<td>20,000</td>
<td></td>
<td></td>
<td>40,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Demineralised Water Tank #1</td>
<td>CF</td>
<td>28209</td>
<td>20,000</td>
<td>20,000</td>
<td></td>
<td></td>
<td>40,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Demineralised Water Tank #2</td>
<td>CF</td>
<td>28209</td>
<td>20,000</td>
<td>20,000</td>
<td></td>
<td></td>
<td>40,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Demineralised Water Tank #3</td>
<td>CF</td>
<td>47564</td>
<td>40,000</td>
<td>40,000</td>
<td></td>
<td></td>
<td>80,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Fire System</td>
<td>LS</td>
<td></td>
<td></td>
<td></td>
<td>22,000</td>
<td></td>
<td>22,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Instrumentation</td>
<td>LS</td>
<td></td>
<td></td>
<td></td>
<td>15,000</td>
<td></td>
<td>15,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Maintain Services to JEP</td>
<td>LS</td>
<td></td>
<td></td>
<td></td>
<td>10,000</td>
<td></td>
<td>10,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Scrap Steel</td>
<td>TN</td>
<td></td>
<td></td>
<td></td>
<td>(240,000)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Sub-total</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>205,000</td>
<td>183,000</td>
<td>37,000</td>
<td>(240,000)</td>
</tr>
<tr>
<td></td>
<td><strong>Common Plant Structures</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Administration and Workshop Building</td>
<td>SF</td>
<td>65,000</td>
<td>70,000</td>
<td></td>
<td></td>
<td></td>
<td>135,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Canteen and Changeroom</td>
<td>SF</td>
<td>11,000</td>
<td>10,000</td>
<td></td>
<td></td>
<td></td>
<td>21,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Bulk Storage House (Front)</td>
<td>SF</td>
<td>5,000</td>
<td>5,000</td>
<td></td>
<td></td>
<td></td>
<td>10,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>First Aid Building</td>
<td>SF</td>
<td>4,000</td>
<td>4,000</td>
<td></td>
<td></td>
<td></td>
<td>8,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Firepump and Emergency Diesel House</td>
<td>SF</td>
<td>5,000</td>
<td>5,000</td>
<td></td>
<td></td>
<td></td>
<td>10,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Main Stores Building</td>
<td>SF</td>
<td>10,000</td>
<td>10,000</td>
<td></td>
<td></td>
<td></td>
<td>20,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Bulk Storage House (Back)</td>
<td>SF</td>
<td>10,000</td>
<td>10,000</td>
<td></td>
<td></td>
<td></td>
<td>20,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Mechanical Workshop</td>
<td>SF</td>
<td>15,000</td>
<td>15,000</td>
<td></td>
<td></td>
<td></td>
<td>30,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Compressor House</td>
<td>SF</td>
<td>5,000</td>
<td>5,000</td>
<td></td>
<td></td>
<td></td>
<td>10,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Inner and Outer Guard House</td>
<td>SF</td>
<td>5,000</td>
<td>5,000</td>
<td></td>
<td></td>
<td></td>
<td>10,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Misc Buildings</td>
<td>SF</td>
<td>10,000</td>
<td>10,000</td>
<td></td>
<td></td>
<td></td>
<td>20,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Scrap Steel</td>
<td>TN</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>210,000</td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Sub-total</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>145,000</td>
<td>149,000</td>
<td>-</td>
<td>294,000</td>
</tr>
</tbody>
</table>

**Total Demolition Station Cost**

2,642,000  1,910,000  723,000  1,300,000  6,575,000  (1,618,640)

**SOIL REMEDIATION (EST)**

<table>
<thead>
<tr>
<th>Description</th>
<th>Unit</th>
<th>Quantity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Soil Testing</td>
<td>No</td>
<td></td>
</tr>
<tr>
<td>Bulk Storage Area</td>
<td>SF</td>
<td>500,000</td>
</tr>
<tr>
<td>Fuel Oil Tank Areas</td>
<td>SF</td>
<td>600,000</td>
</tr>
</tbody>
</table>

**Sub-total**

- - - 1,150,000 1,150,000

**REVISED PROJECT COST**

7,725,000 (1,618,640)

**PROJECT RESERVES**

<table>
<thead>
<tr>
<th>Description</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project Indirects (5%)</td>
<td>386,250</td>
</tr>
<tr>
<td>Contingencies (15%)</td>
<td>1,158,750</td>
</tr>
</tbody>
</table>

**LESS TOTAL PROJECT SALVAGE**

1,618,640

**TOTAL PROJECT COST**

7,651,360
Decommissioning

General Assumptions for the Decommissioning Analysis of Old Harbour

1. Cost of Dismantling/ Demolition include:
   - All site facilities prep work, dismantling and demolition works
   - Storage of materials for sale
   - 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 switchyard 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 achieved, demolition can proceed.

10. All PCB oil will be removed and disposed of properly

11. Only preliminary estimates for soil cleanup have been included and soils investigation will be required to ascertain the final quantities.

12. All structures two 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 forty hour 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, a 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.

**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 15-7 and these have been compared to the engineer’s estimate:

<table>
<thead>
<tr>
<th>RFI Received dated Oct 25, 2013</th>
<th>BIDS</th>
<th>JPS Estimated</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Demolition less Salvage</td>
<td>Demolition Only</td>
</tr>
<tr>
<td>1 Independent Excavating Inc (Ochoia)</td>
<td>3,800,000</td>
<td>3,800,000</td>
</tr>
<tr>
<td>2 Frontier Industrial Corp</td>
<td>515,000</td>
<td>2,215,000</td>
</tr>
<tr>
<td>JPS Engineering Estimate</td>
<td>3,186,360</td>
<td>4,595,000</td>
</tr>
</tbody>
</table>

**OH Book Value Plan**

Paragraph 16c of International Accounting Standard (IAS) 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 have 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 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.
Decommissioning

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 the useful lives of the plants. As a result, these units 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 15-8 below:

Table 15-8: Power Plant Book Values

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

**OH 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 Human Resources (HR) Management System Report.

**OH Current Staff Position**

JPS has a staff of 1429 employees (as at September 2013) and approximately 250 persons work in the Generation Division. Of this number, 78 people 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.

**Workforce Age Profile**

Based on the data, 78 employees currently employed 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.

**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 become redundant. The affected staff 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.

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 outplacement 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.
15.4 Appendix B - Hunts Bay B6 - Decommissioning Cost

Table 15-9: Hunts Bay B6 Site Demolition Preliminary Costing

<table>
<thead>
<tr>
<th>Site Demolition Cost Summary</th>
<th>Unit B6 - 66 MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>No.</td>
<td>Description</td>
</tr>
<tr>
<td>GENERAL</td>
<td></td>
</tr>
<tr>
<td>Planning Cost</td>
<td>LS 1</td>
</tr>
<tr>
<td>Safety Measures</td>
<td>LS 1</td>
</tr>
<tr>
<td>Supervision of Dismantling</td>
<td>LS 1</td>
</tr>
<tr>
<td>Sub-total</td>
<td></td>
</tr>
<tr>
<td>UNIT B6</td>
<td></td>
</tr>
<tr>
<td>Mobilize &amp; Demobilization</td>
<td>LS 1</td>
</tr>
<tr>
<td>Asbestos Remidiation</td>
<td>CF 400</td>
</tr>
<tr>
<td>Boiler &amp; Auxiliary &amp; Stack</td>
<td>LS 1</td>
</tr>
<tr>
<td>Steam Turbine &amp; Building</td>
<td>LS 1</td>
</tr>
<tr>
<td>Intake</td>
<td>LS 1</td>
</tr>
<tr>
<td>GSU &amp; Other Transformers</td>
<td>LS 1</td>
</tr>
<tr>
<td>Onsite Concrete Crushing &amp; Spreading</td>
<td>CY 100</td>
</tr>
<tr>
<td>Debris Handling, Haulage &amp; Disposal</td>
<td>CY 300</td>
</tr>
<tr>
<td>Scrap Steel (S140/TN)</td>
<td>TN 320</td>
</tr>
<tr>
<td>Scrap Non-Ferrous (S3800/TN)</td>
<td>TN 110</td>
</tr>
<tr>
<td>Sub-total</td>
<td></td>
</tr>
<tr>
<td>Fuel Oil Facilities</td>
<td></td>
</tr>
<tr>
<td>No. 1 Heavy Oil Tank</td>
<td>CF 144218</td>
</tr>
<tr>
<td>Unit #3 Day Oil Tank (HFO)</td>
<td>CF 9180</td>
</tr>
<tr>
<td>Soil Remediation</td>
<td>SF</td>
</tr>
<tr>
<td>Scrap metal</td>
<td>TN</td>
</tr>
<tr>
<td>Sub-total</td>
<td></td>
</tr>
<tr>
<td>Common Unit B6 Facilities</td>
<td></td>
</tr>
<tr>
<td>Fire System</td>
<td>LS</td>
</tr>
<tr>
<td>Instrumentation</td>
<td>LS</td>
</tr>
<tr>
<td>Maintain Services to BOP</td>
<td>LS</td>
</tr>
<tr>
<td>Sub-total</td>
<td></td>
</tr>
<tr>
<td>Total Demolition Station Cost</td>
<td></td>
</tr>
<tr>
<td>PROJECT RESERVES</td>
<td></td>
</tr>
<tr>
<td>Project Indirects (5%)</td>
<td></td>
</tr>
<tr>
<td>Contingencies (15%)</td>
<td></td>
</tr>
<tr>
<td>LESS TOTAL PROJECT SALVAGE</td>
<td></td>
</tr>
<tr>
<td>TOTAL PROJECT COST</td>
<td></td>
</tr>
</tbody>
</table>
General Assumptions Hunts Bay Decommissioning Analysis

1. Cost of Dismantling/ Demolition include:
   a. All site facilities prep work, dismantling and demolition works
   b. Storage of materials for sale
   c. 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 switchyard 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 hour 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.

Hunts Bay B6 - Book Value Plan

Paragraph 16 © of International Accounting Standard (IAS) 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 15-10 below:
Hunts Bay 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.

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.

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.

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 counseling, 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.

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

<table>
<thead>
<tr>
<th>No.</th>
<th>Unit Name</th>
<th>Total NBV</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Hunts Bay - B6</td>
<td>2,946,671.73</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Subtotal</td>
<td>2,946,671.73</td>
<td></td>
</tr>
</tbody>
</table>
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 outplacement 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
15.5 Appendix C- Hunts Bay B6 – Repowering Assumptions & Costing

Hunts Bay B6 Estimated Repowering Budget Cost

<table>
<thead>
<tr>
<th>Description</th>
<th>Budget Cost US$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Replacement of existing fuel burners with gas type burners and burner management system</td>
<td>2,000,000</td>
</tr>
<tr>
<td>Boiler, Economiser, Airheater and Forced Draft Fan Works</td>
<td>4,000,000</td>
</tr>
<tr>
<td>Turbine Life Extension</td>
<td>6,500,000</td>
</tr>
<tr>
<td>Rewinding of Generator Stator</td>
<td>1,500,000</td>
</tr>
<tr>
<td>Replacement Excitation System</td>
<td>750,000</td>
</tr>
<tr>
<td>Auxiliary Pumps, Motors, Switchgear Replacement</td>
<td>1,500,000</td>
</tr>
<tr>
<td>10 % Contingency</td>
<td>1,750,000</td>
</tr>
<tr>
<td><strong>Estimated Total</strong></td>
<td><strong>18,000,000</strong></td>
</tr>
</tbody>
</table>

Financial Model Hunts Bay B6 - Repowering
Chapter 16: Guaranteed and Overall Standards

16.1 Introduction

The Office of Utility Regulations ("OUR") regulates the quality of electricity services provided by JPS ("The Company") through its Quality of Service Standards Regime. The regime, introduced in 2000, was implemented to ensure that the Company provides an adequate level of electricity service to its customers. Under the regime, the OUR sets minimum performance standards customers can expect in their electricity supply, when requesting services or doing business with JPS for several service quality indicators, which the Company in its business operations must meet. The Company is required to measure and report its performance against these targets to the OUR on a quarterly basis.

There are two types of standards that are set and monitored by the OUR, Guaranteed and Overall Standards:

1. Guaranteed Standards ("Standards") set service levels that must be met for each individual customer. If the Company fails to meet a guaranteed standard then the Company has to make a prescribed payment to the customers affected. Guaranteed Standards therefore relate to a specific service —such as the time to connect a new supply—with a determined performance level and requires a penalty payment to be paid directly to the customer when this level of service is not attained.

2. Overall Standards set service levels for more general areas of services that affect most or a large numbers of customers such as, how much advance notice is given to customers ahead of a planned outage. These standards cover areas of service where individual guarantees are not feasible but JPS is still required to deliver a set minimum standard of service to all customers. As a result, these standards do not carry specific financial penalties or compensation for individual customers. However, the Company’s performance against the overall standards may affect its earnings through the Q-factor component of the Performance Based Rate-Making Mechanism as Overall Standards relate primarily to reliability of service.

