INDEPENDENT CONSUMER AND COMPETITION COMMISSION

THE FINAL REPORT ON PNG POWER LIMITED’S
ELECTRICITY REGULATORY CONTRACT REVIEW

Electricity Regulatory Contract Review
Foreword

This is the Final Report that completes the review process that the Commission has been undertaking to review the existing Electricity Regulatory Contract with the intention to develop a new regulatory contract for PNG Power Limited (PPL) for the next five years. This report has addressed all issues raised by PPL, industry participants and the general public through submissions and comments to the Commission at different stages of the review process. These submissions are discussed where appropriate in this report.

The submissions and comments provided have been invaluable in assisting the Commission in making its Final Determinations on the appropriate price path to apply to PPL for the regulatory period commencing 1 January 2013.

The principal objective of this review was firstly to determine if the current price control mechanism is appropriate for providing reliable and efficient electricity services throughout the country; and secondly to set a new price path for PPL for the regulatory period commencing 1st January 2013 and ending on 31st December 2017.

Whist the findings and recommendations in this review attempts to assist PPL to improve the current level of electricity service provision, the Commission is still concerned that the service quality of electricity supply in Papua New Guinea remains unacceptably low, with regular outages for many customers. Often customers are forced to invest in emergency power systems. While some improvements are reported by PPL in the reliability of power supply, service quality remains poor and improvement is slow. An additional concern is that the accelerating demand for electricity in Papua New Guinea is placing significant requirements on PPL to invest in new infrastructure. This includes generation capacity, transmission, distribution systems and new management systems. The Commission over the next five years regulatory period will be ensuring that PPL’s capital investment delivers the capacity to meet demand and to improve service quality over the next regulatory period.

The Final Report contains the Final Determinations that will apply for the Supply and the Sale of electricity, the Scheduled Services and the Excluded Services provided by PPL for the regulatory period.

Finally, the Commission would like to thank those Government departments, organizations and businesses who participated in the review process by providing views and comments to the Commission in the course of the review up to its completion.

Copies of the Final Report can be obtained from the Commission’s website at www.iccc.gov.pg

Dr. Billy Manoka, (PhD)
Commissioner & Chief Executive Officer

8th November 2013
# Contents

Foreword ......................................................................................................................... 2

1 EXECUTIVE SUMMARY .......................................................................................... 7
   1.1 Key Findings ........................................................................................................ 7
   1.2 Key Determinations ............................................................................................. 7

2 INTRODUCTION ......................................................................................................... 9
   2.1 Background .......................................................................................................... 9
   2.2 This Report .......................................................................................................... 9
   2.3 Electricity Industry Policy Statement .................................................................... 11
   2.4 Legislative Requirements .................................................................................... 11
   2.5 Cost of funding the next Regulatory Contract review ........................................... 11
   2.6 Regulatory Principles .......................................................................................... 11
   2.7 Conduct and objectives of the Review Process ...................................................... 13
   2.8 Submissions ......................................................................................................... 14
   2.9 Final Determination .............................................................................................. 20

3 RATIONALE FOR REGULATION ............................................................................ 21
   3.1 Current Electricity Industry Structure & Development .......................................... 21
   3.2 Designated Services and Locations ....................................................................... 22
   3.3 Competition in the Electricity Supply Industry ...................................................... 23
   3.4 Electricity Industry Policy ..................................................................................... 24
   3.5 Ring Fencing ......................................................................................................... 24
   3.6 Exclusive Services ............................................................................................... 25
   3.7 Social and Economic Considerations .................................................................... 26
   3.8 Final Determination .............................................................................................. 26

4 THE REGULATORY PROCESS FOR NEW ENTRANTS ........................................... 28
   4.1 Competition in the Industry .................................................................................. 28
   4.2 Entry into the Electricity Industry Market ............................................................. 28
   4.3 New Entrant Pricing ............................................................................................. 30

5 FORM OF REGULATION .......................................................................................... 31
   5.1 Introduction .......................................................................................................... 31
   5.2 Effectiveness of the current ERC and generation constraints ................................ 32
   5.3 Pricing Structure .................................................................................................. 37
   5.4 Price differentiation between service areas .......................................................... 40
   5.5 Relativity Ratios ................................................................................................... 57
   5.6 Competition in the Large Load market .................................................................. 60
Table of Figures

Figure 1: Current structure of electricity industry ................................................................. 21
Figure 2: Zone 1 Outages ......................................................................................................... 34
Figure 3: Zone 2 Outages ......................................................................................................... 35
Figure 4: Zone 3 Outages ......................................................................................................... 35
Figure 5 – Range of prices if de-averaged................................................................................ 51
Figure 6 – Easipay Domestic vs. Domestic credit ..................................................................... 59
Figure 7: Sources of cost ......................................................................................................... 74
Figure 8: Forecast Demand ..................................................................................................... 76
Figure 9 - Increase in Fuel Costs (2012 Kina) ........................................................................ 77
Figure 10 - Generation proportion by Type ........................................................................... 77
Figure 11: Fuel Cost Calculation Process .............................................................................. 78
Figure 12: Current Fuel Expenditure - extrapolated to 2020 if no hydro added .................. 81
Figure 13 - Current Program - Naoro Brown completed in 2019 ........................................ 82
Figure 14 - Overall cost if Naoro - Brown can be delivered by end of 2017 ........................ 82
Figure 15: Operating costs excluding direct power costs ....................................................... 84
Figure 16: Change in operating cost productivity (Kina/kWH) ................................................ 84
Figure 17: Operating cost components .................................................................................. 85
Figure 18: Cost per kWh for operating cost components ...................................................... 85
Figure 19: Depreciation amount per MWh by asset class ...................................................... 91
Figure 20: Risk Premium ....................................................................................................... 98
Figure 21: Cost of equity ....................................................................................................... 98
Figure 22: US regulatory decisions over time ......................................................................... 99
Figure 23: USE 10 year Bond Rates ....................................................................................... 100
Figure 24: Countries with the same credit rating as PNG ..................................................... 104
Figure 25: PNG Power Net Profit before Tax ........................................................................ 109
Figure 26: Average Temperatures ........................................................................................ 112
Figure 27: Electricity Demand ............................................................................................... 112
Figure 28: PPL Demand Forecasting Model ........................................................................ 113
Figure 29: Price Smoothing .................................................................................................. 121
Figure 30: Total Undelivered Energy for Zone 1 from 2005-2010 ........................................ 124
Figure 31: Total Undelivered Energy for Zone 2 from 2005-2010 ........................................ 125
Figure 32: Total Undelivered Energy for Zone 3 from 2005-2010 ........................................ 126
Figure 33: Total Energy Delivered in Zone 1 Mar 2005- Jun 2011 ......................................... 126
Figure 34: Total Energy Delivered in Zone 2 Mar 2005- Jun 2011 ......................................... 127
Figure 35: Total Energy Delivered in Zone 3 Mar 2005- Jun 2011 ......................................... 127
Table of Tables

Table 1: Price Path - MAP .......................................................... 8
Table 2: Price Path - price points .................................................. 8
Table 3: Easipay Charges ............................................................... 30
Table 4: Electricity Prices .............................................................. 33
Table 5: Diesel Centre Sales Volume, Revenue and Fuel Cost .............. 41
Table 6: Illustration of incremental impact of investment under different pricing structures ........................................ 47
Table 7: Price Differentiation .......................................................... 51
Table 8: Service Areas ................................................................... 55
Table 9: Generation Systems List ..................................................... 55
Table 10: Price Relativities ............................................................... 57
Table 11: Current Average Energy Contribution Margins .................... 58
Table 12: Proposed regulated relativities .......................................... 58
Table 13: Commission .................................................................. 62
Table 14 – Current fuel adjustment .................................................. 63
Table 15: Proposed real weights for CWI variables .............................. 66
Table 16: PPL’s Forecast Operating Expenditure .................................... 74
Table 17 - Annual Forecast Demand ................................................ 75
Table 18: Kanudi Fuel Costs ............................................................. 83
Table 19: Kanudi – Non Fuel Costs .................................................. 84
Table 20: Operating expenditure included in building block calculation ... 87
Table 21: PPL’s Capex Program (Real Term Values) 2012 – 2017 ......... 90
Table 22: 2002 RAB .................................................................. 93
Table 23: Value 2013 Opening Regulatory Asset Base ......................... 94
Table 24: Working Capital ............................................................... 94
Table 25: US Inflation rates ........................................................... 103
Table 26: Implied Country Risk Premium ......................................... 105
Table 27: Asset Beta for vertically integrated power companies ........... 110
Table 28: Debt ratios for vertically integrated power companies .......... 115
Table 29: Summary of WACC Inputs and Outputs .............................. 116
Table 30: Opening Balances of the RAB ........................................... 116
Table 31: Depreciation Rates ........................................................... 117
Table 32: Annual Depreciation used in building block calculation .......... 117
Table 33: Building Blocks ............................................................... 118
Table 34: Proposed MWAP over the contract period ......................... 120
Table 35: Price path if X factor applied to existing prices ...................... 120
Table 36: MWAP adjustment at Mid Term Review ............................. 121
Table 37: Reliability targets for current regulatory period (%USE) ........... 128
Table 38: % USE targets proposed in the initial draft report ................. 130
Table 39 - 2008 - 2011 average proportion of USE cause ................... 131
Table 40 - Current USE performance ............................................. 132
Table 41: Performance Improvement Target ....................................... 133
Table 42 – % USE Performance Targets ........................................... 134
Table 43 – Maximum hours of outage with new targets (Notional Hours outage per month) .................................. 134
Table 44: List of Service Areas ........................................................ 137
Table 45: Total Connections Made in Zone 1 ..................................... 139
Table 46: Total Connections Made in Zone 2 ..................................... 139
Table 47: Total Connections Made in Zone 3 ..................................... 140
Table 48: Proposed Capital Expenditure on New Connections (K’000 in 2010 terms) ............................................. 141
Table 49: Schedule for implementation of SAIFI and SAIDI ................ 143
Table 50: Planned Capex - Generation ............................................. 149
Table 51: Planned CAPEX - Transmission and Distribution .................. 150
1 EXECUTIVE SUMMARY

This Executive Summary provides an overview of the Commission’s key Findings and its Determinations that will apply to the Supply and Sale of Electricity, the Scheduled Services and the Excluded Services for the next regulatory period commencing, 1 January, 2013. These key findings and determinations are based on the comments, views and submissions received from PNG Power Limited, key stakeholders and the information gathered independently, as well as, the Commission’s own independent assessment and analysis of the issues and the electricity industry as a whole.

1.1 Key Findings

Having considered PNG Power Limited’s (PPL) capital expenditure program, including its financials, operating expenditure and its future plans for generation and network expansion to meet the growth in demand for electricity services, the Commission’s is of the view that the electricity industry will continue to grow as demand growth increases. This will be driven by the impact of the LNG Project and GDP growth.

The Commission has independently reviewed the data and submissions provided by PPL and have incorporated these into the modelling of the forward looking price path for PPL’s services. As required under the regulatory principles in the previous contract, it has used a building block approach in developing the revenue requirements for PPL, and its regulated services.

The Commission has considered the Government’s Electricity Industry Policy (EIP) statement issued in November 2011 and has modified the proposed regulatory contract as appropriate to secure consistency with the policy to the extent that is consistent with the ICCC Act.

Instead of bench marking, the Commission has chosen to consider the current and past performance of PPL and to analyse changes in the forecast spending.

The Commission is generally concerned about the number of supply outages in PNG, and is therefore, supportive of any efficient investment that will result in more reliable services to customers. Thus, the Commission, in its assessment of PPL’s forecast spending has taken a particular interest in how its spending will improve the reliability of power supply.

It has also found that the current set of performance measures laid out in the Electricity Regulatory Contract (ERC) are not adequate and has made some changes and set new targets which, if achieved, will raise electricity reliability to more acceptable levels by the end of the regulatory period. It is expecting that PPL will improve the reliability of their network to a level whereby it can achieve the new performance targets. Adjustments have been made to PPL’s capital spending plans in order to achieve these new targets and the price path reflects this increased capital spending.

1.2 Key Determinations

The Commission’s determination allows PPL the discretion to differentiate in price between service areas based upon the different costs of providing services in various areas. Prices must be set so that the weighted average of all prices do not exceed the Maximum Weighted Average Price (MWAP). Current price relativities between customer types must be maintained in each service area. In the ICCC’s view, this is consistent with the EIP.

- Each price will be weighted according to the actual quantity of energy delivered, measured in kWh; and
- The contract sets limits on how much any price can change from one year to the next over and above the percentage (%) change of the MWAP.

This is discussed in Section 5 of this report.
The Commission has reviewed PPL’s operating expenditure, capital spending plans and regulatory asset base (RAB), to set a price path. This was done by following the building block method. Under the new contract, PPL’s operating expenditure, capital spending plans will be made subject to assessment of prudence and efficiency and adjustments to the price path are to be made under the terms in the new contract.

The Commission has reviewed PPL’s submissions in relation to the significant impact that fuel price fluctuations have on the financial position of PPL. The current review time frame of 12 months exposes PPL to significant periods of financial exposure. Therefore, the Commission has determined that a process be implemented by the Commission to adjust pricing to reflect changes in fuel cost on a three monthly basis. The three month review process will reflect changes in fuel price only, and the price allowance will be based upon the forecast mix of fuel and non-fuel based forms of generation as determined at the beginning of the contract period. CPI and exchange rate adjustments will continue to be made on an annual basis to the non-fuel portion of the MWAP.

The Commission has determined that an MWAP of K916.42 per MWh be used in 2013. This is the combination of the Fuel WAP 328.86 and a non-fuel WAP of 587.56. The Fuel WAP is subject to quarterly reviews based upon actual fuel price changes. An X Factor adjustment of 6.57% each year will apply to the non-fuel cost components only. This will result in the MWAPs shown in Table 1. If these MWAP’s are applied to existing prices, this will result in the prices shown in Table 2.

Table 1: Price Path - MAP

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>MWAP (Kina / MWh)</td>
<td>916.42</td>
<td>944.06</td>
<td>981.13</td>
<td>1021.11</td>
<td>1068.24</td>
</tr>
<tr>
<td>Fuel WAP (Kina / MWh)</td>
<td>328.86</td>
<td>318.51</td>
<td>315.28</td>
<td>312.30</td>
<td>315.16</td>
</tr>
<tr>
<td>Non Fuel WAP (Kina / MWh)</td>
<td>587.56</td>
<td>625.55</td>
<td>665.85</td>
<td>708.82</td>
<td>753.08</td>
</tr>
</tbody>
</table>

Note: Kina numbers are in nominal terms

Table 2: Price Path - price points

<table>
<thead>
<tr>
<th>Prices (K/kWh)</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Domestic - credit</td>
<td>0.5285</td>
<td>0.5632</td>
<td>0.6002</td>
<td>0.6396</td>
<td>0.6816</td>
</tr>
<tr>
<td>General Supply - credit</td>
<td>0.6716</td>
<td>0.7156</td>
<td>0.7626</td>
<td>0.8127</td>
<td>0.8661</td>
</tr>
<tr>
<td>Industrial - credit</td>
<td>0.3089</td>
<td>0.3292</td>
<td>0.3508</td>
<td>0.3738</td>
<td>0.3984</td>
</tr>
<tr>
<td>Public Lighting - (average)</td>
<td>0.6716</td>
<td>0.7156</td>
<td>0.7626</td>
<td>0.8127</td>
<td>0.8661</td>
</tr>
<tr>
<td>Easipay Domestic</td>
<td>0.3742</td>
<td>0.3988</td>
<td>0.4250</td>
<td>0.4529</td>
<td>0.4826</td>
</tr>
<tr>
<td>Easipay Gen Supply</td>
<td>0.6466</td>
<td>0.6891</td>
<td>0.7343</td>
<td>0.7825</td>
<td>0.8339</td>
</tr>
<tr>
<td>Industrial Demand Price (K/kVA/month)</td>
<td>79.0080</td>
<td>84.1956</td>
<td>89.7239</td>
<td>95.6151</td>
<td>101.8932</td>
</tr>
<tr>
<td>Domestic Credit first block of 30kWh</td>
<td>0.1712</td>
<td>0.1825</td>
<td>0.1944</td>
<td>0.2072</td>
<td>0.2208</td>
</tr>
</tbody>
</table>

Note: Kina numbers are in nominal terms

The actual prices will vary from these prices shown above with the adoption of price differentiation between service areas.

The Commission considered the various proposals by PPL to modify the annual adjustments to the MWAP and has accepted some of these. In particular, the Commission has determined to:
• Allow for capital efficiency and imprudent capital spending by way of an adjustment to the X factor at the mid-term review;
• The CWI will be reduced to three factors with the current two factors which relate to the Kanudi contract being combined and fuel factor being separated out;
• A drought clause will be introduced into the contract to allow for temporary price adjustment due to higher fuel costs during a drought (less hydro and more diesel generation will raise PPL’s fuel cost base); and
• Some additional allowances for adjustment due to major industry changes such as the introduction of competition.

These changes are discussed in Section 5.

The Commission has determined to carry out a mid-term capital expenditure review. This will be carried out in 2015 and may result in an adjustment to the price path for 2016 and 2017.

The current rebate mechanism for poor service has been modified so that targets for % USE are based upon total unplanned outages. A set of new targets has been set for the contract period with reliability payments into a Reliability Improvement Fund that promotes further investment in reliability initiatives by PPL, if the targets are not achieved. In addition to this, the Commission is planning to introduce SAIFI and SAIDI as new performance measures. The Commission has laid out a timetable for the rollout of these performance measures and plans that they are put in place by end of the current regulatory period. This is discussed in Section 8.

2 INTRODUCTION

2.1 Background

Prior to the establishment of the Commission and its enabling legislation, prices of utility services were subject to price control and administered through the former Price Controller’s Office. Since the inception of the Commission, an ERC (which is akin to a general tariff order) has been formerly established under the provision of the ICCC Act and took effect from July 2002. The Regulatory Contract, amongst other things, sets out the tariffs for the respective service categories of PPL, its designated service areas/zones, the minimum service standards required of PPL, the maximum weighted average prices for its services, the capital expenditure required within the regulatory period, the tariff adjustment mechanism and the relevant penalties to be borne by PPL for non-compliance. The current Regulatory Contract is now the subject of this review.

The Commission, as the economic regulator, has now developed a new Regulatory Contract which reflects the current operational circumstances of PPL. This will supersede the current ERC and will bind both PPL and the Commission and possibly other participants in the industry within the regulatory ambit of the Commission for the duration of the regulatory period or at some other point in time in the future, should there be a need for an early review of the ERC.

2.2 This Report

This report represents the Commission’s final determination for the new regulatory period.

In June 2011, in compliance with the regulatory contract, PPL provided a report which proposed the basis of a new regulatory contract for the next regulatory period. The Commission consulted with PPL and in February 2012, the Commission published a Preliminary Draft Report as part of this review. It received several submissions in response to that report including submissions from PPL. Subsequent to this, the Commission consulted further with PPL and discussed various issues outlined in the preliminary draft report. A second Draft Report was published in September 2012. Further discussions were held with PPL to resolve outstanding issues.
This Report is a modified version of the second Draft Report. It has been updated with the latest information provided by PPL and addresses the outstanding issues raised by PPL and other parties.

Where appropriate this report comments upon the latest submissions made. Comments about earlier submissions have been retained to provide the context for the determination.

The Final Report is substantially the same as the second Draft Report, with the following changes having been made.

- The demand forecast has been updated and this has resulted in a change to the price path (see chapter 6).
- The regulatory asset base has been recalculated to allow for items which are currently in work in progress to be added into it when they are commissioned. This has also resulted in a change to the price path (see chapter 6).
- The performance floor target has been modified for Ramu and Gazelle (see section 8.5.5)
- The revenue from non-regulated sales to the Hidden Valley mine has been deducted from the revenue requirement
- The gearing ratio has been lowered to 40% from 50% (see section 6.4.11)
- Application of a 2% for a failure to achieve required service standards.

Apart from these changes, any other changes to the report are for commentary purposes only and do not change the price path or the determination.

2.2.1 The Final Report and the Regulatory Contract

Since this review is important to the Commission and PPL, all issues and concerns surrounding the operational aspect of the entire business of providing electricity services to the people of PNG are discussed at great length in this report and all the key determinations and decisions are locked into the new regulatory contract.

The final report that will form the basis of the new regulatory contract and, as part of its provisions, is one of the ‘linked documents’ which are required to be considered in its interpretation. The new regulatory contract therefore must be read together with the final report. If the regulatory contract is silent on certain areas, the final report determinations and conclusions take effect.

The Commission is proposing to adopt this approach mainly because of its experiences in the past with other regulatory contract reviews that have shown that once a final regulatory contract is released, the final report is ignored. That should not have been the case as the final report discusses the entire industry issues and concerns. What is reflected in the regulatory contract is an extract of the final report, or the key determinations or decisions therein. Going forward, the Commission has decided to adopt a different approach by requiring the final report to be read together with the regulatory contract.

2.2.2 Confidential Provision

The Commission will disclose information to the general public from the course of this regulatory period and subsequent regulatory period, except information that is designated as ‘confidential’ by PPL. It must also be noted that the Commission, may disclose such information if it considers that the information designated as “confidential” by PPL should be disclosed is in the public interest of the general public.

2.2.3 General Information Request

The Commission may also require from PPL to furnish any information or answer any matters relating to the previous contract, this contract or the subsequent regulatory contract. The response to such information request must be given under a signed statutory declaration to be true in every respect to the best of the knowledge of the Chief Executive Officer. The requirement of such authentication is to ensure the completeness and accuracy of
information provided to the Commission as other means of authentication are impracticable. The information requested must also be provided in the form required by the Commission within 14 days of any written request by the Commission to PPL.

2.2.4 Offences

Any offence, criminal act that has been committed, or where PPL or the Commission suspects to have been or likely to be committed, in the previous regulatory contract, this contract or the subsequent regulatory contract by either a persona employed by the Commission, the entity concerned or any other person on any matters relating to the contract must be made known to the Commission, the Board of PPL; IPBC the Minister for Public Enterprise or relevant law enforcement authorities.

The purpose of this provision is to prevent, detect and punish fraudulent activities particularly, but not exclusively, relating to procurement, which is considered to be a significant risk and, by raising costs, adversely affects the public interest as such costs often need to be reflected in prices, or are passed on to the public purse by the need for Government financial assistance.

2.3 Electricity Industry Policy Statement

In November 2011, the PNG government published the Electricity Policy Statement (EIP). There are several elements of the EIP which have an impact upon the ERC.

The Commission has considered the EIP to ensure that this determination is consistent with it and the ICCC Act.

2.4 Legislative Requirements

This review has been undertaken in accordance with Clause 7.1 of the ERC. In undertaking this review, the Commission has had regard to the requirements of the Independent Consumer and Competition ICCC Act 2002 (“the ICCC Act”).

The objectives of the ICCC Act are to enhance the welfare of the people of PNG, to promote economic efficiency, and to protect the long term interests of the people of PNG (Section 5(1) of the Act). It should not exercise any power in a manner that is inconsistent with the requirements of a Regulatory Contract that is in effect (Section 7(4) of the Act). At the same time, the Commission is to act independently in its consideration of the issues and is not subject to direction by government (Section 23 of the Act).

2.5 Cost of funding the next Regulatory Contract review

There is normally a mutual understanding (unwritten) between the Commission and all the regulated entities for the regulated entities to fund the cost of any reviews. This cost is then factored into the financial model that is used by the Commission as one of the costs to determine the price path for the next regulatory period. In this way, the regulated entity recovers the cost of funding the review over the term of the new regulatory period.

The Commission has included a new clause in the new Regulatory Contract to make it mandatory for PPL to fund the cost of any future reviews. This will remove any uncertainty about funding.

The Commission has determined that the cost of regulatory contract review will be borne by PPL, and it will make funds available to the Commission as and when the Commission requests.

2.6 Regulatory Principles
Clause 4.3 of the previous ERC outlines the requirements for establishing a subsequent regulatory contract. The requirements outline the things that the Commission must take into account in the next contract. These include

(i) the legitimate business interests of PPL;
(ii) the legitimate interests of suppliers to, and customers of, PPL;
(iii) the nature and uses of the services the prices of which would be regulated under the draft Electricity Regulatory Contract;
(iv) the costs of supplying the services the prices of which would be regulated under the draft Electricity Regulatory Contract;
(v) the costs of complying with relevant health, safety, environmental, social and other legislation and regulatory requirements applying to the electricity supply industry in Papua New Guinea;
(vi) the return on assets required to sustain past and future investment in the electricity supply industry in Papua New Guinea;
(vii) any relevant international benchmarks for prices, costs and return on assets in comparable industries, taking into account the particular circumstances of Papua New Guinea;
(viii) the financial implications of the draft Electricity Regulatory Contract (if it were to come into force) for PPL and the electricity supply industry in Papua New Guinea;
(ix) any other factors specified in or under relevant legislation; and
(x) any other factors the Regulator considers relevant.

In addition, the replacement contract must be inconsistent with, and must be prepared in accordance with, the Regulatory Principles outlined in Schedule 10 of the current ERC. These are as follows

1. There must be an examination of:
   (a) the value of capital stock at the end of the term of this Contract, which must be based on the depreciated value of the initial capital value used in this Contract (K294,069,000) and the depreciated value of the actual prudent capital expenditures undertaken during the term of this Contract. The depreciation method to be applied to these capital amounts must be the current cost accounting approach applying a depreciated optimised replacement cost (the DORC methodology). The actual capital expenditure made during the term of this Contract must be reviewed to ensure that it was prudent and should be included in the asset base going forward;
   (b) the continued suitability of the real weights, W1 to W5 set out in the table contained in paragraph A.1 of Schedule 3, given the movement of costs during the term of this Contract;
   (c) the appropriate rate of return to apply in setting the new price path;
   (d) the level of future capital expenditure and operating expenditure to maintain service levels, including any efficiency factor to be applied to operating expenditure (other than to fuel and depreciation);
   (e) the allowance for the costs associated with the Kanudi Contract which is expected to terminate in 2014;
   (f) any arrangements that are to apply in relation to, and the timing for, the introduction of access regulation for transmission and distribution networks and the introduction of contestability for electricity consumers; and
   (g) an allowance for accelerated depreciation of any assets identified by PPL as being stranded or potentially being stranded by the introduction of retail competition.

2. PPL must be regulated under an incentive regulation approach.

3. A building block approach must be adopted, consisting of the following components:
   (a) initial capital stock;
   (b) return on capital (WACC);
(c) new capital expenditure;
(d) return of capital - economic depreciation; and
(e) operating expenses.

4. There must be the establishment of a glide path adjustment with a sharing of efficiency gains between PPL and electricity consumers.

The Commission has noted these principles and the price path determined in this report are based upon them.

The Commission also notes that there is the opportunity in the next regulatory period (2018 to 2022) to modify these principles. So while the Commission is basing the price path in the 2013 to 2017 regulatory period upon these principles, it has determined to leave the contract position open to allow for future modification of the detailed analytical and regulatory approach, if such, is needed. The Commission is also of a view that in order to make large scale investments in infrastructure, PPL needs certainty that it will receive an adequate return on its investment. The Commission is therefore proposing to specify in the regulatory contract, that the next regulatory contract must also achieve this outcome. Therefore, Schedule 14 of the new contract contains the following words;

“the ICCC must ensure that PPL continues to earn sufficient return on their capital investment and covers all reasonable costs so that shareholders and debtors of PPL can continue to invest in PPL and make long term investments with confidence.”

### 2.7 Conduct and objectives of the Review Process

In undertaking this review, the Commission has had regard not only to the legislative requirements as outlined above, but also the requirements for due process allowing adequate time for submissions, and adequate time for proper consideration of the data and information provided and gathered independently by the Commission. All interested parties were invited to formally make submissions to the Commission. The Commission considered all the submissions that were received. These are listed and described in section 2.7.

The Commission has reviewed all the financial and market information that it obtained from PPL and its financial advisors and other interested parties and incorporated these into the modelling of the forward looking price path for PPL’s services. The Commission has continued to follow the Regulatory Principles adopted by the Commission in the previous ERC. Therefore, the Commission has used a building block approach to develop the forward revenue requirements for PPL, and for its regulated services. This forward revenue requirement has been modelled against new and anticipated capital expenditure requirements, and the financial viability of the regulated business has been assessed in the context of possible future revenue flows.

Under the regulated price path and other requirements that will apply to PPL, PPL will have the opportunity to meet or better the projected financial outcomes based on cost requirements. For example, if PPL is able to be more efficient in its operating costs while still meeting the minimum service standards set, then it will be able to retain the financial benefit achieved, over the remainder of the regulatory period. In this way, PPL will be provided with an incentive to improve its overall efficiency and performance. It is envisaged that those efficiency benefits will ultimately be shared with consumers in the following regulatory period, and the Commission will be examining ways to ensure that this objective is met over time.

However, if PPL is not able to achieve at least the efficiency levels set in the Regulatory Contract it will bear the financial cost itself. If service standards are reduced as a means of countering this financial cost, then the penalty provisions of the Contract will apply. Thus, the Regulatory Contract endeavours to provide both an incentive and a penalty structure for PPL for the strong improvement of its currently low service performance.

In undertaking this review, the Commission has requested and received various financial data and forecasts from PPL. It has used these numbers and data to update the present regulatory model and to develop the proposed price path outlined in this report.

It should also be noted, that under the terms of the Regulatory Principles and the provisions of Clause 7.1 of the ERC, the current inquiry is seen as a review, mainly but not exclusively, designed to update the ERC and
incorporate recent changed circumstances which impact on the regulatory arrangements and the price path. The Commission has updated the relevant parts of the ERC, and most importantly the regulatory price path and the way the price path will be applied over the next regulatory period including some refinements to the definitions and other relevant sections of the ERC where appropriate. There are a number of key additional provisions in the new contract arising from this review which are aimed at securing greater efficiency improvements; better incentives; a higher standard of accountability; and enhanced transparency, in the public interest.

2.7.1 Time Frames in the Regulatory Contract and its Compliance

The applicable mandatory statutory requirements in the regulatory contract are to be complied with at all times by all parties, in this case, the Commission and PPL. Both the regulator and the regulated entity have a duty under the new regulatory contract to comply with the various statutory deadlines and time frames in order to produce certain outcomes required by the regulatory contract.

It has always been a problem for the Commission in trying to ensure the regulated entities comply with the deadlines specified in the regulatory contracts. Although it has been lenient in the past, it has now come to a situation where it is serious in enforcing strictly the time frames required in the regulatory contract.

PPL has a number of requirements in the new Regulatory Contract that have been added, hence the Commission hereby advises PPL to strictly observe these requirements and take every step necessary to comply with them going forward for the next five year regulatory period and, that includes, the mid-term expenditure review, the service standards reports, the annual tariff adjustments requirements, etc.

2.8 Submissions

The Commission would like to thank the persons who made submissions.

In response to the initial draft report, submissions were made by the following persons;
- Sir Moi Avei, KBE
- Fabian Chow, B.Ec. Llb, for Lae Biscuit Company Ltd
- Tony Koiri – Chief Executive Officer for PPL Limited

In response to the second draft report, submissions were made by;
- Tony Koiri – Chief Executive Officer for PPL Limited
- Thomas Abe – Managing Director – Independent Public Business Corporation (IPBC)

In response to the proposed draft report, submissions were made by;
- John Tangit – Chief Executive Officer for PPL
- Sir Moi Avei, KBE
- Rendle Rimua – Secretary for Department of Petroleum and Energy

A brief summary of the main points made by these submissions follows.

2.8.1 Sir Moi Avei, KBE

This submission supported;

- Use of renewable energy
- Use of “feed in tariff” for IPP’s to address power shortages
- Use of solar energy to avoid the impact of fuel price changes, risk of drought and to help implement load shifting off PPL’s network if peak / off peak plans were introduced.
The Commission notes that:

- It is usually outside of its scope to specify the type of technology used to generate electricity. The only authority the Commission does have in this domain is to assess the prudence and efficiency of any investments that PPL might make. Prudence, however, implies the use of the most cost-effective technology and pricing approaches. Appropriate provisions, therefore, have been introduced in the new contract to ensure such technologies and pricing plans for time of use pricing approaches are properly considered and, if they are shown to be the most cost-effective, then it follows that a public-interest oriented approach would suggest their incorporation into the provision of the services.

The recently adopted EIP promotes the use of feed in tariffs for IPPs to introduce competition into power generation for PPL in their exclusive licence areas. These tariffs will be set by a competitive bidding process and are therefore outside of the scope for this regulatory review. However, the use of this bidding process does allow IPPs to use alternative forms of energy if these are economic. The procurement safeguards introduced into the new contract provide a ‘safety net’ for prudence, efficiency and avoidance of corruption in procurement.

- The Commission did propose to introduce peak / off peak plans in the new contract. However for a variety of reasons such as;
  - An assessment of customer demand indicates that very few customers are able to shift load from Peak to Off Peak. Therefore, the benefit of such plans is likely to be minimal.
  - The Commission is setting PPL some challenging targets and does not want to distract PPL from these. PPL will need all its resources to implement price differentiation and new service measures. However, in the time allowed for an examination of time of use charging options, as would be required by the new contract, PPL should be able to get its house in order and prepare for customer incentive charging structures to smooth demand at least marginally, so as to reduce peak demand from levels that would otherwise prevail and thus reduce the risk of outages from insufficient generation capacity or lack of robustness of the transmission system, either of which leads to unreliability of supply.

The Commission has determined not to do so (See section 5.3.3), but to ensure that appropriate measures are put in place to initiate their serious consideration and the contract provides sufficient flexibility to allow the inclusion of such plans if they are in the public interest.

With regards to solar energy the Commission has required PPL to investigate the costs and benefits associated with the network connected photovoltaic solar generation.

2.8.2 Fabian Chow, B.Ec. Llb, for Lae Biscuit Company Ltd

This submission argued strongly in favour of a move away from “postage stamp pricing” to price differentiation between service areas based upon cost. They argued the following points

2.8.2.1 Regarding Postage Stamp Pricing

- “It is killing off provision of electricity services in needful outstation areas”
- “It has become a no win situation for PNG Power … any surplus gets eaten up into loss-makers. Any loss gets translated into disaster for outstations as PNG Power is unable to provide sufficient subsidies for outstations”.
- “It will become more of a problem as economic activity and the resulting electricity demand comes from outstation areas of higher cost of supply”.
- “It gives false economy to consumers. Consumers are getting cheap priced electricity but at an inconsistent supply. Inconsistent supply is causing consumers associated costs worse than having to pay higher electricity prices.”
“Consider the requirements of present and potential end users so they can locate investments in areas of lowest cost power generation. Appropriate pricing policies need to be adopted…”

“Appropriate pricing policies will need to be entered ……to prevent costly unproductive subsidies of high cost areas.

The submission argued that subsidies would eventually become unsustainable and that they would then need to be removed, resulting in riots.

### 2.8.2.2 Regarding Capital Investment

This submission argued the following points;

- PNG Government should “recycle petro dollars” from “LNG Windfall” into capital investment but not operating costs.
- PNG Power is handicapped with costly Community Service Obligations (CSO) “especially through Postage stamp pricing”.
- “There need to be appropriate price signals and reliability standards met for businesses to grow and prosper in PNG”
- “…cheap electricity is possible in particular areas of PNG. Provided you have someone to pay the capital costs and a user to amortise that cost against the investment. Hydro and Geo-Thermal options can generate surplus capacity at cheap marginal pricing in selected locations provided you find a big base user. If these cheap electricity sources are allowed to be priced accordingly it would go a long way to attracting export industries and downstream processing.” The Submission described an example of where this had occurred.
- “Changes in the regulatory framework have to be made now for these options no matter how far away they seem in the future. …investment decisions are being made now according to predictions on economic scenario of PNG in ten years to come.”

### 2.8.2.3 Regarding Reliability

- The submission emphasised the poor performance of PPL in delivering reliable electricity supplies.
- “Growing industrial need to have reasonable priced electricity based on actual generation costs (plus a reasonable operating margin), so as to meet government goals of export development and local competitively”.
- The submission referred to a commercial opportunity in Bougainville where the major consideration for investment was reasonably priced reliable power.

### 2.8.2.4 Commission’s comments on this submission

The Commission notes that;

- “Postage stamp pricing” is specifically addressed in this report (see section 5.4) and differential pricing is permitted subject to compliance with certain requirements, including observance of the MWAP.
- The EIP will provide a framework where it will be possible for new service areas to be provided with power using the types of funding model described by this submission. The EIP proposes to make specific capital subsidies available for new CSO’s outside of PPL’s exclusive areas. But the EIP is silent about funding for existing subsidies inside PPL’s exclusive areas if postage stamp pricing were removed.
- Reliability is a major concern and this report is proposing to introduce new measures to address it. (see section 8 SERVICE STANDARD REQUIREMENTS).
2.8.3 Tony Koiri – Chief Executive Officer for PNG Power Limited - 1st Draft Report submission

This was an extensive submission which was subsequently supported by a large number of reports on a wide range of issues from various international sources.

PPL’s submission focused particularly on the following issues;

- That the price setting method had failed to achieve its objectives because it left PPL exposed to diesel price fluctuations resulting in higher fuel costs that it could not recover.
- That the ICCC’s proposal as outlined in the initial draft report was not light handed incentive regulation because it;
  - Initiated pricing changes such as peak and off peak pricing,
  - Limited the amount of diesel generation; and
  - Imposed a mid-term review which had the effect of removing incentives for PPL to increase its financial efficiency.
- That the proposed weighted average cost of capital did not reflect the reality of the current world financial markets;
- That the proposed reliability targets were extreme;
- A number of other issues which we have specifically addressed throughout this report.

In response to this submission, the Commission has:

- Modified the annual pricing adjustment so that fuel is separately adjusted for every quarter. This means that electricity prices will change for all customers every three months. (See section 5.7.3 W3 Fuel Weight);
- Modified the mid-term review to allow PPL to retain financial efficiency gains. (See section 5.7.10);
- Extensively reviewed the calculation of weighted average cost of capital (see section 6.4);
- Modified the proposed reliability targets and performance measures (see section 8);
- Removed the proposal to introduce Peak / Off peak pricing plan options (see section 5.3.3); although requiring a proper study of the practicality of its introduction;
- Made a number of other modifications which are discussed throughout this report.

2.8.4 Tony Koiri – Chief Executive Officer for PNG Power Limited - 2nd Draft Report submission

This submission took the form of a number of comments about the various sections of the second draft report. These ranged from making observations to requesting changes. The main points were as follows;

- While power prices have increased in real terms in PNG, the increases in Europe and Australia have been greater.
- PPL expressed their view that they had chosen the optimum forms of generation for their market, environment and financial position and that the draft report did not fairly represent this.
- PPL expressed their view that they had provided sufficient information for the IC CCC to understand the source of outages and that the report implied that they had not.
- The annual adjustment weightings were not what PPL expected them to be.
- PPL restated their view that a retail margin was required.
- PPL highlighted that the demand forecast had changed and needed to be updated.
- PPL responded to the encouragement of the draft reports to bring Naoro Brown forward and noted the difficulties involved with doing this. They also pointed out an error in the IC CCC’s analysis of the timing for Naoro Brown.
• Noted that the operating costs shown in the draft report included a real terms price increase for fuel which should have been removed.
• Identified that the Regulatory asset base was much lower than they expected it to be. This was subsequently identified to be due to Work in progress not being included in the RAB. (It is policy not to include work in progress in “regulatory asset bases”).
• Requested to see working capital calculations.
• Submitted that the asset beta was too high and that the gearing ratio was too high in the WACC calculation.
• Submitted that the performance target floors were unrealistic for some parts of PNG.

In response to this submission several changes were made.

• The demand forecast was changed to reflect the latest forecast.
• The regulatory asset base was modified to reflect the actual timing of investment and the capital spending program was modified to reflect the time at which current work in progress projects would be commissioned and entered into the asset register.
• The gearing ratio was adjusted downwards from 50% to 40%.
• Performance target floors were adjusted.
• As a result of changes the price path was recalculated. Many of the tables in this report have been updated to reflect these changes as appropriate.
• In several cases we have modified the wording in the report to reflect PPL’s input.

2.8.5 Thomas Abe – Managing Director – Independent Public Business Corporation (IPBC)

The IPBC made the following observations;
• Electricity prices have decreased in real terms when compared to other prices.
• PPL have maintained a steady level of operating costs with minimal fluctuations over the regulatory period.
• IPP’s make almost no retail margin.
• PPL have prioritised delivery of reliable power supply to fulfil its mandated duties.
• Noted that working capital is a contentious point and that PPL make losses due to cross subsidies to regional centres. Suggested that an “efficiency carry over mechanism” between PPL and its consumers could be applied but did not elaborate on how this might work.
• Welcomed the move to abolish postage stamp pricing, by using cost based pricing combined with CSO’s applied as required.
• Supported the increased use of IPP’s in the electricity sector.
• Supported the detailed consultation process between the ICCC and PPL and encouraged this to continue to resolve outstanding issues.
• Supported the introduction of quarterly fuel adjustments.
• Supported the mid-term review proposed for 2015.

The Commission welcomed this submission as an endorsement of the proposed changes to the ERC.

2.8.6 John Tangit – Chief Executive Officer for PNG Power Ltd

In response to the Proposed Draft Report and Second Draft ERC, PPL have agreed and accepted the documents as final except only a minor comment on the use of the term “robust and robustness” in clause 8.4(e) of the ERC. The PPL requested that for clear understanding of the meaning by PPL staff and other stakeholders, the terms be defined more clearly.

In response to PPL request, the Commission has considered and redefined the term under a new subsection (f) clause 8.4 of the Regulatory Contract as:
“Clause 8.4 (f): ‘For the purposes of clause 8.4(e) Demand forecasts are robust if they have been developed using appropriate forecasting methodologies and reflect reasonable data assumptions. In particular, whether all relevant factors and key drivers of demand have been taken into account’.”

The PPL has agreed and accepted the Proposed draft report and second draft ERC as final and has approved to be executed by PPL and the Commission as final Report and final ERC.

The Commission acknowledged PPL’s approval and finalised the Final Report and the ERC to be executed as Final Report and Final ERC.

2.8.7 Sir Moi Avei, KBE

The submission supported the Key Finding of the Proposed Draft Report which stated that “generally concerned of supply outages and is supportive of any efficient investment that will result in more reliable services to the customers’’.

- Outages in Port Moresby have been chronic and rather increasing in recent months.
- Regardless of refurbishment of the existing Rouna Hydro station, the expectation of an El Nino will lead to further outages and have impacts on investments and economic growth in the city.
- Supports the Commission that the availability of natural gas in the future is not guaranteed and the proposed commissioning of Naoro-Brown Hydro project in 2019 seem unlikely due to pending environment and land owner issues.
- Immediate action need to be taken to overcome the continuous outage problem and the expectation that Naoro-Brown would come into operation after seven or eight years.
- Renewable energy solutions are expedient in both times and cost. Small and medium private sector users in could consider solar power generation for their own use as well as feed-in to PPL transmission grid.
- Customers need to be informed of the availability of the off-peak tariff so that they can plan their operations to enjoy the financial incentive that is offered by PPL.
- Long term plans have long gestation period and the situation in Port Moresby is in dire need of innovative solutions, not plans that will take time to be established.

2.8.8 Rendle Rimua – Secretary for Department of Petroleum and Energy

The Department of Petroleum and Energy (DPE) has provided its comments with respect to the ERC. The proposed changes under the ERC was to insert new wordings under section 3.4 New Pricing Structure subsection (c) and (c) (ii) and subsection (e) and section 4.2 Process of review of demand forecast.

Under the ERC, under section 3.4 New Pricing Structures
(c) ……including through a report by an independent (insert) national or international consultant….
(ii) ……including photovoltaic Generation, and (insert) other renewable energy sources.
(e) ……insert comments as in (ii) above.

Under ERC, under section 4.2 Process for review of Demand Forecast
(a) ……qualified independent (insert) national or international consultant…
In response to DPE’s comments on the ERC, the Commission has considered that inserting of the word national in Section 3.4 (c) and 4.2 (a) as proposed is not suitable under this circumstances and thus the Commission’s version remains. Whilst the Commission accepted the proposed wording in section 3.4 (c)(ii) and (e) and considered that in the ERC.

Apart from the proposed amendments to be ERC, DPE also provided some general comments.
• The regulator must balance the needs of utilities with those of rural electrification by ensuring open and transparent regulatory systems, approving tariffs and connection fees for new services and enforcing performance standards.
• Reform in the power sector is mainly driven by the need to introduce choice of supplier, to facilitate competition, improve quality of services and affordable prices.
• The anticipated effect is that the Power Sector Reform on the ERC does anticipate the effects of regulatory oversight by the Independent Regulator.
• The anticipated benefits are that electricity regulation does facilitate open and transparent process and public participation. ERC ensures supportive entry and exit rules for third party generators and balances interest of rural consumers, utilities, intentions and goals of governments. It also ensures non-discriminatory open access to the network and ensures fair and optimal costs for rural customers. The regulator can help promote appropriate technologies by the right pricing signals and ensures that efficient gains are passed onto the rural consumers.
• One of the setbacks of Power Sector Regulation on the independent regulator is the over expectation of protection by rural consumers and also does create the potential to compete for financial resources from a common pool.

For the general comments, the Commission considered them as part of the report.

2.9 Final Determination
The ICCC has determined that the new regulatory contract will provide both an incentive and penalty structure for PPL. That is to encourage PPL to improve its overall efficiency and performance with new probity and competitive safeguards for procurement.
3 RATIONALE FOR REGULATION

3.1 Current Electricity Industry Structure & Development

The current structure of the electricity industry in PNG is a vertically integrated monopoly from the generation of electricity through to retailing.

Figure 1: Current structure of electricity industry

The major participant in the electricity industry in PNG is PPL, the successor company of the former PNG Electricity Commission (“Elcom”). PPL is a vertically integrated monopoly which generates, transmits, distributes and sells electricity throughout PNG within its Designated Service Areas as detailed in the ERC, the Electricity Code and its relevant licences. Several other Independent Power Producers (IPPs) generate and distribute electricity within the restricted areas. These include mining, agriculture and forestry companies as well as some plantation estates and mission stations. They provide their own electricity infrastructure and small scale generating units including mini hydro schemes to generate and transmit electricity for private consumption.

More recently, the private sector group Western Province Sustainable Power Limited (“WPSPL”) (Trading as Western Power) has moved to establish new generation and distribution activities in areas not currently serviced by PPL, or jointly with PPL in areas that are part of the monopoly use Designated Service Area.

With the role of IPPs being limited to electricity generation for private consumption needs, the current role of PPL in the electricity industry in PNG is generally considered to be a vertically integrated monopoly.

Practices in other jurisdictions have demonstrated that many countries have unbundled their electricity industry into its competitive components (generation and retailing) and monopoly components (transmission and distribution) and introduced competitive electricity markets to increase the economic efficiency of the industry.

In 2001, the structure of the electricity industry was reviewed by the Department of Finance and Treasury through the engagement of Price Waterhouse Coopers (PWC). PWC’s recommendation to the PNG Government was for PPL’s predecessor (Elcom) to be maintained as a vertically integrated entity in its designated areas and regulated in this form. This recommendation incorporated a recommendation for the entry of competitive generation options over
time, particularly as existing contractual arrangements for the generation of electricity came to an end and gas became more readily available as a fuel for use in generation.

The recommendation to maintain Elcom as a vertically integrated entity was chosen, in recognition of:

- the physical separation and isolation of much of the Elcom network;
- the lack of a fully linked grid network across the country and therefore the limited opportunities for competitive generation activities;
- the potential loss of economies of scale should Elcom be broken up at that time and the implications for costs and pricing in remote areas; and
- the existing contractual obligations on Elcom in terms of the generation of electricity, particularly the Kanudi generation contract.

The Commission’s role with regard to industry structure is to ensure that to the extent that structure is mandated by government policy, the regulatory and pricing arrangements determined by the Commission will seek to maximize the benefits for the economy in terms of economic efficiency while ensuring that current and future demand requirements are met. Any policy decision on the structure of the industry in PNG going forward rests with the government. This has been done via the EIP released in November 2011 and the Commission will seek to give effect to it to the extent it is consistent with the ICCC Act.

PPL is licensed under the Electricity Industry Act to generate, transmit, distribute and retail electricity throughout PNG. PPL services the nation mainly from hydro based Power Systems scattered throughout the country. These power systems include: Port Moresby; Gazelle; Kimbe and Bialla; Ramu; and Pauanda. Other towns and centres are served using diesel generators which are located in the town or centre concerned and service only that location.

In most cases, PPL provides electricity services from the generation stage, down through the transmission and distribution stage and to the retail stage. In certain instances, PPL purchases electricity from an IPP and sells the electricity to consumers using their transmission and distribution networks.

The characteristics of the PNG electricity industry are;

- A small industry in terms of;
  - **Generation capacity**: In total, PPL has a generating capacity of 307.25 MW
  - **Number of customers**: Total number of domestic customers connected is approximately 75,600
  - **Penetration**: 25% of the total population of PNG has access to PPL sourced electricity, but only 1.43% of population have electricity.
- **Low growth and demand**: Outside of the two main centres, Port Moresby and Lae, the demand for electricity is low.
- Segmented power systems due to geographical constraints limiting inter-connection and full national grid options. This results in losses of economies of scale, thus increasing operational costs with minimal chances of recovery.
- An industry which faces high risks due to Law and Order issues such as riots and vandalism including compensation claims.
- Unreliable service due to regular planned and unplanned outages.
- Limited extension of the network into un-serviced rural areas as part of a program to provide electricity to all parts of the country.

PPL has faced considerable financial difficulties which have impacted on the quality and reliability of its service. In addition, PPL has not had the financial ability to extend its services into remoter parts of PNG or to seek to maximize growth opportunities. The geography of the country will continue to limit the opportunity to develop a national grid and achieve economies of scale in operations.

### 3.2 Designated Services and Locations
The licences issued to PPL entitle it to provide the following services within the Designated Areas and up to 10 KM beyond the existing network; Generation services; Transmission services; Distribution services; and Retailing services.

### 3.2.1 Generation Services

As defined under the Generation Licence granted to PPL by the Commission, generation services refers to “services provided by an electricity generating plant”.

### 3.2.2 Transmission Network

The Transmission Licence defines the transmission network as the whole or part of a system for the transmission of electricity that:

(a) Operates a nominal voltage of 66kV or more; or
(b) Operates at a nominal voltage of 11kV in parallel to and in support of any part of that system which operates at a nominal voltage of 66kV or more. Hence, a transmission service refers to the service provided by a transmission network.

### 3.2.3 Distribution Network

The distribution network, is defined by the Distribution Licence granted to PPL as “the whole or part of a system for the distribution of electricity, but does not include any part of the transmission network.

In essence, distribution networks are the electricity infrastructure which “transports” electricity through to consumers once the electricity is “received” from the transmission network at a nominal voltage of 22kV or less and includes the low voltage of 415 and 240 volts.

### 3.2.4 Retail Sector

This refers to the activity of purchasing electricity from the generator and on selling to the final consumers.

### 3.3 Competition in the Electricity Supply Industry

Notwithstanding PPL’s monopoly position, the current regulatory arrangements allow for some form of limited contestability in the industry, especially, at the generation level. If a generator wishes to establish itself within the Designated Service Area, it potentially can sell electricity to PPL as the monopoly supplier. However, it may not transmit, distribute or retail electricity to final customers. PPL is not required to purchase electricity from the private generator and thus if PPL does not wish to buy electricity from these sources, the generator has no other customers that it can supply.

The existing regulatory arrangements do allow for any electricity undertaker once licensed by the Commission to generate and sell electricity outside the exclusivity area of PPL (which is 10km from the existing network of PPL). Should an electricity undertakers “own demand” requirement be greater than 10MW, then a private generator can generate and supply for its own consumption within the Designated Service Area regardless of whether the location is within or outside the exclusivity zone provided that the electricity undertaker is licensed or exempted by the Commission under Section 43A of the Electricity Industry Act.

Independent generators already exist in PNG. In the Port Moresby system, the IPP (Hanjung) generates power at its Kanudi power station and sells it to PPL under a power purchase contract which ultimately commits PPL until 2014. In addition, the Wau Township has its power generated by PNG Forest Products and sold to PPL for supply to final customers.
WPSPL, a subsidiary of PNG Sustainable Development Program Limited (PNGSDP) over the past few years have introduced additional generation capacity and is currently transmitting electricity in Western Province. WPSPL is seeking to generate and sell electricity to PPL and other larger customers in areas such as New Britain and also possibly to retail directly to consumers outside the Designated Areas.

The existence of these independent generators does not in itself represent a contestable generation market, in that PPL has negotiated separately with the generators to supply electricity under long term contracts. However, it does demonstrate the potential for new entry and provides evidence of the practicality of using IPP’s to supply PPL.

### 3.4 Electricity Industry Policy

In November 2011, the Government published an electricity industry policy statement (EIP) as previously noted.

The EIP identifies three electricity markets in PNG:
1. PPL’s exclusive supply (retail areas) with loads less than 10MW;
2. Large Loads of 10MW or greater; and
3. Small loads located outside of PPL’s exclusive supply areas, especially in the rural areas.

The EIP provides for the introduction of competition into the generation of electricity for both Market 1 and Market 2. The introduction of more generation capacity can be initiated by either PPL or by the Government. When more generation is needed then a competitive bidding process will be used to select an IPP (independent power producer). PPL will be excluded from this bidding process. PPL will purchase power from these IPP’s at the rate specified by the competitive bidding process. There are implications in the entry of the IPPs for the Commission in the exercise of its licencing powers and in relation to whether or not such IPPs will seek regulatory certainty under a regulatory contract of their own.

In both Market 1 and Market 2 PPL will continue its monopoly position in providing transmission and distribution infrastructure within its exclusive licence areas.

The potential for competition already exists in Market 2 (large loads), but to support this, third party access arrangements will need to be developed by the Commission. Thus a competitor will be able to generate their own electricity, connect to PPL’s transmission and distribution network and deliver this power to retail customers with loads of more than 10MW. This will also require PPL and the Commission to develop transmission and distribution “wheeling” tariffs to support the wires network being used by new generation competitors, and to ensure competitive neutrality of the electricity network.

Market 3, particularly those areas not already serviced by PPL or another existing licenced undertaker is to be supplied by service providers selected via a competitive tender process. As these areas are expected to be uneconomical in commercial terms, it is envisaged that a subsidy or grants will be provided to the winning service provider. These grants may cover the initial capital investment but the Commission would expect that ongoing subsidy or grants would not be required for operating & maintenance expenditure. Such operational costs should be supported fully by the locally connected customers (or end users). This service provider is then liable to deliver a CSO (customer service obligation). The service provider will own the assets and will be required to build, operate and maintain them. The Commission will provide regulatory oversight of these CSOs in relation to tariffs, service performance delivery and future investment.

### 3.5 Ring Fencing

The Commission as part of this new regulatory contract has now improved the quality and increased the frequency of PPL’s reporting system to the Commission. If and when the Commission considers it appropriate to promote competition in the market, it may require PPL to adopt a ring fencing approach for all the designated service areas and report to the Commission on an annual basis.
PPL may be required to submit to the Commission for each of the existing designated service areas;

- Accounting details of its Generation, Transmission, Distribution and Retail Services businesses operated by PPL or any relevant shareholder of PPL,

- Its annual reconciliation between revenues and costs delivered by its Generation, Transmission, Distribution and Retail Services businesses operated by PPL or relevant shareholder of PPL, and

- A Strategic Capital Plan. The emphasis of this Strategic Capital Plan is to capture in detail any funding arrangements of projects, whether it is directly funded by PPL or from other relevant parties (stakeholders, private investments, etc), the actual capital expenditures for delivering that particular services, any financial information associated with the projects, etc.

The reporting across each service area must be completed and submitted to the Commission by no later than 30 June of each regulatory period. This information must be tied back to either, audited financial statements where available or monthly management reports to the board, where audited financial statements are not available. Importantly, the audited financial statements do not necessarily need to be signed by the Auditor General, rather must have cleared all other audit standards and is signed by a qualified accountant as required by the regulatory contract.

3.5.1 Regulatory and Statutory Accounts

The Commission requires from PPL two months after the close of each financial year, all its regulatory accounts to be reconciled with statutory accounts and must be certified by a registered auditor firm or company which is nominated by the Commission as being true and fair under generally accepted accounting principles. These financial statutory accounts must be submitted to the Commission two (2) months after the close of the financial year during the regulatory period.

All the submissions must also be authenticated by the Chief Financial Officer of PPL in effect stating that the financial information provided is true in every aspect to the best of his/her knowledge and belief, true and accurate and that the financial accounts have been submitted to the Auditor General within the time specified in the required legislation. It must also be noted that where the financial statements have not been submitted to the Auditor General or external auditors for audit, the auditor must certify that the financial statements and returns are reconciled with the statutory accounts submitted to the Auditor General or external auditors for audit and are consistent with generally accepted accounting principles and proper accounting records.

All information related to the regulatory statutory accounts must be in conformity to Clause 9 of the Electricity Regulatory Contract.

3.6 Exclusive Services

PPL currently holds an exclusive licence to retail electricity within 10km of its electricity network covering the major centres and smaller towns of the country. This licence was granted by the Commission consistent with government policy in July 2002 and will expire at the end of 2014.

Licences have been granted to IPPs to generate electricity within the Designated Service Area for sale to PPL. No licences have been issued for the distribution or transmission of electricity in the Designated Service Area other than that held by PPL. It is not anticipated that licences for such transmission or distribution services would be issued while PPL retains exclusivity in terms of the retailing of electricity. PPL may however, agree to enter into arrangements with other parties for the generation and transmission of electricity to the PPL network in the designated area, and in such cases, the Commission would consider favourably an application for a licence, subject to compliance with a Third-Party Access Code (to be developed in the near term).

The granting of exclusive areas to PPL carries with it certain responsibilities. These responsibilities apply to maintaining minimum levels of service standards, and the overall operating performance including ensuring that electricity supply is available either continuously or on an “as agreed” basis.
Where PPL has entered into supply arrangements with IPPs, it is PPL’s responsibility to ensure that its supply guarantee requirements are met by that IPP who as the generator is acting on PPL’s behalf. Negotiations of supply contracts with an IPP have been left to arm’s length commercial negotiations between the IPP and PPL. However, the Commission notes that the use of a ‘postage stamp’ pricing arrangement across the PPL network can have implications for the way in which these negotiations with the IPPs are conducted. As the prices in a particular location are currently cross subsidized by the prices paid in other areas in which a full cost recovery is made (namely Port Moresby and Lae), the cost of generation and distribution in a particular location outside these two main areas is not likely to be fully recovered by the postage stamp tariff rate charged in other locations. The Commission will be closely examining the operating costs claimed by PPL, and in particular, the costs of electricity generated by IPPs, or by PPL’s own facilities to ensure that these costs achieve an appropriate balance between ensuring security of supply and embracing economically efficient generating practice. It should be noted the provisions of the Third-Party Access Code will need to be supported by principles of generation dispatch, where both PPL and IPP generators are connected to the one grid. Linkages to these regulatory frameworks will need to be embedded in the PPL Regulatory Contract, to ensure compliance with the EIP to the extent that is consistent with the ICCC Act and a seamless introduction of generation competition into the relevant PNG markets.

3.7 Social and Economic Considerations

There are wider economic and social benefits to be gained by extending the electricity network across the country. Access to electricity should desirably not only be in the main urban areas, but be available across the whole nation, bringing greater access to the range of other complementary services that are possible through access to electricity. The extension of the electricity network will require significant new investment.

The Government’s EIP describes how the network will be expanded into new service areas by means of a competitive bidding process to supply Community Service Obligations (CSOs).

However, extension of PPL’s network within its exclusive licence areas is still a desirable outcome which the Commission would like to promote. The introduction of price differentiation may assist PPL to carry out further investment in high cost areas, even as competitive generations are allowed to access its main grids. The economic and social benefits from an extension of the electricity network to remote areas will primarily be captured by those who gain access to the extended electricity network. However, there are wider benefits that flow to the nation as a whole, such as:

- an increase in economic activity;
- greater employment opportunities outside the main centres;
- improved living standards;
- access to other public services requiring electricity such as water and sewerage, financial and communication services; and
- potentially reduced crime rates.

These wider benefits could lend support for some form of external funding. The EIP provides for this by means of CSOs. Where this occurs, it will have implications for the way in which the Commission determines appropriate prices that PPL should charge, the requirements for new capital expenditure by PPL, and the service standards that PPL should meet.

3.8 Final Determination

The ICCC has determined that:
(a) The ICCC will continue to regulate prices of electricity services for the next regulatory period.
(b) The Electricity Regulatory Contract will be modified to reflect the requirements of the Electricity Industry Policy, to the extent that is consistent with the ICCC Act including mandated compliance with a Third-Party Access Code and Generation Dispatch Principles (potentially included in the Third-Party Access Code).
(c) PPL will continue to retain the exclusivity granted to it for the Designated Service Areas within 10km of its electricity network and that no new licences will be issued to the Designated Areas, in relation to transmission, distribution and retail activities.
4 THE REGULATORY PROCESS FOR NEW ENTRANTS

4.1 Competition in the Industry

The EIP allows for the introduction of competition into generation of electricity to support all markets within PNG. It also promotes competition for customers with large loads and a competitive bidding process for CSO’s in new service areas.

4.1.1 Third Party Access Codes

To support competitive generation of electricity and competition in the large loads market, there will be a requirement for third parties to connect to PPL’s network. To ensure this can happen in an efficient and timely manner, the Commission will develop a third party access code consistent with Government policy direction for the industry and the ICCC Act. The access code will provide the necessary guidelines, rules, procedures and pricing requirements to access the existing power line infrastructures of PPL.

The Commission has not evaluated or formed any view of how a third party access code might impact upon the building block method of price determination used to determine the price path under the contract. Therefore, the Commission has made provision in the ERC for changes to the ERC should they be required to support Third Party Access.

4.1.2 Retail Competition

In response to the issues papers, Treasury submitted a submission which discussed the benefits of retail competition. The Commission commented on the Treasury submission in the preliminary draft report. However since then the EIP has been published. The EIP has outlined the Government’s policy on retail competition. The EIP states;

“For retail market protection, which should be granted to participants in the industry after winning the competition into an identified market (in the competition for the market), exclusivity provisions will feature in the licences issued. Competition for the market infers that a single participant that wins the competitive tender will hold the licences for the industry in generation, distribution and retail.”

Because the EIP did not choose to require retail competition, the Commission is also not proposing to introduce retail competition into PPL’s exclusive licence area for discrete loads below this level.

4.2 Entry into the Electricity Industry Market

In order to enter the market for electricity services, the necessary licensing requirements outlined under section 24 of the Electricity Industry Act must be met by the applicant. A person or entity is exempted from holding a licence if the electricity produced is for personal consumption or for the use of the entity producing it; the power generated is to cater for own operations and not to be supplied to a third party.

The types of licenses issued by the Commission include; generation, transmission, distribution and retail.

Over the past few years, new electricity undertakers have entered the market for electricity services. However, these new entrants are only based in areas currently not serviced by PPL or in the generation segment of the industry. They include:

- Western Province Sustainable Power Ltd (trading as Western Power);
- PNG Forest Products; and
- Hanjung.
Western Power currently provides electricity services in areas in Western Province where PPL currently is not servicing or its operations do not exist. Western Power currently holds a generation, distribution and retail licence. However, Western Power has expressed interest in applying for a transmission licence, and the Commission has informed Western Power to submit a new licence application for consideration. In addition, Western Power also has plans to expand to other centres in the near future where PPL does not operate.

PNG Forest Products (PNG FP) currently generates electricity for its own operational needs. However, because of the excess power it was able to produce, it applied for a generation licence to enable it to sell the excess power to PPL. PPL currently through a power purchase agreement (PPA) purchases the power from PNG FP and supplies it to the Bulolo Township including the Hidden Valley Mine.

Hanjung currently generates power at Kanudi and sells the power to PPL. It is exempted from holding a licence because this arrangement with PPL was established prior to the establishment of the current regulatory framework for the industry in 2002.