Prior to 2009, the Guaranteed and Overall Standards were reviewed every five (5) years at the time of the Company’s price control review. During the 2009 price control review, the OUR determined the Standards would undergo a mid-tariff review every two years; with the first review being performed in 2012. No new guaranteed standards requiring automatic compensation would be introduced at the mid-tariff review, and the OUR would not introduce any new automatic standards; nor would penalties be adjusted, but existing standards could be modified, and new non-automatic ones added.

For the third price control review in 2014, this chapter discusses JPS performance against the standards and proposes modifications to the Guaranteed and Overall Standards based on the efficacy of the current regime, and the operational and resource constraints currently faced by the Company.

16.2 Guaranteed Standards

Guaranteed Standards are set to provide a minimum level of service that must be met for each customer on each service transaction. If the standards are not met then, customers are entitled to
receive compensation. These compensatory payments were initially made based on a claim by a customer, but since January 2010 some standards now attract automatic compensation. Automatic compensation payments are automatically credited to the customers’ accounts when a breach is detected or brought to the Company’s attention; without further action required of the customer. Non-automatic standards require the customer to make a claim. Guaranteed Standards cover areas such as connections, customer complaints, and estimation of billing charges. JPS monitors and reports to the OUR breaches committed and associated compensation, paid and unpaid, on a quarterly basis.

JPS has fourteen Guaranteed Standards. In effect however, the Company has eighteen Guaranteed Standards as several standards are multi-part with distinct service requirements and associated penalties and are tracked separately.

The OUR made several modifications to the Guaranteed Standards at the 2009-2014 Price Control Review which took effect in November 2009. The key changes include:

- The Introduction of three (3) new Standards:
  1. EGS11 – Wrongful Disconnection
  2. EGS12 – Reconnection after Wrongful Disconnection
  3. EGS13 – Meter Change Notification

- The introduction of automatic compensation for the following Guaranteed standards
  1. EGS06 – Reconnections after payment of overdue amount
  2. EGS11 – Wrongful Disconnection
  3. EGS12 – Reconnection after Wrongful Disconnection
  4. EGS9 – Meter Replacement

- The Guaranteed Standards are now subject to a mid-tariff review, every two years, subsequent to the Price Control Review.
- The OUR indicated that it will not make any adjustments to the compensation structure during the mid-tariff review but may introduce new standards or modify old ones.

The first mid-tariff review of the Standards scheme was completed in 2012. In its determination the OUR issued a clarifications to existing Standards, including EGS 1, EGS2, EGS 6, and EGS 8 with no new standard being introduced. However, the maximum number of periods for compensation for a single breach was increased from four (4) to six (6) periods of non-compliance. The OUR also increased the time allowed for customers to submit a claim to 132 working days (six months) after the occurrence of the breach.

The new service standards became effective on July 1, 2012. Table 16-1 lists the current Guaranteed Standards.

---

### Table 16-1: Guaranteed Standards

<table>
<thead>
<tr>
<th>Code</th>
<th>Focus</th>
<th>Description</th>
<th>Performance Measure</th>
</tr>
</thead>
<tbody>
<tr>
<td>EGS l(a)</td>
<td>Access</td>
<td>Connection to supply New</td>
<td>New service Installations within five (5) working days</td>
</tr>
<tr>
<td>Code</td>
<td>Focus</td>
<td>Description</td>
<td>Performance Measure</td>
</tr>
<tr>
<td>--------</td>
<td>------------------------</td>
<td>--------------------------------------</td>
<td>-------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>EGS1(b)</td>
<td>Access</td>
<td>Connection to Supply-Simple</td>
<td>Connections within four (4) working days where supply and meter are already on premises.</td>
</tr>
<tr>
<td>EGS2(a)</td>
<td>Access</td>
<td>Complex Connection to Supply</td>
<td>Between 30m and 100m of existing distribution line</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>(i) estimate within ten (10) working days</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>(ii) connection within thirty (30) working days after payment</td>
</tr>
<tr>
<td>EGS2(b)</td>
<td>Access</td>
<td>Complex Connection to Supply</td>
<td>Between 101m and 250m of existing distribution line</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>(i) estimate within fifteen (15) working days</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>(ii) connection within forty (40) working days after payment</td>
</tr>
<tr>
<td>EGS3</td>
<td>Response to Emergency</td>
<td>Response to Emergency</td>
<td>Response to emergency calls within five (5) hours-emergencies defined as broken wires, broken poles, fires</td>
</tr>
<tr>
<td>EGS4</td>
<td>First Bill</td>
<td>Issue of First Bill</td>
<td>Produce and dispatch first bill within forty (40) working days after service connection</td>
</tr>
<tr>
<td>EGS5(a)</td>
<td>Complaints/ Queries</td>
<td>Acknowledgements</td>
<td>Acknowledge written queries within five (5) working days</td>
</tr>
<tr>
<td>EGS5(b)</td>
<td>Complaints/ Investigations</td>
<td></td>
<td>Complete investigation within thirty (30) working days</td>
</tr>
<tr>
<td>EGS5(c)</td>
<td>Complaints/ Queries</td>
<td>Investigations involving 3rd party</td>
<td>Complete investigation within sixty (60) working days if 3rd party involved</td>
</tr>
<tr>
<td>EGS6</td>
<td>Reconnection</td>
<td>Reconnection after Payments of</td>
<td>Reconnection within twenty-four (24) hours of payment of overdue amounts and reconnection fee.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td><strong>Attracts automatic compensation</strong></td>
</tr>
<tr>
<td>EGS7</td>
<td>Estimated bills</td>
<td>Frequency of Meter reading</td>
<td>Should NOT be more than two (2) consecutive estimated bills (where company has access to meter).</td>
</tr>
<tr>
<td>EGS8</td>
<td>Estimation of Consumption</td>
<td></td>
<td>An estimated bill should be based on the average of the last three (3) actual readings</td>
</tr>
<tr>
<td>EGS9</td>
<td>Meter Replacement</td>
<td>Timeliness of Meter Replacement</td>
<td>Maximum of twenty (20) working days to replace meter after detection of fault which is not due to tampering by the customer.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td><strong>Attracts automatic compensation</strong></td>
</tr>
<tr>
<td>EGS10</td>
<td>Billing Adjustments</td>
<td>Timeliness of adjustment to customer's account</td>
<td>Where necessary, customer must be billed for adjustment within three (3) months of identification of error, or subsequent to replacement of faulty meter</td>
</tr>
<tr>
<td>EGS11</td>
<td>Disconnection</td>
<td>Wrongful Disconnection</td>
<td>Where the company disconnects a supply that has no overdue amount or is currently under investigation by the OUR or the company and only the disputed amount is in arrears.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td><strong>Attracts automatic compensation</strong></td>
</tr>
<tr>
<td>EGS12</td>
<td>Reconnection</td>
<td>Reconnection after Wrongful Disconnection</td>
<td>The company must restore a supply if wrongfully disconnected within five (5) hours.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td><strong>Attracts automatic compensation</strong></td>
</tr>
<tr>
<td>EGS13</td>
<td>Meter</td>
<td>Meter Change</td>
<td>The company must ensure that a note is left at the customer's premises and/or utilize its text messaging service indicating the meter change including date of the change and meter readings at the time of change, reason for change and serial number of new meter</td>
</tr>
<tr>
<td>EGS14</td>
<td>Compensation</td>
<td>Making compensatory Payments</td>
<td>Accounts should be credited within thirty (30) days of verification of breach</td>
</tr>
</tbody>
</table>
16.3 Performance Review

This section presents a summary of the performance of the Company against the Guaranteed Standards for the time period 2009 –2013. Overall, the Company’s performance improved during the review period and has now achieved a high level of compliance with nine of the existing guaranteed standards. Marked improvement was made in areas including billing adjustments and complex connections. However, the company’s performance and measurement for some standards were severely constrained by issues with its Customer Information System (CIS) and the processes supporting it. This situation should be significantly mitigated by a major upgrade of the system, which should be completed in August 2014.

EGS1 – Connection to Supply: New or Simple

This standard requires JPS to complete connections of supply within a required minimum performance standard from the day, which all conditions for service are satisfied. The minimum standard for new connection, no supply, or meter on premises, is five (5) working days. If there is supply and a meter on the premises, simple connection, then the connection should be completed within four (4) working days. In addition, the OUR in its mid-tariff review added that:

“The contract within these categories is considered established where the JPS acknowledges that all information/documents/fees deemed necessary for provision of the service are provided”

The figure below shows JPS annual average performance.

*Figure 16-1: Performance – Simple Connections*

EGS1a – New Installations

As shown above, over the five year period under review, the Company consistently connected more than ninety-five percent (95%) of requests for new supplies within the standard of five (5) days. The Company averaged 597 breaches per year for the period, which represents J$1.23M per annum in potential compensatory payments.

EGS1b – Simple Supply Connection
The Company connected ninety-four percent of all simple supply requests for the reporting period 2009-2013. This performance reflects challenges the company had been experiencing with its Customer Information System (“CIS”), which should be mitigated by the CIS upgrade and general improvement in associated input processes. These improvements should lead to improved performance against this standard in 2014 and beyond.

Breaches averaged 546 annually over the review period, representing approximately J$1.15M in potential compensatory payments.

**EGS2– Complex Connections to Supply**

This standard applies where the request for connection involves additional construction or network augmentation. The standard stipulates requests where the distance of the customer’s connection point from the distribution network is between 30m and 100m, a quotation or estimate of charges to enable the supply, should be provided within 10 days of request for connection and the connection be completed within thirty working days after payment has been made on the estimate. For connection points beyond 100m from the network, quotations must be provided within 30 days of request and the connection be completed within forty working days after payment on the estimate. The Company’s average annual performance against this standard is illustrated below:

**Figure 16-2: Performance – Complex Connection 1**

![Complex Connections to Supply](image-url)
Figure 16-3: Performance – Complex Connections 2

As shown in the graphs the company had made significant improvements in all categories for this standard for the first three (3) years of the review period. The decrease since 2011 resulted from a dramatic fall in requests involving complex connections since 2010. Consequently, the company’s performance is being measured on a smaller base, which exaggerates the variations in performance from year to year. The tables below illustrate this, showing the annual averages for breaches and the potential compensatory payments over the five (5) year period.

Table 16-2: Complex Connections – Breaches

<table>
<thead>
<tr>
<th></th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>EGS2a(i) – Complex Connections 1: Quotation</td>
<td>199</td>
<td>87</td>
<td>5</td>
<td>5</td>
<td>19</td>
</tr>
<tr>
<td>EGS2a(ii) – Complex Connections 1: Construction</td>
<td>105</td>
<td>29</td>
<td>5</td>
<td>2</td>
<td>9</td>
</tr>
<tr>
<td>EGS2b(i) – Complex Connections 2: Quotation</td>
<td>46</td>
<td>15</td>
<td>0</td>
<td>1</td>
<td>4</td>
</tr>
<tr>
<td>EGS2b(ii) – Complex Connections 2: Construction</td>
<td>6</td>
<td>3</td>
<td>0</td>
<td>3</td>
<td>1</td>
</tr>
<tr>
<td>Total</td>
<td>356</td>
<td>134</td>
<td>10</td>
<td>11</td>
<td>33</td>
</tr>
</tbody>
</table>

Table 16-3: Complex Connections – Potential Compensation (J$)

<table>
<thead>
<tr>
<th></th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>EGS2a(i) – Complex Connections 1: Quotation</td>
<td>1,742,700</td>
<td>144,000</td>
<td>7,500</td>
<td>7,500</td>
<td>29,400</td>
</tr>
<tr>
<td>EGS2a(ii) – Complex Connections 1: Construction</td>
<td>748,700</td>
<td>54,001</td>
<td>18,000</td>
<td>3,000</td>
<td>13,800</td>
</tr>
<tr>
<td>EGS2b(i) – Complex Connections 2: Quotation</td>
<td>579,600</td>
<td>40,500</td>
<td>-</td>
<td>1,500</td>
<td>6,000</td>
</tr>
<tr>
<td>EGS2b(ii) – Complex Connections 2: Construction</td>
<td>56,200</td>
<td>4,500</td>
<td>-</td>
<td>4,500</td>
<td>1,650</td>
</tr>
<tr>
<td>Total</td>
<td>3,129,209</td>
<td>245,011</td>
<td>27,511</td>
<td>18,512</td>
<td>52,863</td>
</tr>
</tbody>
</table>
EGS3 – Response to Emergency

This standard measures the percentage of responses to emergencies made within the stipulated minimum five (5) hours. Figure 16-4 below shows the Company’s annual performance for the period 2009 – 2013.

Figure 16-4: Performance – Emergency Response

As illustrated in Figure 16-4 the Company had an average annual performance of ninety percent (90%) over the period with an average of 1,122 breaches per annum and J$2M in potential compensation per year.

EGS4 – Issue of First Bill

The standard stipulates the Company must deliver the first bill to the customer within forty working days of service connection. The company’s actual performance is shown below.

Figure 16-5: Performance – First Bill

The Company’s billing punctuality for the period was 99.8 percent per annum. There was an average of 125 breaches per year which represents approximately J$345,000 in potential compensation annually.
EGS5 – Complaints/Queries

From September 2013, the limitation of the Company’s current CIS system has prevented JPS from reporting on compliance rates for this standard. The upgrade of the Company’s CIS will improve the data collection. The upgrade will be completed in August 2014 allowing the Company to begin reporting on EGS5 in 2015.

EGS6 – Reconnection

This standard measures the percentage of customers whose supply was reconnected within the minimum standard after all outstanding amounts were paid. The standard is 24 hours. This standard attracts automatic compensation.

The Company’s performance on EGS 6 for the review period is shown in Figure 16-6 below.

**Figure 16-6: Performance – Reconnection**

On average, 98 percent of reconnections were completed within 24 hours over the review period. Breaches of this standard have fallen from an average of over 2,000 per year to 501 last year. Consequently, the average compensation was also reduced from over J$4M to J$1.4M in 2013.

EGS7 – Frequency of Estimates & EGS8 – Estimate Calculation

Both standards monitor the use of an estimation routine for billing purposes. EGS7 measures the frequency with which an estimate will be used to derive the billed amount while EGS8 measures times the Company uses the last three actual readings as the basis for an estimated bill.

EGS7 stipulates that there should not be more than two (2) consecutive estimated bills. The performance against the EGS7 standard is illustrated below.

**Figure 16-7: Performance – Estimated Bills**
More than two consecutive estimated bills were sent to customers less than two percent (2%) of the time on average over the review period. But, because of the high number of bills distributed monthly (approximately 600,000), there were over 40,000 breaches per year with potential compensation of over J$90M per year over the review period and over J$100M per year since 2010.

Currently, JPS is incurring a significant amount of potential penalties for breaches and therefore, the effect has negatively affected all cost centers. In 2013 alone, there were 32,674 breaches and the compensation paid was J$234,000 with the net compensation to be paid of $118M. The Company continues to face significant financial risk from this standard, which bucks the worldwide trend to fewer and more automated meter readings and a greater use of estimates.

Compliance rates for EGS8 –Estimation of Consumption is currently not available because of constraints with the company’s Customer Information Systems, which should be resolved with the CIS upgrade.

**EGS9 – Meter Replacement**

The standard measures the frequency which meters are replaced within the minimum performance standard after a detected fault. The minimum standard is replacement within 20 days.

**Figure 16-8: Performance – Replacement of Meters**

The company averages 99% compliance per annum for this standard. There have been only two (2) breaches of this standard since 2011.
EGS10 – Billing Adjustments

This standard measures the percentage of billing adjustments that were reflected on bills within the minimum standard after detection of an error, etc. The minimum standard is three (3) months.

Figure 16-9: Performance – Billing Adjustments

Performance against this standard improved steadily over the period and is presently at 96 percent compliance due to breaches falling by over 86 percent from 3,800 in 2009 to 542 in 2013.

EGS11, EGS12 – Wrongful Disconnections; Reconnections

These standards address disconnections carried out in error. EGS11 measures the percentage of disconnections that were done without suitable cause while EGS12 measures the percentage of accounts disconnected in error that were reconnected within the minimum standard of five (5) hours. The company’s performance on EGS11 is illustrated below.

Figure 16-10: Performance – Wrongful Disconnections

Since the standard was introduced in 2010, the Company’s performance on EGS11 has been consistently 99 percent in compliance. There were 350 breaches in 2011 when the standard was first reported on, since then breaches has dropped to 126 in 2013.

The company’s performance on EGS12 is shown below.
Guaranteed and Overall Standards

Figure 16-11: Performance – Reconnection after Wrongful Disconnection

While the compliance rate against this standard since its inception has remained at 89 percent, since 2011, breaches of the standard has fallen 40 percent from thirty-four in 2011 to twenty in 2013.

EGS13 – Meter Change

The Compliance rate for this standard that measures when notice of a meter change is given to an affected customer, is currently not available because of the difficulty of verifying this infield activity. This difficulty is only partial offset by the ability to use text message delivery of the notification, as the database of associated customer number is still significantly incomplete. However with the implementation of a new workforce management system, as part of the suite of new processes and systems that will accompany the CIS upgrade, the company will be able to begin reporting on this standard in late 2014, early 2015. The Company will seek flexibility from the OUR on the range of delivery formats, including SMS and emails, the notification can take in order to increase the incidence of compliance.

EGS14 – Compensation

This standard measures the percentage of compensatory payment that is credited to customer accounts within the minimum performance standard of 45 days. Figure 16-12 shows the Company’s performance for the last five (5) years.
The Company has credited customer accounts within 45 days over 98 percent of the time over the last 5 years. There was a total eighty-nine breaches during that time which averages approximately eighteen breaches per year at a potential compensation of over J$54,000 per year over the period.

16.4 Proposed Modifications to Guaranteed Standards

In this section, we present recommendations for possible revision to the current Guaranteed Standards regime and key aspects that contribute to its effectiveness for both customers and in providing incentives for JPS to maintain the intended minimum level of service.

16.4.1 Effectiveness of Standards

The effectiveness of the Guaranteed Standards is often gauged in public discourse by the actual level of payments made by the utility relative to breaches committed and the potential compensation that would be owed to customers if a payment were made in each instance of breach. The fact that a large amount of potential compensation goes unclaimed is often highlighted as clear evidence that the standards are not having their intended effect. This conclusion is understandable.

It should however be borne in mind that Guaranteed Standards around the world are intended to ensure that the utility provides a certain minimum quality of service to a customer on each occasion that the service is accessed or requested. The costs of the penalty payments associated with the standards are an incentive to move utilities to invest to routinely deliver the services in keeping with the standard. As utilities invest or adjust their operations to avoid this cost or the threat of the additional cost, payment, or potential compensation will naturally fall. An overall decrease in the payments and a fall in the unclaimed or potential compensation are actually commensurate with increasing delivery of the service levels intended by the Guaranteed Standards.

This trend is evident in JPS’ performance against the Guaranteed Standards over the last regulatory period. JPS has demonstrated improvement in compliance against most standards resulting in lower breaches and therefore fewer compensatory payments and smaller amounts of unclaimed compensation.
More than any other utility in Jamaica, JPS has promoted the Guaranteed Standards through bill stuffers, brochures, mass media advertisements, customer education programmes, and at community level forums. We have also made it easier for customers to make claims by simplifying the application form and process and making it available on our website and at our Parish Offices. Yet, we do realize that a significant amount of compensation goes unclaimed. JPS will therefore continue to work with the OUR to improve the mechanism for getting compensation to affected customers. Our ultimate objective however is to continue to fine tune our operations to deliver the service our customers expect and so avoid altogether the inconvenience the Guaranteed Standards are designed to mitigate.

Our effectiveness, by design, will lead to falling compensation.

16.4.2 Modification of Compensation Level

Compensation under the current Guaranteed Standards regime is determined as follows:

<table>
<thead>
<tr>
<th>Customer Class</th>
<th>Compensation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Domestic: Rate 10 – Residential Service</td>
<td>Reconnection Fee equivalent</td>
</tr>
<tr>
<td>General Service: Rate 20 – General Service</td>
<td>Four times customer charge</td>
</tr>
<tr>
<td>Power Service: Rate 40 – Low Voltage</td>
<td>Four times customer charge</td>
</tr>
<tr>
<td>Power Service: Rate 50 (all MV) – Large Power</td>
<td>Four times customer charge</td>
</tr>
</tbody>
</table>

In addition, breaches of the standard attract compensatory payments for a maximum of six (6) periods of non-compliance.

The standards also specify special compensation of twice the reconnection charge for residential customers and five times the customer charge for commercial customers for wrongful disconnection and tardy reconnection after a wrongful disconnection. At the current tariff charges, a residential customer would be entitled to a payment of $1,650 (US$15), a R20 customer, $3,405.60 (US$31.50) and power service customers, $24,768 (US$229) for each instance of breach.

This compensation level represented 24% of the $6,790.24 bill (February 2014) for an average residential customer with average consumption of 165 kWh. For the Rate 20 and Rates 40 & 50 it represented 8 percent and 1 percent respectively for average consumptions for the rate classes.

This level of compensation compares very favourably with similar jurisdictions such as Trinidad where the average compensation for a domestic and commercial customer breach is TT$50 (US$8) and TT$600 or US$96 for an industrial customer. Bearing in mind that Jamaica also has a longer than the standard maximum period of compensation (six vs. four for most jurisdictions) the compensation level for guaranteed standards is very reasonable. Furthermore, the OUR periodically adjusts the reconnection fee to take account of inflation, the last being in 2013, thereby preserving the real value of the compensation.

In another section of this filing, JPS has proposed a replacement of the current customer charge with a network access charge that effectively will incorporate the customer charge with a portion of demand charge. This will affect the basis which commercial customers’ guaranteed standards
are calculated. To address this, JPS is proposing that for the Rates 20, 40 & 50 the current level of charge (four times the customer charge) is converted to the nominal value and be used as the compensation level for the various classes; that is $3,405.60 for a R20 customer, and $24,768 for power service customers. The values would be adjusted for inflation at each inter-regulatory period review of the standards.

Other than the proposed amendment to accommodate the tariff JPS does not believe there is a basis for modification to the payment values and mechanism at this time as it is offering customers a fair and reasonable compensation.

16.4.3 Exemptions & Exceptions

The Standard has operated since inception on the basis, except force majeure conditions, payments are validly to be made in every instance of claim or breach. This is true in the vast majority of instances. But, most jurisdictions have considered it important to establish guidelines on exemptions to inform customers and the utility of those circumstances under which Guaranteed Standard payments are not obligatory. JPS is proposing for approval a list of exemption from the Standards, which are typical across jurisdictions. It is important to note that in making its quarterly report on performance, JPS will be required to report on any exemption invoked in relation to any breach/claim and the reasons. In the event of any dispute the OUR will make the final decision on any exemption.

Proposed exemptions:

JPS is not obliged to make Guaranteed Standard payments in the following circumstances:

- The customer informs JPS before the Standards contravention period that they do not want JPS to take any action or further action in regard to the matter
- The customer agrees with JPS the action already taken by JPS meets the requirement of the standard. But in the event JPS has promised to take further action, the action must be completed without delay, or in the agreed timeline, for this exemption to be invoked.
- Where information is required from the customer and it is not given to the appropriate telephone number, address or email account as indicated by JPS or is done at a time outside the reasonable hours established by JPS.
- It was not reasonably practicable for JPS to perform the necessary standard due to:
  - Severe weather, as agreed by the OUR.
  - Industrial action by JPS’ employees.
  - The act or default of a person not working directly for, or as an agent for JPS to the premise.
  - The existence of circumstances, which would cause JPS to break the law by following the Standards
  - Circumstances of an exceptional nature beyond the control of JPS, and JPS had in each case taken all reasonable steps to both prevent the circumstances from occurring and from having an effect.
• Belief on the part of JPS that the information provided is of a frivolous or vexatious nature

• The breach occurs during a period when the customer has failed to pay charges due after receiving a disconnection notice.

16.4.4 Modifications to Existing Standards

EGS1 – Connections to Supply – New or Simple

JPS proposes that EGS1 (a) and EGS1 (b) be combined into a single standard with a minimum performance standard of five (5) days to complete any new or simple connections. This will allow JPS to better track and report performance about simple connections.

EGS2 – Connections to Supply – Complex

JPS has no objection to the current minimum standard as the default. However, under circumstances peculiar to a customer’s location or requirement where connection within the standard may not be practicable, JPS and the customer should be allowed the latitude to determine a mutually agreed schedule for connection by a specified date. In those instances, JPS would be liable to pay compensation if the connection is not completed by the agreed date.

EGS3 – Response to Emergency

JPS recommends that this standard be removed from the list of Guaranteed Standards and instead be monitored as an Overall Standard. The justification for this recommendation is that other factors such as safety considerations already ensure that utility companies react timely to emergency situations thus tracking emergency response for individual customer compensation is unnecessary and inappropriate. A review of service quality standards in Trinidad and Barbados as well as research on service quality regulation in other jurisdictions conducted by the Ontario Energy Board\textsuperscript{110} revealed that the use of an emergency response guaranteed standard is not widespread.

Furthermore, Guaranteed Standards are meant to compensate a customer for the company’s failure to provide a service to an individual customer or respond to an individual or well-defined set of customers based on the Company’s actions or inaction that caused an inconvenience. Emergencies, by nature, are usually unplanned and random events that can be triggered by third parties. While it is reasonable for JPS to have a standard to respond to these emergencies, individual customer compensation under these circumstances is inappropriate. The tracking of the company’s response to emergencies is foremost and most importantly a matter of public safety and should be tracked as an Overall Standard.

EGS4 – Issue of First Bill

The Company’s performance for the review period shows that we have achieved the right balance between the processes, and timing required to generate an initial bill with the objective of getting the first bill to the customer at the very earliest. This standard should therefore remain at the current target.