New Britain Palm Oil is currently building its own power generation plant in Kimbe, West New Britain and it is anticipated that should excess power be sold to PPL in Kimbe, NBPOL will be required to apply for a generation licence.

4.2.1 Introduction of new IPPs to supply PPL

Section 4.3.1 in the EIP introduces “Competition through Feed-in Tariffs in PPL’s Exclusive Supply Area” as follows;

“Competition within PPL’s exclusive service areas for supply through feed-in tariffs can only be opened when established arrangements signal the need for this to occur (or when it is more efficient for PPL to source power from third parties other than itself). These signals and their respective responses can take one of the following forms:

- PPL’s own request to the facilitator of competition (regulator) requiring additional capacity: should PPL encounter shortfalls in its capacity to supply additional or growing demand, the Government, in consultation with the relevant regulators, would verify this need for capacity then proceed with opening and facilitating competition.
- Urgency or need of additional power substantiated by the established arrangements: Even without the request by PPL for additional generation capacity from sources other than itself, the Government, in consultation with the relevant regulators, can open up competition to address any shortfall in supply. This may occur if, for instance, the reliability of supply has dropped well below the minimum benchmark and becomes a chronic problem, or if PPL continues to insist on tariff increases, which the economic regulator can take as a signal requiring competitive entry. This competition though would take place after PPL fails to comply with certain terms and directions given and enforced on it by the appropriate regulator to show cause or to address the malady within a specified time frame.

Where competition takes place as a result of either of the above situations, PPL cannot be allowed to compete against other competitors. This exclusion of PPL from the competition rules out the possibility of PPL making any attempt to stifle entry by other players through the undesirable allocation of its cost of generation to transmission and distribution.”

The new regulatory contract requires PPL to commission a study into the viability of small scale grid-connected generation, including photo-voltaic generation, following which appropriate regulatory decisions will be taken.

New IPPs will be required to comply with existing law and licencing conditions, and with new regulatory frameworks required to be set up to support this form of competition, for example the Third-Party Access Code arrangements.
4.2.2 Final Determination

The ICCC’s determination is to support the EIP to the extent it is consistent with the ICCC Act. The ICCC agrees with the EIP that there is a need for further investment in the sector to support the growth in demand and enhanced service delivery.

The ICCC will continue to issue electricity undertaker licences to IPPs that intend to enter the industry outside PPL’s exclusive licence areas and meet the requirements outlined under Section 24 of the Electricity Industry Act and consistent with the EIP. This includes IPPs who wish to supply a large load (10MW or bigger) within PPL’s exclusive geographic zone.

As outlined by the EIP, the ICCC will also issue licences for generation to supply PPL to the winning bidder or bidders of any competitive bid opened by the Government.

The ICCC will also require PPL to explore the costs and benefits of small scale grid-connected generation, including photo-voltaic generation.

4.3 New Entrant Pricing

Whilst it would be desirable to have new entrants into the industry charge rates below the existing rates charged by PPL entrants may face cost structures that are above PPL’s average cost. Entry therefore by generators with a cost structure above that provided by diesel generation would be problematic. It must be noted that the separate grids exclusively serviced by diesel powered generators are loss making centres for PPL. However, PPL, in its capacity as an SOE, continues to serve these centres as part of its community service obligations. This is because the uniform tariffs that are currently applied by PPL in these centres simply cannot cover the operational costs of these centres on a standalone basis. A major factor contributing to the PPL’s financial stress associated with operating these loss making centres is the significant increase in the world market price for crude oil, feeding through into the price of diesel fuel, over the last regulatory period (10 years).

However, PPL has been able to cross-subsidise these loss making centres through its profitable centres. These profitable centres include the Designated Service Areas in the Ramu (especially Lae City) and the Port Moresby Systems. These profitable centres rely on hydro power generated from Yonki in Eastern Highlands Province and Rouna in Central Province. These hydro powered centres are also backed up by diesel power stations (both reciprocating diesel generators and open cycle gas fired turbine generators being run on heated diesel).

In the case of a new entrant like Western Power, it does not have profitable centres that can cross subsidise its loss making centres. Western Power also relies on small diesel power stations to supply electricity to its customers in Western Province and has therefore also been subject to the same increases in diesel prices. However, it is able to continue supplying electricity in its Service Areas in Western Province with the financial support it is getting from its parent company – PNG Sustainable Development Program (PNGSDP) as part of its social service objective.

Table 3: Easipay Charges

<table>
<thead>
<tr>
<th>Entity</th>
<th>Domestic Customers (Easipay)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PPL</td>
<td>66.99 toea/KWh</td>
</tr>
<tr>
<td>Western Power</td>
<td>100.00 toea/KWh</td>
</tr>
</tbody>
</table>

Due to the high cost of supplying power in its service areas in Western Province, Western Power is currently charging its domestic customers K1 per KWh as compared to the 2012 rates for PPL for domestic Easipay customers of 66.99 toea per KWh. PPL’s 2012 rates were set by the Commission in accordance with its price path under the current Regulatory Contract.
IPP’s like PNG Forest Products and Hanjung generate power in Bulolo and Kanudi respectively and sell the power generated to PPL. The rates that PPL currently pays for the power generated by each of these two entities has been set through bilateral negotiations between PPL and these two entities respectively. The Commission did not play any role in setting the current rates that PPL pays for power generated by these two entities hence, it was a commercial decision between PPL and these two parties.

Having noted the limitation above, the introduction of competitive feed in tariffs by a competitive bidding process does provide some potential for development of cheaper forms of generation and passing these benefits on to customers.

In addition, the Commission requires that PPL shall within the first regulatory year demonstrate to the Regulator’s satisfaction that it has investigated the cost and benefits associated with the implementation of:

(a) time of use pricing; and

(b) feed in tariffs for small scale network connected generation including Photovoltaic Generation

4.3.1 Submission’s to the Issues Paper
The Commission did not receive any comments on new entrants pricing.

5 FORM OF REGULATION

5.1 Introduction

Schedule 10 of the current ERC outlines the regulatory principles that should be followed in administering and replacing the current Regulatory Contract. It says that PPL must be regulated under an incentive regulation approach.

The Commission notes that PPL in its submission interpreted the meaning of incentive regulation as:

“Incentive regulation simply means that the form of regulation provides incentives for the regulated business to minimise costs and achieve efficiency gains”.

There are two approaches or ways of interpreting the submission on this point. On the first approach, taking a literary view of ‘costs’ as meaning the financial costs of delivery, without regard to the quality of service provided (in the sense of reliability, consistency in terms of voltage etc.), the ICCC believes that incentive regulation has a broader meaning and should also include incentives for improving service quality to consumers. The second approach involves ‘quality-correction’, concept adopted and involving an assumption by economists making price comparisons, namely, that the goods or services being compared for price are of equivalent quality and, if not, then quality-differential value adjustments are made for price. Arguably, on the second approach, if ‘costs’ is given the same meaning, it would imply the ‘equivalent costs’ of supplying electricity services of equivalent quality or standards of service. Similarly, if ‘efficiency gains’ includes allocative efficiency improvements based the optimisation of service quality, to maximise allocative efficiency by reducing overall costs to users, including those imposed by poor service quality. If meant in that sense, PPLs formulation is correct. On the other hand, if ‘efficiency’ is meant in the narrow sense of maximising the ratio of outputs to inputs, then it is an incomplete definition. Service quality is an integral part of the regulatory framework because, if it were not explicitly included in the regulatory incentives, then PPL may be encouraged to reduce costs by reducing service quality as a literal and legalistic response to regulatory requirements, to minimise its costs, such responses by regulated entities having become known as ‘gaming’ of regulatory requirements.
The Commission does not suggest that PPL has compromised service quality to reduce capital or operational costs in the current contract period, but does believe that service quality remains poor for many electricity consumers, and that more specific service quality measures and incentives are needed to provide incentives for accelerated improvements in service quality.

The ERC and EIP share a number of objectives. These include:

- Electricity services are affordable;
- Service is delivered to as many consumers as possible;
- Returns on investment are sufficient to encourage further investment in new generation, transmission and distribution infrastructure;
- Supply of electricity becomes increasingly more reliable; and
- Increased accessibility by encouraging the satisfaction of growing market demand for electricity is met.

The Commission recognises that some of these objectives appear to be in conflict with each other and that to achieve them will require a balanced approach. These objectives will be supported by encouraging PPL to manage itself in an efficient and cost effective manner, to both reduce costs and improve service to customers.

The current ERC seeks to achieve these outcomes through a number of adjustment mechanisms in the electricity price permitted to be charged by PPL:

- Initial prices were set in 2002, to provide a regulated weighted average cost of capital return on PPL’s assets;
- Prices are adjusted each year to reflect changes in costs through the indexation process;
- Prices are capped to ensure that they remain affordable at current levels, and to ensure that PPL does not extract monopoly rents;
- Rebates are paid to customers for outages or slow service in connecting new customers;
- Allowances are made for capital investments which will improve the quality of service or reduce operating costs; and
- Adjustments are made to the price path to ensure the cost of imprudent investment is not charged to customers, but is borne by PPL.

Inherent in the contract are the following trade-offs.

- Lower consumer prices will make services more affordable, but will reduce PPL’s ability to invest in new infrastructure to supply demand and improve service quality;
- Lower prices may increase demand, resulting in more outages where demand for electricity exceeds supply capability;
- Higher prices will support increased investment in better infrastructure, but may reduce demand;
- Higher prices may tend to balance supply and demand by supporting increased supply capacity and limiting demand, which could result in improved service quality;
- Cost reductions by PPL may be achieved through improved operational efficiency and investment decisions and,
- Cost reductions through reduced operational costs and reduced capital expenditure achieved through greater efficiency in operational expenditure, investment planning and procurement systems will reduce the need for price increases to fund efficient investment.

The new Regulatory Contract must identify an optimal balance for the cost and performance factors discussed above.

5.2 Effectiveness of the current ERC and generation constraints

It is apparent that only some of these objectives have been meet with the current regulatory contract:
• Electricity prices have doubled in nominal terms and but usage charges have only increased from 2% to 13% in real terms over the contract period (see Table 4). Although taking a shorter term view, from 2007 to 2009 average domestic prices remained the same in real terms and actually decreased from 2009 to 2011 by 6.5% in real terms.

Table 4: Electricity Prices

<table>
<thead>
<tr>
<th>Electricity Prices (K/kWh)</th>
<th>2002 Prices</th>
<th>2002 prices in 2013 Value</th>
<th>2012 Prices</th>
<th>Nominal % Increase</th>
<th>Real Terms % Increase</th>
</tr>
</thead>
<tbody>
<tr>
<td>Domestic - credit</td>
<td>0.325</td>
<td>0.676</td>
<td>0.765</td>
<td>135%</td>
<td>13%</td>
</tr>
<tr>
<td>General Supply - credit</td>
<td>0.418</td>
<td>0.870</td>
<td>0.891</td>
<td>113%</td>
<td>2%</td>
</tr>
<tr>
<td>Industrial - credit</td>
<td>0.228</td>
<td>0.474</td>
<td>0.571</td>
<td>151%</td>
<td>21%</td>
</tr>
<tr>
<td>Easipay Domestic</td>
<td>0.271</td>
<td>0.564</td>
<td>0.629</td>
<td>132%</td>
<td>11%</td>
</tr>
<tr>
<td>Easipay Gen Supply</td>
<td>0.408</td>
<td>0.848</td>
<td>0.869</td>
<td>113%</td>
<td>2%</td>
</tr>
<tr>
<td>Domestic Credit first block of 30kWh (K/kWh)</td>
<td>0.197</td>
<td>0.409</td>
<td>0.450</td>
<td>129%</td>
<td>10%</td>
</tr>
<tr>
<td>Industrial Demand Price (K/kVA/month)</td>
<td>24.42</td>
<td>50.78</td>
<td>69.61</td>
<td>185%</td>
<td>37%</td>
</tr>
</tbody>
</table>

• PPL has remained profitable over the term of the contract period, although the level of profitability has varied from year to year.
  o In 2008, PPL’s profitability fell drastically due to sudden increases in fuel and then recovered the following year.
• PPL have invested K600 million over the regulatory period.
• The service provided by PPL is generally unreliable with multiple outages per day in all Zones, although there are indications that service quality has improved to some degree in recent years. The Commission does not believe that current service quality is acceptable, or that current trends in service quality improvement are enough.
• Unreliable services are costing customers significant additional expense. Many customers are forced to supply their own power backup, due to the regular and protracted nature of these outages. The resulting investment in standby generating equipment, fuel and maintenance represents a significant cost to consumers and the national economy that would not be required if electricity services were reasonably reliable.
• It is likely that Market demand for power is not being fully met by PPL. The outages alone represent a material shortfall in actual delivery from market demand.

In the short term, it appears that the only practical way for PPL to meet increasing demand is to continue to supply incremental demand for electricity through diesel generation. While diesel generation infrastructure is relatively quick to design, specify, purchase and install, and capital costs are smaller in relative terms, infrastructure life is relatively short and running costs are high and can be volatile due to the dependence on imported diesel fuel.

In contrast hydro power tends to require much larger upfront capital amounts and long planning horizons. But the economic life of hydro assets is much longer than diesel generators and operating costs are very low. The net result is that hydro generation has a much lower total long run average cost of power (including both capital costs and operating costs) per kWh generated when compared to diesel generation.

The Commission is pleased to note that PPL has invested in additional hydro generation capacity during the term of the contract. Specifically PPL have spent K133 million upgrading the Rouna 2 hydro power station and K100 million on the Yonki toe of the dam hydro power station which is planned for commissioning in mid-2013.
The Commission also notes that PPL has not been provided with access to gas from the LNG project, which could have been used to lower the cost of operating Kanudi power station. It is not clear why this is the case when the Oil and Gas Act specifically provides for domestic market supply obligations. This is a matter on which the Government should cast light for the information of the public.

In the medium and long term, economic benefits for PPL and consumers will come from a reduced proportion of generation coming from diesel generation. The Commission is aware that PPL is planning further increased hydro generation capacity as well as considering other forms of electricity generation. This should lower its average cost of generation, reduce exposure to imported fuels and make their costs more predictable.

Overall, the Commission is of the view that the financial impact of fuel costs on PPL’s financial results is a consequence of long term investment decisions, rather than the method used for regulating prices. The Commission recognises that PPL may not have had the capital resources or the opportunities at the beginning of the current ERC or during the ERC to make larger investments in cheaper alternative forms of generation. Consequently, PPL has had to rely upon diesel fuels and will continue to do so in the short term. The Commission, therefore, recognises that a practical solution must therefore be found to manage the exposure to overseas fuel prices during the next regulatory contract.

It is the view of the Commission that the current ERC has not been optimal. Therefore, the Commission has determined that it will continue to use the current approach to regulating PPL for the next regulatory contract period but will make significant modifications to improve the outcomes both for PPL and for PPL’s customers.

5.2.1 Reliability of supply

During the term of the current ERC, planned outages have reduced, while unplanned outages have continued at high levels.

Figure 2: Zone 1 Outages
From the information provided to the Commission by PPL, the Commission understands that many outages result from the need for PPL to disconnect loads in areas of high demand, to protect under-provisioned generation capacity from being overloaded, which would then result in widespread loss of electricity services. Other outages are as a result of failures of transmission or distribution infrastructure.

Where service quality problems are related to lack of generation capacity, there are likely two causes. The reduced available capacity could be because existing generation plant has not been maintained and is hence unavailable because spare parts are not available on site or regular maintenance has not been carried out. Or it could be because of a lack of generation capacity in total even where availability of plant is high. Engineering reports provided in PPL’s submissions suggest very strongly that PPL has systematically mismanaged its regular maintenance programs and has not invested in spare parts, such that many generators are idle awaiting repair. While the Commission favours pricing structures which encourage investment in more generation infrastructure, a very quick turn-around in reliability could be achieved by getting existing idle generation plant serviced and repaired quickly and returned to active duty. In particular, the Commission wants to promote pricing structures which reward PPL when they sell more power, and discourage load shedding as a response to inadequate generation capacity. In addition PPL needs to be penalised if its maintenance planning and implementation is not at industry norms.
Where service quality problems are related to the unreliability of transmission and distribution networks, then the Commission favours pricing that will cover the cost of more robust networks, particularly through the implementation of centralised systems operation and dispatch.

5.2.2 The effectiveness of the pricing structure

PPL in their submission also described what they saw as “shortcomings” of the current regulatory mechanism.

“Under the maximum average price cap, PPL has limited revenue certainty, as lower sales will generally lead to lower revenue and higher sales will generally lead to higher revenue (notwithstanding the balance mechanism, which will not necessarily[be] effective in balancing revenue recovered with the revenue requirement, as discussed below).”

It is the Commission's view that all business in both competitive and non-competitive industries has some level of uncertainty. It is always difficult to exactly predict customer demand and future sales. The cost of this uncertainty is built into the WACC, which considers uncertainty due to both market risk and country risk. The WACC should reflect the return required by an indifferent investor given the risk inherent in the investment.

It is also the view of the Commission that the risk of falling customer electricity demand in PNG is relatively low. Despite electricity prices rising in real terms, it appears that PPL has been unable to satisfy demand, and therefore even where very strongly incentivised to generate and deliver energy, its poor performance in reliability terms (idle generation plant without repair) has created revenue losses of its own making that does not reflect market risk. Furthermore, PPL has been a monopoly provider so they don’t have the uncertainty of competitive risk. Therefore, the Commission does not view PPL’s concern as a material factor to be considered in the current electricity market. It is not a matter of falling demand, but rather PPL’s inability to service the growing demand reliably. Indeed, in the past, PPL has paid substantial compensation to large users to ‘go off grid’.

PPL in its submission went on to describe their incentives under the current ERC.

“In PPL’s view, these incentives under the maximum average price cap are potentially inconsistent with PNG Government objectives to increase access to electricity in PNG.”

The Commission agrees with PPL that it does have an incentive to reduce costs. The Commission also observes that there is a large potential cost reduction to be gained by replacing diesel generation with hydro-generation.

PPL’s statement appears to be saying that they do not have enough incentive to sell more power to existing customers. The Commission is of the view that the ERC gives PPL every incentive to invest in power generation infrastructure and to supply electricity to any customer where the price determined by the price cap exceeds the marginal cost of delivery. Analysis carried out by the Commission indicates that this will be true for approximately 90% of PPL’s existing customer base.
In addition, on the revenue side, an outage of supply to existing customers reduces the revenues collected, and forces up prices unnecessarily. Were PPL simply to service all existing customers at 99% reliability, they would experience a significant reduction in unit costs (more variable costs offsetting large fixed costs, leading to lower average costs), and a significant increase in profitability which could be applied to additional investment.

For the other 10% of customers where the price does not cover the marginal cost of supply, the Commission agrees that the effect of using a uniform price to subsidise high cost customers will create the effect that PPL have no incentive to sell more power to these customers. But this is the minority of customers served by PPL.

However, if PPL have a constrained supply of electricity then the Commission also agrees that PPL has an incentive to only sell more power to those that have the lowest cost of supply. From the Commission’s perspective, this also emphasises the issue of constrained supply creating undesirable effects, where the constrained supply is as a result of poor generation maintenance, poor investment planning and poor operational efficiency.

PPL also claimed that the price cap provides a disincentive to connect new customers. This will be true if connection charges do not cover the marginal cost of connection.

The Commission also agrees that because the current price is expressed per kWh, this will have the effect that the revenue earned via fixed charges (or charges that are not expressed as per kWh), will decrease the amount of revenue that can be earned via per kWh charges. However, with the current set of prices in the price list, the only tariff that might have this effect is the industrial customers demand charge. The demand charge is a charge per kVA for the maximum amount of power a particular customer can use at any point in time. The Commission is of a view that this is likely to be aligned with actual energy use. So while PPL’s argument appears to be correct in theory, the Commission is of the view that it is not relevant in particular in relation to the current pricing structure. The Commission has therefore dismissed this as a consideration.

It appears that PPL also regards street lighting as fixed charges. However, the prices paid for street lighting should be in direct proportion to the energy used by the lights. So while public lighting prices may be structured as fixed charges, it is still appropriate that they are regulated via a per kWh pricing structure.

The other prices which PPL appear to regard as fixed prices are the minimum prices which customers must pay each month. If the customer pays the minimum charge yet does not use the power, then PPL have received revenue for which they did not have to provide service. The Commission does not think that the use of minimum monthly charges creates a disincentive to connect new customers. Rather to the contrary, it is because minimum charges are low that PPL may not have an incentive to connect new customers.

The Commission notes that revenue from connection charges is not included in the MAP calculation, so these charges will not have the effect of reducing the amount that PPL can recover from energy sales. As an Excluded Service PPL is encouraged to connect as many customers as possible, without impact to the price cap.

The Commission also notes that PPL’s comments seem to imply that they have a choice in whether or not to supply electricity to customers. In the Commissions view, the ERC compels PPL to supply any customer who requests service within the service areas for which they have a monopoly licence. Furthermore, PPL must supply to any customer as much power as they require within the constraints of the services offered in each zone. Failure to deliver power must be considered to be “an outage”.

This requirement to supply is the same regardless of the marginal cost of supplying that particular customer. The MAP (Maximum Average Price) is an average price designed to cover average costs. If all customers were charged the same price then the losses made on some customers will be compensated by the positive margins from other customers.

5.3 Pricing Structure

Prices are charged for establishing a connection to PPL’s network and then for the usage of PPL’s network. First this report will discuss the usage prices and then it will consider connection charges.
5.3.1 Usage Charges

There are currently three usage pricing structures used by PPL.

(a) A single energy price expressed as a price per kWh. This is used for General Supply Credit, Easipay General Supply and Easipay Domestic.
(b) A monthly charge for a defined quantity of power. Public lighting is expressed this way, where the monthly charge depends upon the wattage of the light bulb used.
(c) A two tier energy price plan, where there is a lower rate for a specified quantity of energy and a higher rate for any additional energy consumed. This is used for Domestic Credit, where the customer pays a lower rate per kWh (currently 47.94 Toea per kWh) for the first 30kWh’s consumed each month then a higher rate per kWh (currently 81.47 Toea per kWh) for any additional energy consumed in the same month.
(d) A Peak Demand charge plus a charge for energy consumed. This is used for Industrial customers where the customer pays a rate per kVA for the maximum amount of power that their connection can deliver. Currently, this is set at K74.14 per kVA per month. So if a customer has a connection to PPL’s network that is capable of delivering 1000 kVA then the customer would pay K64,700 per month plus the a charge for the amount of power they actually consumed (currently set at 60.86 Toea per kWh).

There is one further feature of the PPL usage prices. This is the use of minimum charges. All plans have minimum charges which are currently as follows:

- Industrial Customers – minimum of 200kVA per month;
- General Supply Credit – minimum of K18.00 per month;
- Easipay General Supply – minimum K50 per Receipt;
- Domestic Credit – K12.00 per month; and
- Easipay Domestic – K10.00 per receipt.

Internationally, many jurisdictions use two other pricing mechanisms to provide pricing signals to electricity customers. These are:

- Fixed monthly charges (in addition to a usage charge); and
- Peak and Off Peak rates. The examination of the feasibility of time of use charging is a feature of the new regulatory contract.

5.3.2 Fixed monthly charges

Fixed monthly charges are used as a pricing signal to customers that there is a cost of just being connected to the network, even if the customer does not use any power. This includes:

- the cost of maintaining and reading a meter;
- maintaining the lead-in connection from the network to the customer’s premises; and
- a contribution to the cost of the distribution lines which run past the customers premise.

Fixed charges are also used to cover the cost of providing peak demand capacity. Currently, PPL uses this type of charge for industrial customers, but not for any of their other customer types.

Minimum charges can be thought of as a proxy for fixed monthly charges, although they are not the same as they do include a quantity of usage.

The Commission does not propose to introduce any new fixed monthly charges.
5.3.3 Peak and Off Peak Pricing in PNG

In the initial draft report, the Commission proposed that Peak / Off Peak pricing plans be introduced as an option in some areas, which customers could choose to adopt if they wanted to. It was expected that the customer would pay for the installation and purchase of new meters to support this.

In light of PPL’s submission on this subject, the Commission has determined not to proceed with this proposal temporarily, for the following reasons.

- An assessment of customer demand indicates that very few customers are able to shift load from Peak to Off Peak. Therefore, the benefit of such plans is likely to be minimal.
- The Commission is setting PPL some challenging targets and does not want to distract PPL from these. PPL will need all its resources to implement price differentiation and new service measures. However, in the time allowed for an examination of time of use charging options, as would be required by the new contract, PPL should be able to get its house in order and prepare for customer incentive charging structures to smooth demand at least marginally, so as to reduce peak demand from levels that would otherwise prevail and thus reduce the risk of outages from insufficient generation capacity or lack of robustness of the transmission system, either of which leads to unreliability of supply.

While, the Commission have not sort to implement Peak / Off Peak pricing plans at this time, it requests that PPL examine and report to the Commission on the cost and benefits of the implement of Peak / Off Peak pricing plans. This should include the examination of the potential for such pricing plans to incentivise load management for large industrial users.

5.3.4 Two tier energy pricing plans

The Domestic Credit pricing plan has two tariffs. One for the first 30 kWh of energy consumed each month and one for the balance. The first price is currently set at 47.94 Toea per kWh and the second price is set at 81.47 Toea per kWh. This pricing structure makes electricity cheaper for low volume users. It is essentially a subsidy paid by high volume users to low volume users. It has the effect of making electricity more accessible to low income households.

The Commission is of a view that this pricing structure was put in place for social reasons and that any change to this arrangement would be a matter for Government policy. The Commission does not propose to change this structure.

5.3.5 Change of Pricing Structures

There is currently no process specified in the ERC for changing pricing structures or for introducing new pricing structures. The Commission is of the view that it is likely that over time, new pricing structures may be desirable. If current pricing structures are unable to change then this will restrict innovation or changes that might promote more efficient use of electricity infrastructure resources.

The Commission has introduced a provision in the ERC, which allows PPL to propose new pricing plans or changes to existing pricing plans. PPL will be able to make such proposal once per year in conjunction with the annual price review process described in the ERC. Time of use charging is also required to be examined with the possibility that, if it proves in the public interest, regulatory amendments can be made to accommodate such desirable change.

This would require PPL with in the first eighteen months (18) of the regulatory year to demonstrate to the Commission’s satisfaction, through a report by an international independent consultant appointed by the Commission at the cost of PPL, if the Commission requires that it has investigated the cost and benefits associated with the implementation of; (i) time of use pricing, and (ii) feed in tariffs for small scale network connected generation including Photovoltaic Generation. The requirement for this new pricing structure is outlined in clause 3.4 (c) of the Electricity Regulatory Contract.
5.3.6 Efficiency Gains and Price Reductions

5.3.6.1 Efficiency Gains

Having to establish the efficient cost of providing the regulated services and based on PPL’s forward cost projections and the proposed capital expenditure for the next regulatory period, the Commission is of the view that over the next five years, PPL should realise some level of efficiency gains from such capital expenditure, or else the purpose of the expenditure is negated. The efficiencies gained should translate either into reduced operational costs of the regulated business; network expansion; or service standard improvement. New capital investment allowed by the regulator in the core business of the regulated services occurring prudently, therefore, should see measurable overall improvement in the electricity service delivery to the people of PNG, either in the form of reduced costs and, therefore, prices from such capital investment, or network expansion, or improvement in service standards. If such outcomes are not visible within a reasonable period of time, the purpose of regulation is defeated.

5.3.6.2 Price Reductions

Whilst improving overall electricity services delivery is a form of realising efficiency gains and benefits of the new capital expenditure, the Commission is also of the view that price reduction is the ideal means of sharing the efficiency gains. As consumers have been continuously paying increased prices over the years compared to no or minor price reductions, it is the Commission’s preferred option now to give back some benefit to consumers through price reductions.

There is no reason why the Commission should continue to give real price increases without any efficiency dividend (although it is accepted that nominal price increases should be allowed for inflation) Price increases have been allowed in the past ten years and going forward the Commission expects price reflecting only nominal increases once they operate at efficient cost, less efficiency gains from capital efficiency or from the admittedly weak incentives for SoEs to reduce costs and retain a part of the benefits of cost savings. Capital efficiency should cause real prices to decrease but this has not been happening over the years and this has been the Commission’s concern. Whilst efficiency gained may initially cross subsidise certain high cost service areas, they should eventually be shared with consumers by way of price reduction. The Commission expects this to occur during this regulatory period before the next regulatory re-set.

On an annual basis, PPL must explain to the Commission why it has not achieved its expected efficiency level, which is expected to be documented as part of the current process of settling a new regulatory contract. The Commission is proposing real and meaningful penalties for the senior management by way of remuneration limit adjustments in the financial analysis or the financial model for the next five years and any potential price increase for the first and second year of the next regulatory period which is 2013 and 2014 will not be allowed beyond such adjusted financial model parameters. Remuneration limit adjustments, while not yet designed, could take the form of reductions proportionate to failure to achieve projected levels of efficiency gains, service improvement or price reductions. Furthermore, remuneration reductions for poor performance are to be recommended by the Commission to be imposed by the PPL Board, Chairman of IPBC as shareholder of PPL or representatives of the shareholders, copied to the Minister for Public Enterprises suggesting to reduce PPL’s senior management and CEO’s annual remuneration packages.

5.4 Price differentiation between service areas

In this section, the Commission considers the arguments for or against a weighted average tariff basket or price differentiation between service areas.

5.4.1 Postage Stamp Pricing
“Postage Stamp” Pricing is a mechanism where uniform national prices are used to charge for services provided across the nation so that users and communities located in areas where supply costs are higher and provision of services are uneconomic, are not disadvantaged relative to those located in areas where supply costs are lower and provision of services are economic. Effectively, this is delivering a Community Service Obligation (CSO) to high supply cost areas funded through internal cross subsidization from PPL’s profitable service areas to those unprofitable service areas.

For PPL, postage stamp pricing is applied nationally to cross-subsidise the diesel generation centres in PNG. In 14 regional centres, PPL generates, distributes and supplies electricity to the local community on a non-commercial basis at the national uniform retail tariff. Sales in these centres are about 10% of the PPL total sales and are cross subsidised by the Port Moresby and Ramu grid systems.

Because of the small scale, the high costs of logistics and the use of diesel generation, these centres are unprofitable as a group and record operating losses. The cost of diesel fuel alone for the centres (K66m in 2010) exceeds the sales revenue (K54m in 2010). Clearly, there is a significant cross subsidy within PPL of these regional centres as a group.

Table 5: Diesel Centre Sales Volume, Revenue and Fuel Cost

<table>
<thead>
<tr>
<th>Centre</th>
<th>Sales (MWh)</th>
<th>Revenue K’000</th>
<th>Fuel Costs K’000</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aitape</td>
<td>1,144</td>
<td>840</td>
<td>1,433</td>
</tr>
<tr>
<td>Alotau</td>
<td>10,144</td>
<td>7,445</td>
<td>7,262</td>
</tr>
<tr>
<td>Buka</td>
<td>5,269</td>
<td>3,651</td>
<td>5,956</td>
</tr>
<tr>
<td>Daru</td>
<td>2,577</td>
<td>1,900</td>
<td>3,383</td>
</tr>
<tr>
<td>Finschaffen</td>
<td>589</td>
<td>413</td>
<td>800</td>
</tr>
<tr>
<td>Kavieng</td>
<td>7,587</td>
<td>5,750</td>
<td>5,419</td>
</tr>
<tr>
<td>Kerema</td>
<td>1,134</td>
<td>793</td>
<td>1,650</td>
</tr>
<tr>
<td>Kimbe</td>
<td>10,841</td>
<td>7,842</td>
<td>8,711</td>
</tr>
<tr>
<td>Lorengau</td>
<td>5,054</td>
<td>3,689</td>
<td>5,1221</td>
</tr>
<tr>
<td>Maprik</td>
<td>1,165</td>
<td>855</td>
<td>1,061</td>
</tr>
<tr>
<td>Popondetta</td>
<td>5,670</td>
<td>4,160</td>
<td>5,261</td>
</tr>
<tr>
<td>Samarai</td>
<td>189</td>
<td>130</td>
<td>275</td>
</tr>
<tr>
<td>Vanimo</td>
<td>4,769</td>
<td>3,430</td>
<td>4,601</td>
</tr>
</tbody>
</table>

1 The term ‘cross-subsidisation’ in its technical economic meaning refers to supply at a price that does not recover any part of the variable costs and does not fully recover fixed costs. In this situation, it does appear to apply collectively in respect of supply to these towns as a group cost centre, given that the fuel costs (which are a part of the variable costs) are not fully recovered in revenue for this group of towns as a whole. In respect of individual towns, however, that technical meaning may not apply, as revenue appears to exceed fuel costs. Variable costs, though, extend beyond fuel costs. It would require detailed cost analysis to establish whether every town in this list is ‘cross subsidised’ in the true sense. Colloquially, ‘cross-subsidy’ is accepted as meaning under recovery of fully distributed costs, which include both fixed and variable costs. In the latter sense, most, if not all towns would be likely to be ‘cross-subsidised’ by PPL.

There is another aspect to cross-subsidisation, which is relevant to CSOs. The efficiency with which services are delivered affects costs. The efficiency of planning, investment and operational functions determine fixed, variable and overall costs. It may well be that an efficient operator could supply one or more towns at the postage stamp price on a ‘break even’ or profitable basis, but that cannot be known unless the provision of the service is competitively tendered on the basis of the lowest supply price to users.

Hence, in this report, while the term ‘cross subsidy’ is used, care should be taken in interpretation as it does not necessarily imply that PPL’s costs are efficient.
5.4.2 PPL’s First Submission

PPL proposed in its 2011 submission that the price cap be changed to a cap that applies to a “weighted average tariff basket”. However, in its more recent submissions (March 2012), they have decided that they would prefer to retain the current uniform tariff arrangements, where the same price applies to all customers of the same customer-type (e.g. Domestic, Industrial, General Supply etc.) across all areas serviced by PPL.

In its 2011 submission, PPL outlined how a weighted average basket of tariffs might work.

“The operation of a tariff basket arrangement is typically as follows:

- The cap applies to a weighted average of prices of a basket of services;
- Prices are adjusted each year to account for inflation (in this case the Cumulative Weighted Index) as a pre-defined X factor which reflects the annual change in cost over time to ensure the total revenue requirement over the regulatory period is earned, based on actual demand;
- At the beginning of each year, there is also flexibility for individual prices to move by more or less than the CWI and X factor dictate, as long as the CWI and X factor limits are met on average; and
- If the business manages to deliver service at a lower cost than expected, then it may retain any additional profits earned. If it costs the regulated entity more to deliver service than expected, it cannot increase prices above the price cap, and must absorb the cost increases. Any extra revenue from sales above the forecast can be retained.”

PPL outlined what they considered to be the benefits of moving to a weighted average tariff basket. The Commission has commented on each point separately:

1. “Additional sales volumes provide additional revenue at the actual tariff rates, as opposed to a capped average rate under the maximum average revenue cap. This provides a direct link between revenue earned and the tariff structure and means that (in most cases), PPL will earn more revenue from increase sales volume in all areas, not just those with a relatively low marginal cost to serve."

In the Commission’s view, this is a confused comment and seems to misunderstand the way the current ERC works. At present all additional sales of electricity result in additional revenue and this revenue is directly proportional to the price charged for electricity. The price can change from one year to another based upon the change in the MAP (Maximum Average Price) and the X factor. Contrary to PPL’s statement even sales to high cost areas result in higher revenue in direct proportion to the volume of the sales.

2. “Incentives for efficient pricing (that is, for prices to reflect underlying costs). Because actual revenue depends upon actual tariffs, risks for the business associated with variation in demand can be minimised by pricing as closely to marginal costs as possible to ensure that revenues and costs vary in the same proportion”

The Commission agrees that there is significant benefit in having prices reflect underlying costs. It provides an efficient pricing signal to customers. Customers will purchase electricity if the value to the customer exceeds the cost. In the long run, efficient pricing signals lead to efficient allocation of resources.

3. “Increased revenue from fixed price services (such as public lighting charges and the minimum charges for other customers) will not reduce the revenue that PPL is able to earn from volume sales of electricity, meaning an incentive for connecting new customers exists.”

The Commission has already addressed this issue in section 5.2.2. The Commission does not think that the existing structure reduces the revenue that PPL is able to earn from volume sales of electricity for any other reason than PPL being constrained in the supply of electricity.
Even if it is accepted that PPL is in some way constrained from increasing their supply of electricity, then it does not necessarily follow that a move to a Weighted Average Basket of Prices will enable PPL to increase fixed charges without affecting their ability to charge more for the power they deliver. Any increase in one price point, must be countered by a decrease in another price point sufficient to offset the increase.

4. “Relatively simple to administer. The tariff basket pricing formula is based on variables currently collected by PPL and reported to the ICCC, making the transition to this methodology relatively simple. In addition, the direct link between revenue and tariffs will make (efficient) pricing strategies simpler to develop.”

The Commission agrees that a Weighted Average Basket of Prices is not likely to be overly difficult to operate. However, Sales information will need to be collected according to the form of price differentiation used in the price basket. So if prices vary by service area, as well as by customer type, then information will need to be collected for each customer type in each service area. The Commission notes that the number of prices might change from around 35 to as many as 1,120 if every service area had its own set of prices. In practice, the number is likely to be a lot less than this higher number as several service areas are likely to be grouped together.

The Commission also agrees that a Weighted Average Basket of Prices will provide PPL with more flexibility to move prices to both reflect marginal costs and market demand. This will increase PPL’s ability to develop pricing strategies for various purposes.

5. “PPL is also of the view that the tariff basket approach is more consistent with the PNG Government objective regarding affordability and access to electricity as set out in the draft Electricity Industry Policy”.

The Commission agrees that the tariff basket approach is consistent with the EIP and the ICCC Act.

5.4.3 PPL’s Second Submission

In its March 2012 submission, PPL stated the following;

“PPL has decided to retain a single MAP for the next regulatory period and not seek the introduction of a Weighted Average Tariff Basket as:

- The EIP has confirmed the continuation of uniform tariffs at least in the immediate term;
- The wide range of issues that would need to be addressed as a package should competition be introduced; and
- The quality of service area information and data will improve during this period. The full regulatory period will be necessary to develop the data sets identified by the ICCC.”

The Commission has the following comments in response to this.

- The Commission is of a different view from PPL regarding the EIP’s view of uniform tariffs. It is the Commission’s view that the EIP encourages a move away from uniform tariffs in order to promote more investment in high cost areas (see section 5.4.4).
- The Commission does not see competition as a relevant reason for not introducing a weighted average of tariffs at this time. In fact the introduction of competition forces PPL to better understand its cost base and to introduce tariffs which allow new entrants to connect to its networks, without PPL having to cross-subsidise these new competitors and the tariff rebalancing required is more easily achieved under a Weighted Average of Prices. While other issues might need to be addressed to support competition if it were introduced, they are separate issues. The Commission also notes that the EIP does not propose to introduce competition in PPL’s exclusive “small load” market.
- However, if PPL does not set its tariffs at more cost reflective levels for customers of greater than 10MW, it will lose these customers to the new entrants it is required to connect under the EIP.
• The Commission notes and accepts that the ability to provide the supporting data may take time to develop, but this data gathering must start within the coming regulatory period.

5.4.4 Government Policy

In November 2011, the Government published an Electricity Policy Statement (EIP). The objectives of this policy are stated as:
• Improving access in the provision of electricity services;
• Improving reliability of electricity supply; and
• Ensuring that power is affordable for consumers.

It is the Commission’s view that migration to a Weighted Average Basket of Services is likely to support the first two of these objectives, but work against the third objective of affordability, for those customers located in areas where supply involves higher than average cost.

• If PPL is able to cover the cost of making electricity available to new customers, it is more likely to do so;
• If PPL is able to cover the cost of making electricity services more reliable it is more likely to do so; and
• If a weighted average basket of services results in higher prices in high cost areas, then electricity will become less affordable for consumers located in such areas.

The EIP identifies three electricity markets in PNG:

1. PPL’s exclusive supply (retail areas) with loads less than 10MW;
2. Large Loads of 10MW or greater; and
3. Small loads located outside of PPL’s exclusive supply areas, especially in the rural areas.

In market 1, competition may be introduced into generation through feed in tariffs. But PPL will retain exclusivity in the retail market. In market 2, PPL will face competition if alternative suppliers choose to enter the market as it does now although only in circumstances where access to its network is not required. In market 3, PPL will have the opportunity to compete to win the exclusive opportunity to supply CSOs in new areas where they do not currently offer service.

The ERC will apply to the prices which PPL offers in market 1 and in market 2. Prices in market 3 are likely to be subject to regulation by the Commission, but this will not be covered by the ERC which is the subject of this report.

The policy statement makes several comments about pricing and pricing structures (See appendix section 10.4). Specifically, under the heading of Affordability it states the following:

“Inefficient operation by power companies is one reason making power less affordable. There is an essential need to decrease costs in the operations for supply of electricity by power companies through improved efficiency. Uneconomic areas, particularly rural areas, are naturally high cost areas for investments, and therefore power companies would naturally set high prices to recover costs. However this is suppressed by the Government’s regulation of maintaining uniform tariffs.

Incentives that make electricity undertakers seek efficiency measures to minimize their costs and an enforceable and suitable price mechanism should alleviate the situations that bring about unaffordable prices of electricity. In the Government’s identified priority areas that are uneconomic for private investments, appropriate measures should ensure that the objective of affordability is achieved.

This may include funding CSO’s …. but also requires the adoption of appropriate price mechanisms to attract investment and promote efficient delivery of electrification services.

This approach to price regulation is currently being implemented by the ICCC, and will be maintained under this policy, whereby the ICCC has the flexibility to adjust prices to reflect the higher cost of delivering services in some areas. Such an approach has been adopted with the pricing of services delivered by the PNG Sustainable Energy
Limited in the Western Province. Flexibility in price regulation encourages investments in remote areas, improving accessibility, but also ensures efficient operations and consequentially more affordable operators are encouraged to invest in remote areas where the cost of service may be higher. This Policy primarily seeks to encourage more efficient investment by the private sector and competition as avenues to improving affordability, thus making efforts to overcome current challenges.

Under the heading of “Economic Regulation – Price Regulation” the EIP states the following:

“The economic regulator will implement a robust price regulation to ensure that the industry is vibrant in all commercial ventures through profits earned, whilst ensuring that the objective affordability, hence accessibility, remains attainable.

It is its absolute responsibility for the economic regulator to adopt a specific kind of price regulation mechanism that will ensure that electricity service provision in both low-cost and high-cost areas of investments in the industry in PNG is sustainable. Considerations should be made on the situation of rural areas where prices applied in urban areas may turn out to be unaffordable. The economic regulator will consult the responsible Department or the body in charge of the policy when imposing tariff in rural areas under a specific price mechanism it employs.”

The EIP specifically addresses the risk of unaffordable pricing in high cost rural areas by making provision for Government subsidies for Community Service Obligations in prioritised high cost areas. The Commission interprets these areas as being areas which are not currently serviced by PPL, and therefore, are not a consideration for the ERC.

The Commission takes several key messages from the EIP.
- It is not prescriptive about pricing structures.
- It views national uniform tariffs as being a barrier to investment and it views this as also being a barrier to PPL being able to make investment in high cost areas.
- It is promoting a move away from national uniform tariffs.
- It implies an assumption that the Commission is already moving away from uniform national tariffs.
- It expects that prices should reflect costs.
- It expects that IPP’s and PPL should be profitable in all areas (urban and rural) but not earn economic rents.
- Where a cost based approach results in a price that is unaffordable, then a CSO should be used.
- PPL can also apply for funding for CSOs, but PPL need to demonstrate the need for one.
- It wants the Commission to consult with the Government about rural prices.
- The EIP supports price flexibility which allows higher prices to be charged in higher cost areas.

5.4.5 Likely effect upon PPL’s behaviour

The EIP has as one of its objectives the promotion of electricity investment in high cost areas and sees uniform prices as a barrier to this investment.

It is highly likely that de-averaged prices might not have the immediate effect that the EIP envisages. To understand this we need to consider the effect of the regulatory contract upon PPL’s incentives for investment.

- PPL is required to meet all electricity demand in the areas they service, regardless of where it might be located, so PPL’s business case for new investment is focused upon the least cost method of delivering additional capacity to meet demand, regardless of whether or not it is a high cost or low cost location.
- Electricity infrastructure assets have a longer economic life (30 to 50+ years) than the period of the regulatory contract (5 years). So the effect of the price reset that occurs when the contract is reviewed every year is going to drive a focus onto long term investment, more than short term gains that may be available to PPL within the contract period.
- The building block approach to determining revenue requirements and tariffs in the current regulatory regime allows PPL to recover opex and depreciation as well as a return on capital. Consequently, PPL’s profit margin is...
determined by the depreciation and the regulated return on capital. The long run difference between revenue and cost for a particular investment is specified by the regulatory contract. In the long run PPL will receive a return on any capital investment they make provided the Commission includes it as part of the Regulatory Asset Base. Therefore, PPL will be indifferent as to whether or not an investment is in a high cost areas or a low cost area.

- In the short term, the incremental cost of delivering new capacity in all areas tends to be met by using high cost diesel generation. While the average cost per kWh might vary a lot from one area to another, the incremental cost of generation per kWh is likely to be very similar in all areas. Distribution and Transmission costs will also vary from one area to another, but these costs tend to be viewed from a longer term perspective.

From this we can conclude that uniform or de-averaged prices will make no difference to PPL’s returns and will not change their investment behaviour directly.

However, if PPL had the discretion to de-average their prices then there would be two opposing factors that might drive their behaviour.

- **Public Opinion** – If PPL do increase prices in high cost areas, they are likely to receive criticism from both the affected parties and also the political elements that support them. This is likely to discourage PPL from de-averaging their prices across geographic areas.

- **Competition in Market 2 (Large Loads – greater than 10 MW)** – It is likely that the cost of providing service to large load customers will be less than the average cost. So, if, PPL’s prices in this market are based upon the average cost then a competitor will be able to undercut them. This is often referred to as “Cherry Picking” and is the primary risk when new entrant generation plant is allowed to connect to an existing electricity network. This is likely to encourage PPL to de-average their prices across geographic areas, but only to the extent that customers of this nature exist. Overall the impact of this is not likely to be particularly material on the small load market,

- except that higher revenue recoveries will be needed in this market to allow PPL to compete with the lower prices offered to large load customers by new entrant generation.

The Commission, of course, has the obligation to prevent higher prices being charged to small load customers to fund competition by PPL in the large load market, as that should be determined by ‘competition on the merits’ in that market. It is not the role of the Commission to set up charging systems which make it easier for PPL to compete in the large load market. That is a matter for relative efficiency between competitors.

Therefore, while PPL does have the discretion to offer lower prices in the large load market under the current uniform pricing arrangements, they are not able to increase pricing elsewhere to compensate. So the net effect of matching a competitors price in Market 2, would be that overall they would not earn the revenue required to cover their costs. This would then mean that, if PPL persisted in seeking to compete in the large load market at prices that did not recover the full cost of provision in that market, it could not continue to invest in its network to maintain service standards.

Competition in Market 2 is likely to impact upon the current subsidy enjoyed by customers in high cost areas of Market 1. The largest source of subsidies will be PPL’s largest customers in low cost areas and these are likely to be in Market 2. So the net effect of introducing competition into Market 2, is likely to remove some of PPL’s ability to provide a subsidy to customers in high cost areas in Market 1. However, the overall impact of this is assessed as being likely to be small, but would depend on market dynamics.

---

2 Short term positive and negative impacts are possible from individual Investments, but these will be negated at the next regulatory reset. Regulatory reset are every 5 years while asset life averages around 20. Any short term losses or gains above and beyond the regulatory building block forecast is thus only short lived and has minimal impact on PPL’s investment decisions.
5.4.5.1 Illustrative example

PPL has indicated in its submissions to the Commission that under the approach to estimating its revenue requirement in the current Regulatory Contract, it is indifferent as to whether it invests in low-cost areas or high-cost areas. The following tables illustrate the dynamics of uniform or cost reflective prices from PPL’s perspective. If there are three areas with different consumption volumes and different costs, then Table 6 compares the situation where a uniform price is used and where cost reflective prices are used. We have set the cost reflective prices so that in each area the margins are the same and so that total revenue is the same for both the uniform price scenario and the cost reflective price scenario.

We have shown three calculations;
1. The starting position which includes all existing demand delivered at average cost.
2. The perceived incremental value of incremental demand if it were assumed to be delivered at average cost.
3. Incremental contribution from incremental demand delivered at incremental cost.

Table 6: Illustration of incremental impact of investment under different pricing structures

<table>
<thead>
<tr>
<th>Starting Position</th>
<th>Uniform Price</th>
<th>Cost Reflective Prices</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Area 1</td>
<td>Area 2</td>
</tr>
<tr>
<td>Price Kina / kWh</td>
<td>1.00</td>
<td>1.00</td>
</tr>
<tr>
<td>Volume kWh</td>
<td>50,000</td>
<td>40,000</td>
</tr>
<tr>
<td>Revenue Kina</td>
<td>50,000</td>
<td>40,000</td>
</tr>
<tr>
<td>Average Cost Kina / kWh</td>
<td>0.50</td>
<td>0.40</td>
</tr>
<tr>
<td>Total Cost Kina</td>
<td>25,000</td>
<td>16,000</td>
</tr>
<tr>
<td>Contribution Kina</td>
<td>25,000</td>
<td>24,000</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Incremental Volume at average cost</th>
<th>Uniform Price</th>
<th>Cost Reflective Prices</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Area 1</td>
<td>Area 2</td>
</tr>
<tr>
<td>Incremental Volume kWh</td>
<td>1,000</td>
<td>1,000</td>
</tr>
<tr>
<td>Incremental Revenue Kina</td>
<td>1,000</td>
<td>1,000</td>
</tr>
<tr>
<td>Average Unit Cost Kina / kWh</td>
<td>0.50</td>
<td>0.40</td>
</tr>
<tr>
<td>Incremental Cost Kina</td>
<td>500</td>
<td>400</td>
</tr>
<tr>
<td>Incremental Contribution Kina</td>
<td>500</td>
<td>600</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Incremental Volume at incremental cost</th>
<th>Uniform Price</th>
<th>Cost Reflective Prices</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Area 1</td>
<td>Area 2</td>
</tr>
<tr>
<td>Incremental Volume kWh</td>
<td>1,000</td>
<td>1,000</td>
</tr>
<tr>
<td>Incremental Revenue Kina</td>
<td>1,000</td>
<td>1,000</td>
</tr>
<tr>
<td>Incremental Unit Cost Kina / kWh</td>
<td>2.00</td>
<td>2.00</td>
</tr>
<tr>
<td>Incremental Cost Kina</td>
<td>4,000</td>
<td>4,000</td>
</tr>
<tr>
<td>Incremental Contribution Kina</td>
<td>-3,000</td>
<td>-3,000</td>
</tr>
</tbody>
</table>

It should be noted that the situation described in 2 above is not strictly correct. Incremental demand cannot be delivered at average cost. However there is often the perception that it is. So to understand how the EIP’s expectations might be different from reality, this is included.
For simplicity this analysis assumes that a change in price will not change demand (which clearly would not be true). Only long run volume driven costs are included, as fixed costs will not change with volume and are therefore not relevant to this pricing decision.

5.4.5.2 Results from Illustrated Example

If incremental power is delivered at incremental cost, under the uniform price, then PPL is likely to receive about the same incremental contribution in each area. However under the cost reflective price scenario, when power is delivered at the incremental cost then PPL will be worse off when it delivers power in low cost areas, than when it delivers incremental power in high cost areas.

From this we can conclude that uniform prices are more likely to produce an efficient outcome than prices which reflect average costs. This result is a function of the building block method of regulating prices. Under a different regulatory method the results might be different.

If incremental power is delivered at average cost, as some might perceive will occur, then under a uniform price, PPL would be worse off in high cost areas and better off in low cost areas. However under the cost reflective price scenario, in all cases PPL will be better off, by the same % margin. As already noted this does not reflect reality as incremental volume is delivered at increment cost not average cost. However the perception that this will drive investment would encourage someone to argue in favour of cost reflective prices.

The example results are summarised in the table below

<table>
<thead>
<tr>
<th>View of incremental Cost</th>
<th>Reality</th>
<th>Effect under uniform prices</th>
<th>Effect under cost reflective prices</th>
</tr>
</thead>
<tbody>
<tr>
<td>Long Run Average Cost</td>
<td>Miss leading as does not occur in reality</td>
<td>Favours investment in low cost areas</td>
<td>Indifferent between areas</td>
</tr>
<tr>
<td>Long run incremental cost</td>
<td>PPL’s actual incentive</td>
<td>Indifferent between areas</td>
<td>Favours investment in high cost areas</td>
</tr>
</tbody>
</table>

The key issue for PPL in making investment decisions therefore becomes the incremental cost for PPL to deliver more power.

5.4.5.3 Pricing Theory

Economic theory says that prices should reflect long run average costs, where the long run represents the time frame in which all asset costs are replaced. Only at this price can a business be confident that it can be sustainable at current prices, and that its fixed costs can be recovered over the life of the assets. Also the long run cost reflects the cost that a new entrant would face if they entered the market, and therefore is competitively neutral to new entry.

However, because PPL is operating under uniform prices to recover a revenue requirement developed under the building block regulatory model, it contends it will cover its costs regardless of how costs vary between high cost and low cost areas. PPL will therefore see no advantage in migrating to cost based prices, at this stage, or even towards cost reflective tariffs (which seek to only partially recover the full costs in high cost areas).

The Commission draws the distinction between costs based tariffs where all the costs in a particular service area are recovered in the tariffs applied to the consumption volumes within that area, and cost reflective tariffs. In high cost areas, cost reflective tariffs lie somewhere between the average cost and the full cost for that service area, and full cost recovery is not achieved which requires a cross subsidy from another service area, which is recovering above its full costs.
5.4.5.4 Evaluation

PPL has provided the following feedback in relation to whether it would prefer to move away from uniform tariff arrangements, which have been used in the regulatory period which finished on 31 December 2012.

- Cost based or cost reflective prices make no difference to PPL’s incremental investment decisions under the incentives of the current building block approach of the regulatory contract.
- In the short term, investment decisions will focus on the least cost method of delivering incremental capacity requirements to meet demand increases or replace/refurbish existing assets.
- In the long term PPL receive a return on all capital investment included in the RAB, and so there is no incentive for PPL to choose the lowest cost option. The regulatory frame work relies upon the Commission to ensure PPL chooses the lowest cost means of delivery.

The Commission notes that where there is a strong profit motive, a regulated entity would seek to choose the lowest cost under the regulated price cap determined from the revenue requirement calculated using a building block methodology based on the RAB, as the higher profits would flow to the shareholder during the regulatory period. Then, in the following regulatory period these cost reductions would be shared with consumers through lower prices than would otherwise be necessary, as there is a lower cost base. Because PPL on its own admission is not focused sufficiently on reducing prices to consumers, the Commission is forced to ensure PPL is focused on least cost delivery of services overall, to maintain the objective of economic efficiency in service delivery to consumers as is one of the primary objectives under the ICCC Act so as to maximise allocative efficiency throughout the economy, a primary means of achieving the statutory objective of maximising the welfare of all Papua New Guineans. This is discussed further below.

5.4.6 Impact upon Customers

While a move to cost reflective prices may not directly drive PPL’s investment decisions, the Commission is of the view that they will have an impact upon customers.

- Cost reflective prices provide efficient cost signals to customers. Customers who value the service more than the cost of the service will buy it. Those customers who value the service less than the cost of the service will not buy it. In standard economic (market) theory this supports efficient allocation of resources in Papua New Guinea.

- The effect of cost reflective prices will lead to slower economic development in high cost areas and faster economic development in low cost areas.

- Customers in rural areas are probably less able to afford higher electricity prices than those in the city. If prices were moved so that the prices fully reflected average cost in each area, then prices would be expected to drop by about 20% in Port Moresby, drop by 55% in Lae/Ramu, and increase by as much as 220% in some other areas (See section 5.4.10 and Figure 5). While it is not envisaged that prices would change this much in the immediate future, the full benefits of cost reflective prices would not be achieved until prices do actually reach these sorts of levels.

- Social unrest in response to a move away from uniform prices is considered likely, unless innovative methods in tariff adjustment processes are adopted and new low-cost generation investments come on line to displace the generally higher cost resulting from diesel generation plant. Fully attributed costs would strongly encourage such low-cost generation investments either by PPL or by others, if the area is not protected under PPL’s monopoly rights

- Lower prices in urban areas may stimulate demand which PPL may struggle to supply, but would encourage additional economic growth and likely lead to additional employment. PPL would be forced to address supply shortages or fall into serious breach of its service standards obligations.
5.4.7 Other Impacts

- The goals of PNG are to ensure 70% of the population have access to power by 2030. As 85% of the population live outside urban areas, then much of the new investment will be in high cost areas. Continuing use of uniform prices will require that the cross subsidy is increased. While population migration to the city (Port Moresby and Lae) may shift demand to the city, the requirement to provide coverage in rural areas (for the remaining population) means that the cost of rural networks will not be reduced by population migration- indeed, the scale effects on unit costs mean the reverse is likely to be the case.

- The introduction of even limited or token price differentiation between service areas would indicate the future direction of prices to the market and create the precedent that will support future development of electricity infrastructure in PNG, particularly in rural areas where additional new investment is needed.

- Makes the cost of subsidies explicit. If prices reflect costs, then it will be easier to see which service areas require subsidies. These subsidies can then be provided by the Government using CSOs as described by the EIP. However just identifying costs without introducing cost reflective tariffs would also identify where CSOs are needed, although the pressure to do so would be muted.

5.4.8 Past experience of PPL

PPL’s predecessor attempted to introduce de-averaged prices in the 1980’s. This was met with resistance from customers. As a result of this resistance, it elected to revert to uniform pricing. PPL predicts a similar resistance if de-averaged prices are introduced now.

5.4.9 PPL Systems

PPL’s main billing system (Gentrack) is capable of handling many different tariffs at the same time and is not a hindrance in implementing cost reflective tariffs.

However, PPL’s pre-pay system, Ezipay, will require significant modification to support cost reflective tariffs. As currently configured, a customer could buy an Ezipay token in a low cost area and use it for a meter in a high cost area. The metering is uniform and is not able to reflect the cost of service delivery in high cost areas.

5.4.10 Potential Range of prices

The Commission’s analysis indicates that if prices were aligned with the marginal cost of energy supply, then the range of prices between service areas might be as shown in Figure 5 indicating a price variation of almost 400%, depending on the cost of supply.

While the Commission does not assume that PPL would or would not intend to recover electricity costs in direct proportion with this price range, the actual potential variation of electricity prices is so great that a decision to move to a weighted average tariff basket is a matter for government policy direction. We have already established that the government supports a move in this direction, but is also generally concerned about affordability. At the same time a key objective of the EIP is accessibility, which implies the promotion of all incentives for expansion and entry by competing providers, which can only occur with cost-based or a high degree of cost-reflective pricing, any regulatory decision on pricing, therefore, must draw a balance between these two apparently opposing policy directions, which can only be reconciled by a robust CSO structure, optimised by competitive bidding on the basis of the lowest supply price in new areas, presumably requiring prices higher than average costs.
5.4.11 Forms of price differentiation

The Commission must also consider how the introduction of a new pricing structure might produce undesirable results. If PPL had discretion to price differentiate between customers in any way they chose, then it is likely that customers in Market 2 would receive lower prices at the expense of customers in Market 1. This means that the burden of providing subsidies to high cost areas in Market 1 will fall to small load customers in low cost areas of Market 1. While these customers may be more able to afford higher prices than those in high cost areas, they are still less able to pay higher prices than customers in Market 2.

Therefore, the introduction of a weighted average basket of services raises questions about exactly how prices should be de-averaged.

Currently, regulated electricity prices differentiate by customer type but not by geographic area. For example, domestic customers pay different prices from general supply customers. But all domestic customers pay the same price and all general supply customers pay the same price. There is a spectrum of the level of price differentiation that an average basket of tariffs could support.

Table 7: Price Differentiation

<table>
<thead>
<tr>
<th>Level of Differentiation</th>
<th>Description</th>
<th>Example</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. No differentiation</td>
<td>• Only one price. All customers, of all types pay the same price per kWh.</td>
<td>• A Domestic customer in the highlands will pay the same price as a General Supply customer in Port Moresby.</td>
</tr>
</tbody>
</table>
| 2. Differentiation by Customer Type | • Different types of customers pay different prices.  
• But all customers of the same type pay the same price. | • A Domestic customer in the highlands will pay the same price as a Domestic customer in Port Moresby.  
• A General Supply customer in the highlands will pay the same price as a General Supply customer in Port Moresby.  
• But a Domestic customer, whether in Port Moresby or the Highlands will pay a different price from a General Supply customer in Port Moresby or the Highlands. |
| 3. Differentiation by Region and by Customer Type, with fixed relativity | • Different types of customers pay different prices.  
• Prices vary from one region to another.  
• The relative price paid by different customer types is | • A Domestic customer in the highlands pays a different price from a Domestic customer in Port Moresby.  
• A General Supply customer in Port Moresby pays a different price from a Domestic customer in Port Moresby.  
• The ratio between the price for a Domestic customer |
4. Differentiation by Region and by Customer Type, with no consistent relativity between customer types

- Different types of customers pay different prices.
- Prices vary from one region to another.
- The relative price paid by different customer types is different in each region

- A Domestic customer in the Highlands pays a different price from a Domestic customer in Port Moresby.
- A General Supply customer in Port Moresby pays a different price from a Domestic customer in Port Moresby.
- The ratio between the price for a Domestic customer and the price for a General Supply customer is different in Port Moresby when compared to the Highlands.

5. Full Differentiation

- All customers can pay different prices
- Different Domestic customers in Port Moresby pay different prices.

In making a choice between these alternative types of price differentiation, the Commission needs to consider the purpose for allowing differentiation. Specifically, the purpose here would be for two reasons, firstly, where prices move towards cost reflective levels, a demand side management (DSM) price signal is provided to consumers so that they are encouraged to reduce any unnecessary consumption, and secondly the recovery of costs is higher (but unlikely to be full cost recovery) which encourages further investment in high cost areas. Therefore, the only form of new price differentiation that the Commission would want to introduce would be one that supported these joint outcomes, but in a balanced way. As the regulated prices already include price differentiation by customer type, the Commission does not propose to remove this. So the form of price differentiation that the Commission would support in a weighted average basket of services is type 3 in the Table 7 above, for the coming regulatory period, although subject to the outcome of the reports required to be commissioned by PPL into the feasibility of time of use charging structures and small scale grid-connected generation systems, including, but not limited to photo-voltaic systems. These two matters will have a non-trivial impact on pricing mechanisms and cannot be ruled out at this stage for the duration of the new regulatory contract, which provides a framework for their consideration and implementation, if in the public interest.

5.4.12 Options for the Commission

If the Commission were to introduce price differentiation between service areas, then there are two main options;

- **Option 1)** Give PPL the discretion but not the requirement to differentiate prices by service area. Limit price increases above the weighted average to a maximum of 8% per annum; and
- **Option 2)** Make it mandatory for PPL to differentiate prices between customers on the Port Moresby system, Ramu system and all other systems combined. Limit price increases above the weighted average to a maximum of 8% per annum.

Both options to allow for changes arising from the outcomes of the reports on time of use charging and incorporation of small scale grid-connected generation systems.

5.4.12.1 Evaluation of these two options

- Both options allow for flexible prices across geographic areas, with in the annual price increase limit of 8%.
- Both options are commercially sustainable. Under option 1, PPL will be able to price differentiate if it needs to, in order to address any issues of commercial sustainability, should competitive generation access be allowed to its existing main electricity networks.
  - **Option 1**
    - Allows PPL the flexibility to manage its business and address business issues as it sees fit.
    - It is closer to “light handed” regulation - this, however, is not a major concern as regulation should seek to maximise effectiveness, rather than attain some theoretical low level of intrusion, for its own sake.
However as long as PPL stick with uniform prices, then an initial hurdle will remain for it to introduce de-averaged prices.