\textsuperscript{110} \url{http://www.ontarioenergyboard.ca/documents/cases/RP-2003-0190/sqr_discussionpaper_150903.pdf}
5a, b, c Complaint Queries

JPS proposes that EGS5 a,b&c be united into one standard to require that customer written queries are to be acknowledged, investigated and a response provided to the customer in 30 days. Where a clearly identified 3rd party is involved the allowed time is 60 days.

EGS6 – Reconnection

The Company continues to allocate significant resources to achieving compliance with this standard, as JPS is of the view that customers ought not to be without supply above 24 hours after making payment and this is in the Company’s interest. The Company has no objection to the standard remaining at the current target level.

EGS7 – Frequency of Estimates

JPS proposes that this standard should be revised.

The stipulation that all meters should be read monthly runs contrary to international trends across jurisdictions to either reduce or automate reads to improve operational efficiency that benefits customers through cost savings. While there might have been good reasons for the OUR to adopt the stricter policy position formerly, the Company’s current performance against the standard; international best practice and the need to pursue opportunities for efficiency gains offer compelling reasons for a revision of the policy at this juncture.

This standard currently restricts JPS from developing and offering alternative billing solutions for our customers. For example, billing on estimated consumption –budget billing- has been used in some jurisdictions to help customers budget more effectively by estimating their forward yearly consumption based on their historical consumption patterns and billing a flat amount every month based on that estimate with pre-determined point(s) of reconciliation. These billing options, along with the launch of prepaid electricity service offer customers greater freedom, control, and flexibility over their budgets. The Company is therefore proposing that it be allowed to return to the standard of billing customers on an actual reading in alternate months with bills based on estimates (based on the last three actual readings) in the intervening months.

EGS8 – Estimate Calculation

No objection to the current standard.

EGS9 – Meter Replacement

No objection to the current standard.

EGS10 – Billing Adjustments

JPS recommends that the billing exception threshold be revised upward as part of the revision of this standard. Billing adjustments continue to be a major challenge for the company despite the seemingly high level of compliance. The large number of exceptions generated because of the low threshold at which exceptions are triggered –residential –30%, commercial –60% – creates a significant need to review and rebill customers. These thresholds are considered low and JPS has formerly petitioned the OUR to allow a higher level of tolerance on bill variability-given the unpredictable patterns of consumption demonstrated by our customers. Every month 16,000 residential and 4,000 commercial exceptions are generated. Of the average 20,000 exceptions flagged for “abnormal” variation in consumption, approximately 80 percent were
verified as accurate by subsequent meter readings. JPS has no other objection to the current standard.

**EGS11, EGS12 – Wrongful Disconnections; Reconnections**

JPS has no objection to the current standard. A significant factor in wrongful disconnections is the coincidence of timing between the time of payment of bills (that are overdue) and the time at which disconnection orders are issued and executed. With the introduction of an early payment incentive and a late payment fee, the Company is confident that this mechanism will lead to payment behavior modification that will reduce even further the incidence of disconnections generally. Given the pending system upgrades and the automatic nature of the compensation the standard presents a strong deterrence to JPS to avoid the inconvenience of wrongful disconnections.

The Company also strongly recommends that the OUR again considers allowing JPS to impose penalties on customers that illicitly reconnect themselves without paying the requisite reconnection fees. This penalty will create another point of deterrence to unlawful handling/tampering of meters and assist in the fight against losses.

**EGS13 – Meter Change**

JPS proposes that the method of informing customers of a meter change be expanded to include email notification in addition to the physical card currently used and text messages already allowed.

**EGS14 – Compensation**

JPS recommends that the current performance standard be revised to compensation being paid (credited to customer accounts) within 35 days or by the subsequent billing period after verification of the breach.

16.4.5 Automatic & Non-Automatic Guaranteed Standards

Jurisdictions that have adopted Guaranteed Standards have a mix of standards for which compensation is automatically applied for a breach and others which rely on a customer claim triggering the process. Claims initiated by customers tend to encourage customer interest and activism about the quality of service provided by their utilities such as JPS. Except for promoting standards through customer education, JPS has also made ex-gratia payments of equivalent amounts to the guaranteed standard compensation to customers in instances of breach without the customer formally making a claim. Admittedly; however, customers have been slow in making claims and regulators, including the OUR, have responded by making more standards subject to automatic compensation that is, payments are credited to customers, with or without their knowledge or action in relation to a breach.

The eighteen Guaranteed Standards JPS is required to meet, monitor and report on is a large amount for a utility of the size of JPS. The UK, the originator of the standards, has ten primary standards with the complexity of standards governing customer connections handled in a separate code. Both Trinidad and Barbados have eight Guaranteed Standards. JPS is therefore already expending significant resources guaranteeing the quality of service customer receive at high levels of compliance under the current GS regime.
Guaranteed and Overall Standards

In 2009 JPS adopted four (4) standards that attracted automatic compensation and the OUR signaled its intent to continue to move more standards to automatic compensation. In its recent tariff review of the National Water Commission (NWC), the OUR demonstrated that gradual movement by converting a further four (4) of the water utility’s standards to automatic compensation. JPS therefore anticipates an additional amount of the standards and recommends the following:

- Four additional standards to be converted to automatic in the 2014 rate review.
- JPS and the OUR to review performance against the standards at the inter-regulatory standards review due in 2016 to determine what if any additional steps are needed to increase the effectiveness of the standards.
- JPS to increase ex-gratia payments it currently makes to customers on non-automatic standards and report on these compensatory payments in its quarterly reports for consideration in the 2016 review.

Lead time is critical in order to re-engineer processes and systems to be able to accommodate the automatic detection, compensation and reporting of breaches. As advised, the Company is currently in the midst of an upgrade of its customer information system (CIS) that is at the heart of our operations control, billing and data management. The CIS will also be the primary system to manage and report on the GS. The CIS cutover is planned for August 2014. As with any major core system implementation, it is expected to take approximately 6 months to fully integrate into the business after cutover. Consequently, any new requirements, such as new automatic compensation standards, cannot be considered before December 2014 and will take approximately 4-6 months to develop depending on complexity. JPS is therefore further proposing that the commencement date for any additional automatic standards from the 2014 rate review be June 2015.

16.5 Overall Standards

The Overall Standards continue to provide a strong framework for the provision of a high quality of service for our customers.

Processes and systems are now in place to measure and report performance against the Overall Standards annually as required. The remaining standards to be measured and reported on will take effect with the full integration of the Outage Management System (OMS) and the Customer Information System, the upgrade of which is scheduled for August 2014. It will also be dependent on the OUR’s long delayed approval of the meter sampling methodology that will allow implementation of sample meter testing as prescribed in the meter testing protocol established between the OUR, JPS and the Bureau of Standard, Jamaica.

Table 16-5: Overall Standards

<table>
<thead>
<tr>
<th>Code</th>
<th>Standard</th>
<th>Units</th>
<th>Targets</th>
</tr>
</thead>
<tbody>
<tr>
<td>EOS1</td>
<td>Minimum of 48 hours prior notice of planned outages</td>
<td>Percentage of planned outages for which at least forty-eight hours advance notice is provided</td>
<td>100%</td>
</tr>
<tr>
<td>EOS2</td>
<td>Percentage of line faults repaired within a specified period of that fault being reported</td>
<td>Urban: 48 hours; Rural: 96 hours</td>
<td>100%</td>
</tr>
</tbody>
</table>
Guaranteed and Overall Standards

<table>
<thead>
<tr>
<th>Code</th>
<th>Standard</th>
<th>Units</th>
<th>Targets</th>
</tr>
</thead>
<tbody>
<tr>
<td>EOS3</td>
<td>System Average Interruption Frequency Index (SAIFI)</td>
<td>Frequency of interruptions in service</td>
<td>To be set annually</td>
</tr>
<tr>
<td>EOS4</td>
<td>System Average Interruption Duration Index (SAIDI)</td>
<td>Duration of interruptions in service</td>
<td>To be set annually</td>
</tr>
<tr>
<td>EOS4A</td>
<td>Customer Average Interruption Duration Index (CAIDI)</td>
<td>Average time to restore service to average customers per sustained interruption</td>
<td>To be set annually</td>
</tr>
<tr>
<td>EOS6</td>
<td>Frequency of meter reading</td>
<td>Percentage of meters read within time specified in the Licensee's billing cycle (currently monthly for nondomestic customers and bi-monthly for domestic customers)</td>
<td>99%</td>
</tr>
<tr>
<td>EOS7</td>
<td>Frequency of meter testing</td>
<td>Percentage of rates 40 and 50 meters tested for accuracy annually</td>
<td>50%</td>
</tr>
<tr>
<td>EOS7</td>
<td>Frequency of meter testing</td>
<td>Percentage of other rate categories of customer meters tested for accuracy annually</td>
<td>7.5%</td>
</tr>
<tr>
<td>EOS8</td>
<td>Billing Punctuality</td>
<td>98% of all bills to be mailed within a specified time after meter is read</td>
<td>5 Working days</td>
</tr>
<tr>
<td>EOS9</td>
<td>Restoration of service after unplanned (forced) outages on the distribution system</td>
<td>Percentage of customer's supplies to be restored within 24 hours of forced · outages in both Rural and Urban are.is.</td>
<td>98%</td>
</tr>
<tr>
<td>EOS10</td>
<td>Responsiveness of call center representatives</td>
<td>Percentage of calls answered within 20 seconds</td>
<td>90%</td>
</tr>
<tr>
<td>EOS11</td>
<td>Effectiveness of call center representatives</td>
<td>Percentage of complaints resolved at first point of contact</td>
<td>To be set</td>
</tr>
<tr>
<td>EOS12</td>
<td>Effectiveness of street lighting repairs</td>
<td>Percentage of all street lighting complaints resolved within 14 days</td>
<td>99%</td>
</tr>
</tbody>
</table>

**EOS 1- Minimum of forty-eight (48) hours prior notice of planned outages**

This is the percentage of Planned Outages for which at least forty-eight (48) hours advance notice is required.

The Company’s performance on EOS 1 for 2013 is shown in the Figure below.

**Table 16-6: 2013 Performance - Planned Outages**

<table>
<thead>
<tr>
<th></th>
<th>Q1</th>
<th>Q2</th>
<th>Q3</th>
<th>Q4</th>
<th>VTD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Compliance (%)</td>
<td>76.5%</td>
<td>88.5%</td>
<td>91.7%</td>
<td>93.3%</td>
<td>87.8%</td>
</tr>
<tr>
<td>Target (%)</td>
<td>100.0%</td>
<td>100.0%</td>
<td>100.0%</td>
<td>100.0%</td>
<td>100%</td>
</tr>
</tbody>
</table>

The compliance rate for 2013 was 87.8%, which fell below the 100% target. JPS expects significant improvement from the implementation of an OMS in Q4 2013 that will lead to improved performance against this standard.

**EOS 6a- Frequency of Meter Reading (Rate 40 & 50)**

Currently, no data is available. The reporting methodology is under development as part of the CIS upgrade which will include a service order management tool.

**EOS 6b- Frequency of Meter Reading (Other rates)**
Guaranteed and Overall Standards

Currently, no data is available. The reporting methodology is under development as part of the CIS upgrade which will include a service order management tool.

**EOS 7A- Frequency of Meter Testing (Rate 40 & 50)**

JPS continues to await the OUR’s response on the proposed sample meter testing methodology that will allow the Company to move to the sample testing of meters as proposed in the meter testing protocol.

**EOS 7B- Frequency of Meter Testing (Other Rates)**

JPS continues to await the OUR’s response on the proposed sample meter testing methodology that will allow the Company to move to the sample testing of meters as proposed in the meter testing protocol.

**EOS 8- Billing Punctuality**

Currently, no data is available. The reporting methodology is under development as part of the CIS upgrade.

**EOS 9 – Customer Supply Restoration**

Table 16-7: 2013 Performance - Supply Restoration

<table>
<thead>
<tr>
<th>Q1</th>
<th>Q2</th>
<th>Q3</th>
<th>Q4</th>
<th>YTD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Compliance (%)</td>
<td>100%</td>
<td>99%</td>
<td>99%</td>
<td>100%</td>
</tr>
<tr>
<td>Target (%)</td>
<td>98.0%</td>
<td>98.0%</td>
<td>98.0%</td>
<td>98.0%</td>
</tr>
</tbody>
</table>

Compliance with this standard with a target of 98% was consistently high across the year and is this trend is expected to continue into the next regulatory period underpinned by the improved capabilities provided by the OMS trend.