- **Option 2**
  - Will make little difference to PPL’s actual investment decisions, as PPL are compelled to invest to meet demand under the ERC, regardless of returns in any geographic location, and PPL receive a return on any investment they make.
  - Is more prescriptive and therefore less “light handed” - this, however, is not a major concern as regulation should seek to maximise effectiveness, rather than attain some theoretical low level of intrusion, for its own sake.
  - It takes decision making away from PPL.
  - However, it also ensures that PPL has the capability to price differentiate.
  - It removes the initial hurdle to introducing de-averaged prices. Once PPL have some form of differentiation in place they are more likely to use it further if needed from a commercial perspective.

In deciding what to do the Commission needs to:

- Reflect the goals of the EIP in the ERC within the framework imposed by the ICCC Act. While issues such as social unrest may be a very real concern, it is not the Commission’s role or PPL’s role to address these matters, except to the extent consumer education will assist consumers in understanding limitations for investments in high costs rural areas.

- Consider PPL’s practical limitations. It will take some time for PPL to implement any form of tariff de-averaging, and a series of milestones are necessary in the next regulatory period to at least ensure PPL can begin to comply with government policy in this respect. PPL may well need this capability to support its competitive bids for CSOs and its ability to compete in the large load market.

- Consider the longer term perspective. Electricity infrastructure investment requires long-term planning. Decisions made now will have a long term impact and PPL needs to be encouraged to continue to invest in its infrastructure for the long -term benefit to new and existing customers within PNG.

- In terms of areas outside its geographical monopoly, some or all of the considerations above may not be highly relevant in public policy terms. Other entrants can enter if PPL is forced to de-average prices. It does not have to be PPL that provides services in new areas. Indeed, delay in de-averaging prices acts as a barrier to entry to potential competitors. That is obviously in PPL’s own interest but not in the interest of national economic development. Unnecessary delay in PPL introducing differential prices, therefore, may well be seen as a strategy to foreclose potential entrants from competing in new areas.

### 5.4.13 Conclusions

The EIP envisages that PPL would have the flexibility in the ERC to vary its prices between high cost and low cost areas as a minimum. However, arguably, the EIP does not make price de-averaging mandatory.

Raising prices in high cost areas may not produce the results that the EIP envisages. This is for reasons including:

- Customers in high cost areas may not be able to afford prices which completely cover the cost of service in these areas.
- There is likely to be a strong negative public response to this type of price change.
- Any significant increase in electricity prices in high cost areas may depress demand and create negative economic value, through negative contribution to joint and common costs.
- In the long run this will drive more efficient investment but won’t change PPL’s direct incentives under its current interpretation of the incentives provided by the building block regulatory method.
• Cost based de-averaged pricing, however, would create strong incentives to innovate in generation technology and use of alternative energy sources, such as solar, wind, bio-mass, to reduce costs so as to expand the market and such dynamic incentives are a significant factor in terms of national economic development.

CSOs in combination with de-averaging and other government or aid agency funding initiatives may be necessary to balance a need for improved investment incentives and with managing the effect of rising electricity price rises to recover the costs of new investment.

The building block method gives PPL the same return on any approved capital investment, regardless of its location. De-averaging prices makes no difference to the return PPL receives, all other variables held constant.

### 5.4.14 Final Determination

The ICCC’s determination is to change the ERC from uniform national prices to a Weighted Average Basket of Tariffs. Specifically, the ICCC will allow PPL the discretion to price differentiate between customers of the same type in different geographic areas, so long as the relative price between different customer types is maintained across all geographic areas.

The ICCC’s rationale for supporting this is that:

- Allowing this form of price differentiation will support increased investment in higher cost areas within PPL’s exclusive zone; and
- In order to compete in Market 2 (for the customer group whose loads are greater than 10MW within PPL’s exclusive zone) PPL must be able to vary prices away from the national average price for similar sized customers.

The ICCC is also including a clause in the Regulatory Contract which allows the ICCC to require PPL to differentiate their prices, in some way, between geographic regions, should this be required during the period of the new Regulatory Contract. This clause will not be activated before 2015. This will enable the ICCC to support the EIP if it becomes apparent that differentiated prices are needed and that PPL is not moving towards the implementation of the EIP policy intent.

This provision will be a significant precautionary measure to prevent and, if necessary, correct, any unnecessary delay in PPL introducing differential pricing that may be reasonably inferred to be based on the purpose of creating an economic barrier to entry to potential competitors in new areas not subject to monopoly rights or even in areas now subject to monopoly rights which expire in 2014.

The ICCC proposes that what was previously referred to as the MAP (maximum average price) will now be referred to as the MWAP (maximum weighted average price). The MWAP is essentially the same as the MAP, but the ICCC has renamed it to emphasis a fundamental change to the pricing structure which this approach can support under the new Regulatory Contract.

The ICCC proposes that the following set of rules be used until circumstances warrant change in accordance with the provisions of the new contract:

- The weighted average of all PPL’s prices will not exceed the MWAP (Maximum weighted average price) specified by the ERC;
- In calculating the MWAP, each price will be weighted according to the actual quantity of energy delivered measured in kWh in the prior year;
- Prices may vary from one service area to another service area at PPL’s discretion;
- The contract will set limits on how much any price in any one service area can change from one year to the next over and above the % change of the MWAP, subject to the restrictions below:
- Customers of the same customer type within each service area must receive the same price. A non-differentiation clause in the ERC restricts PPL from discriminating between customers on any other basis than their service area and their customer type. (The exception to this rule is customers in market 2, large load customers with more than 10MW subjects to the restrictions below.)
- In each area, the price relativity between customer types must be maintained according to the specified relativity ratios. (Except for large load customers). See Section 5.5.
• For large load customers, PPL may set individual prices to ensure that they are competitive.
• For large load customers, PPL’s prices must be equal to or above the long run incremental cost of providing service to this group of customers. (See section 5.6)

No price can be increased by more than 8% in addition to the annual MWAP adjustment. The exception to this is large load customers in the instance where a larger increase is required to ensure the price covers the cost of providing service to these customers.

It should be noted that the introduction of contestable generation for customers in market 2, large load customers with more than 10MW of load is not triggered by the final determination by the Commission on the Regulatory Contract for PPL. Other enabling activities and decisions are required under the EIP and under the ICCC Act, including but not limited to the development of a Third Party Access Code, potentially separate Regulatory Contracts for new entrants, transparent tendering to similar bidding arrangements for new entrants, the issuance of relevant licences by the Commission, and other supporting regulations and/or policy decisions.

5.4.15 Data requirements

To support price differentiation between service areas, the Commission is of the view that PPL will need to start to gather segmented information about their generation and network costs and customers by service area and by grid system. PPL will need to justify to the Commission, which, in turn, will need to justify to the public why prices are different in different areas.

The Information that will be required is as follows:

• Data for doing annual reviews of the MWAP;
• Data for the mid-term review and to reassess the price path for the next contract review in 2016;
• Data required to support third party access arrangements in particular the separation of network costs from the other generation and retail costs from the other generation and retail costs; and
• Data required estimating the cost of providing service to large load customers, in particular the separation of network tariffs from the bundled retail tariffs currently subject to the price control mechanisms in the Regulatory Contract.

The Commission has specified the list of service areas (See Table 8: Service Areas) which are covered by the contract and also the list of generation systems (See Table 9: Generation Systems List).

Table 8: Service Areas

<table>
<thead>
<tr>
<th>Service Area</th>
<th>Service Area</th>
<th>Service Area</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aitape</td>
<td>Kavieng</td>
<td>Mumeng</td>
</tr>
<tr>
<td>Alotau</td>
<td>Kerema</td>
<td>Mt Hagen</td>
</tr>
<tr>
<td>Bialla</td>
<td>Kimbe</td>
<td>Popondetta</td>
</tr>
<tr>
<td>Buka</td>
<td>Kokopo</td>
<td>Port Moresby</td>
</tr>
<tr>
<td>Central</td>
<td>Kundiawa</td>
<td>Samarai</td>
</tr>
<tr>
<td>Daru</td>
<td>Lae</td>
<td>Vanimo</td>
</tr>
<tr>
<td>Finschhafen</td>
<td>Lorengau</td>
<td>Wapenamanda</td>
</tr>
<tr>
<td>Goroka</td>
<td>Madang</td>
<td>Wau</td>
</tr>
<tr>
<td>Gusap</td>
<td>Maprik</td>
<td>Wewak</td>
</tr>
<tr>
<td>Ialibu</td>
<td>Mendi</td>
<td>Yonki</td>
</tr>
<tr>
<td>Kainantu</td>
<td>Minj</td>
<td></td>
</tr>
</tbody>
</table>

Table 9: Generation Systems List

<table>
<thead>
<tr>
<th>Generation Systems</th>
<th>Generation Systems</th>
<th>Generation Systems</th>
</tr>
</thead>
<tbody>
<tr>
<td>Port Moresby</td>
<td>Alotau</td>
<td>Kerema</td>
</tr>
<tr>
<td>Ramu</td>
<td>Bainyi / Maprik</td>
<td>Lombrum / Lorengau</td>
</tr>
<tr>
<td>Gazelle</td>
<td>Buka</td>
<td>Popondetta</td>
</tr>
<tr>
<td>Bialla</td>
<td>Daru</td>
<td>Samari</td>
</tr>
</tbody>
</table>
5.4.15.1 Annual Data requirements

If PPL choose to price differentiate between service areas, then for each service area they set separate prices for, they must provide:
- A description of pricing plans in that service area;
- The number of customers on each pricing plan in that service area; and
- The weighted average usage in kWh for each pricing plan in that service area.

5.4.15.2 Other Data requirements

The following list of data will be required by 1st April 2015 to support price differentiation between service areas, should this be required. Alternatively if PPL choose to introduce price differentiation prior to this time, the Commission will require PPL to provide this information for the particular areas where prices are to be increased. This information is also expected to be used to reassess the price path for a potential regulatory period from 2018 to 2022.

For each service area, the Commission will require PPL to provide:
- Number of customers by pricing plan;
- Number of customers with large loads (i.e. greater than 10MW);
- Usage by pricing plan (MWh per year);
- Km’s of distribution lines by voltage;
- Km’s of feeder by voltage;
- Number of Transformers by voltage and capacity (kVA);
- List of Substations describing transformer capacity at each one;
- Name of the Generation System that supplies the service area;
- Km’s of Transmission line which are dedicated to serving a service area specified by voltage & kVA;
- Km’s of Transmission line which are used by a service area but shared with other service areas specified by voltage and kVA;
- Annual Maintenance costs for distribution lines;
- Annual Maintenance costs for transformers;
- Annual Maintenance costs for customer’s connections (the lead-in connection from a customer’s premise to the PPL distribution network);
- Annual Maintenance costs for customer meters;
- Annual Maintenance costs for feeder cables;
- Annual Maintenance costs by transmission lines;
- Profile of load in MW (Peak / Off Peak) periods for each service area;
- Average energy losses by service areas;
- Age profiles for all assets; and
- The overhead costs associated with the business and not directly attributed to any particular service area; and
- Any other relevant information.

For each generation system, the Commission will require PPL to provide:
- Number of power stations;
- Each power station should be described in terms of number of generating units, name plate (or rated) capacity of each generating unit in kVA and the dispatchable capacity of each generating unit in kVA (or normal capacity factor under current conditions and when well maintained);
- Type of generating unit (Hydro, Diesel, CCGT, OCGT or specified if another type);
- Age of generating unit and expected future life;
• Annual Maintenance Cost split between maintenance costs which relate directly with the power station units and maintenance costs which relate to supporting infrastructure such as staff accommodation, road and maintenance workshops’ etc.;
• Generation profile in the past 12 months (showing outages, peak period generation, off peak period generation, maintenance shutdown periods); and
• For Diesel generating units PPL should also provide the following data for the prior year:
  o Conversion rate (litres per MWh of output); and
  o Local Fuel Price (Kina / Litre).
• Age profiles for all assets and expected remaining life of all assets

Information about capital projects carried out during the Regulatory Contract period:
• All capital projects should be classified as to which service area or generation system they will support.
• They should also be classified as either relating to Generation, Transmission, Distribution or Retail.
• They should specify the effective amount of capacity that they will deliver. Capacity should be specified in kVA and expected losses for each component estimated.
• This information should be provided for all capital projects which are either already complete, in progress or planned to be commenced within the contract period.

5.5 Relativity Ratios

Regulated electricity prices are currently set so that Easipay is cheaper than Credit, Domestic is cheaper than General Supply etc. The Commission also notes that the price change mechanism in the current ERC has maintained the current price relativities between customer types. However, with a move to a Weighted Average Basket of Tariffs, PPL will have the ability to change the relativity between customer types, unless the Commission specifies what these relativities should be under the provisions of the ERC.

The Commission is of the view that the relative prices between these customer types should be maintained. One of the objectives of the EIP is affordability. The Commission expects that in some cases domestic customers will be more expensive to provide service to on an average per kWh basis, than general supply or industrial customers. The Commission also expects that many domestic customers are least likely to be able to afford higher electricity prices than general supply or industrial customers and that domestic customers are also likely to be more price elastic. The Commission therefore wants to protect the interests of domestic customers. If prices are held lower for domestic customers then uptake of service may be higher overall, which may provide more economies of scale to PPL, even in a small way.

The Commission notes that in the absence of competition in this market, domestic customers rely upon the Commission to protect them.

It is therefore necessary to create a mechanism within the Regulatory Contract to achieve this should PPL choose to price differentiate between different service areas. The current prices and their relative ratio to the Easipay Domestic price are shown in Table 10.

Table 10: Price Relativities

<table>
<thead>
<tr>
<th>Customer category</th>
<th>2012 Prices</th>
<th>Price Relativity Ratio (K/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Domestic – credit</td>
<td>0.7650</td>
<td>1.22</td>
</tr>
<tr>
<td>General Supply – credit</td>
<td>0.8909</td>
<td>1.42</td>
</tr>
<tr>
<td>Industrial – credit</td>
<td>0.5714</td>
<td>0.91</td>
</tr>
<tr>
<td>Public Lighting - (average)</td>
<td>0.8909</td>
<td>1.42</td>
</tr>
<tr>
<td>Easipay Domestic</td>
<td>0.6290</td>
<td>1.00</td>
</tr>
<tr>
<td>Easipay Gen Supply</td>
<td>0.8690</td>
<td>1.38</td>
</tr>
</tbody>
</table>
Industrial Demand Price (K/kVA/month)               69.61               110.68  
Domestic Credit first block of 30kWh               0.4502               0.72

It is common in many jurisdictions for consumers to receive a subsidy for regulated utility services for either social or political reasons and sometimes for economic reasons. In jurisdictions where market driven pricing is used, or where generation competition is introduced then industrial customers can often demand lower prices, because of their larger size and the market power this gives them.

The Commission has estimated the long run marginal cost of delivering power in each service area, and the margins at current prices. The costs used include the annualised capital costs and operating costs of generation, distribution, and transmission infrastructure as well as customer specific equipment like meters and customer premise connections. This analysis was based upon information supplied by PPL. Table 11 shows the resultant weighted average contribution (weighted by energy usage) for each customer type.

These results indicate that domestic customers are receiving a significant subsidy, which is paid for by general supply customers and industrial customers. This cross subsidy is a result of growth in high cost areas where the predominant usage is domestic. So, in fact, domestic customers in low cost areas are also paying a subsidy to customers in high cost areas.

Table 11: Current Average Energy Contribution Margins

<table>
<thead>
<tr>
<th>Customer Type</th>
<th>Average price in Kina per kWh</th>
<th>% Gross Contribution Margin</th>
</tr>
</thead>
<tbody>
<tr>
<td>Domestic – credit</td>
<td>0.64</td>
<td>-43%</td>
</tr>
<tr>
<td>General Supply – credit</td>
<td>0.83</td>
<td>39%</td>
</tr>
<tr>
<td>Industrial – credit</td>
<td>0.54</td>
<td>25%</td>
</tr>
<tr>
<td>Public Lighting – credit</td>
<td>0.77</td>
<td>n/a</td>
</tr>
<tr>
<td>Easipay Domestic</td>
<td>0.58</td>
<td>-9%</td>
</tr>
<tr>
<td>Easipay Gen Supply</td>
<td>0.81</td>
<td>28%</td>
</tr>
</tbody>
</table>

The Commission notes that a shift to price differentiation between service areas may reduce or remove this subsidy over time.

The Commission regards the price relativity between customer types to be the outcome of prior government policy settings. Where government policy in the future seeks to change these relativities such that an increase in cross subsidy is required to implement the new government policy, than the Commission would expect that the government will provide the subsidy funds or financing arrangement which would allow cross subsidy to be reduced at least to the prevailing level of cross subsidy which exists at the time of the policy change, or otherwise there will be long-term financial sustainability issues for PPL. Therefore, the Commission does not propose to change the relativities as they currently stand unless PPL can demonstrate the need for change because of the introduction of generation competition in to the electricity industry sector, or further government guidance or input is provided via an industry policy statement or some equivalent form of advice. The current EIP simply specifies that prices should be affordable.

To protect the current relativity of domestic prices, the Commission has determined that in any particular service area the relativities shown in Table 12 must be maintained (to second decimal place on the Price Relativity Ratio plus or minus a small amount determined by use of full units in the fourth decimal of the price in Kina/kWh).

Table 12: Proposed regulated relativities

<table>
<thead>
<tr>
<th>Customer Category</th>
<th>2012 Prices</th>
<th>Price Relativity Ratio (K/kWh)</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Service Type</th>
<th>Price Ratio</th>
<th>Relativity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Domestic – credit</td>
<td>0.7650</td>
<td>1.22</td>
</tr>
<tr>
<td>General Supply – credit</td>
<td>0.8909</td>
<td>1.42</td>
</tr>
<tr>
<td>Public Lighting - (average)</td>
<td>0.8909</td>
<td>1.42</td>
</tr>
<tr>
<td>Easipay Domestic</td>
<td>0.6290</td>
<td>1.00</td>
</tr>
<tr>
<td>Easipay Gen Supply</td>
<td>0.8690</td>
<td>1.38</td>
</tr>
<tr>
<td>Domestic Credit first block of 30kWh</td>
<td>0.4502</td>
<td>0.72</td>
</tr>
</tbody>
</table>

Industrial customers have been excluded from this determination because of the issues associated with competition in the large load market (see section 5.6), and the different units upon which tariffs are based (i.e. Kina/kVA/month, which is a capacity unit rather than an energy unit).

The Commission has included these price relativity ratios in the Regulatory Contract and PPL must maintain these relativities in any particular service area.

### 5.5.1 Rebalancing constraints

Currently, there is a rebalancing constraint of 1.5% per annum written into the ERC. This means that PPL can change prices by up to 1.5% more or less than the X factor allows each year as long as the average price equals the MWAP.

In its 2011 submission, PPL have proposed that the rebalancing constraint be lifted to 2.5% per annum. PPL has indicated that it wants to have the flexibility to be able to increase the attractiveness of Easipay relative to Credit plans in order to migrate more customers to pre-payment, and thus, reduce the debt recovery pressures on PPL. Currently, domestic credit is slightly cheaper than Easipay, if customers use less than 70kWh of power (see Figure 6). But Easipay will be cheaper for customers who use larger quantities of power. This comparison ignores the effect of commission payments to Digicel for Easipay top-ups (see Section 5.7.1). The effect of these commission payments is likely to make Easipay far more expensive for most small customers.

**Figure 6 – Easipay Domestic vs. Domestic credit**

In the Commission’s view, the difference between Easipay and Credit should simply be the payment method and not the price. If a customer is struggling to pay their bills on time, then the price difference would need to be substantial for the customer to migrate from Credit to Easipay. This would be likely to distort the overall relativities of electricity prices, and allow Digicel to extract more rents from electricity supply payments where it experiences no competition in providing such services to consumers for PPL. Bill payment issues should be specifically addressed as bill payment issues rather than as an electricity pricing issue.
The Commission has determined that the rebalancing constraint, will limit the amount any particular price can vary from the ratios shown in Table 12, from year to year. Thus, any price must be within 1.5% of the ratio, at any time during the contract.

5.6 Competition in the Large Load market

The EIP provides for the preservation of competition in the Large Load market where customers have a load of more than 10MW. These customers may be located inside or outside PPL’s exclusive licence area.

The Commission must ensure that competition in this market is fair. In particular, it needs to ensure that PPL does not use cross subsidies from other customers or service areas to exclude competition from this market. Equally, PPL must be able to adjust its prices in this market so that they are competitive within the constraints of the economically efficient costs of technology they have deployed. This, of course, does not prevent PPL from exploiting innovations in technology to gain efficiencies which would reduce their supply costs and enhance its ability to compete. Indeed, such innovation is likely to ‘spill over’ into small load supply and facilitate network expansion or entry into new areas previously uneconomic to enter.

As previously stated the EIP has three objectives:
- Improving access in the provision of electricity services;
- Improving reliability of electricity supply; and
- Ensuring that power is affordable for consumers.

These objectives indicate that if a lower cost generation provider can provide customers with lower cost electricity supply services then they should win the customer’s business. Equally, if PPL can provide the customer with lower cost service then PPL should retain the customer’s business. It is important, therefore, that PPL’s prices in the large load market reflect the cost of providing generation services in this market.

In order to remove the possibility of ant-competitive cross subsidy from the monopoly wires network infrastructure part of PPL’s business, and to allow PPL and potential new generation entrants to compete on an equal footing for electricity generation, the Regulatory Contact will require that PPL develop electricity distribution and transmission tariffs, within the next regulatory period. These tariffs shall be equally applied to a large load customer, whether or not they have a contract for energy supply from either PPL or the new entrant generator, or whether energy is supplied through a power purchase agreement (PPA) with PPL, or as a separate independent power producer (IPP). From a transparency point of view, such tariffs shall be published, and included in the regulatory financial reporting arrangements. PPL shall apply the same network tariffs to itself, as it does to its generation competitors.

The Commission recognises that it will need to develop a methodology to ensure that PPL’s prices for large load customers cover its costs associated with providing service to these customers. The Commission does not propose to do this as part of the current ERC development, but the ERC will need to incorporate the mandated requirement for PPL to develop network tariffs during the coming regulatory period under a public consultation process conducted by the Commission. Such network tariff development will need to be undertaken in parallel with the development of a Third Party Access Code, which will cover and lock down the non-price terms and conditions of access for third party generation to PPL’s existing primary electricity networks. The Commission also expects it will take PPL some time to establish the data allowing estimates of the cost of providing network services to this specific group of customers.

For the large load customer segment, PPL will need to compete on the price for the generation of electricity, where loss factors are applied to cater for different generation injection points. PPL will not be able to engage predatory pricing for provision of such generation services. The Commission therefore determines that PPL’s energy prices for customers with loads of greater than 10MW must exceed or be equal to the cost of providing energy supply service to these customers, including reasonable costs associated with wholesale customer service delivery. In this sense PPL must not employ predatory pricing to prevent or limit the entry of new competitive generation capacity. This is specified in the ERC and the ERC makes provision for cost estimation and network tariff setting and structure
methodologies to be established at a later date, probably in parallel with the development of the Third Party Access Code.

The Commission invites submissions from interested parties on this issue, and the timing to ensure all aspects of third party access are available when required.

### 5.7 Modifications to Annual Tariff Adjustment Process

Currently the ERC uses the following formula to calculate any annual changes in the MWAP.

\[ MAP_t = MAP_{t-1} \times CWI_t \times (1 - X_t) \times (1 - CEF) \times (OUR_t) + TPTA \]

Where
- \( MAP_{t-1} \) is the Maximum Annual Price Cap for Regulatory Year \( t-1 \);
- \( CWI_t \) is the change in the Cumulative Weighted Index over the 12 month period ending on 30 September in Regulatory Year \( t-1 \) and is designed to reflect inflationary effects and increase in external, uncontrollable costs faced by PPL.
- \( X_t \) is the value of X for Regulatory Year \( t \). \( X_t \) is a predetermined smoothing factor, used to smooth the impact of any predetermined increases (or decreases) in PPL’s prices;
- \( CEF \) is the Capital Efficiency Factor, which is based on the Imprudent Capital Shortfall, as determined at the mid-point of the current regulatory period;
- \( OUR_t \) is the Over / Under Recovery Adjustment for Regulatory Year \( t \). Where the Actual Weighted Average Tariff differs from the MWAP, the difference is added to the MWAP for the next Regulatory Year; and
- \( TPTA \) is an amount determined by the ICCC to account for any positive or negative tax change events.

In the current ERC the following constraints also apply:

- The tariff for customers in respect of a premises or public lighting installation cannot increase by more than 1.5% more than the increase in the MWAP in any year;
- Tariffs for General Supply Customers cannot increase by more than the increase in the MWAP; and
- Minimum charges for General Supply Customers, Domestic Customers and the first 30kWh/month for Domestic Customer on credit meters must not increase by more than the increase in the MWAP.

PPL in its submission has proposed a number of changes to the tariff adjustment mechanism.

#### 5.7.1 Minimum Tariffs

PPL has proposed that the restrictions on increases in minimum tariffs for each customer category be removed and that minimum tariffs be allowed to move in line with the annual weighted average increase for all tariff classes. Since publishing the initial draft report, the commission has had further discussion with PPL on this topic.

PPL is concerned that if minimum payments are set too low then the proportion of customer payments which are paid as commissions will be too high. This is because PPL pay a fixed amount per payment to Digicel as a commission for collecting payments on PPL’s behalf. Table 13 illustrates this. If a customer pays 10 Kina then they effectively pay 11% of their payment as commission. However, if the customer pays 20 Kina, then the commission drops to just over 5% of the power purchase cost. Effectively, the larger the payment a customer makes the more power they get for their money.
The Commission understands that the commission is charged directly to the customer by Digicel and that this does not appear as either a revenue line or a cost line in PPL’s accounting records. Therefore, these commissions will have no effect upon the regulated electricity prices.

### Table 13: Commission

<table>
<thead>
<tr>
<th></th>
<th>Example 1</th>
<th>Example 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customer Payment (Kina)</td>
<td>10</td>
<td>20</td>
</tr>
<tr>
<td>Commission (Kina)</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Power Purchase (Kina)</td>
<td>9</td>
<td>19</td>
</tr>
<tr>
<td>Commission as % of Power purchase</td>
<td>11.1%</td>
<td>5.3%</td>
</tr>
<tr>
<td>Power Price (Kina per KWh)</td>
<td>0.6290</td>
<td>0.6290</td>
</tr>
<tr>
<td>Quantity purchased (kWh)</td>
<td>14.3</td>
<td>30.2</td>
</tr>
</tbody>
</table>

PPL is concerned that customers are tending to make the minimum payment and that this is costing the customer more. In many cases, the minimum payment represents less than a week of electricity for a customer. The effect also increases the volume of payments on the Easipay system which in turn requires additional cost to PPL to upgrade the system.

The Commission’s view is that having low minimum payments is an important mechanism to ensure that low income households and small businesses are able to have access to electricity. This is counter balanced by the commission costs which customers must pay. While the commission cost creates a natural incentive for the customer to make larger top-ups in order to minimise transaction fees, this will only work if customers are aware that they are paying a commission.

The Commission has therefore decided to take a compromise position here and increase the minimum payments to 15 Kina. This will then be adjusted annually using the CPI and not the X factor.

### 5.7.2 Cumulative Weighted Index

The Cumulative Weighted Index (CWI) is designed to ensure that annual changes in PPL’s prices reflect changes in externally driven input costs over which it has no control. Currently, the CWI comprises:

- W1, adjusted PNG CPI;
- W2, Kina / Australian dollar exchange rate – representing the purchasing power of the Kina with regard to purchasing products and service from overseas;
- W3, average fuel price;
- W4, Kina/US dollar exchange rate – representing the costs to PPL associated with the Kanudi Capital Recovery Charge; and
- W5, a combination of the Kina/US dollar exchange rate (0.7) and the PNG CPI (0.3) representing the costs to PPL associated with Kanudi Variable Operation and Maintenance Costs.

The sum of the weights in each regulatory year must be equal to 1.

PPL has proposed some amendments to the CWI.

### 5.7.3 W3 Fuel Weight
W3 in the current contract is designed to allow the MWAP to adjust for changes in fuel price, thereby minimising PPL’s exposure to profit risk associated with volatility in fuel costs.

5.7.3.1 Issues with the current method of fuel adjustment

PPL’s main concern with the fuel weight is that fluctuations in the price of fuel do not necessarily get reflected in the annual price adjustments, as the fuel weight does not take volumes of fuel purchased into account. Over the course of the current regulatory period, there have been significant variations in both the price of fuel and the costs incurred by PPL. The actual cost incurred by PPL is a function of both price and volume.

Table 14 shows the % variance of the actual cost over the forecast cost.

**Table 14 – Current fuel adjustment**

<table>
<thead>
<tr>
<th>Year</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td>% Variance of actual over forecast</td>
<td>-6%</td>
<td>-5%</td>
<td>45%</td>
<td>-8%</td>
<td>16%</td>
<td>34%</td>
</tr>
</tbody>
</table>

The variation in costs has been due to both:
- Unforeseen changes in fuel prices; and
- Changes in the mix of hydro and diesel sources to generate power.

Hydro power generation is heavily reliant upon climate conditions and an extended period of drought could lead to the requirement for significantly more power generation from diesel sources, which increases PPL’s fuel consumption.

The variation in price and the % share of generation which is diesel-based makes it difficult to forecast the proportion of PPL’s costs that should be attributed to fuel.

In its 2011 submission, PPL submitted the following:

“The weights provided for fuel costs in the CWI for the current regulatory period have been significantly below the actual proportion of PPL’s costs made up by fuel and do not adequately account for the substantial variation in costs experienced by PPL.”

“PPL is proposing to remove the fuel weight from the CWI, and instead introduce a specific fuel adjustment factor (F-factor), based on variations between forecast and actual fuel costs.”

PPL proposed that the F-factor would work as follows:
- PPL’s smoothed revenue requirement and fuel cost forecasts for each year would be set out in the ERC;
- At the end of each quarter, actual fuel costs would be compared to forecasts; and
- The F-factor would be calculated as the difference between actual and forecast costs, expressed as a proportion of the smoothed revenue requirement for that quarter.

In the initial draft report, the Commission agreed that PPL’s proposal would better reflect actual costs to PPL.

However, the Commission was generally concerned that PPL has not been investing in lower cost methods of generation such as hydro and that, under such a pricing mechanism, PPL would have no incentive to invest in lower cost generation.

- PPL would have no material downside risk when using expensive diesel generation, as higher fuel usage will result in higher prices; and
- PPL would receive no financial benefit from investing in cheaper hydro power generation, as lower cost generation will be reflected in lower prices.
The Commission was and still is of the view that the introduction of the Fuel Factor by itself would support a systemic high cost power supply. If the Commission were to approve such a change it would also need to be accompanied by mandated requirements to invest in cheaper forms of generation.

In its 2012 submission, PPL focussed heavily on this issue. In summary, they repeated its concerns that:

- The annual review process had the effect of under recovery of its fuel costs;
- Because fuel represents such a large portion of its costs, it had the potential to bankrupt them;
- As a consequence it argued that the beta used in the WACC calculation should be much higher;
- PPL submitted that it did have incentives to invest in other forms of generation and that they had done so in response to high diesel prices and that it currently has an optimal mix of types of generation; and
- Because of major increases in the price of fuel, the weighting of fuel in the annual price adjustment had become misaligned with its actual costs.

Furthermore, PPL raised concerns about:
- Being reliant upon a monopoly supplier of fuel; and
- Not being able to buy forward contracts which gave them certainty over their prices.

PPL argued strongly that a quarterly review of the MWAP to reflect changes in fuel prices would go a long way towards resolving these issues.

In response, the Commission has determined to make quarterly price reviews of the fuel component of the MWAP.

In the Commission’s view, the current arrangement:
- Exposes PPL to major cash flow issues and negative financial impact under circumstances where there are major increases in the fuel price;
- Does not allow for changes in mix due to drought conditions; and
- Does not allow for unplanned changes in mix of hydro and diesel due to higher than forecast demand.

However, it also:
- Allows for planned changes in the mix of hydro and diesel generation;
- Allows for changes in fuel prices;
- Discourages PPL from making unplanned investment in additional high cost generation which uses fuel; and
- Encourages PPL to invest in additional low cost generation which does not use fuel.

### 5.7.4 New method of fuel adjustment

The Commission wishes to retain the positive elements of the current approach while addressing the negative impacts. Therefore, the Commission has determined to use a new method of calculating fuel costs into the contract.