**EOS 10- Effectiveness of Call Centre Representatives (Percentage of Calls answered within 20 seconds)**

Table 16-8: 2013 Performance - Percentage of Call Answered Within 20 secs

<table>
<thead>
<tr>
<th>Q1</th>
<th>Q2</th>
<th>Q3</th>
<th>Q4</th>
<th>YTD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Compliance (%)</td>
<td>87%</td>
<td>78%</td>
<td>63%</td>
<td>67%</td>
</tr>
<tr>
<td>Target (%)</td>
<td>90.0%</td>
<td>90.0%</td>
<td>90.0%</td>
<td>90.0%</td>
</tr>
</tbody>
</table>

The 2013 performance was 72.6% of calls answered within the standard period of 20 seconds. It is not clear where the OUR obtained the benchmark data in setting the performance target for this standard at 90%. JPS’ survey of call center benchmarks finds that industry standard target is 80% given the balance necessary between efficient staffing; the need to provide quality time to customers already engaged on calls and acceptable call wait time for holding callers. JPS expects that compliance rate will continue to improve given the implementation of the workforce management software called Avaya Quality Monitoring Tool. However even with this, a compliance rate of 90% will require JPS to provide significantly more resources to the call center, which reduces the cost efficiency of its operations. The Company is therefore requesting that the OUR reconsider this target and reset it more in keeping with the international benchmark of 80%.
EOS 11- Effectiveness of Call Centre Representatives (Complaints: First Contact Resolution)

Table 16-9: 2013 Performance - First Contact Resolution

<table>
<thead>
<tr>
<th></th>
<th>Q1</th>
<th>Q2</th>
<th>Q3</th>
<th>Q4</th>
<th>YTD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Compliance (%)</td>
<td>98%</td>
<td>97%</td>
<td>97%</td>
<td>98%</td>
<td>97.3%</td>
</tr>
<tr>
<td>Effective FCR (%)</td>
<td>50%</td>
<td>63%</td>
<td>70%</td>
<td>71%</td>
<td>63.1%</td>
</tr>
</tbody>
</table>

The effectiveness of Call Centre Representatives as it relates to first contact resolution of complaints has shown variation in performance over the 2013 measurement period but has shown a definitive upward trend since third quarter 2013. The compliance rate will improve given the implementation of the workforce management software called Avaya Quality Monitoring Tool.

Please note that the targets for this standard has not been set by the OUR since its inclusion in the Overall Standards. In setting a target for EOS 11 the company would like the Office to note the following:

1. First Contact Resolution can be measured in a variety of ways, and many companies use one or a combination of the following:
   a. Agent records of the contact (in our case a CCS contact)
   b. Quality Analyst monitoring (done in 2013)
   c. Customer Surveys (not done at JPS)
   d. In 2014 we are only using agent records

2. First Contact Resolution has to measure realistically what can actually be resolved by the agent on the first contact, and does not require the customer to do anything further.
   a. This was not the case in the Centre in 2013 when the Company measured FCR for all customer interactions. This puts agents at a disadvantage because in the case of a new connection for example, the agent can only start the process, they can’t complete it or see it through to completion. Therefore if the customer has to call back because the crew did not turn up, then it goes against the agent. This was remedied in 2014 when it was decided to only measure FCR for a pre-defined category of customer contacts.

3. First Contact Resolution has to be measured within a time period, not simply year to date. The Company is using the last 30 days prior to the day of pulling the report.

4. It is only measured for the Contact Centre, this will start at the end of 2014 for the parishes once Banner is upgraded.

5. FCR target for 2013 was 90%, for 2014 it is 85% which is more in keeping with Contact Centre benchmarks and considering the changes we have made to how it is calculated.

EOS 11- Effectiveness of street lighting repairs

Table 16-10: 2013 Performance - Streetlight Repairs

<table>
<thead>
<tr>
<th></th>
<th>Q1</th>
<th>Q2</th>
<th>Q3</th>
<th>Q4</th>
<th>YTD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Compliance (%)</td>
<td>34%</td>
<td>41%</td>
<td>21%</td>
<td>15%</td>
<td>25.5%</td>
</tr>
<tr>
<td>Target (%)</td>
<td>99.0%</td>
<td>99.0%</td>
<td>99.0%</td>
<td>99.0%</td>
<td>99.0%</td>
</tr>
</tbody>
</table>

This measures all the percentage of streetlight complaints resolved within fourteen (14) days. The compliance rate has been undesirably low throughout 2013 relative to the target and the
Company’s policy. Lamps are being repaired, but the average resolution time is more than 14 days. The under-performance on this standard last year is directly resulting from the unavailability of resources to fund the repair and rehabilitation of streetlights. Evaluation of performance against this target must be done within the context of the significant arrears (more than 90 days on average) being carried by the primary customer of streetlight services. Public lighting is a valued and important service for the safety, security, and welfare of citizens. JPS is deeply concerned about its inability to perform at the required standard resulting from the lack of available resources and is in constant discussion with the relevant authorities on this matter. It is JPS’ commitment to expedite the repair of lamps and to perform at the target level once the normal funding stream of streetlight service payment is resolved.
Chapter 17: Demand Projections

17.1 Introduction

JPS hired Castalia to develop a model for forecasting JPS’ total demand (sales of electricity plus system losses). The model will support the tariff calculations in the 2014-2019 Rate Case submission to the Office of Utility Regulation, and help with short to medium-term financial forecasting and planning.

This report presents the approach we used for developing the model to forecast JPS’ total demand for the regulatory period from 2014 to 2019. It describes the approach and assumptions that we used to build the model. It also presents the results of the demand forecast for three different scenarios.

This report is structured as follows:

- **Modeling Approach** (Section 17.2): This section describes our approach for forecasting JPS’ total demand from 2014 to 2019. We began by projecting electricity sales based on historic trends. We then adjusted those projections by the expected impact resulting from JPS’ customers implementing energy efficiency measures, and the impact of wheeling and net billing on electricity sales.

- **Model Assumptions** (Section 17.3): This section presents our assumptions for forecasting electricity sales and system losses. We describe the assumptions for each rate class separately.

- **Scenario Results** (Section 17.4): This section presents the results of our forecast. We forecasted four different scenarios. The scenarios vary depending on two variables—the introduction of natural gas in JPS’ generation mix and system losses.

17.2 Modeling Approach

This section sets out the approach used to forecast JPS’ total demand (electricity sales plus system losses) from 2014 to 2019. It begins by presenting the approach used for projecting JPS’ sales of electricity.

17.2.1 Forecasting Sales of Electricity

The first step in forecasting JPS’ sales of electricity was building a baseline model that projects sales based on the assumption that historic trends will be continued in the future. For that purpose, we first carried out a historic trend analysis. We then adjusted the baseline sales forecast for variations in sales in each rate class due to regulatory, managerial, or technological changes that we expected would change the historical trend. In particular, we modeled the impact of efforts to promote energy efficiency and reduce consumption of electricity. We also considered the impact of the planned introduction of natural gas in JPS’ energy generation mix on electricity sales. Furthermore, we analyzed the impact of recently introduced government initiatives such as Net Billing and Wheeling.
17.2.1.1 Step 1: Historic trend analysis

We forecasted baseline electricity sales for each of JPS’ rate classes separately. JPS has the following rate classes:

- Residential customers (R10)
- Small commercial customers (R20)
- Large commercial customers, low voltage (R40)
- Large commercial customers, high voltage (R50)
- Street lighting (R60).

We defined electricity sales in each category (except for street lighting) as a function of the change in the number of customers and the change in average electricity consumption per customer. We thus projected the change in the number of customers, and the change in average electricity consumption per customer for each rate class. For street lighting (R60), we projected electricity sales without breaking it down into the number of customers and average consumption.

We forecasted the change in the number of customers and the change in average consumption for rate classes R10, R20, R40 and R50 based on the assumption that trends in the past will be continued in the future. To do that, we analyzed which exogenous variables were closely correlated to the change in customer numbers and average consumption for each rate class in the past. We then projected the change in customer numbers and average consumption for each rate class based on the expected change of the exogenous variables in the future.

To analyze the correlation between the exogenous variables and the change in customer numbers and average consumption, we used a historic time series approach. We then used an econometric model to validate the results of the time series analysis. To do this analysis, we used historical data from 1988 to 2012. The econometric regressions confirmed the results of our historic time series analysis. The results of our analysis are shown in Table 17-1.

Table 17-1: Exogenous Variables per Rate Class

<table>
<thead>
<tr>
<th>Rate Class</th>
<th>Number of customers</th>
<th>Average consumption</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Correlated</td>
<td>Uncorrelated</td>
</tr>
<tr>
<td>Residential (R10)</td>
<td>Number of households</td>
<td>Dispose income, real</td>
</tr>
<tr>
<td>Small Commercial (R20)</td>
<td>None</td>
<td>GDP per capita, real</td>
</tr>
<tr>
<td>Large Commercial LV (R40)</td>
<td>Visitor arrivals</td>
<td>GDP per capita, real</td>
</tr>
</tbody>
</table>
We forecasted JPS’ sales of electricity to its four largest customers in 2012 separately. JPS’ four largest customers are the National Water Commission, the Cement Company, Cable & Wireless, and the Port Authority of Jamaica. In 2012, the total electricity consumption of the four largest customers was 343GWh. This represents 11 percent of the total electricity consumption of 3,103GWh in 2012, and 25 percent of the total electricity consumption of rate classes R40 and R50.

We used a survey of the four largest customers as the primary method for forecasting JPS’ baseline electricity sales to these customers. This direct contact with JPS’ largest customers allowed us to find out about their plans to close or expand their businesses. The National Water Commission, for example, plans to significantly expand its water and wastewater services by 2020. Based on these customers’ plans, we estimated the annual compound growth rate of the electricity sales to each of these customers from 2014 to 2019.

17.2.1.2 Step 2: Impact analysis of energy efficiency measures by customers

For sales in rate classes R10 and R20, we estimated the number of customers that would implement energy efficiency measures by 2019 and the reduction in average consumption resulting from those energy efficiency measures. We then multiplied the number of customers that would implement energy efficiency measures by the reduction in average consumption to calculate the total reduction in consumption by rate class.

To estimate the number of customers that would implement energy efficiency measures by 2019, we evaluated the potential for replacing currently available electric equipment in households and small businesses with more efficient equipment. We also analyzed the past speed of energy efficiency adaptation in Jamaica and used this historic trend to project the increase of customers that would implement energy efficiency measures by 2019.

For electricity sales to customers in rate classes R40 and R50, we identified the energy efficiency measures with the highest savings potential and the lowest payback periods for the industrial sector. We then estimated the reduction in industrial customers’ average consumption resulting from implementing these measures. We applied the expected average consumption reduction to all customers, except for the four largest customers. Through the customer survey, we asked these four customers about their specific plans for implementing measures to increase energy efficiency during the next five years.

For street lighting (R60) we estimated the impact of the planned replacement of streetlights with LEDs on total consumption. We assumed that the replacement would start in 2017 and that it would take about ten years to replace all streetlights.
17.2.1.3 Step 3: Analysis of impact of using natural gas to generate electricity on average electricity tariff

The OUR has selected Energy World International (EWI) as the preferred bidder to provide 381MW of generation capacity from a natural gas-fired combined cycle power plant.111 EWI has finalized a power purchase agreement with JPS and is awaiting the issue of license from the Minister of Energy for the right to generate power for the national grid. Construction on the power plant is expected to begin in early 2014, and finish in 2016.112

Since the cost of generating electricity with gas-fired plants is cheaper than the current generation cost using HFO and diesel-fired plants, this project is expected to reduce the price of electricity in Jamaica. In projecting JPS’s sales of electricity, we estimated the decrease in JPS’ average electricity tariff that would result from JPS using natural gas to generate electricity. We estimated that the real average electricity tariff would decrease by US$0.09 per kWh beginning from the year in which the gas-fired plant would be commissioned. In the scenarios in which we assumed natural gas is introduced, we assume that EWI will begin generating electricity with natural gas in 2017.

The projected decrease in the average tariff resulting from the generation of electricity with natural gas affects the projection of electricity sales in the following three ways:

- When the average real electricity tariff decreases, electricity consumption in rate classes R10, R20 and R50 increases through the price elasticity of demand. That is, the lower the electricity tariff, households and businesses consume more electricity.
- When the average real electricity tariff decreases, customers are more likely to buy electricity from JPS rather than switching to net billing. Customers’ decision to engage in distributed generation depends largely on their expectations regarding JPS’ average real tariff. As the expected tariff decreases, the viability of distributed generation falls.
- When the average real electricity tariff decreases, customers are more likely to buy electricity from JPS rather than generating and wheeling their own electricity. The lower customers expect the tariff to be, the less viable is it for customers to switch to wheeling.

17.2.1.4 Step 4: Impact analysis of net billing

The OUR established a framework for net billing for distributed scale renewable energy technologies such as small solar photovoltaic systems and small wind turbines. The program offers customers a Standard Offer Contract, which pays customers the short-run avoided cost of electricity generation plus a premium of 15 percent for up to 100kW.113 We forecasted the potential decrease in JPS’ electricity sales resulting from the use of net billing for each rate class by:

---

113  Jamaica Public Service Company, “Standard Offer Contract for the Purchase of As-Available Energy from Intermittent Renewable Energy Facilities up to 100kW”.

JPS Tariff Application 2014 – 2019  p. 382 of 412
Analyzing whether or not distributed generation is financially viable for the average customer\footnote{By “average customer in each rate class” we mean a customer whose monthly consumption is equal to the monthly average consumption per customer in his rate class. With regard to residential customers, the JPS demand forecast model differentiates between an “average customer in block 1” and an “average customer in block 2”.} in each rate class. In doing so, we assumed that customers would use solar PV systems rather than small wind turbines because solar PV systems have a lower long run marginal cost than wind turbines.

If distributed generation were determined to be financially viable, multiplying the number of customers that would switch by the estimated decrease in JPS’ electricity sales per customer that would switch. Even if distributed generation is viable, we assumed that—due to financial, technical, and physical constraints—not all customers for whom it would be viable would decide to do net billing. For each rate class, we estimated the percentage of customers who would switch to net billing if it were viable for them. We estimated this percentage for each rate class by eliminating the customers that would not do it because they do not have the money, the space, or the authority to install their own solar PV-system at their home or business.

To analyze whether or not distributed generation is financially viable for the average customer in each rate class, our model compares the net present value of the following three options that the average customer has:

- **Option 1:** Generate own electricity with a solar PV system that is as large as customer’s facilities allow, and sell as much excess electricity to the grid as possible.\footnote{This is the best option if both the long run marginal cost of the solar PV system and the price that JPS would pay for each kWh sold to the grid are lower than JPS’ average electricity tariff. In this case, the customer could sell each kWh to the grid at a higher price than the kWh cost of his solar PV system.}

- **Option 2:** Generate own electricity with a solar PV system that is tailored to the customer’s consumption, but minimizes sales to the grid.\footnote{This is the best option if the long run marginal cost of the solar PV system is lower than JPS’ average electricity tariff, but higher than the price that JPS would pay for each kWh sold to the grid. In this case, the customer would lose money on each kWh sold to JPS.}

- **Option 3:** Buy electricity from JPS at JPS’ average tariff per kWh.\footnote{This is the best option if the long run marginal cost of the solar PV system is higher than JPS’ average electricity tariff for long enough that the net present value of the cost of the solar PV system is higher than the net present value of buying electricity from JPS.}

If Option 1 or 2 have the lowest net present value, our model calculates the annual sales loss in kWh that JPS would face if the average customer decided to switch to net billing. If Option 3 has the lowest net present value, the model assumes that there is no annual sales loss for JPS from net billing because it is not financially viable for any customer in the rate class.

\textbf{17.2.1.5 Step 5: Impact analysis of wheeling}

The OUR is working to increase the diversity of generation options through the introduction of wheeling. Wheeling would allow customers to transmit self-generated power to operations in
various parts of the country. JPS would continue to control the grid and self-generators would pay JPS for transmitting power from the generation site to sites where they draw energy.

In July 2013, the OUR issued its decisions on the framework for electricity wheeling in Jamaica. The decisions are published in the OUR Determination Notice on the JPS Electricity Wheeling Framework.118 The Determination Notice outlines the terms and conditions of wheeling through JPS’ customers.

We forecasted the expected decrease in JPS’ electricity sales that would result from wheeling by:

- Analyzing whether or not wheeling is financially viable for the four largest customers, and for the eligible average customer in rate classes R40 and R50. We assumed that a customer is eligible for wheeling, if he has a minimum electricity export and import capacity of 1MVA.119 We assume that customers would consider medium speed or high-speed diesel generators for their own generation.

- If wheeling were financially viable, considering the likelihood that the large customers’ would switch to wheeling. We based this assessment on our conversations with large clients and market research. We determined that some clients would not switch to wheeling even if it were financially viable. One reason is that these companies do not have any direct experience in electricity generation.

- If wheeling were financially viable and the customer were likely to switch to wheeling, multiplying the number of customers in each rate class that would switch by the estimated decrease in JPS’ electricity sales per customer that would do wheeling.

To analyze whether or not wheeling is financially viable for a customer, our model compares the net present value of an average customer’s cost of own generation with the net present value of buying electricity from JPS at JPS’ average electricity tariff. We estimated the cost of a customer’s own generation based on the assumption that a customer would use a small diesel generator. We added an estimated wheeling fee of 0.09US$ per kWh to the cost of a small diesel generator. We estimated a different long-run marginal cost for each rate class, because we assume that the size and therefore the cost of the diesel generator depend on how much electricity the average customer in each rate class consumes.120

If switching to wheeling has the lowest net present value for the average customer, the model calculates the annual decrease in electricity sales (in kWh) that JPS would have if the average customer switched to wheeling. Otherwise, the model assumes that there is no decrease in electricity sales due to wheeling because it is not financially viable for any customer in that rate class.

---


119 In its Determination Notice dated 9 July 2013 (JPS Electricity Wheeling Framework, Determination Notice), the OUR determined a wheeling threshold of 25kVA. However, based on JPS’ current discussions with the OUR we assume that this threshold will be changed to 1MVA.

120 We estimated the following long-run marginal costs of diesel generators for different generator sizes: 0.5MW-1MW: 31.40J$/kWh; 1MW-5MW: 31.23J$/kWh; 5MW-10MW: 26.97J$/kWh; 10MW-15MW: 23.13J$/kWh; 15M-20MW: 21.23J$/kWh.
17.2.2 Forecasting System Losses

We forecasted JPS’ system losses by disaggregating total system losses into technical losses and non-technical losses. We projected technical losses by assuming that they will reach a reasonable level by 2019. We consider losses reasonable if they are limited to technical losses that are within JPS’ control, and if JPS maintains and operates its transmission and distribution network appropriately. We projected non-technical loss reductions by estimating the annual decrease of non-technical losses resulting from JPS’ planned Loss Reduction Program\textsuperscript{121}.

We did not consider the impact of exogenous variables on system losses, because a historic trend analysis showed that no exogenous variable significantly drove system losses from 2002 to 2012. Our historic trend analysis looked at exogenous variables such as the real average electricity tariff, real disposable income per capita, and a crime index that reflected the number of robberies and murders in Jamaica.

17.3 Model Assumptions

This section presents the assumptions we used for projecting JPS’ electricity sales and system losses. It begins by describing the assumptions we used to project JPS’ sales of electricity. It then sets out our assumptions for forecasting JPS’ system losses.

17.3.1 Assumptions for Forecasting Electricity Sales

This section describes the detailed assumptions that we used to project electricity sales for each rate class. It first presents our assumptions on the number of customers and average consumption in each rate class. It then describes our assumptions on the three factors that are expected to reduce total consumption in each rate class—any measures customers could take to increase energy efficiency, net billing, and wheeling.

17.3.1.1 Residential customers (R10)

The assumptions for projecting the number of customers and average electricity consumption in rate class R10 are based on the results of our historic trend analysis. The assumptions regarding the reduction in total consumption reflect our impact analysis of energy efficiency measures by customers, net billing and wheeling. Table 17-2 summarizes our key assumptions for projecting JPS’ sales of electricity to residential customers.

\textsuperscript{121} JPS’ planned Loss Reduction Program includes activities such as replacing meters, installing new meters, and auditing residential and commercial customers.
### Table 17-2: Model Assumptions for Residential Customers (R10)

<table>
<thead>
<tr>
<th>Variable</th>
<th>Model Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Number of customers</strong></td>
<td></td>
</tr>
<tr>
<td>Household growth</td>
<td>The expected number of households in Jamaica by 2019 is a function of the expected total population divided by the expected average household size. Total population increases on average by 0.4 percent per year from 2014 to 2019. We assume the average household size remains constant at 3.1 persons per household.</td>
</tr>
<tr>
<td>Coverage target</td>
<td>Coverage target of 70 percent by 2019. Coverage measures the percentage of households that are connected to JPS’ network, and that are active customers.</td>
</tr>
<tr>
<td><strong>Average consumption</strong></td>
<td></td>
</tr>
<tr>
<td>JPS’ average electricity tariff, real</td>
<td>The average consumption of electricity by customers in the R10 rate class decreases by 0.235 percent when the JPS’ real average tariff increases by 1 percent (price elasticity of demand&lt;sup&gt;122&lt;/sup&gt;)</td>
</tr>
<tr>
<td>Disposable income, real</td>
<td>The average consumption of electricity by customers in the R10 rate class increases by 0.132 percent when the average disposable income increases by 1 percent (income elasticity of demand&lt;sup&gt;123&lt;/sup&gt;)</td>
</tr>
<tr>
<td><strong>Reduction in total consumption</strong></td>
<td></td>
</tr>
<tr>
<td>Energy efficiency measures by customers</td>
<td>Customers implement energy efficiency measures:</td>
</tr>
<tr>
<td></td>
<td>▪ R10 Block 1: 5 percent of all households that consume less than 100kWh per month implement energy efficiency measures by 2019. Each household that implements energy efficiency measures reduces its average electricity consumption by 30 percent.</td>
</tr>
<tr>
<td></td>
<td>▪ R10 Block 2: 15 percent of all households that consume more than 100kWh per month implement energy efficiency measures by 2019. Each household that implements energy efficiency measures reduces its average electricity consumption by 25 percent.</td>
</tr>
<tr>
<td>Net Billing</td>
<td>5 percent of customers in rate class R10 who consume more than 100kWh per month switch to net billing by 2019, if it is financially viable. If maximizing the solar PV system is the most viable option, the average customer installs a 3kW solar PV system. If tailoring the solar PV system to the average customer’s consumption is the most viable option, the average customer installs a 1kW solar PV system.</td>
</tr>
</tbody>
</table>

<sup>122</sup> The price elasticity of demand measures how sensitive customers are to price changes. It measures the percentage decrease in demand if the price increases by 1 percent. In the context of the electricity sector, it measures the percentage decrease in consumption if the tariff increases by 1 percent. We projected the price elasticity of demand of JPS’ customers from 2014 to 2019 based on an econometric regression of changes in customers’ average consumption on changes in JPS’ average real tariff from 1988 to 2012.

<sup>123</sup> The income elasticity of demand measures how sensitive customers are to changes of their disposable income. It measures the percentage decrease in demand if the disposable income increases by 1 percent. In the context of the electricity sector, it measures the percentage decrease in consumption if the disposable income increases by 1 percent. We projected the income elasticity of demand of JPS’ customers from 2014 to 2019 based on an econometric regression of changes in customers’ average consumption on changes in their disposable income from 1988 to 2012.
The increase in the number of residential customers per year was estimated based on the assumption JPS will achieve a service coverage target of seventy percent (70%) by 2019. Assuming a coverage target of 70 percent and a total number of households in Jamaica of 898,950 by 2019, we project a total number of residential customers of 629,265 by 2019. We projected the number of households based on expected population growth, and assumed that household size remains constant. For the years 2014 to 2018, we used the IMF’s projections of population growth that are published in the IMF’s World Economic Outlook 2013.124 For 2019 we assumed the same growth rate as in 2018.

The historic trend analysis showed that average consumption is driven by the real average electricity tariff and the real disposable income. We used the price elasticity from our regression to project the impact of changes in JPS’ average real tariff on electricity sales. We assumed that JPS’ average real tariff would increase by 3 percent per year on average in real terms. We also considered a decrease in JPS’ real average tariff in 2017 if EWI were to begin generating electricity that year. Furthermore, we used the income elasticity from our regression to project the impact of changes in the real disposable income on JPS’ sales of electricity. We assumed that the changes in real disposable income from 2014 to 2019 would be the same as the changes in real GDP per capita. We used the changes in real GDP per capita as projected from 2014 to 2018 by the IMF in its World Economic Outlook 2013.125 We assumed that the percentage change in 2019 is the same as in 2018.

We assume that a relatively low percentage of households will adopt energy efficiency measures by 2019. This is based on Jamaica’s experience with a relatively slow uptake of energy efficiency measures in the past five years. Furthermore, we assume that the potential for households to increase the efficiency of their use of electricity is limited by the fact that not many households have appliances that could be replaced with more efficient equipment.126

For the following reasons we assume that only 5 percent of customers will choose to do net billing, even if it is financially viable:

- Many of JPS’ customers do not have the financial capacity to bear the initial capital cost of a solar PV system or to borrow the money to do so
- Many of JPS’ customers do not live in places where they could install a solar PV system; for example, many live in apartment buildings or do not own their own homes
- Many customers may not have confidence in using new technology for generating electricity or experience with its operation and maintenance
- Not all customers live in regions with the minimum capacity factor that would be required for the feasibility of household solar PV systems (at least 19 percent).

We assume if net billing is financially viable only five percent (5%) of customers would switch to it by 2019. The decrease in JPS’ electricity sales per customer depends on the size of the solar PV system that the average customer would install. The JPS demand forecast model optimizes

124 IMF, World Economic Outlook Database 2013, April 2013.
125 IMF, World Economic Outlook Database 2013, April 2013.
126 In the Jamaican Conditions of Living Survey 2010, 80 percent of Jamaican households said that they have refrigerators, but only 4.2 percent claimed to have air conditioning.
Demand Projections

the system size based on the most viable option. If maximizing the solar PV system is the most viable option, we assume that the average customer would install a 3kW solar PV system. If tailoring the solar PV system to the customer’s consumption is the most viable option, we assume that the average customer would install a 1kW solar PV system.

17.3.1.2 Small commercial customers (R20)

The assumptions for projecting the number of customers and average consumption of electricity in rate class R20 are based on our historic trend analysis. The assumptions regarding the reduction in total consumption of electricity reflect our impact analysis of energy efficiency measures by customers, net billing and wheeling. Table 17-3 summarizes our key assumptions for projecting small commercial sales.