The MWAP will be split between two components. A Fuel Weighted Average Price (FWAP) and a Non Fuel Weighted Average Price (NFWAP) so that:

\[ \text{NFWAP} = \text{MWAP} - \text{FWAP} \]

- The FWAP will be calculated using the method explained in section 6.1.1.2;
- The NFWAP will be calculated by subtracting the FWAP from the MWAP;
- The initial MWAP is calculated from the building block method as it currently is;
- The FWAP will be recalculated every quarter using the method explained in section 6.1.1.2;
- The NFWAP will be adjusted at the end of each calendar year;
- The annual NFWAP adjustment will reflect changes in CPI, Australian dollar exchange rate and US dollar exchange rate. This will be done using a CWI as explained in the following sections; and
• The NFWAP adjustment will also be adjusted using an X factor, to reflect cost changes as calculated using the building block method explained in section 6.

This means that NFWAP will change once per year, but FWAP will change every quarter. Consequently, the MWAP will also change every quarter.

The Commission was reluctant to introduce price reviews every quarter because it creates less financial certainty for PNG businesses and households. However, the Commission is convinced that the consequences of not addressing the fuel issue is such that PPL is likely to suffer significant financial harm which in turn will affect the reliability of electricity services provided to PNG as a nation.

The Commission is of the view that the proposed changes will remove the risk that PPL will not recover fuel costs due to events beyond their control as well as maintaining incentives for PPL to find cheaper ways of generating electricity. If PPL increase the use of diesel based generation above that which is prudent or planned, then PPL will not be able to recover these costs. Equally, if PPL use less fuel than planned by introducing lower cost means of electricity generation, then PPL will be able to keep the savings and the price will not be reduced.

In the initial draft report, the Commission proposed to introduce a drought clause, to address increased fuel usage caused by drought conditions. This will now be covered by use of force majeure conditions when the fuel costs are calculated. See section 6.1.1.2.

### 5.7.5 Calculating CWI

The current CWI calculation is made up of 5 components. This will be reduced to 3 components as follows

\[
CWI = W_1 \times \% \text{ CPI change} + W_2 \times \% \text{ Kina/AUD change} + W_3 \times \% \text{ Kina/USD change}
\]

Where:
- \( W_1 \) = the proportion of non-fuel costs which are affected by inflation in PNG;
- \( W_2 \) = the proportion of non-fuel costs which are affected by the Australian dollar exchange rate;
- \( W_3 \) = the proportion of non-fuel costs which are affected by the US dollar exchange rate;
- \( \% \text{ CPI change} \) = the annual \% change in the PNG CPI;
- \( \% \text{ Kina/AUD change} \) = the annual \% change in the Kina / Australian dollar exchange rate;
- \( \% \text{ Kina/USD change} \) = the annual \% change in the Kina / US dollar exchange rate; and
- The sum of \( W_1, W_2 \) and \( W_2 \) must equal one.

Because fuel costs are calculated separately there is no longer an adjustment for fuel built into the CWI.

### 5.7.6 W1 Adjusted PNG CPI

Under the current ERC, PPL must submit its proposed tariffs by the second Friday in November of each year. Adjusted PNG CPI figures for the 12 month period ending on 30 September are required for the calculation of the CWI.

However, according to PPL, adjusted PNG CPI figures provided by the National Statistics Office are frequently late. This makes updates to the MWAP and ensuring any rebalancing of tariffs is consistent with the ERC, difficult.

To allow sufficient time for PPL to update prices and rebalance tariffs, PPL proposed that the ERC be amended to specify that if the Adjusted PNG CPI figures for the 12 month period ending on 30 September are not available by the first Friday of November, then PPL may use the Adjusted PNG CPI for the 12 month period ending on 30 June instead.
The Commission thinks this is a practical solution and has allowed for this in the new ERC.

W1 will apply by default to all non-fuel costs which are not covered by W2 and W3. So W1 is calculated by subtracting W2 and W3 from 1.0.

\[ W1 = 1 - W2 - W3 \]

### 5.7.7 W2 – Kina / Australian Dollar Exchange Rate

No issues were raised with this element of the CWI. So the Commission does not propose to change it.

The Commission understands from PPL that 75% of Maintenance and Consumables are exposed to the Kina / Australian dollar exchange rate. And so W2 will be set accordingly. For 2013, this will be 8.5% of Non-Fuel costs.

### 5.7.8 W4 and W5 – The Kanudi contract

In the current ERC, W4 and W5 were designed to account for costs incurred by PPL under the Kanudi contract:

- W4 adjusts the MWAP to account for changes in the Kina/US dollar exchange rate and is designed to reflect changes to PPL’s costs related to the Kanudi CRC (capital recovery charge) and Fixed Operating and Maintenance Costs (FOMC); and
- W5 adjusts the MWAP to account for changes in both the Kina/US dollar exchange rate and PNG CPI. With W5, the Kina/USD dollar exchange rate is given a weight of 70% while PNG CPI is given a weight of 30%. W5 is designed to reflect changes to PPL’s costs related to the Kanudi VOMC (Variable Operation and Maintenance Costs).

All Kanudi related costs (other than fuel) are met in US dollars. Fuel costs are treated as a direct pass-through to PPL, and are therefore subject to the same variation in amount as PPL’s other costs.

“Accordingly, PPL is proposing to combine the current two Kanudi related weights into a single weight, based on variations in the real Kina/USD exchange rate. Kanudi related fuel costs will be treated in the same way as other fuel costs faced by PPL.”

The Commission agreed with this proposal. The new weighting for the Kanudi contract will be renamed W3 and will be applied only to the Kina / US dollar exchange rate.

The non-fuel costs of the Kanudi contract represent 5.2% of total non-fuel costs in 2013.

### 5.7.9 Real weights for CWI

The weightings are determined based upon the proportion of cost for each building block.

- W1 is set by subtracting W2 and W3 from 1.0;
- W2 is set at 75% of consumables and maintenance costs as a proportion of total non-fuel revenue requirement costs; and
- W3 is set as the cost of the Kanudi Contract (excluding fuel) as a proportion of the total non-fuel revenue requirement costs.

The Commission has determined to use the weightings shown in Table 15

Table 15: Proposed real weights for CWI variables
### 5.7.10 Capital efficiency factor

Currently, the Capital Efficiency Factor (CEF) is based upon the Imprudent Capital Shortfall, as determined at the mid-point of the current regulatory period. The CEF is calculated as follows:

\[
CEF = (0.0012 \times ICP) + 0.049
\]

The CEF specifies that if PPL was found to have not met its capital expenditure target at the mid-term capital expenditure review (that is, 80% of the Total Forecast Capital Expenditure), the MWAP would be reduced in the remaining years of the period by an amount proportional to the shortfall.

PPL pointed out that:

> “The CEF has been zero for the entirety of the current regulatory period due to PPL meeting its capital expenditure benchmarks – that is, the Imprudent Capital Percentage (ICP) was zero.”

> “PPL is of a view that the CEF should be removed from the price control formula. The building blocks framework and price cap mechanism provide clear incentives for PPL to undertake prudent and efficient capital expenditure, this will be reflected in lower RAB, reducing prices going forward”.

The Commission does not agree with the argument that because the CEF has not been used it is not required. The fact that it has not been used may mean that its presence in the contract has been a factor in holding PPL accountable to its capital spending forecasts.

The Commission does agree that in theory the long run building block framework and price cap mechanism does create incentives for PPL to undertake prudent and efficient capital expenditure. However, in the short term, during the life of the contract, this is not the case. Short term imprudent capital spending will not be reflected in tariffs without the use of the CEF.

The Commission also notes that it has limited resources and a limited view of PPL’s actual capital spending. It is therefore difficult to assess the “prudence” or otherwise of PPL’s capital spending in advance. It is therefore valuable to the Commission to have a mechanism to claw back capital spending from the MWAP at a later date.

There is also the issue that, formerly, there was no safeguard against inefficient procurement. Under the new contract, efficiency of procurement (assessed against a range of criteria) will be a factor which is to be taken into account in allowing or disallowing capital expenditure from cumulative capital expenditure under the broad criteria of ‘prudence’ which also reflects ‘efficiency’. Whether such a provision would have altered previous CEF performance is unknown, but will be a consideration in PPL’s procurement under the new contract.

The Commission considers, therefore that the CEF remains a useful mechanism but has determined to apply it in a different manner. The MWAP will be recalculated using the X factor to reflect the assessment at the mid-term review of capital efficiency as follows:

- Identify capital projects which have not been carried out and remove these from the RAB;
- Identify imprudent and in efficient capital spending and remove this from the RAB;
- Identify capital projects that have been delayed, but are still budgeted;
- Identify capital projects which have been delivered earlier than planned;
- Leave capital costs for prudent spending as budgeted even if actual costs were higher or lower;
• Recalculate RAB for the contract period based upon the actual timing of projects and after removing undelivered projects or imprudent or inefficient spending;
• Recalculate the return of capital amounts;
• Recalculate the return on capital amounts;
• Leave the operating costs unchanged from the budgeted operating costs;
• Inflate all costs into 2015 values;
• Recalculate the Revenue Requirement for the full five year period; and
• Recalculate the X factor for years 2016 and 2017 so that the NPV of the forecast revenue for the full contract period will be equal to the NPV of the revenue requirement as it would have been assessed using the assessed efficient capital spend.

In effect this will simplify the formula which describes the MWAP. The CEF factor will disappear as this is now built into the X factor which is adjusted at the mid-term review. We have also expressed the X factor as a positive number.

\[ MWAP_t = NFWAP_{t-1} \times CWI_t \times (1 + X_t) \times (OUR_t) + FWAP_t + TPTA \]

The Commission has estimated what impact this approach would have on the MWAP with various increases or decreases in capital spending. The results of this analysis are shown in section 6.8.4.

PPL in its 2012 submission expressed concern that this recalculation of the regulatory asset base (RAB) was removing incentives for it to increase its efficiency. To address this, the Commission made the following modifications or clarifications in the approach.

• Non-fuel operating expenditure is not reassessed, but remains as forecast in the initial MWAP calculation.
• The cost of budgeted capital projects is left unchanged, regardless of whether or not the actual cost of these projects is higher or lower than the amount budgeted.
• Only capital projects where PPL has either failed to build the proposed infrastructure, or where PPL is judged by the Commission to have wasted capital or spent capital imprudently or inefficiently, are removed.
• The timing of projects will also be adjusted for, because the Commission recognises that higher or lower demand may require a change in timing. The Commission also wishes to give PPL some flexibility in their capital spending to ensure that it can deliver the required service levels specified by the contract.
• For the purpose of clarification, the Commission also determines that any capital projects which are funded by grants, budgetary subventions or by funds from the “Reliability Improvement Fund” (see section 8.5.8) will not be included in the RAB; and appropriate adjustments will be made to the ‘X’ or smoothing factor to fairly reflect the economic benefit of the financial value differential between concessional loans and market priced loans.
• The Commission will maintain a list of capital assets which are listed in PPL’s asset register but will be excluded from future RAB calculations.

### 5.7.11 Other pass-through events

PPL has proposed that a pass-through clause for “other pass-through events” be written into the ERC.

The clause would specify:

• The application process for cost pass-through;
• The relevant factors that should be taken into account by the Commission in deciding whether to approve the pass-through amount; and
• The application of any approved pass-through amount.

PPL envisages that the type of events which might activate the Pass-through clause would include:

• Any change to the level of competition in the electricity industry, including the introduction of additional zones for exclusive supply or sale of electricity;
- An obligation placed on PPL to supply service to new areas where the obligation to serve those new areas was not identified at 30 March 2012 and included in PPL’s forecasts;
- Any requirement for PPL to provide additional CSO services to those CSO services provided at 30 March 2012;
- Costs incurred due to the introduction of third party access arrangements;
- The requirement to plan for, bring forward or construct assets or undertake operating expenditure associated with generation capacity above that assumed in its forecasts; and
- An increase in the level of water licence fees.

PPL also proposed that the pass-through application should have a threshold where the change required PPL to spend K250,000 above forecast expenditure in any year.

The Commission is supportive of this change. The Commission also notes that it has limited resources to process such applications and will therefore need to pass the cost of assessing any “pass-through” proposal to PPL. The Commission would provide PPL with a cost estimate upon receiving an application for a pass-through assessment and give PPL the opportunity to proceed or halt its application once the likely cost is known.

The Commission has therefore written a pass-through clause for “other pass-through events” into the ERC.

The clause specifies:
- The application process for cost pass-through;
- The relevant factors that should be taken into account by the Commission in deciding whether to approve the pass-through amount; and
- The application of any approved pass-through amount.

PPL will pay the cost of carrying out the assessment of its application.

### 5.8 Length of Regulatory Period

The current ERC covered a regulatory period of 10 years. It was due to be terminated on 31 December 2011 and provides for a new ERC to be put in place for the five year period from 1 January 2012 until 31 December 2016. Due to a number of delays discussed in the Forward to this document, the commencement of the next Regulatory Period is 1 January 2013 and it will terminate on 31st December 2017.

The Commission considers that there is a trade-off between investment certainty and short term performance concerns.

- To provide PPL with sufficient certainty that it will continue to invest in electricity infrastructure, a longer regulatory contract period would be desirable;
- But with the current poor reliability of electricity supply, PNG cannot afford to wait longer than 5 years to address any ongoing issues, which might arise under the new contract.

PPL also proposed that the timing of the next regulatory review be amended. They proposed that “the next revised draft regulatory contract be given to Commission on 1 April 2016 – 3 months later than the current process. The reason for this amendment is that this later date will allow 2015 actual expenditure and revenue to be known, enabling a more accurate review of actual outcomes against forecasts.

The Commission supports this proposal, but with the change to the contract period, the next revised draft regulatory contract will now be given to the Commission on 1st April 2017.

#### 5.8.1 Determination

The ICCC sees no reason to deviate from the five year term envisaged by the current ERC for the next ERC.
5.8.2 Mid Term Expenditure Review

As part of its capital expenditure program, PPL has submitted to the Commission the projects it will undertake over the forthcoming regulatory period. The Commission will undertake a mid-term review of these projects to assess whether they have been implemented as planned. This mid-term review will be made on the outcomes monitored as at the 1st June 2015 and PPL will be required to submit to the Commission by this date the projects it has undertaken over the first two and half years (January 2013 to June 2015) of the regulatory period and the corresponding costs.

If the Commission is not satisfied that PPL has adequately implemented the projects, over the first two and half years (2013 to June 2015) of the regulatory period or if capital spending is assessed to be imprudent, then the Commission will consider re-opening the revenue path and recalculating the X Factor (see section 5.7.10). The Commission shall appoint an independent international consultant to do a capital expenditure progress report and a capital expenditure forecast report. All these are further detailed in Clause 4.1 of the Electricity Regulatory Contract.

The Commission shall, if it considers it necessary or desirable, will appoint an appropriately qualified independent international consultant to assess the prudence and efficiency of the operational expenditure and the robustness of demand forecasts, included latent or unmet demand. The reasonable cost of such independent consultant shall be met by PPL.

If any operational expenditure are found not to be prudent and efficient or forecasts of demand are found not to be robust by the consultant, the Commission shall make adjustment to the Smoothing Factor (X) to reflect only the prudent and efficient operational expenditure and robust demand forecasts. If the Regulator does adjust the X Factor in Schedule 6 of the Regulatory Contract, then this will apply to the regulatory years for 2016 and 2017. All these are further detailed in Clause 4.2 of the Electricity Regulatory Contract.

In the initial draft report, the Commission proposed to carry out a review of PPL’s capital spending plan. This has now been completed and the resultant capital plan is now built into the price path determined in this report. A summary of the findings can be found in section 6.2.

5.8.3 PPL’s Assets and Capital Works-in Progress Inspections

The Commission as part of its assessment of ‘prudence in terms of value for money’ in any procurement, whether competitively tendered or whether in conformity with priorities agreed at the start of the contract will do a physical inspection of PPL’s assets at the discretion of the Commission and any appropriately qualified independent international consultant.

This inspection will occur anytime whether before, during or after the conclusion of the contract regulatory period with a view to assess against relevant performance indicators and outcomes contemplated for meeting/exceeding/failing to meet those levels.

As part of the procurement processes, the Commission will require PPL to provide documentation as evidences of competitive tendering either operational or capital procurement that contributes to the efficiency and prudence of the projects. It must also be noted that all necessary requirements of any competitive capital and operational procurements as outlined in the Regulatory Contract under Clause 8 must be compliance.

6.5.4 ICCC’s Determination

The ICCC’s determination is to allow a mid-term capital expenditure review. The mid-term capital review will assess PPL’s implementation of the projects they have identified for implementation in the forthcoming regulatory period, and which are funded under the [MWAP]. The mid-term review will start on 1st June 2015.

For the mid-term review PPL is required to co-operate with the ICCC by providing detailed descriptions of the projects they have undertaken over the first two and half years (2013 to June 2015) of the regulatory period and the corresponding costs by this date.
If the ICCC is not satisfied that PPL has implemented the items identified in the capital expenditure program over the first two and half years (2013 to June 2015) of the regulatory period then the ICCC will consider re-opening the revenue path and recalculating the X Factor as described in section 5.7.10.

5.9 Retail Margin

In its 2012 submission, PPL raised the issue that there is currently no retail margin built into the price path.

“PPL makes no margin on sales of power sourced from any current or future independent power producers such as Hanjung Power or PNG Forest Products – even though it enters into long term contracts with risks. IPP’s currently supply PPL with about 16% of its total supply needs and the Electricity Industry Policy envisages that future generation needs will be met by IPP’s after a competitive bidding process.”

“A retail profit margin is a prerequisite for retail competition (together with a competitive generation sector and cost reflective tariffs).”

“Australian regulators had adopted retail EBITDA margins of 5% in Queensland (QCA, 2009), the ACT (ICRC, 2009) and South Australia (ESCOSA, 2007). In 2010, Professor Stephen Gray made a comprehensive study of retail margins for the NSW Independent Pricing and Regulatory Tribunal (IPART).”

The Commission does not think there is any need to introduce a retail margin. All of PPL’s forecast costs are covered by the building block method and this includes any retail costs.

The EIP does not promote retail competition in PPL’s exclusive area of operations (i.e. Market 1 as defined in Section 3.4). So the situation which PPL describes is not likely to arise in the contract period.

The Commission’s understanding of the risk PPL undertakes when entering into contracts with IPP’s is that they must pay the capital charges to the IPP even if they do not use the electricity made available by the IPP. In the Commission’s view, this is no different from any other generating plant which PPL might own. In all cases if there is a drop in demand, then PPL will under recover its capital costs. The difference between PPL purchasing power from an IPP and generation capacity which PPL owns directly, is that PPL receives a return on the capital of the latter.

The Commission does however note that increased use of IPP’s will reduce PPL’s internally generated free cash flow and PPL’s gross margin in an accounting sense. Also the Commission notes that PPL will have incentives to self-invest in generation rather than in using IPP’s. The Commission expects that it is for this reason that the EIP provides for the Government in consultation with regulators to mandate the use of IPP’s if there is a shortage of supply. Overall the Commission expects that this will provide a positive incentive to provide sufficient power supply so as to avoid the mandated used of IPPs.

The building block method does not allow for any margin on either capital costs or operating costs. The return on capital component of the building blocks is simply recovering the cost of capital. There is no margin built into this. In the Commission’s view, it would be inconsistent with the building block approach to include a retail margin of any sort.
6 THE BUILDING BLOCK APPROACH

There are different forms of economic regulation. The Commission has traditionally adopted the Building Block approach to regulation. This form of regulation was initially stipulated in the initial Regulatory contracts for the various state owned enterprises including PNG Power established by the then Minister before the establishment of the ICCC. The Building block approach was initially chosen due to its ability to curtail the ability of the monopolist firm to extract monopoly rents from customers thereby keeping prices affordable. Other benefits associated with the Building Block approach include: that it is a relatively straight-forward, stable, and predictable process that is easily understood.

The objective of the building block approach is to estimate the total revenue that the service provider will require each year of the regulatory period to provide its investors with a reasonable rate of return and to allow the service provider to meet the appropriate costs incurred in providing the regulated services.

The primary focus and key feature of the building block approach, particularly in the case of State-owned enterprises, is its ability to curtail the ability of the monopolist to extract monopoly rents (higher prices) from customers. The building block approach is the methodology commonly adopted by many jurisdictions in setting prices and revenues in Australia and the UK.

There are a number of shortcomings with the building block approach. Primary amongst these shortcomings is that it provides limited incentives for the management to exert maximum effort as the firm’s profitability is not sensitive to managerial effort. This may lead to managers exerting the minimum effort that they can get away with. Other shortcomings include:

- The difficulty for the regulator in determining a service provider’s efficient costs;
- Information asymmetry provides for regulatory gaming;
- The review of efficient cost is extremely data intensive; and
- The time and cost involved in the review process.

The Commission recognises that in order for the Building Block approach to avoid monopoly rents and produce optimal economic outcomes it is vital that the cost included in the building block model are efficient and that there are meaningful incentives for management to reduce costs. The original regulatory contracts did not allow close scrutiny of costs.

Through the new regulatory contract with PNG Power, the Commission has implemented a number of mechanisms to mitigate the shortcomings of the building block approach. These mechanisms also set out to establish and reinforce incentives for improved performance and managerial effort along with increased transparency and accountability mechanisms.

In addition under paragraph 35 (2) e of the ICCC Act, the regulatory contract must “specify pricing policies and principles that are to be adopted in any regulatory contract that is issued in replacement of that regulatory contract on the expiry of its term”. Clause 4.3 stated of the 2002-2011 Regulatory Contract that “A building block approach must be adopted, consisting of the following components:

(a) initial capital stock;

(b) return on capital (WACC);
(c) new capital expenditure;
(d) return of capital - economic depreciation; and
(e) operating expenses.

Thus the Commission is bound to the use of the building block approach for the upcoming regulatory period. In the New Regulatory Contract the Commission has adjusted the “specify pricing policies and principles” such that it shall not be bound to the use of the building blocks approach in future Regulatory Contracts.

The building block approach is used to calculate the revenue requirement for PPL to continue to run their business efficiently and to continue to invest in network infrastructure to meet market demand. The revenue requirement is an estimate of the total costs of the business and hence the total revenue required to cover those costs.

The blocks are as follows;

\[
\text{Total efficient costs} = \text{operating expenditure.} + \text{return of capital (an allowance for asset depreciation).} + \text{return on capital (Regulatory Asset Base times an appropriate rate of return).}
\]

The Commission has viewed the current level of spending as an indication of the level of cost required to maintain the current level of performance. It is difficult for the Commission to assess the level of efficiency of PPL from a financial perspective. While there are currently frequent outages, this may still reflect efficient use of the resources currently available to PPL under the existing price cap.

The Commission was not able to find a comparable set of companies with which to bench mark PPL against, within the time and resources available to the Commission. A comparable company would need to be, vertically integrated, similar in size, operate in a similar climate, with similar terrain and deliver a similar level of service quality. Costs would need to be adjusted to reflect local labour rates, fuel costs and other operating costs. The Commission considers that while such a bench marking exercise would be extremely useful, finding appropriate companies to bench mark against would be difficult. The result would need to have multiple adjustments made in order to make any comparisons valid which would dilute the value of the exercise from a regulatory price setting perspective.

Instead of bench marking, the Commission has chosen instead to consider the current and past performance of PPL and to analyse changes in the forecast spending.

The Commission is concerned about the number of electricity outages in PNG and is therefore supportive of any efficient investment that will result in more reliable services to customers. Thus, the Commission, in its assessment of PPL forecast spending has taken a particular interest in how its spending will improve the reliability of supply. Generally, the Commission is not supportive of increased spending that will not result in an improved service to customers.

The general approach taken by the Commission is to identify the price of inputs at the start of the ERC and to allow the Maximum Average Price to change during the period of the ERC to reflect any changes.

### 6.1 Operating Expenditure

Since the initial draft report, PPL has updated their forecast operating expenditure and supplied actual values for 2011. It appears that there were also some errors in the historic operating costs information provided by PPL in their 2011 submission. PPL has therefore corrected this information. The Commission has also met with PPL to discuss their operating costs and to acquire further clarification on several points.

The real terms forecast of operating expenditures submitted by PPL for the new regulatory period for 2013 to 2017 is shown in Table 16.
Table 16: PPL’s Forecast Operating Expenditure

<table>
<thead>
<tr>
<th>K(000’s)</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating Expense</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fuel Costs</td>
<td>232,027</td>
<td>235,369</td>
<td>245,642</td>
<td>255,896</td>
<td>271,105</td>
</tr>
<tr>
<td>Purchase of Power</td>
<td>99,135</td>
<td>81,422</td>
<td>77,880</td>
<td>77,880</td>
<td>77,880</td>
</tr>
<tr>
<td>Purchase of Water</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>Salaries &amp; Wages- Direct</td>
<td>45,005</td>
<td>46,355</td>
<td>47,745</td>
<td>49,178</td>
<td>50,653</td>
</tr>
<tr>
<td>Other Direct Personnel Cost</td>
<td>38,891</td>
<td>39,172</td>
<td>39,440</td>
<td>40,679</td>
<td>41,709</td>
</tr>
<tr>
<td>Repairs &amp; Maintenance</td>
<td>17,640</td>
<td>18,081</td>
<td>18,533</td>
<td>18,996</td>
<td>19,471</td>
</tr>
<tr>
<td>Consumables</td>
<td>45,735</td>
<td>46,878</td>
<td>48,050</td>
<td>49,251</td>
<td>50,483</td>
</tr>
<tr>
<td>Freight and Cartage</td>
<td>4,260</td>
<td>4,367</td>
<td>4,476</td>
<td>4,588</td>
<td>4,703</td>
</tr>
<tr>
<td>Other Operating Costs</td>
<td>10,186</td>
<td>10,186</td>
<td>10,186</td>
<td>10,186</td>
<td>10,186</td>
</tr>
<tr>
<td>Administration Expense</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Overheads</td>
<td>72,697</td>
<td>74,514</td>
<td>76,377</td>
<td>78,287</td>
<td>80,244</td>
</tr>
<tr>
<td>Bad debt expenses</td>
<td>3,152</td>
<td>3,231</td>
<td>3,311</td>
<td>3,394</td>
<td>3,479</td>
</tr>
<tr>
<td>Salaries &amp; Wages - Indirect</td>
<td>19,567</td>
<td>20,154</td>
<td>20,759</td>
<td>21,382</td>
<td>22,023</td>
</tr>
<tr>
<td>Other Indirect Personnel Costs</td>
<td>15,512</td>
<td>15,890</td>
<td>16,279</td>
<td>16,893</td>
<td>17,312</td>
</tr>
<tr>
<td>Total Operating Expenditure</td>
<td>603,811</td>
<td>595,622</td>
<td>608,682</td>
<td>626,614</td>
<td>649,251</td>
</tr>
</tbody>
</table>

Operating costs make up the largest portion of PPL’s costs as shown by Figure 7. Together Fuel, Power Purchase and Operating Expenditure makes up 70% of PPL’s total costs.

Figure 7: Sources of cost

6.1.1 Fuel

Fuel represents a high proportion of the total PPL operating expenditure for both current and forecast numbers.

PPL has three types of power source;
- Hydro-generation
- Diesel-generation
- IPP (Independent Power Providers)
The Commission understands that fuel costs for input to MWAP will be a function of:

a. The total quantity of generation required,
   i. Customer demand,
   ii. System losses,

b. The proportion of diesel generation of the total load (Total Demand minus Hydro minus IPP),

c. The efficiency of the diesel generation,

d. The price per litre of fuel consumed.

Furthermore, the Commission recognises that the quantity of energy provided using diesel generation can deviate from forecast due to drought. Drought is recognised as a Force Majeure event where hydro generation forecasts accepted by the ICCC were not met through events beyond PPL’s control.

Significant growth in energy demand is expected during the next regulatory period. The additional demand, described in Section 6.1.1.1, will be supplied via a combination of hydro and diesel generation.

The operating model provided by PPL proposes that the first option for generation is hydro, then purchased power (IPP) and lastly diesel generation. In the larger systems diesel generation is primarily used for peak demand. The operating model means that diesel generation output can be determined as the total required generation, less the generation available from hydro and purchased power. For each year, PPL has provided a forecast for the output from each hydro-generation unit and IPP source, taking into account planned maintenance activities.

The key attributes of the proposed generation cost model are:

a. Hydro and efficient IPP generation sources are to be used first;

b. Diesel generation will continue to be the base generation capacity for smaller generation systems, and provide peak load, network support and interim capacity until additional hydro generation becomes economic in larger generation systems;

c. The change in fuel purchase price will be used to adjust MWAP on a quarterly basis;

d. A ceiling will be applied to fuel volume input to MWAP at the point hydro generation should be added to the generation pool, based on an estimate of the best economic value for the country and for PPL; and

e. The model will provide incentives for PPL to maintain the most efficient mix of generation for the required demand.

The Commission has determined to use a fuel cost model which allows change of the variables beyond the reasonable control of PPL. The diesel fuel cost per litre is currently beyond the control of PPL. For each generation system, the variables which are to be set at the commencement of the regulatory period are:

a. Forecast demand,

b. Systems losses (vary annually with improvement targeted for the next regulatory period),

c. Total forecast annual hydro output,

d. IPP forecast output,

e. Diesel efficiency.

**6.1.1.1 Forecast Demand**

The calculation of the cost of fuel for input to the calculation of the MWAP is dependent on the forecast demand for energy. PPL has provided the forecast for demand on a Generation System basis, with the total shown in Table 17.

**Table 17 - Annual Forecast Demand**

<table>
<thead>
<tr>
<th>(MWh)</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Energy Sales</td>
<td>854,416</td>
<td>948,169</td>
<td>1,030,074</td>
<td>1,072,103</td>
<td>1,114,131</td>
<td>1,153,256</td>
<td>854,416</td>
</tr>
<tr>
<td>Regulated Energy</td>
<td>794,239</td>
<td>881,389</td>
<td>920,514</td>
<td>962,543</td>
<td>1,004,571</td>
<td>1,043,696</td>
<td>794,239</td>
</tr>
</tbody>
</table>
The PPL supplied forecast exhibits a relatively constant growth during the regulatory period. The Commission accepts the PPL forecast in demand growth for the Regulatory Period.

However, the Commission requires that PPL provide the detailed demand forecasts (including estimates of latent or unmet demand), which underpin its capital and operational expenditure program to the Commission for the Mid-term Capex review. It must also be noted that the Commission if necessary, shall appoint an appropriately qualified independent consultant to assess the prudency and efficiency of the capital or operational expenditure and the robustness of demand forecasts, including latent or unmet demand. The cost of the independent consultant will be met by PPL.

Figure 8: Forecast Demand

If PPL can achieve greater reduction in system losses, or an increase in hydro output, the benefit of reduced diesel generation cost will be realised by PPL. If the proportion of diesel generation increases without an increase in demand, PPL will not receive additional fuel volume in the MWAP calculation.

As new generation projects are planned to be completed, the base line assumptions for each Generation System are adjusted. For example, the Ramu system shows year on year increases in hydro output as the Yonki Toe of Dam power station, and Ramu refurbishment projects are delivered. New hydro capacity is also planned in Kimbe, Buka and Popondetta during this contract period. The most significant deficiency is the lack of new hydro capacity in the Port Moresby system, where all growth in demand is to be supplied by increased diesel generation. Port Moresby generation is discussed further in the prudent use of fuel section 6.1.1.4.

Based on the PPL provided forecast information, fuel costs are expected to increase by 48% from 2012 to 2017 (excluding IPP purchases). Figure 9 shows the increase in expenditure excluding inflation (i.e. real terms).
Of particular concern to the Commission is the increase in the percentage of power that will be supplied using diesel generation. This will drive up the weighted average price of power generation. The Commission is concerned that PPL should have incentives in place to encourage investment in lower overall cost sources of power. In the absence of competition, the only tool available to the Commission to address this issue is a pricing tool. The Commission notes that PPL is planning to build some new hydro generation capacity during the course of the regulatory contract with hydro generation assets listed in the Capital Works Program.