<table>
<thead>
<tr>
<th>Variable</th>
<th>Model Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of customers</td>
<td>Number of customers grows in line with historic trend (compound annual growth rate from 2004 to 2012: 1.7 percent)</td>
</tr>
<tr>
<td>Average consumption</td>
<td>R20 customers average energy consumption decreases by 0.098 percent when the real JPS average tariff increases by 1 percent</td>
</tr>
<tr>
<td>Reduction in total consumption</td>
<td>15 percent of all customers implement energy efficiency measures by 2019. Each customer that implements energy efficiency measures reduces his average electricity consumption by 25 percent.</td>
</tr>
<tr>
<td>Net Billing</td>
<td>7.5 percent of customers in rate class R20 switch to net billing by 2019, if it is financially viable. If maximizing the solar PV system is the most viable option, the average customer installs a 20kW solar PV system. If tailoring the solar PV system to the average customer’s consumption is the most viable option, the average customer installs a 4kW solar PV system.</td>
</tr>
</tbody>
</table>

The number of customers was estimated based on the historic growth rate of the number of customers from 2004 to 2012. No exogenous variable clearly impacted the historic trend of the number of customers. Therefore, there was no reason to believe that the historic growth rate of the number of customers would change in the future based on any changes in exogenous variables.

The historic trend analysis showed that average consumption is only driven by the real average electricity tariff. We thus used the price elasticity from our regressions to project the impact of changes in JPS’ real average tariff on JPS’ electricity sales.
We assume that a relatively low percentage of commercial customers will adopt energy efficiency measures by 2019. This is based on Jamaica’s experience with a relatively slow uptake of energy efficiency measures in the past five years.\textsuperscript{127}

We assume that only 7.5\% of customers would switch to net billing by 2019, if it is financially viable. If maximizing the solar PV system is the most viable option, we assume that the average customer would install a 20kW solar PV system. If tailoring the solar PV system to the customer’s consumption is the most viable option, we assume that the average customer would install a 4kW solar PV system.

\textbf{17.3.1.3 Four largest customers}

The assumptions for projecting the sales in rate classes R40 and R50 to JPS’ four largest customers are primarily based on the results of a survey conducted by JPS in November 2013. Table 17-4 summarizes our key assumptions for projecting JPS’ sales of electricity to its four largest customers.

\begin{table}[h]
\centering
\caption{Model Assumptions for Four Largest Customers}
\begin{tabular}{|l|p{14cm}|}
\hline
\textbf{Customer} & \textbf{Model Assumptions} \\
\hline
National Water Commission (NWC) & According to NWC’s Tariff Submission for the period from 2013 to 2018, NWC’s consumption of electricity will decrease by about 2 percent per year. While the NWC plans to expand its services, it also plans to implement energy efficiency initiatives. The decrease of electricity consumption due to energy efficiency initiatives is expected to outweigh the increase in electricity consumption due to service expansion. \\
\hline
Cement Company & \begin{itemize}
\item According to JPS’ survey of the Cement Company, its consumption of electricity will increase by about five percent (5\%) per year due to its planned service expansion (exports to Venezuela)
\item When surveyed by JPS in November 2013, the Cement Company reported that it plans incremental process improvements. We assume that this incremental improvements will decrease the company’s consumption of electricity by about 1 percent per year
\end{itemize} \\
\hline
Jamaican Port Authority (JPA) & \begin{itemize}
\item According to JPS’ survey of the JPA, the company does not plan to expand its services.
\item When surveyed by JPS in November 2013, the JPA stated that it plans to implement energy efficient lighting. We assume that this initiative will decrease consumption of electricity by about 1 percent per year
\end{itemize} \\
\hline
Cable & Wireless & \begin{itemize}
\item According to JPS’ survey of Cable & Wireless, its baseline consumption of electricity will not increase because the company only plans minor network extensions
\item When surveyed by JPS in November 2013, Cable & Wireless reported that it plans to decrease electricity consumption by about 5 percent per year through energy efficiency initiatives
\end{itemize} \\
\hline
\end{tabular}
\end{table}

\textsuperscript{127} For instance, the Energy Fund that was launched in 2008 by the Development Bank of Jamaica has had significantly less penetration than anticipated. Many of the recommended measures of the Programme of Environmental Management in Hospitals and Schools have not been implemented due to lack of public funds and the requisite policies to support private investment funding. Furthermore, hotels have been slow to introduce energy efficiency measures.
Based on the surveys and our discussions with the four largest customers, we assume that if wheeling were financially viable, only the Jamaican Port Authority would do wheeling (starting in 2017). We assume that none of the large customers will switch to net billing.

**17.3.1.4 Large commercial customers LV (R40)**

The assumptions for projecting the number of customers and average consumption in rate class R40 are the result of our historic trend analysis. The assumptions on the reduction in total consumption reflect our impact analysis of energy efficiency measures by customers, net billing and wheeling. Table 17-5 summarizes our key assumptions for projecting electricity sales in rate class R40. The sales of the four largest customers in rate class R40 were projected separately.

**Table 17-5: Model Assumptions for Large Commercial Customers LV (R40)**

<table>
<thead>
<tr>
<th>Variable</th>
<th>Model Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of customers</td>
<td></td>
</tr>
<tr>
<td>Visitor arrivals</td>
<td>Number of customers grows in line with historic trend (compound annual growth rate from 2004 to 2012: 2.11 percent)</td>
</tr>
<tr>
<td>Average consumption</td>
<td></td>
</tr>
<tr>
<td>GDP per capita, real</td>
<td>Average consumption grows at the same rate as projected GDP per capita</td>
</tr>
<tr>
<td>Reduction in total consumption</td>
<td></td>
</tr>
<tr>
<td>Energy efficiency measures by customers</td>
<td>All customers implement energy efficiency measures. Each customer reduces his average electricity consumption by 1 percent.</td>
</tr>
<tr>
<td>Wheeling</td>
<td>Only eight out of the fifteen customers in the R40 rate class with more than 1 MVA switch to wheeling by 2019, if it is financially viable. Customers, who switch to wheeling, generate their total consumption using their own diesel generators. When comparing the net present value of the cost of wheeling to the net present value of buying electricity from JPS, we add a “dead band” of 10 percent to the net present value of the wheeling cost. That is, only if the cost of wheeling plus a 10 percent margin are lower than the cost of buying electricity from JPS, wheeling is considered the more viable option.</td>
</tr>
<tr>
<td>Net Billing</td>
<td>5 percent of customers in rate class R40 with less than 1MVA per month switch to net billing by 2019, if it is financially viable. The average customer installs a 100kW solar PV system. Customers in rate class R40 with more than 1 MVA don’t switch to net billing.</td>
</tr>
</tbody>
</table>

The change in the number of customers from 2014 to 2019 was estimated based on the historic correlation of customer growth with total population growth and visitor arrival growth. As total population and visitor arrivals are expected to continue to grow in line with the historic trend in
the regulatory period from 2014 to 2019\textsuperscript{128}, we assume that the number of customers will also continue to grow in line with the historic trend.

The historic trend analysis showed that there is a close correlation between average consumption and real GDP per capita. We assume that average consumption will continue to grow in line with the expected real GDP per capita. We used the changes in real GDP per capita as projected from 2014 to 2018 by the IMF in its World Economic Outlook 2013\textsuperscript{129} We assumed that the percentage change in 2019 is the same as in 2018.

We assume a decrease in total sales of 1 percent per year from 2014 to 2019 through energy efficiency measures. We assume that the industrial sector would mostly implement gradual improvements for lighting and motors.

We assume that if net billing is financially viable, only five percent (5%) of customers would switch to it by 2019. The average customer would install a 100kW solar PV system. This is the maximum installed capacity per premises for which a customer is entitled to net billing under JPS’ net billing framework.

17.3.2 Large commercial customers MV (R50)

The assumptions for projecting the number of customers and average consumption in rate class R50 are the result of our historic trend analysis. The assumptions on the decrease in total consumption of electricity reflect our impact analysis of energy efficiency measures by customers, net billing, and wheeling. Table 17-6 summarizes our key assumptions for projecting electricity sales in rate class R50. The sales of the four largest customers in rate class R50 were projected separately.

<table>
<thead>
<tr>
<th>Variable</th>
<th>Model Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of customers</td>
<td>Number of customers grows in line with historic trend (compound annual growth rate from 2004 to 2012: 6.25 percent)</td>
</tr>
<tr>
<td>Average consumption</td>
<td>Average consumption grows at the same rate as projected GDP per capita</td>
</tr>
<tr>
<td>GDP per capita, real</td>
<td>R50 customers average energy consumption decreases by 0.190 percent when the real JPS average tariff increases by 1 percent (price elasticity of demand)</td>
</tr>
<tr>
<td>Average JPS electricity tariff, real</td>
<td>All customers implement energy efficiency measures. Each customer reduces his average electricity consumption by 1 percent.</td>
</tr>
<tr>
<td>Reduction in total consumption</td>
<td>If wheeling is financial viable, only fourteen out of the thirty customers in the R50 rate class with more than 1 MVA switch to wheeling by 2019 viable.</td>
</tr>
</tbody>
</table>


\textsuperscript{129} IMF, World Economic Outlook Database 2013, April 2013.
Customers that switch to wheeling generate their total consumption using their own diesel generators. When comparing the net present value of the cost of wheeling to the net present value of buying electricity from JPS, we add a “dead band” of 10 percent to the net present value of the wheeling cost. Only if the cost of wheeling plus a 10 percent margin are lower than the cost of buying electricity from JPS, wheeling is considered the more viable option.

<table>
<thead>
<tr>
<th>Net Billing</th>
</tr>
</thead>
<tbody>
<tr>
<td>If net billing is financially viable, 5 percent of customers in rate class R50 with less than 1MVA per month switch to net billing by 2019. The average customer installs a 100kW solar PV system.</td>
</tr>
<tr>
<td>Customers in rate class R50 with more than 1 MVA don’t switch to net billing.</td>
</tr>
</tbody>
</table>

The change in number of customers in rate class R50 from 2014 to 2019 was estimated based on the historic growth rate of the number of customers in rate class R50 from 2004 to 2012. No exogenous variable clearly impacted the historic trend of the number of customers. Therefore, there was no reason to believe that the historic growth rate of the number of customers would change in the future based on any changes in exogenous variables.

The historic trend analysis showed that average consumption in rate class R50 is closely related to real GDP per capita and the real average electricity tariff. We assume that average consumption will continue to grow in line with the expected change in real GDP per capita from 2014 to 2019. We used the changes in real GDP per capita as projected from 2014 to 2018 by the IMF in its World Economic Outlook 2013. We assumed that the percentage change in 2019 is the same as in 2018. Furthermore, we used the price elasticity from our econometric regressions to project the impact of JPS’ projected real average tariff changes on electricity sales.

We assume a decrease in total sales of 1 percent per year from 2014 to 2019 through energy efficiency measures. We assume that the industrial sector would mostly implement gradual improvements for lighting and motors.

We assume that only five percent (5%) of customers would switch to net billing by 2019, if it is financially viable. The average customer would install a 100kW solar PV system.

### 17.3.2.1 Street lighting (R60)

The assumptions for projecting the number of customers and total consumption of streetlights are based on our historic trend analysis. Table 17-7 summarizes our key assumptions for projecting sales in rate class R60.

<table>
<thead>
<tr>
<th>Variable</th>
<th>Model Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of customers</td>
<td>Number of customers grows in line with historic trend (compound annual growth rate from 2004 to 2012)</td>
</tr>
</tbody>
</table>

---

130 IMF, World Economic Outlook Database 2013, April 2013.
The historic trend analysis showed that total electricity consumption of electricity by streetlights is driven by urban population growth. We do not expect any streetlight additions from the Government’s highway expansion project during the regulatory period. We thus assume that total consumption will grow from 2014 to 2019 at the same rate as the urban population. For the urban population, we assume that it will continue to grow at its historic trend from 2014 to 2019. We thus used the compound annual growth rate of population growth from 2001 to 2011 to project urban population growth.

17.3.3 Assumptions for Forecasting JPS’ System Losses

We forecasted the technical losses based on achieving a target for technical losses by 2019. Technical loss reduction initiatives that are being pursued by JPS include bulk capacitor bank installations, feeder balancing, and power factor correction.

Non-technical losses estimates for 2014-2019 were obtained from JPS’ Losses Team. The team’s planned loss reduction programs includes RAMI and CAMI installations, audits and strike force operations, installation of total meters and activities to reduce internal inefficiencies. The losses team assumed that JPS’ will be able to convert some of the non-technical losses into sales. Loss recovery from JPS initiatives is expected to increase from 43GWh in 2014 to 56GWh in 2019.