PPL has stated in the “PPL Submission to ICCC Prelim Draft Report” that the current mix of generation technology is optimal. The Commission does not support this position, but acknowledges that any change to the mix of generation will take significant time to implement. Figure 10 shows the proposed decrease in overall demand satisfied by hydro sources during the regulatory period along with the increase in proportion supplied from diesel sources.

A submission was received which advocated increased use of other sources of power generation (see section 2.8.1). This submission suggested that use of solar energy might reduce exposure to fluctuating diesel prices. The Commission acknowledge that this would have a desirable effect and that the trade-off may be higher infrastructure costs. In the Commission’s view PPL are able to make this trade-off within the context of the ERC.

The use of other potential energy sources to produce electricity is or may become an important key area to assist PPL’s network in terms of load shifting. It must also be noted that it is outside of the Commission’s scope to specify the type of technology used to generate electricity. The only authority the Commission does have in this domain is to assess the prudent nature of any investments that PPL might make. With the EIP in place, it promotes the use of “feed-in tariffs” tariffs for IPPs to introduce competition into power generation for PPL in their exclusive licence areas. These tariffs will be set by a competitive bidding process and are therefore outside of the scope for this regulatory review. However, the use of this bidding process does allow IPP’s to use alternative forms of energy.
Therefore, it is PPL’s responsibility to ensure that any small scale generation network from reliable energy sources that has the potential of investment and reducing high infrastructural costs must be captured in PPL’s objectives or plans.

6.1.1.2 Calculation of Fuel Costs

For each Generation System the volume of fuel to be used each year is calculated using defined input variables. The volume of fuel required for each year is then multiplied by the per litre fuel cost. The calculation of fuel cost for input to the MWAP calculation is completed on a per system basis following the process shown in Figure 11.

Figure 11: Fuel Cost Calculation Process

6.1.1.2.1 Fuel Volume Calculation

Pre-defined and agreed values based on the current generation capacity and planned capital projects for each Generation System for the regulatory period are used in the calculation. For each year, values include:

- Annual customer demand (Demand\text{\scriptsize MWh})
- Annual hydro production output (to be modified as projects are planned for completion) (Hydro\text{\scriptsize MWh})
- Annual IPP production as applicable (IPP\text{\scriptsize MWh})
- System losses (SysLos)
- Conversion Factor (CF) litres / kWh

Calculated values are:

- Diesel MWh of production calculated, based on subtracting hydro and IPP output from the annual demand.\text{\scriptsize Diesel}_\text{MWh}; and
- Fuel Volume is calculated using diesel demand and the corresponding conversion factor. (Fuel\text{\scriptsize L})

$$\text{Diesel}_\text{MWh} = (\text{Demand}\text{\scriptsize MWh} / (1-\text{SysLos})) - \text{Hydro}_\text{MWh} - \text{IPP}_\text{MWh}$$
Fuel \_L = \textit{Diesel}_{MWh} \times 1000 \times CF

6.1.1.2 Fuel Cost Calculation

Based on the calculated Fuel Volume, the Fuel Cost is calculated for each system and then summed for an annual network total fuel cost.

\textit{Fuel Cost} = \textit{Fuel} \_L \times \textit{FP} \_L

The updated fuel price (\textit{FP} \_L) each quarter is to be used to adjust the FWAP.

6.1.1.3 Quarterly FWAP Adjustment

As discussed in section 5.7.4, the Commission has accepted that sudden and substantial variation in fuel purchase price can significantly impact PPL. As the fluctuation in fuel price is beyond the control of the PPL, an adjustment of FWAP every quarter is proposed. The FWAP will be recalculated each quarter based on updated diesel purchase price for each Generation System and updated Kanudi fuel cost in K/MWH.

For each quarter the average PPL fuel price for the previous quarter will be inserted into the fuel cost model for each region. Also the Kanudi IPP average fuel charge K/MWH for the previous three months will also be updated. No other elements to the fuel model including demand, forecast hydro output, forecast IPP output, systems losses or conversion factor are to be modified. The updated FWAP will be used to adjust the MWAP every quarter.

6.1.1.4 Prudent use of fuel

The key factor in efficient generation is the optimal mix between hydro and diesel generation. Hydro generation has a high initial cost for construction, with low operational costs while diesel generation has relatively low capital cost, and a high operational cost due to the high and variable cost of fuel.

Two of the current Port Moresby generation units are suitable for operating on natural gas rather than diesel. The Commission understands that the cost of fuel could be significantly reduced for these units if natural gas was used instead of diesel, but that the LNG project does not have any spare capacity available. However, with expansion to the LNG production capacity planned, additional capacity may be made available. PPL is encouraged to seek access to natural gas supply during this regulatory period to reduce the overall fuel cost input to the MWAP by requesting the Government to support its efforts to invoke the domestic market supply obligations mandated by the \textit{Oil and Gas Act}. 

Expenditure on new hydro generation projects (capital) and fuel cost (operational) for diesel generation is included in the calculation of the MWAP. Due to the high capital cost for hydro generation, there is a level of demand for any generation system which must be exceeded before an additional hydro plant becomes economic compared to using diesel generation. Once this threshold is passed, the benefit of hydro continues until the capacity of the hydro generation is exceeded.

The timing of hydro projects is critical to the efficient management of the electricity system. If a hydro project is completed too early, the cost of capital input to the MWAP is not efficient and if the project is delivered too late, the increasing cost of diesel generation does not provide an efficient outcome. The most significant planned capital project in this period is the Naoro-Brown Hydro power station.

The current information supplied by PPL for the Naoro – Brown hydro project is:

- 80 MW Hydro power station;
- Construction to commence 2015;
- Construction to be completed 2019; and
• Total cost K795 million.

During the period 2013 to 2017, the annual electricity demand for Port Moresby is forecast to increase by 74 GWh from 453 GWh to 527 GWh. This is an increase of 16.2% in generation output, which will be entirely supplied by increasing the diesel generation capacity.

The required forecast increase in diesel generation for Port Moresby during the period 2013 to 2017 is 62.9%. The increase is reflected in the number of litres of diesel forecast to be used and the associated cost of fuel. Using 2012 Kina value, the cost of fuel in Port Moresby during 2017 will be K134.5 million. The level of diesel generation forecast for Port Moresby in 2017 is equivalent to 28.5% of the planned Naoro-Brown Hydro power station capacity.

The cost to the consumer, the MWAP, is calculated using the return on invested capital, plus operational costs including fuel purchase. To minimise the overall cost, the optimum balance between capital investment and operational expenditure must be identified and delivered.

The annualised capital cost for Naoro – Brown power station (using an annualisation factor of 0.1308)\(^4\) is K104 million. In simple terms, when the equivalent cost of fuel can be avoided, the hydro power station becomes financially viable. Allowing additional cost to run diesel plant during planned maintenance periods for Naoro Brown of K10 million / annum, the assumed annual cost would be K114 million. This analysis assumes that the capital cost of existing diesel generating units is a sunk cost, and is therefore not included.

Once the Port Moresby annual fuel cost exceeds the annualised cost of the Hydro power station, the new Hydro power station should be ready for service. The Commission recognises that a project with the magnitude of Naoro Brown cannot be delivered in a very short timeframe.

Based on the current PPL demand forecast, the diesel fuel cost in 2016 will be K121 million rising to K135 million in 2017. Both annual costs exceed the threshold cost for the economic use of the Naoro-Brown Project as shown in Figure 12.

---

\(^4\)Based on Pre Tax Real WACC of 13.05% and a 50 year life. The ICCC notes an error was made in the second draft report which used a Post Tax Real WACC and ignored the tax shield on fuel costs.
The Naoro-Brown Hydro power station is currently programmed for delivery in 2019 providing generation output in 2020. With the addition of Naoro-Brown in 2020, K62 million in annual costs will be saved (see Figure 13).

Figure 12: Current Fuel Expenditure - extrapolated to 2020 if no hydro added
If the Naoro-Brown Hydro power station can be delivered in 2017, additional earlier savings can be achieved as shown in Figure 14. An early commissioning of Naoro-Brown provides significant economic benefit to the country and PPL.

Figure 14 - Overall cost if Naoro - Brown can be delivered by end of 2017.

As the Naoro-Brown project has not formally commenced, the Commission accepts that it is unlikely that a project of this magnitude can be delivered by the end of 2016. However, the Commission regards the current completion date of 2019 as inconsistent with efficient investment. The Commission believes that a reasonable target for the completion of the Naoro-Brown project is the end of 2017, and every effort should be made to accelerate the project.

The Commission proposes that the Port Moresby fuel volume used in the FWAP calculation in the current and next regulatory period is to be capped at the current 2017 forecast volume, providing incentive for commissioning of the Naoro-Brown Hydro power station by the end of 2017.

To provide incentive for PPL to complete the hydro project prior to the end of 2017, the Commission proposes that there would be no adjustment to the MWAP within the current period if the project was completed prior to 2017 and any savings would be retained by PPL.

In the second draft report, the Commission invited PPL to comment on the requirement to accelerate the Naoro Brown Hydro Project and what measures have been considered to improve the delivery timeframe. PPL made the following comments;

“Gas Supply

- Access to gas supply in Port Moresby cannot be negotiated by PPL alone. It requires strong government support (NEC decision) as the project agreement that potentially allows for domestic supply in Port Moresby is between the government and the developer.
PPL is working with the IPBC and relevant Ministers to proceed with negotiations but the ICCC should be aware that the regulated entity, PPL is not in a position to take sole responsibility for the eventual outcomes.

**Naoro Brown**

- As with the gas supply, the Naoro-Brown project requires government support to proceed to the next phase.
- PPL was well on its way to implement the project in collaboration with the World Bank, when the Government policy clashed with World Bank policy and the collaboration was put on hold.
- PPL managed to complete a full feasibility despite this, and is proceeding with preparatory construction work (road access) and a social and environmental study for the 2013 year. The ICCC should be aware that the project would flood a substantial area and change the natural habitat for several communities. The social and environmental assessment must be allowed sufficient time to avoid local as well as international critique. This is not something that can be glazed over in the interest of shorter delivery times.
- The Naoro-Brown is a K800 million greenfield hydro project with difficult access and some geological challenges. To promise earlier completion at this stage when government support, financing arrangement, further detailed geological assessments, environmental and social assessment are yet to be confirmed or completed is not prudent.
- The Naoro-Brown project competes with additional gas based generation. It is less costly and less risky to proceed with incremental gas based generation additions than it is with a large scale greenfield hydro project.
- A final Naoro-Brown investment decision will be made in collaboration with IPBC and GoPNG once, but not before, access to gas supplies have denied or confirmed."

### 6.1.2 Purchased Power

PPL purchase power in the following Generation Systems:

- Port Moresby
- Ramu
- Kimbe

In Port Moresby, PPL purchase power via the Kanudi contract. The contract comes to an end in 2014. PPL have stated that they expect to renegotiate the continuation of the contract without the current Capital Recovery Charge (CRC) and the associated generation output is forecast to continue.

The Commission is proposing that the ERC be based upon what PPL expect the new payment arrangements to be. The ICCC notes that this determination will set expectations for the outcome of any negotiation over the Kanudi contract.

Fuel payments under the Kanudi contract are passed directly through to PPL. PPL’s submission proposes that fuel under the Kanudi project be handled in same way as other fuel. The Commission accepts PPL’s proposal and will treat Kanudi Fuel in the same way as all other fuel.

The fuel cost for Kanudi is calculated based on a conversion factor of 373.08 K/MW. The predicted cost (real terms) for Kanudi fuel payment is shown in Table 18.

<table>
<thead>
<tr>
<th>Table 18: Kanudi Fuel Costs</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Kanudi</strong></td>
</tr>
<tr>
<td>MWh</td>
</tr>
<tr>
<td>Cost (2012 Value)</td>
</tr>
</tbody>
</table>
Payments under the Kanudi contract are adjusted for changes in the US dollar exchange rates. The Commission has based the allowance for Kanudi contract costs based upon 2012 estimates. These are shown in Table 19.

Table 19: Kanudi – Non Fuel Costs

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>CRC Charge</td>
<td>21,255,039</td>
<td>21,255,039</td>
<td>3,542,507</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>FOMC Charge</td>
<td>12,026,156</td>
<td>12,026,156</td>
<td>12,026,156</td>
<td>12,026,156</td>
<td>12,026,156</td>
</tr>
<tr>
<td>VOMC Charge</td>
<td>8,025,976</td>
<td>8,025,976</td>
<td>8,025,976</td>
<td>8,025,976</td>
<td>8,025,976</td>
</tr>
</tbody>
</table>

Other purchased power costs have also been based upon the costs provided by PPL to Commission.

6.1.3 Other Operating Expenses

Since the initial draft report was published, the Commission has held further discussions with PPL about their operating cost forecasts. PPL has provided the Commission with corrected and updated actual and forecast operating costs. The Commission has adjusted these into 2012 values, to give a real terms view of how costs have changed and how PPL is forecasting that they will change over the regulatory period.

Figure 15: Operating costs excluding direct power costs

![Graph showing operating costs excluding direct power costs](image)

Figure 15 shows PPL’s real terms operating costs excluding fuel and purchased power costs. From this, it can be seen that between 2007 and 2010, PPL’s operating costs increased by almost 50%. Figure 16 shows how operating cost per kWh of output have changed in real terms and how it is forecast to change over the next regulatory period. In general, it shows that PPL has become less productive in terms of operating costs. However, the forecast shows an improvement.

Figure 16: Change in operating cost productivity (Kina/kWh)

![Graph showing change in operating cost productivity](image)
Figure 17, shows real terms operating costs broken down into components. It is possible that there may have been some changes in cost classifications over the time period, so a decrease in one component might be related to an increase in another. Figure 18 shows how each cost component will change per unit of output (kWh) in real terms.

**Figure 17: Operating cost components**

![Operating Cost Components - Real Terms](image)

**Figure 18: Cost per kWh for operating cost components**

![Cost per kWh for operating cost components](image)

### 6.1.3.1 Personnel costs

Personnel costs have increased by 48% over the 10 year period of the regulatory contract. PPL’s forecast shows that personnel costs in 2017 will be slightly higher than in 2010.

PPL commented in its 2012 submission that;

> “PPL has endeavored to maintain current staffing levels throughout the forecast period. However, PPL is embarking on a substantial skill level increase and attitude improvement in O&M areas as well as administrative functions.

> The implementation of these staffing strategies will entail the recruitment of overseas experts and higher skilled local manpower at significantly higher remuneration levels than what is the current average.

> PNG is also a developing country with strong economic growth. Generally, such a context will result in real wealth and remuneration growth and competition for skilled personnel particularly from resource projects. PPL therefore expects a real increase in the average remuneration levels and has applied a factor of 1.03 in its regulatory forecast.”
The Commission has discussed personnel costs with PPL. Of particular concern is PPL’s ability to retain staff with expert knowledge of their network. PPL say there has been a general trend for mining companies to recruit PPL staff to support power requirements at their various regional operations. In order to retain these staff, PPL have had to increase salaries. In this context, the Commission does not see a real terms increase of 3% as excessive.

6.1.3.2 Repairs, Maintenance and Consumables

PPL explained in its 2012 submission that

“These cost categories are generally accepted as having a fixed part and a variable part with the variable portion being in direct relation to the energy produced. A typical, relationship for hydro as well as thermal generation is for the variable cost to be 3 times that of the fixed cost.”

“PPL has conservatively assumed that variable cost roughly represent 50% of total cost for repairs and maintenance and consumables. With an average demand increase of 5%, half of that, (i.e. 2.5% has been applied as the real increase in the regulatory forecast.”

“It should be noted that the PPL’s assets is severely aged and repairs and maintenance cost tends to increase exponentially towards the final years, just before it is more economical to replace the equipment through capital investments.”

The Commission accepts PPL’s maintenance forecast. However, the Commission is concerned that PPL’s maintenance forecast appears to be theoretical and not based upon detailed maintenance programming. With increasing capacity in the network, the Commission expects that maintenance cost would increase with increased capacity for Generation, Transmission and Distribution. Conversely, as old assets are replaced, it would be expected that some maintenance costs would decline as explained by PPL. The forecast of maintenance cost should reflect these changes, rather than using a simple % annual change. The Commission expects that over the duration of the next regulatory period, PPL will gather more detailed data about its network which will support more detailed maintenance programs and hence better forecasting capability.

6.1.3.3 Overhead costs

PPL made the following comments about their overheads;

“The average annual real increase in overheads has been 13.8% in the 2007 – 2011 period. At the same time demand has increased by an annual average of around 4%.

A significant contributor to these changes is the massive increase in security cost. Travel cost due to centralization of engineering services and insurance premiums are two other large overhead items.

It is clear to PPL that increases of this magnitude are untenable in the long run and expect to keep real increases in overhead at around 50% of the demand increases. Consequently, a 2.5% real increase has been applied in the regulatory forecast.

Initiatives have been taken to manage increases in the cost of security but increase in real terms are still expected as guard wages rise and PPL’s capital program is delivered with overseas staff requiring both police and guard company protection. Insurance costs are correlated with the value of the asset base and PPL’s capital program is likely to at least double within the regulatory period.”

The Commission is generally concerned about real increases in overhead costs. Overhead costs represent about 7 Toea per kWh which is about 8% of total costs. It is reasonable that insurance costs would increase as the value of PPL’s assets increase. However, the Commission is less convinced that labour rates for security staff will increase at rates which are higher than the rate of inflation.
6.1.3.4 Call Centre

In the initial draft report, the Commission encouraged PPL to progress the development of a customer call centre. PPL has confirmed that it is making progress with a project to develop a call centre operation which will be more responsive to customer issues. For the purposes of this price review, the Commission has assumed that the cost of this call centre is included in the operating costs as presented by PPL.

6.1.3.5 Determination on Operating costs

The ICCC has determined to accept PPL’s forecast “Other operating costs” (i.e. operating costs excluding fuel and power purchases which have been addressed separately in section 6.1.1.)

6.1.4 Regulatory Costs

The Commission has also included in PPL’s operating costs an allowance for Regulatory Compliance and Support. This is to cover the cost of activities required by the Commission to ensure that the required outcomes of the ERC are achieved. These are activities which the Commission will carry out, for which the Commission may require PPL to reimburse the Commission, so that the Commission can recover its direct costs. It would also cover PPL’s own costs to employ expert advice to address regulatory issues should they need to.

The Commission envisages that the costs this will cover the activities including the following:

- Reimbursing the Commission for costs incurred which are related to contracting an independent expert to assess the reliability of PPL’s network;
- Costs associated with hiring independent experts to audit SAIDI and SAIFI measurement;
- Costs associated with auditing PPL’s rebate calculations;
- Cost incurred by the Commission in carrying out the mid-term review;
- Classification of PPL’s assets by service area and asset class;
- Supporting new reporting requirements;
- The cost of assessing pass-through events as they arise; and
- The cost of supporting the introduction of third party access to its network.

The Commission is proposing to set this allowance at K1.5 million per year.

6.1.5 Summary of Operating Expenditures

The Commission is proposing to adopt the operating expenditure shown in Table 20 in the building block calculation. Table 20 figures are in real terms and therefore exclude inflation.

Table 20: Operating expenditure included in building block calculation

<table>
<thead>
<tr>
<th>Kina (000's)</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Purchase of Power excluding fuel</td>
<td>43,807</td>
<td>29,555</td>
<td>29,473</td>
<td>29,473</td>
<td>29,473</td>
</tr>
<tr>
<td>Purchase of Water</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>Salaries &amp; Wages - Direct</td>
<td>45,005</td>
<td>46,355</td>
<td>47,745</td>
<td>49,178</td>
<td>50,653</td>
</tr>
<tr>
<td>Other Direct Personnel Cost</td>
<td>38,891</td>
<td>39,172</td>
<td>39,440</td>
<td>40,679</td>
<td>41,709</td>
</tr>
<tr>
<td>Repairs &amp; Maintenance</td>
<td>17,640</td>
<td>18,081</td>
<td>18,533</td>
<td>18,996</td>
<td>19,471</td>
</tr>
<tr>
<td>Consumables</td>
<td>45,735</td>
<td>46,878</td>
<td>48,050</td>
<td>49,251</td>
<td>50,483</td>
</tr>
<tr>
<td>Freight and Cartage</td>
<td>4,260</td>
<td>4,367</td>
<td>4,476</td>
<td>4,588</td>
<td>4,703</td>
</tr>
</tbody>
</table>
### 6.2 Capital Expenditure

The Commission expects that PPL will continue to invest in infrastructure to meet customer demand. The cost of this investment should be covered by the MWAP set by the Commission.

If PPL were operating in a static market and its current levels of service remained unchanged, the Commission would expect that in the long run, PPL’s capital investment would average out to be about the same as its depreciation. For this to be true:

- Demand would need to be flat;
- Inflation would be zero; and
- The number of outages would remain at current levels.

Under such a scenario, there would be some lumpy investments where PPL replaced major assets. However, if the cost of these assets is spread out over time we would expect that in the long run, average capital investment would equal average depreciation.

However, the Commission recognises that PPL’s business is in a materially different environment from the one described above.

- Customer demand is growing which requires investment in more generation capacity, transmission capacity and distribution capacity;
- PPL is expected to connect new customers and to expand the coverage of its network;
- In many cases, the areas where PPL is expected to expand the coverage of its network is in areas where the cost of providing service is higher than the current average cost;
- PPL is expected to improve the performance of its network, by carrying out such investments as are required to reduce the number of outages; and
- PNG is experiencing high levels of inflation, which means that the replacement cost of assets is likely to be significantly higher than the depreciation amounts on historic costs might indicate.

All of these factors are likely to result in levels of capital expenditure which are higher than depreciation of historic cost might indicate.

The MWAP pricing structure allows for some of these factors:

- The MWAP is structured on a per MWh basis so that the cost of growth is covered in the long run. As the quantity of MWh’s delivered increases, PPL’s revenues will also increase. The Commission accepts that in the short run, if, PPL invests in significant incremental capacity and this capacity was not planned when the contract was initiated, they may need to carry the cost of unused capacity in the short term and that the MWAP may not adjust to cover this, unless specific allowance is made for it;

- The MWAP also allows for the cost of increasing the number of connections. New customers will increase the quantity of power sold by PPL which will increase its revenues. The Commission accepts that if new customers use less than average quantities of power, then those customers will be contributing less to the cost of fixed and common costs. However, provided that the MWAP exceeds the incremental cost of power delivered and the

<table>
<thead>
<tr>
<th>Other Operating Costs</th>
<th>10,186</th>
<th>10,186</th>
<th>10,186</th>
<th>10,186</th>
<th>10,186</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overheads</td>
<td>72,697</td>
<td>74,514</td>
<td>76,377</td>
<td>78,287</td>
<td>80,244</td>
</tr>
<tr>
<td>Bad debt expenses</td>
<td>3,152</td>
<td>3,231</td>
<td>3,311</td>
<td>3,394</td>
<td>3,479</td>
</tr>
<tr>
<td>Salaries &amp; Wages - Indirect</td>
<td>19,567</td>
<td>20,154</td>
<td>20,759</td>
<td>21,382</td>
<td>22,023</td>
</tr>
<tr>
<td>Other Indirect Personnel Costs</td>
<td>15,512</td>
<td>15,890</td>
<td>16,279</td>
<td>16,893</td>
<td>17,312</td>
</tr>
<tr>
<td>Regulatory Compliance Costs</td>
<td>1,500</td>
<td>1,500</td>
<td>1,500</td>
<td>1,500</td>
<td>1,500</td>
</tr>
<tr>
<td>Total Opex Excluding Fuel</td>
<td>317,956</td>
<td>309,886</td>
<td>316,133</td>
<td>323,810</td>
<td>331,239</td>
</tr>
</tbody>
</table>
incremental cost of connecting new customers, PPL will still be better off by connecting these new customers; and

- The MWAP allows for increases in the cost of inputs by adjusting for inflation and exchange rate fluctuations.

The MWAP does not allow for some of these factors. Specifically:

- The MWAP does not allow for the cost of increasing service levels and reliability. So specific provision must be made to allow for this via the use of a price path. As already noted, the Commission is supportive of capital investment that will improve the reliability of electricity supply. So the Commission has allowed increases in the MWAP over the contract period to allow PPL to make these types of investments. This is done by including the forecast capital spending in the MWAP calculation.

- The MWAP does not allow for the cost of increasing network coverage in high cost areas. In some circumstances, PPL may receive grants for extending their network into certain areas. However, even if the cost of building the extended network is fully funded by a third party, the current prices charged under the MWAP structure may not cover the marginal cost to PPL of supplying energy to these customers. In the preliminary draft report, the Commission proposed that these areas be excluded from the ERC. However the Commission notes that the EIP provides for these high cost new service areas separately. These areas will be serviced by the winner of a competitive bidding process in conjunction with a government funded CSO. This therefore confirms that the ERC does not need to cover these areas.

The Regulatory Asset Base (RAB) is the Commission’s estimate of the current value of PPL’s investment. It attempts to reflect both the cost to replace PPL’s assets and the current age of the assets. Based upon the RAB, the Commission determines the amount of capital that needs to be recovered each year, to allow PPL to continue to invest as required.

Therefore, in an assessment of capital spending, the following types of investment are acceptable;

- Replacement and upgrades of existing assets that support customer demand at current service levels;
- New projects that will increase the reliability and quality of service to customers; and
- Significant increases in capacity where there may be material spare capacity costs which are not currently covered by the existing MWAP.

The Commission has used depreciation costs per MWh of delivered power as a way of assessing the potential lift in capital spending (see in section 6.2.1). The Commission recognises that this approach has some flaws.

- New projects may increase the cost per MWh because they are economically inefficient, small in scale or are built in high cost service areas; and
- Imprudent capital spending will also increase the depreciation amount per MWh.

However, the ICCC has the ability to claw back any price allowance for imprudent capital spending, at the mid-term review.

### 6.2.1 PPL Capex Plan

The Commission has noted that PPL’s capex plans are a moving target. PPL supplied the Commission with different versions of its Capex plan at different times.

- Version 1 – Summary level only – K1.45 billion over the regulatory period;
- Version 2 – Project List – K1.41 billion over the regulatory period; and

The ICCC has used the March 2012 as the most recent information. This is shown in Table 21.
Table 21: PPL's Capex Program (Real Term Values) 2012 – 2017

<table>
<thead>
<tr>
<th>Kina (000's)</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generation - Hydro</td>
<td>139,000</td>
<td>159,000</td>
<td>53,000</td>
<td>83,700</td>
<td>177,622</td>
<td>196,565</td>
</tr>
<tr>
<td>Generation - Thermal</td>
<td>22,542</td>
<td>87,927</td>
<td>80,125</td>
<td>60,875</td>
<td>28,375</td>
<td>14,900</td>
</tr>
<tr>
<td>Transmission</td>
<td>9,810</td>
<td>32,106</td>
<td>62,205</td>
<td>84,384</td>
<td>100,581</td>
<td>86,055</td>
</tr>
<tr>
<td>Distribution</td>
<td>13,473</td>
<td>13,951</td>
<td>14,447</td>
<td>14,963</td>
<td>16,100</td>
<td>16,657</td>
</tr>
<tr>
<td>Office &amp; Residential</td>
<td>8,000</td>
<td>5,000</td>
<td>5,000</td>
<td>9,000</td>
<td>6,500</td>
<td>4,000</td>
</tr>
<tr>
<td>Motor Vehicles</td>
<td>2,880</td>
<td>3,240</td>
<td>3,240</td>
<td>3,240</td>
<td>2,790</td>
<td>3,240</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>15,788</td>
<td>21,680</td>
<td>20,535</td>
<td>20,472</td>
<td>21,563</td>
<td>19,945</td>
</tr>
<tr>
<td>Plant, Tools &amp; Equipment</td>
<td>2,794</td>
<td>4,650</td>
<td>5,683</td>
<td>7,227</td>
<td>8,314</td>
<td>6,648</td>
</tr>
<tr>
<td>TOTAL</td>
<td>214,287</td>
<td>327,554</td>
<td>244,235</td>
<td>283,861</td>
<td>361,845</td>
<td>348,010</td>
</tr>
</tbody>
</table>

A review of the proposed Capital and Operation investment in the Port Moresby and Ramu Systems was conducted by Gravelroad during May 2012. A summary of the report is included below.

6.2.2 PPL Capital Review (Port Moresby and Ramu)

“In general, the Ramu system capital plan proposes significant increases in generation capacity through unit refurbishment and a new hydro power station currently under construction. The Ramu transmission network is likely to remain “thin” and a potential failure point beyond the current regulatory period due to the lack of redundant transmission routes.

In contrast, the Port Moresby system has a robust transmission network with redundant paths, but little excess generation capacity. PPL has added short term and expensive generation capacity to try to meet growing demand. The current capital program shows that a large efficient hydro station will not be delivered to the POM system until after the current regulatory period, and diesel power generation is proposed in the short term to meet increasing demand for electricity.

PPL has identified a number of cross system initiatives to improve the visibility of the network operation which should be prioritised and completed. The GIS (Geographic Information System) project is currently capturing the transmission and distribution feeder network in POM and will then progress to Ramu. To enable alternative network performance measures such as SAIFI, and improve asset management, the GIS capture project should be accelerated and customer location data also captured. The other beneficial cross system initiative is the implementation or expansion of SCADA (supervisory control and data acquisition) systems to establish central monitoring and control of the electricity network.

The growth in demand has placed increasing pressure on the distribution network with conductor upgrades, switching re-arrangements and localised protection identified in the distribution PPL infrastructure planning document (TDP). An initial review would appear to indicate that sufficient funds have not been included in the capital plan to complete the required improvements in the Distribution Networks.”

6.2.3 PPL Operations Review (Port Moresby and Ramu)

“The supplied planning documents and capital expenditure plan indicate that PPL is acting to improve a number of operational issues. This position was supported during the visits to the POM and Ramu systems. Network improvement projects including protection upgrades and capacitor bank installations are included within the capital expenditure program and operational support initiatives such as SCADA implementation are also proposed.
An area which is still considered as a shortfall is the recording and management of system performance data. Capture of the power network assets in a GIS system has commenced, although how that information will be used and made available to others is still unclear. Further systems are required for asset management and performance data recording. Until customer location data is captured and new systems are implemented, it will not be possible to provide reporting of proposed improved performance measures such as SAIFI. Until detailed location based system performance information is verified and made available, it is not possible to accurately assess the system reliability performance or trends at the customer level.

We do expect that if PPL can deliver the promised investments in system assets and the management and control of these assets in the next regulatory period, then significant and sustained improvements in efficient operation and service reliability can be achieved.

It is recommended that the ICCC take a more active role in monitoring the investments in system assets and their active management over the next regulatory period, and this report suggests critical tasks that should be monitored and managed through incentive based regulation."

The review identified that the projects proposed were aligned with either increasing capacity or improving performance and were considered prudent investment. The large “Naoro – Brown” Hydro project was identified as a required investment but not delivered until after the regulatory period. Further review of the timing of this project (Section 6.1.1.4) has identified that it would be economically prudent if this project were ready for service by the end of the Regulatory Period rather than two years into the next period as forecast.

Some portion of the new works will be due to network quality improvement and increased capacity to support improved service levels.

Figure 19 shows a real term assessment of how capex will impact upon PPL’s depreciation per MWh by asset class. The chart shows that PPL is increasing its investment relative to the total amount of energy that they are delivering. Most notable is the significant increase for generation.

The capex plan includes 5 new hydro generation projects and 3 new diesel power stations. This is in addition to new diesel generators at existing power stations.

Figure 19: Depreciation amount per MWh by asset class

The Commission is proposing to accept PPL’s capital spending program with the exception of the timing for the Naoro Brown power station. The capital spending as outlined will be used to estimate the forecast RAB for the contract period. The RAB is then used to identify the Capital that needs to be recovered under the MWAP.

The Commission is proposing that provisions be made in the ERC via the Mid Term Review, to reduce prices during the course of the ERC, if PPL do not carry out their proposed Capital Works program. The Commission will require ongoing reporting of the progress of the capital works program.
6.3 Regulated Asset Base (RAB)

The return on capital is calculated as the WACC times the RAB.

In order to calculate the Return on capital, the value of PPL’s capital assets must be estimated. The Commission recognises that there are some trade-offs required when estimating the value of the asset base.

There are generally two extreme positions.
- Book Value; and
- Replacement value.