In addition, JPS plans to collaborate with key stakeholders of government to implement a Community Renewal Program geared at improving services to low-income communities island-wide, in an integrated way that emphasizes community responsibility and payment as the quid pro quo for service normalization. As part of the program, JPS plans to regularize around 5,000 to 10,000 customers per annum. It is assumed that prior to regularization efforts, these customers were nonpaying consumers of electricity. The assumption is that these consumers were consuming at the rate of the average Rate 10 customer, that is, at approximately 150kWh/month and that they will continue to do so post regularization. Thus, it was assumed that in the first full year of the program, 5.8GWh of losses will be converted to electricity sales. At the end of each year an additional 5.8GWh of sales would be recovered from newly regularized customers however, it is assumed that only 70% of the sales recovered in the previous year would be brought forward to the current year. This assumption is fair given that it is expected that some customers will revert to electricity theft. The program is expected to start in 2015 when it is expected that 2.1GWh of electricity sales will be recovered. By 2019, the program will be expected to recover 18.1GWh of sales. Table 17-8 summarizes our key assumptions for projecting system losses.

---

131 Quoted from the Community Renewal Program: White Paper
Table 17-8: Assumptions for System Losses

<table>
<thead>
<tr>
<th>Component</th>
<th>Model Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Technical losses</td>
<td>▪ Technical losses decrease on a linear trend from 9.1 percent in 2014 to 8.1 percent in 2019</td>
</tr>
<tr>
<td>Annual reduction in non-technical distribution losses (as percentage of net generation) due to JPS’ Loss Reduction Program</td>
<td>▪ Reduction of non-technical system losses according to JPS’ five-year losses plan and the objectives of the Community Renewal Program. Losses move from 26.34% in 2014 to 22.37% in 2019.</td>
</tr>
</tbody>
</table>

17.4 Scenario Results

This section presents our projections of total demand (electricity sales plus system losses) based on three different scenarios. We first describe the assumptions for each scenario. We then compare the results of the four scenarios. Finally, we present the detailed results for each scenario.

17.4.1 Scenario Assumptions

To get a better understanding of the potential impact of JPS’ plans to use natural gas for generating electricity and to reduce system losses, we modeled four different scenarios. The scenarios vary depending on two variables—the introduction of natural gas in JPS’ generation mix, and the expected change in JPS’ system losses. Table 17-9 summarizes the main assumptions of the model for the three different scenarios.

Table 17-9: JPS Demand Forecast Scenario Assumptions

<table>
<thead>
<tr>
<th>Key Variables</th>
<th>Base Case With Natural Gas</th>
<th>Base Case Without Natural Gas</th>
<th>Efficient Scenario with Natural Gas</th>
<th>Efficient Scenario without Natural Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>Introduction of Natural Gas</td>
<td>Natural gas is introduced into the generation fuel mix in 2017</td>
<td>Natural gas is not introduced into the generation fuel mix in 2017</td>
<td>Natural gas is introduced into the generation fuel mix in 2017</td>
<td>Natural gas is not introduced into the generation fuel mix in 2017</td>
</tr>
<tr>
<td>System Losses</td>
<td>JPS’ Loss Reduction Program includes technical loss reduction initiatives but does not reduce non-technical losses</td>
<td>JPS’ Loss Reduction Program includes technical loss reduction initiatives but does not reduce non-technical losses</td>
<td>JPS’ Loss Reduction Program reduces both technical and non-technical losses and a Community Renewal Program is introduced which will further reduce</td>
<td>JPS’ Loss Reduction Program reduces both technical and non-technical losses and a Community Renewal Program is introduced which will further reduce</td>
</tr>
</tbody>
</table>

System losses are made up of technical losses and non-technical losses. JPS’ Loss Reduction Program aims at reducing both technical and non-technical losses. In the scenarios where we assume that the program is not effective, we project that non-technical losses will not decrease. However, we assume in all three scenarios that technical losses will decrease by 2019, and thus lead to an overall reduction in system losses by 2019.
The four scenarios can be described as follows:

- **Base Case with Natural Gas**: This scenario is the base case scenario because the achieving results from technical losses initiatives are more certain for JPS. This scenario assumes that JPS introduces natural gas into its generation mix in 2017. Based on this assumption, the average electricity tariff is expected to decrease in 2017 due to the lower cost of generating electricity with gas-fired plants. The lower average electricity tariff leads to an increase in consumption of electricity because of the price elasticity of demand. It also decreases households’ and businesses likelihood to switch to wheeling or net billing. This scenario assumes that JPS’ Loss Reduction Program would not be effective and would therefore not lead to a reduction of non-technical losses. This scenario thus forecasts the highest demand.

- **Base Case without Natural Gas**: This scenario differs from the base case scenario only with regard to the introduction of natural gas. This scenario assumes that JPS will not introduce natural gas in its generation matrix before 2020. Based on this assumption, we do not expect any decrease in the average real electricity tariff in the period from 2014 to 2019. The higher average electricity tariff (compared to the base case with natural gas) leads to lower consumption of electricity because of the price elasticity of demand, and because of its impact on households’ and businesses decisions to choose wheeling or net billing. This scenario thus leads to a lower demand than the base case with natural gas. We do not expect this scenario to be the most likely because JPS is committed to introducing natural gas into its generation mix.

- **Efficient Scenario with Natural Gas**: This scenario differs from the base case scenario only with regard to system losses. We call it the “efficient scenario” because it assumes that JPS will be able to reduce non-technical losses to an “efficient level” from 16.97 percent in 2014 to 14.4 percent in 2019. This scenario is considered the most likely scenario.

- **Efficient Scenario without Natural Gas**: This scenario differs from the efficient scenario only with regard to the introduction of natural gas. Like the base case without natural gas scenario, we do not expect any decrease in the average tariff during this regulatory period and thus demand for electricity will be lower and household and businesses a more likely to switch to wheeling or net billing.

### 17.4.2 Comparison of the Results of the Four Scenarios

Figure 17-1 and Figure 17-2 compares the results of the four scenarios. They show how total demand is projected to change from 2014 to 2019 in all four scenarios. In the base case scenario with natural gas, we project total demand to increase at a CAGR of 0.4 percent per annum from 2014 to 2019.
4,130GWh in 2014 to 4,212GWh in 2019. In the base case scenario without natural gas, we project total demand to decrease at a CAGR of about -0.5 percent from 4,130GWh in 2014 to 4,026GWh in 2019. In the efficient scenario with natural gas, we project total demand to decrease at a CAGR of about 0.1 percent from 4,184GWh in 2014 to 4,140GWh in 2019. In the efficient scenario without natural gas, demand is projected to decrease at a CAGR of 0.9% per annum from 4,184GWh in 2014 to 3,960GWh in 2019.

Figure 17-1: JPS Total Demand, 2007-2023 (Scenario Comparison)

Figure 17-2: JPS Total Demand, 2007-2023 (Scenario Comparison)

The details for each scenario are explained in the following sections.
17.4.3 Base Case with Natural Gas

In our base case scenario “Base Case with Natural Gas” we project demand to increase at a CAGR of 0.4 percent per annum from 4,130GWh in 2014 to 4,212GWh in 2019 (see Figure 17-3). In this scenario, JPS’ sales of electricity are projected to increase at CAGR of 0.6 percent from 3,039GWh in 2014 to 3,143GWh in 2019. System losses as a percent of net generation are projected to decrease from 26.34 percent in 2014 (1,090GWh) to 25.4 percent in 2019 (1,069GWh). System losses decrease due to a decrease in technical losses. Non-technical losses are not expected to decrease in this scenario.

In this scenario, we assume that natural gas will be introduced into the generation mix in 2017. This would decrease the real average electricity tariff in 2017. As a consequence, demand in 2017 would increase even more than in the other years.

Assuming that JPS introduces natural gas into its generation mix by 2017, we do not expect wheeling to become a financially viable alternative for most JPS’ customers. No sales is expected to be lost to wheeling by 2019 in this scenario. We also expect the impact of customers deciding to do net billing to be relatively low. By 2019, we expect a JPS sales loss due to net billing of 284GWh (see Figure 17-4). Since losses reductions are only confined to technical losses in this scenario, there will be no recovery of sales from loss reduction initiatives.
17.4.4 Base Case Without Natural Gas

The scenario “Base Case without Natural Gas” differs from the base case scenario “Base Case with Natural Gas” with regard to the introduction of natural gas. In this scenario, total demand is projected to decrease at a CAGR of 0.5 percent per annum from 4,130GWh in 2014 to 4,026GWh in 2019 (see Figure 17-5). This annual decrease is primarily due to a decrease in sales at an annual rate of minus 1 percent from 3,039GWh in 2014 to 3,004GWh in 2019. Due to a projected decrease in technical losses, system losses as a percent of net generation are projected to decrease from 26.34 percent in 2014 (1090GWh) to 25.4 percent in 2019 (1,022GWh).
In this scenario, total demand decreases primarily because total sales decrease from 2014 to 2019. Total sales decrease because without natural gas the real average electricity tariff continues to rise in 2017 (instead of decreasing as in the scenario with natural gas). Figure 17-6 compares the total sales in the base case scenario “Base Case with Natural Gas” to the scenario “Base Case without Natural Gas”.

The comparison shows that total sales would decrease if natural gas were not introduced during the regulatory period. Total sales would decrease for the following three reasons:

- Demand would decrease because of the price elasticity of demand
Demand Projections

- Net billing would become a financially viable option for a larger number of customers
- Wheeling would become a financially viable option for more customers than in the base case with natural gas.

Assuming that natural gas is not introduced into the generation mix, we expect that net billing would lead to a sales loss of 284GWh by 2019 (see Figure 17-7). In this scenario, wheeling becomes a financially viable alternative for many customers because the average electricity tariff continues to rise in 2017 (instead of decreasing as in the scenario with natural gas). Considering a dead-band of 10 percent and an annual average real tariff increase of around 3 percent, some customers would switch to wheeling instead of buying electricity from JPS. The annual loss of sales of electricity due to wheeling would be 68GWh by 2019.

**Figure 17-7: Base Case without Natural Gas: Sales, Wheeling and Net Billing, 2012-2023**

17.4.5 Efficient Scenario With Natural Gas

The scenario “Efficient Case with Natural Gas” differs from the base case scenario “Base Case with Natural Gas” with regard to system losses. In this scenario, total demand would decrease at an annual rate of around 0.1 percent from 4,184GWh in 2014 to 4,172GWh in 2019 (see Figure 17-8). System losses would decrease from 26.34 percent (1,102GWh) in 2014 to 22.4 percent (926GWh) in 2019. Total sales would increase at an annual rate of around .8 percent from 3,082GWh in 2014 to 3,214GWh in 2019.
Total demand decreases in the “Efficient Scenario with Natural Gas” scenario compared to the base case scenario “Base Case with Natural Gas” because it assumes that system losses are a bit more. In the “Efficient Scenario” we assume that JPS’ planned Loss Reduction Program and the Community Renewal program will be successful (see Figure 17-9). Therefore, system losses do not only decrease due to a reduction of technical losses, but also due to a reduction of non-technical losses. Assuming that the JPS Loss Reduction Program is successful, we project that JPS’ system losses will decrease from 26.34 percent in 2014 to 22.4 percent in 2019 (“Efficient Scenario”). It is expected that recovery of sales from JPS’ losses initiatives will contribute 43GWh to sales in 2014 and 56GWh in 2019. In addition, the Community Renewal program will yield an additional 2.1GWh of sales in 2015 when the program begins and rise to 18.1GWh in 2019.
17.4.6 Efficient Scenario without Natural Gas

The scenario “Efficient Case without Natural Gas” differs from the “Efficient Case with Natural Gas” scenario with regard to the introduction of natural gas into the fuel mix. In this scenario, total demand would decrease at a CAGR of -0.9 percent per annum from 4,184GWh in 2014 to 3,960GWh in 2019 (see Figure 17-10). Demand decreases due to the combined effect of decreasing sales and decreasing losses. Total sales are projected to decrease at an annual rate of around 0.1 percent from 3,082GWh in 2014 to 3,075GWh in 2019. The sales decline is less than in the case of the “Base Case without Natural Gas” because in the “Efficient Case without Natural Gas” scenario, the sales recovery from non-technical loss recovery initiatives and from the implementation of the Community Renewal program will offset some of the sales losses due to more customers switching to net billing and wheeling.
Figure 17-10: Efficient Scenario without Natural Gas: Sales and System Losses, 2007-2023

Figure 17-11: JPS Efficient Scenario Sales with and without Natural Gas, 2007-2023
Annex A: Cost of Capital Study

The Cost of Capital Study will be submitted in a separate document
Annex B: X Factor Study

The X-Factor Study will be submitted in a separate document.
Annex C: Depreciation Study

The Depreciation Study will be submitted in a separate document
Annex D: JPSCo Wheeling Proposal

The Wheeling Proposal will be submitted in a separate document
Annex E: Decommissioning Study 1: Old Harbour

Decommissioning Study 1 will be submitted in a separate document.
Annex F: Decommissioning Study 2: Hunts Bay

Decommissioning Study 2 will be submitted in a separate document
Annex G: Non – Technical Losses Study

Non – Technical Losses Study will be submitted in a separate document
Annex H: Audited Financial Statements

The Audited Financials will be submitted as a separate document