Replacement value is particularly relevant to consider, because it is the price that a new entrant would pay if they were entering the market and it will also drive the prices that would operate in an efficient competitive market.

In an efficient competitive market, the long run price would reflect the replacement cost of the assets required to participate in that market. If the price falls below the replacement cost, then no new entrants will enter the market and existing participants will leave the market when their assets need replacing. As existing participants leave the market, supply will diminish and demand will exceed supply which will drive up the price. If the price rises above the replacement cost, then new entrants will enter the market. As new entrants enter the market supply will increase. If supply exceeds demand then prices will fall.

So replacement cost can be seen as the price that would operate if the electricity market was competitive.

The major argument against using replacement cost is that PPL does not have a new network and has not invested the capital represented by the cost of a replacement network. So if prices were set at replacement levels, then PPL would be seen to receive a windfall gain. It would increase its returns merely because its network had been re-valued.

Book value on the other hand provides an accurate measure of what PPL have actually spent on their network. It reflects the cost of the network when it was new plus the age of the network. The value reflects the capital that PPL have already recovered from their business and can be argued to provide an accurate estimate of the current level of investment held by the PPL in their network.

The problem with basing prices on book value is that if many of the assets of a business are generally old, as is the case for PPL, then a price based upon book value will be well below the replacement cost. This is fine if no assets need replacing. However, if PPL needs to invest in new assets, as it does, then the prices they receive for their services will not cover the cost of the new investment. Prices based upon book value will therefore generally discourage new investment.

The Commission is of the view that the current high rate of outages reflects the need for significant new investment in electricity infrastructure. And that PPL need to be confident that if they invest in new assets they can expect to receive an adequate return on that investment.

A compromise is therefore needed between the two extreme positions of replacement cost and book value. Typically, most regulators address this issue by estimating the cost of replacing the network with new assets and then depreciating this cost to reflect the current age of the assets.

This approach will produce a RAB which is in between a replacement cost and current book value. It reflects both the cost of replacement and the current age of the assets. It generally reflects the level of investment that PPL would have if their historic cost was the same as replacement cost.

Also, using this approach means that whenever the RAB is reassessed its value will reflect any additional investment that PPL has made up to the date of valuation.
In 2002, the assets of PPL were re-valued to establish a RAB. It is understood by the current staff at the Commission that the method used was the one just described. So a replacement cost of PPL’s assets as they were in 2002 was estimated and then this was depreciated to reflect its current age. Table 22: 2002 RAB outlines the 2002 RAB.

### Table 22: 2002 RAB

<table>
<thead>
<tr>
<th>K (000s’)</th>
<th>Regulatory Cost in 2002</th>
<th>Accumulated Regulatory Depn 2002</th>
<th>RAB</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capitalised overheads</td>
<td>16,002</td>
<td>0</td>
<td>16,002</td>
</tr>
<tr>
<td>Distribution</td>
<td>132,827</td>
<td>62,540</td>
<td>70,287</td>
</tr>
<tr>
<td>Generation - Hydro</td>
<td>172,080</td>
<td>64,790</td>
<td>107,290</td>
</tr>
<tr>
<td>Generation - Diesel</td>
<td>70,921</td>
<td>49,451</td>
<td>21,470</td>
</tr>
<tr>
<td>Land</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>14,868</td>
<td>13,829</td>
<td>1,039</td>
</tr>
<tr>
<td>Motor Vehicles</td>
<td>11,427</td>
<td>11,148</td>
<td>279</td>
</tr>
<tr>
<td>Office &amp; Residential</td>
<td>38,543</td>
<td>21,227</td>
<td>17,316</td>
</tr>
<tr>
<td>Plant, Tools &amp; Equipment</td>
<td>9,198</td>
<td>8,836</td>
<td>362</td>
</tr>
<tr>
<td>Transmission</td>
<td>90,437</td>
<td>30,413</td>
<td>60,024</td>
</tr>
<tr>
<td>Total</td>
<td>556,303</td>
<td>262,234</td>
<td>294,069</td>
</tr>
</tbody>
</table>

In order to update the RAB to reflect its current value, we must once again find values that both reflect its likely replacement cost and its current age.

The Commission is of the view that carrying out a full revaluation of PPL’s assets would be both difficult and unnecessary. So the Commission has taken the approach of inflating assets into today’s monetary values.

The Commission has a policy of only including assets in a company’s Asset Register as belonging to the RAB. Consequently any items which are work in progress will be excluded from the RAB. For PPL work in progress is currently estimated to be K185 million. This is a consequence of large scale projects, such as “Yonki Toe of the Dam”, which take multiple years from initiation to commission date. Therefore ignoring work in progress items is likely materially under state the value of their assets over the regulatory period. Another consequence of projects with long development times is that the commission date shown in the asset register may be some time after the actual date of spending. Therefore using the commission date to work out how much inflation has occurred since spending will understate the effect of inflation upon PPL’s returns.

To address this, the Commission took the following approach:

- Actual capital spending each year from 2002 to 2011 was identified using audited accounts.
- Work in progress was subtracted from actual capital spending.
- This amount was assumed to represent the Asset Register amounts and the year in which capital was spent. The values produced were less than those shown in the asset register.
- Work in progress amounts were then added to the future capital expenditure forecast, in the years when these WIP projects are forecast to be commissioned.

The RAB was calculated as the sum of the balances for each asset class.

- The opening balance from the 2002 RAB for each asset class was used.
- To this balance new annual capital spending was added and annual depreciation deducted to calculate the closing balance for that year.
- The closing balance was then inflated using that years CPI data to calculate the opening balance for the following year.
• An opening balance was calculated for each year from 2002 to 2011.

Table 23 gives the value of the updated RAB by asset class. The total value is 1.277 billion Kina. The Commission is proposing to use this value to establish cost of capital component of the building blocks.

Table 23: Value 2013 Opening Regulatory Asset Base

<table>
<thead>
<tr>
<th>Asset Class</th>
<th>2012 Kina</th>
</tr>
</thead>
<tbody>
<tr>
<td>Distribution</td>
<td>150,927,839</td>
</tr>
<tr>
<td>Generation – Hydro</td>
<td>290,250,888</td>
</tr>
<tr>
<td>Generation – Thermal</td>
<td>177,867,931</td>
</tr>
<tr>
<td>Land</td>
<td>-</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>48,552,912</td>
</tr>
<tr>
<td>Motor Vehicles</td>
<td>29,780,810</td>
</tr>
<tr>
<td>Office &amp; Residential</td>
<td>305,059,630</td>
</tr>
<tr>
<td>Plant, Tools &amp; Equipment</td>
<td>55,821,303</td>
</tr>
<tr>
<td>Transmission</td>
<td>209,418,882</td>
</tr>
<tr>
<td>Capitalised overheads</td>
<td>8,830,287</td>
</tr>
<tr>
<td>Total Opening Balance</td>
<td>1,276,510,483</td>
</tr>
</tbody>
</table>

6.3.1 Return on Working Capital

In their submission, PPL proposed that the revenue requirement should also make allowance for the funding cost of working capital.

“PPL is proposing to recover an allowance for working capital due to extremely high levels of debt and payment delays from customers”.

In principle, the Commission is supportive of this. However, the Commission does not want to remove any incentive PPL may have to efficiently collect prompt payments from customers. The Commission also considers that the growing number of PPL’s customers who have Easipay meters is generally reducing the cost of working capital over time.

PPL is forecasting an average of 64 debtor days over the next regulatory period with an average of 30 creditor days. The Commission is of a view that this number of debtor days is unacceptably high and proposes that a more acceptable level would be 45.

The Commission has therefore made an allowance for working capital based upon the following assumptions:

- Creditor days = 30;
- Debtor days = 45;
- 40% of capital is funded out of cash-flow with the remaining funded via loans;
- 59% of Easipay revenue is received via retailers and has debtors days of 7; and
- 34.5% of Easipay revenue is received from Digicel and has debtors’ days of 2.

Using these assumptions, plus the capex and opex allowances explained elsewhere in this report produces the working capital amounts shown in Table 24.

Table 24: Working Capital
The funding cost of working capital is then calculated by multiplying that annual amount of working capital by the WACC.

### 6.3.2 Gifted Assets and ‘soft’ loans

Regulated entities submit their capex plans to the Commission during the 5 year regulatory reset of Regulatory Contracts. The cost of these planned capital investments are passed onto consumers through the tariff increases. However, over the course of the regulatory period, regulated entities sometimes get ‘contributed’ or ‘gifted’ assets from the State and donor agencies. Apart from capital funding of asset acquisitions, deeply concessional loans for such acquisition, from international donors has also been obtained by at least one SoE.

The Commission takes the view that funding of capital increases by price increases based on the weighted average cost of capital or debt should not be duplicated by ‘gifted’ assets or concessional interest rate borrowings and that the regulated allowance for the cost of acquisition of capital or borrowing should be reduced by the value of any such capital subventions or concessional interest loans. The Commission is of the view, therefore, that regulated entities (including PPL) are not entitled to recover the costs of acquiring such contributed assets or concessional value of interest on borrowings from their price paths; hence, any such gifted assets or ‘soft’ loans should be excluded from the regulated asset base and appropriate adjustment to the aggregate cost of capital or debt should be made to avoid ‘double-dipping’.

The Commission is conscious of the possibility that certain regulated entities may have been ‘double-dipping’. Therefore, PPL has an obligation to inform the Commission of any contributed assets from Government or donor agencies within this regulatory period to ensure that consumers are not overcharged for the regulated electricity services.

The Commission has allowed a capital expenditure program for PPL in its price path for this regulatory period. Given the approved capex for this regulatory period, the Commission proposes to conduct a mid-term expenditure review in mid-2015 to ascertain whether PPL has actually made the necessary capital investments. The Commission has provided the necessary incentives for PPL to invest in its capital assets to grow its business.

The Commission will also require PPL to ensure that any outsourced capex is competitively tendered. This is because any capex considered to be imprudent or inefficient by the Commission will not be treated as capital expenditure hence, excluded from the actual cumulative expenditure during the mid-term expenditure review. These also include the identification of grants, concessional interest loans or other ‘monetary value’ subventions and reductions from ‘market cost of capital or debt’. The economic value of concessional loans will be factored into the calculations for cost of debt. The Commission as much as possible would like to ensure that any “grants” considered as gifted assets must not be factored into the actual cumulative expenditure.

### 6.4 Weighted Average Cost of Capital (WACC)

The concept of Weighted Average Cost of Capital (WACC), as referred to in most finance literature, represents the opportunity cost of capital to the regulated business. It should be set at a level that is deemed to adequately compensate the business for providing electricity services. The WACC methodology has been developed from the Capital Asset Pricing Model (“CAPM”) to form a reasonable basis for regulatory cost of capital. It is designed to calculate the minimum rate of return required by indifferent providers of debt and equity to run PPL’s business.

The WACC used should reflect the riskiness of PPL. Therefore, in setting the input parameters to calculate WACC, it is important to understand the type of business that PPL is. PPL has the following characteristics. It is:

<table>
<thead>
<tr>
<th>Year</th>
<th>Working Capital</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>27,690,792</td>
</tr>
<tr>
<td>2014</td>
<td>40,349,195</td>
</tr>
<tr>
<td>2015</td>
<td>46,360,205</td>
</tr>
<tr>
<td>2016</td>
<td>51,775,256</td>
</tr>
<tr>
<td>2017</td>
<td>60,668,453</td>
</tr>
</tbody>
</table>
- a state owned enterprise;
- in a developing country;
- a monopoly;
- selling most of its load to price inelastic customers;
- subject to unpredictable changes in fuel prices.

PPL made a substantial submission on the input parameters of the WACC calculation. The Commission has considered its submission and have made various comments about it through this section of the report.

### 6.4.1 Determination of WACC

The WACC calculation formula is outlined below:

\[
Post\_tax\ WACC = \frac{E}{V} R_s + \frac{D}{V} R_d \times (1 - t)
\]

Where:
- \(R_s\) = return on equity
- \(R_d\) = return on debt
- \(t\) = tax rate
- \(E\) = market value of equity
- \(D\) = market value of debt
- \(V\) = market value of the business (i.e. \(D + E\))

The return on debt \((R_d)\) is calculated by adding a debt margin to the risk-free market rate.

\[R_d = R_f + DM\]

Where
- \(R_f\) is the risk free rate in PNG; and
- \(DM\) is the debt margin

According to the CAPM formula, the return on equity for a particular business is derived by adding the international risk free rate to the product of the Equity Beta and the Market Risk Premium (i.e. the difference between the market return and the risk free rate). The margin, that is the equity beta \((\beta_e)\) reflects how risky a business is relative to the overall market. Therefore, the return on equity \(R_s\) as indicated in the above WACC formula is derived by using the CAPM formula outlined below:

\[R_s = R_{f\_international} + \beta_e \times (R_m - R_f)\]

Where
- \(R_{f\_international}\) is the risk free rate;
- \(\beta_e\) (equity beta) is a measure of correlation between a business’s risk and that of the overall market;
- \(R_m\) is the market rate of return;
- \(R_f\) is the risk free rate in PNG;
- \((R_m - R_f)\) is the Market Risk Premium (“MRP”).

The international risk free rate \((R_{f\_international})\) is calculated as follows;
Where:

\[
R_{f,\text{international}} = \frac{(1 + R_f)}{(1 + USA_{CPI})} \times (1 + PNG_{CPI}) \times (1 + CRP) - 1
\]

Where:

- \( R_f \) is the risk free rate in the USA;
- \( USA_{CPI} \) is the inflation rate in the USA;
- \( PNG_{CPI} \) is the inflation rate in PNG; and
- \( CRP \) is the country risk premium assigned for PNG.

The ICCC prefers using the Monkhouse formula as shown below to calculate the equity beta.

\[
\beta_e = \beta_a + (\beta_a - \beta_d) \times \left[ 1 - \left( \frac{R_d}{1 + R_d} \right) \times t \right] \frac{D}{E}
\]

Where

- \( \beta_a \) is the correlation between return on the assets of the business and the market (known as the asset beta)
- \( \beta_d \) is the correlation between the return on debt and the debt returns generally in the market (known as the debt beta).

(Note: The initial draft report contained an error in this formula which has now been corrected).

Given the above equations for the calculation of the WACC, the Commission has to decide on the range of parameters used in the WACC calculation. These include

- Risk Free Rates
- Inflation
- Debt margins
- Taxation
- Market Risk Premium
- Equity beta
- Gearing ratio

6.4.2 Relationship between Risk Free Rate and Market Risk Premium

PPL in its submission highlighted the relationship between the risk free rate (RFR) and the market risk (MRP) premium, referencing various reports and other literature. The main point of this is that:

- \textit{RFR and MRP are not constant over time}
- \textit{MRP tends to move in the opposite direction to RFR movements}  
  (See Figure 20: Risk Premium)
In periods of high investor risk aversion, there is a flight from risky assets to safe assets. This tends to push up the price of safe assets (thus reducing the yields).

The Return on Equity (the sum of RFR and MRP) is much more stable. (see Figure 21: Cost of equity)

The negative relationship between the RFR and the MRP is factored into regulatory regimes in the US and UK.

US Regulatory decisions have yielded consistent returns on equity with fluctuations in RFR and MRP generally offsetting one another. (See Figure 22: US regulatory decisions over time).
Figure 22: US regulatory decisions over time

```
“PPL submits that the ICCC has two options to address the change in risk free rate and the MRP from their long term trends in this period where the market volatility and uncertainty depresses yields on Government securities;

- Adopt an MRP that reflects the current market environment (i.e. adopt a higher MRP than the long term MRP); or
- Adjust the risk free rate to a level that reflects the long term average.”
```

The Commission agrees with PPL that the input parameters used in calculating the WACC should be consistent with each other. In general, the Commission prefers to take a long term view. The information provided by PPL provides strong support for taking a long term view as it demonstrates that the cost of equity appears to remain stable even as the risk premium and risk free rates change. However, the Commission recognises that over the next five year period, some input costs might be different from the long term position and this may affect the cost of capital for PPL. The Commission has considered this issue in determining the inputs.

The Commission also notes that investment in power infrastructure is a longer term investment which will go well beyond the time period in which the GFC will continue to impact. Typically, a hydroelectric power station will have an economic life in excess of 50 years, and transmission and distribution infrastructure should have economic lives which are longer than 30 years. The Commission is therefore of the view that generally a long term perspective should be used particularly for the cost of equity. However, it is also recognised that in the short term financial loans will reflect the current cost of debt rather than the long term cost of debt. So there is still a case for considering the impact of short term factors.

### 6.4.3 Risk Free Rate
The risk free rate of return represents the rate of return on a security, or portfolio of securities, that has no default risk and is not correlated with returns on other assets in the economy. The general accepted approach by regulators is to use the yield from certain long term government securities to generate an estimate of the risk free rates. These instruments are commonly accepted as the lowest risk debt instrument observable, and as a result, are viewed as reasonable proxies for a “risk free” rate of return.

Due to the lack of an appropriately traded government bonds in PNG, the Commission has previously used the 10 year US government bond rate plus an allowance for country risk premium with an adjustment for the difference between US and PNG inflation. The Commission recognises that due to the recent down grade of the credit rating for the US Government, the US Government is no longer as “Risk Free” as it once was. However, in the current economic climate, US Government bonds are still regarded as being one of the safest investments available. The Commission has decided to continue to use 10 year US Government bond rates as the basis for estimating a ‘Risk Free” rate.

In its 2011 submission, PPL used the 5-day average of the zero coupon 10-year US Government bond rate for the period from 3 November 2010 to 9 November 2010. This produced a rate of 2.84%.

In the initial draft report, the Commission proposed to use a rate of 3.35% and PPL supported this proposal. In reviewing this, the Commission notes the following:

- The long term average 10 year US Treasury yield since 1871 is 4.64% (see Figure 23);
- 10 year bond yields were depressed during the 1930’s and 1940’s when the world economy was affected by depression and a world war;
- Yields rose after the 1973 oil shock and did not come back down to the long term average rate until 2001 when the internet bubble burst;
- In previous determinations, the Commission has used 3.7% (2009 Water and Sewerage Review) and 3.7% (2009 PNG Ports); and
- The average daily rate for the past 10 years (To August 1st 2012) is 3.76%. The GFC started about five years ago, so about half of this average reflects GFC conditions.

Figure 23: USE 10 year Bond Rates

On balance, the Commission has determined to use 3.7% for the following reasons.

- This is consistent with previous determinations;
- It is close to the daily average for the last 10 years, which includes the GFC period;
- While 3.7% is lower than the long term rate, it is higher than the current rate and likely to be more reflective of the rate over the next five years; and
• If used consistently with the market risk premium, then the cost of equity should reflect a long term view as noted in section 6.4.2.

6.4.4 Market Risk Premium

The market risk premium (MRP) reflects the additional return over and above the risk free rate that an investor would expect to earn by holding a well-diversified portfolio of assets.

The derivation of a MRP reflects the circumstances in the market. The market for equity in the PNG economy has limited coverage, limited trading volume, and debt markets remain immature. Hence the MRP is not readily apparent from the available data on the PNG markets. It is also important in this process to differentiate between the factors that may have been included in the derivation of the risk free rate when addressing the issue of the MRP. It would be inappropriate to include the country risk premium in both the derivation of the risk free rate and in the MRP.

PPL in its 2011 submission noted that;

“Australian studies on the historical risk premium approach generally indicate that the EMRP (equity market risk premium) would be in the range of 5% to 8%. In recent years, it has been common market practice in Australia in expert’s reports and regulatory decisions to adopt an EMRP of 6%.

We note that there are no available studies on the EMRP in the PNG Market”.

In its 2012 submission, PPL argued that market risk premiums had increased. They provided an extensive set of quotes from various experts. We have summarised these with the following bullet points.

• In 2009, the Australian Energy Regulator (AER) set the MRP at 6.5%;
• In the PNG Ports Regulatory Contract, the Commission quoted the work of Officer and Bishop as support for its 6% MRP decision. In 2009, Officer and Bishop released a report saying they recommended the MRP be 7%;
• In 2012, Professor Stephen Gray based upon Option implied volatility, spreads between high rated bonds and low rated bonds, and dividend implied yields concluded MRP was in excess of 7%;
• Dr Neville Hathaway (Capital Research) used dividend yields with growth applied for forecasts to predict forward looking MRP and concluded that MRP was above historical levels and that the current ranges was 6.6% to 7.6%;
• Competition Economics Group (CEG) found the spread between Government securities and BBB bonds still remained at high levels and that this was a proxy for the level of the MRP;
• Nera Economic Consulting used dividend growth models to develop forecasts of MRP. They found that MRP was above 6% and that the level depended upon bond rates. Higher bond rates meant lower MRP and lower bond rates meant lower MRP.

Because PPL has referred to the PNG Harbours regulatory contract, the Commission has also referred back to the work done at that time and is of a view that the comments made then are still relevant.

“In Australian regulatory decisions the most common assumption regarding the value of the MRP has until recent times been 6 per cent. However, there is a divergence of views on the appropriateness of this judgment. On the one hand it is argued that a long series of historical returns shows a 1-year average MRP of over 7 per cent, and that the use of even a 6 per cent MRP has scant statistical support. On the other hand, it is argued that plausible views as to growth prospects for dividends, and surveys of financial market practitioners’ expectations, both suggest an MRP below 6 per cent.”

The Commission notes that both PricewaterhouseCoopers and PNG Ports have noted the regulatory precedent set in Australia, where the MRP has recently been increased from 6 per cent to 6.5 per cent. However, the Commission notes that the Australian regulatory precedent is only one of many points of view it considers. The Commission is not totally reliant on Australian practice to set the appropriate rate of the MRP.

Further, the Commission notes comments made by Officer and Bishop who noted that the MRP is not a precise science. Indeed Officer has long argued that 6 per cent is appropriate due in large part to the fact that it is an integer. Officer’s argument has been in part based on the fact that 6.5 per cent implies a greater degree of precision than supported by the data. The Commission notes that even in the Australian context the treatment of other issues, namely imputation credits, there has been considerable variability over the past 10 years in the treatment of various WACC parameters. In terms of the increase in the MRP, the Australian regulatory debate has centred on a spike in more recent times due to the Global Financial Crisis (GFC). However, the Commission notes that PNG was largely insulated from the effects of the GFC thereby diminishing the need to follow the Australian lead. The lack of impact from the GFC was in large part due to luck, and limited exposure to leveraged financial investments within the PNG market. At the same time PNG is proving to be countercyclical with economic activity expected to be robust over the next five years.

As such the economic uncertainty typical of other economies is somewhat absent from PNG. Rather, the economy is likely to grow significantly leading to more stable, less risky returns. In addition, the majority of foreign investment over the next few years is likely to come from the US rather than Australia. This in turn suggests that the Australian benchmark return for the MRP is problematic. Historically the US MRP is lower than the Australian MRP. At the same time Officer and Bishop note that the MRP is currently above historical averages and that the MRP will change over time. In order to address this volatility the Commission is of the view to hold the MRP constant rather than adjust it. Further, the absence of a definitive statement on the MRP in the PNG context and the influence that foreign investment dollars have in PNG, the Commission considers that it is appropriate to adjust of any specific PNG country risks through the Country Risk Premium rather than the MRP.”

In 2012, a survey of estimates of market risk premiums was carried out by Pablo Fernandez, Javier Aguirreamalloa and Luis Corres (IESE Business School). For the USA, the survey received 2,223 responses with an average response of 5.5%. The upper quartile was 6% and the lower quartile was 4.5%.

The Commission notes that to be consistent with section 6.4.2 Relationship between Risk Free Rate and Market Risk Premium, the market risk premium and the risk free rate should be consistent over time. Figure 22: US regulatory decisions over time indicates this should be about 10.5%. Therefore, if the risk free rate is set at 3.7%, the market risk premium would be about 6.8%. Apparently, American regulators have perceived market premiums to be higher than those surveyed by the IESE business school.

An alternative approach is to take the long term average of both the market risk premium and the risk free rate. Again referring to the 2009 PNG Ports determination:

“The corporate finance textbook by Brealey and Myers is perhaps the most known and respected of all. They state the belief that the MRP based on long-horizon bonds is in the range 4.5 per cent to 7.1 per cent. Meanwhile, the investment bank UBS notes that a global market risk premium of about 5 per cent is appropriate given the historical data, market expectations, and a review of available literature.”

We have already identified that the long run risk free rate in the US is 4.64%. So this would indicate that the most likely total equity market returns would be in the range of 9.1% to 11.7% with the most likely result being around 9.6%. For both the PNG Ports Determination (2009) and the Water and Sewerage Determination (2009), the market return was assumed to be (3.7% + 6.0% =) 9.7%. This puts both these determinations firmly in the middle of the long term range and very close to the most likely result.

To be consistent with previous decisions, the Commission is proposing to use a MRP of 6%. The Commission is not persuaded by the evidence before it, that there is a need to deviate from these previous determinations.
6.4.5 US Inflation

PPL in their submission presented an analysis of projected US inflation rates from the “Monetary Policy Report to Congress, Economic Intelligence Unit (EIU) and the international Monetary Fund (IMF). PPL stated;

“Based on our consideration of the US inflation projections above and having particular regard to longer term projections, a US inflation rate of 2.0% has been used to determine the inflation differential between the US and PNG.”

In the preliminary draft report, the Commission proposed to use a US inflation rate of 1.5585%. However, since that time US inflation rates have increased, but are forecast to be 2% for the next 12 months. In addition, the US Federal Open Market Committee has set a target for inflation of 2%.

Over the last five years the actual rates were those shown in Table 25.

Table 25: US Inflation rates

<table>
<thead>
<tr>
<th>Year</th>
<th>% Increase in CPI</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>4.28%</td>
</tr>
<tr>
<td>2009</td>
<td>0.03%</td>
</tr>
<tr>
<td>2010</td>
<td>2.63%</td>
</tr>
<tr>
<td>2011</td>
<td>1.63%</td>
</tr>
<tr>
<td>2012</td>
<td>2.93%</td>
</tr>
</tbody>
</table>

In view of this, the Commission has revised the rate it intends to use for US inflation to 2%.

6.4.6 PNG Inflation

PPL in their submission presented the following:

“In determining the future PNG inflation rate, we have had regard to the projection included in the Monetary policy Statement, issued by the Governor of the Bank of PNG in March 2010 and the PNG inflation projections prepared by the EIU, Oxford Economics and the Asian Development Bank (ADB).

Inflation in PNG has historically been towards the lower single digit range (i.e. 0% to 4%), however following an increase in oil and food prices in 2008, inflation peaked at 13.5%, then declined to a rate of 5.3% in 2009....following relatively high levels of inflation in 2010 and 2011, the inflation rate is generally projected to continue to decrease in the future.

Accordingly, PPL has selected a future inflation rate for PNG of 5.0% to determine the inflation differential between the US and PNG.”

The Commission notes that:

- The Government in their 2011 National Budget have also assumed that inflation will be around 5% in the medium term.
  “Over the medium term, inflation is assumed to gradually moderate to around 5% per annum which represents the long term average inflation for PNG.”
- The Bank of PNG released a Monetary Policy Statement on 30th September 2011 in which they forecast underlying inflation of 7% in 2012 and 6% in 2013.
The Commission has placed more weight on the current higher rates of inflation and is proposing to use a rate of 7.00%.

6.4.7 Country Risk Premium (CRP)

6.4.8
Country risk is the additional return an international investor requires because of its perception of the risk of investing in a particular country.

6.4.8.1 Previous Determinations

In previous determinations, the Commission has used a CRP of 3%. Both the Water and Sewerage determination (2009) and the PNG Ports determination (2009) used 3%.

This rate was originally set by Rothschild’s at the time of 2001 privatisation processes. It was considered to be the rate which was appropriate over the long term in PNG, despite other estimates at the time generating a much higher CRP.

In 2009, the Commission commissioned PricewaterhouseCoopers (“PwC”) to advise on the country risk premium. PwC provided the Commission with estimates of the range of CRP for PNG over the six quarters to the end of March 2009. The PwC estimates ranged from 2.5% to 8.1% depending on the quarter. However, the Commission was concerned that this range was heavily skewed by the impact of credit market dislocation associated with the GFC.

Following the 2009 report from PwC, the Commission sought the counsel of Ross Garnaut formerly of Rothschild’s and current chair of Lihir Gold and board member of Ok Tedi. Professor Garnaut suggested that in his experience the long term average CRP in PNG was 3 per cent. At that time, given the amount of capital deployed by both companies in PNG, the Commission decided to defer to Professor Garnaut regarding the CRP.

6.4.8.2 Methodology for determining CRP

Because PNG does not issue sovereign bonds, estimates of CRP are generally based upon an analysis of country credit ratings. A typical approach to this analysis is;

- Estimate the credit rating of the country;
- Find other countries with the same credit rating and who have issue US denominated government bonds; and
- Look at the difference in bond rate yields between the US and the country issuing the bond.

Currently, PNG has a B+ rating from Standard and Poors and a B1 rating from Moody’s. Other countries with similar ratings to PNG are shown in Figure 24.

Figure 24: Countries with the same credit rating as PNG

<table>
<thead>
<tr>
<th>Country</th>
<th>Rating</th>
</tr>
</thead>
<tbody>
<tr>
<td>Honduras</td>
<td>B+</td>
</tr>
<tr>
<td>Ghana</td>
<td>B+</td>
</tr>
<tr>
<td>Dominican Republic</td>
<td>B+</td>
</tr>
<tr>
<td>Cook Islands</td>
<td>B+</td>
</tr>
</tbody>
</table>
Albania       B+
Cape Verde   B+
Kenya        B+
Nigeria      B+
Mozambique   B+
Papua New Guinea B+
Senegal      B+
Sri Lanka    B+
Uganda       B+
Ukraine      B+
Venezuela    B+
Zambia       B+

In its 2011 submission, PPL submitted the analysis shown in Table 26. This gave an implied Country Risk Premium for PNG of 2.9%.

**Table 26: Implied Country Risk Premium**

<table>
<thead>
<tr>
<th>Issuer</th>
<th>S&amp;P Rating</th>
<th>Maturity</th>
<th>Yield (%)</th>
<th>USD 10 Yr Government Yield</th>
<th>Implied CRP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lebanon</td>
<td>B</td>
<td>9 Mar 2020</td>
<td>5.710%</td>
<td>2.84%</td>
<td>2.87%</td>
</tr>
<tr>
<td>Lebanon</td>
<td>B</td>
<td>12 Apr 2021</td>
<td>6.01%</td>
<td>2.84%</td>
<td>3.17%</td>
</tr>
<tr>
<td>Dominican Republic</td>
<td>B</td>
<td>6 May 2021</td>
<td>5.5%</td>
<td>2.84%</td>
<td>2.66%</td>
</tr>
<tr>
<td>Dominican Republic</td>
<td>B</td>
<td>6 May 2021</td>
<td>5.64%</td>
<td>2.84%</td>
<td>2.8%</td>
</tr>
<tr>
<td>Average</td>
<td></td>
<td></td>
<td>5.715%</td>
<td>2.84%</td>
<td>2.875%</td>
</tr>
</tbody>
</table>

In both its 2011 and its 2012 submissions, PPL referred to the work of Aswath Damodaran (Stern School of Business at New York University). Damodaran uses the following method:

- “I start with the country rating from Moody’s and estimate the default spread for that rating (based upon traded country bonds) over a default free government bond rate. This becomes a measure of the added country risk premium for that country;
- I add this default spread to the historical risk premium for a mature equity market to estimate the total risk premium; and
- The equity country risk premium is likely to be greater than the country’s default spread. You can estimate an adjusted country risk premium by multiplying the default spread by the relative equity market volatility for that market. I have used the emerging market average of 1.5 to estimate country risk premium.

Damodaran has arrived at a country risk premium of 6% for PNG using this method (January 2012).
The Commission notes that Damodaran does not use this country risk premium in the same way as the Commission does. Damodaran adds this country risk premium directly to the market risk factor. Whereas in the method used by the Commission, the country risk premium is used to calculate an international risk free rate.

\[
R_{f\text{international}} = \frac{(1 + R_f)}{(1 + USA_{cpi})} \times (1 + PNG_{cpi}) \times (1 + CRF) - 1
\]

\[
R_e = R_{f\text{international}} + \beta_e \times (R_m - R_f)
\]

The market volatility is allowed for by the Commission by multiplying the market risk premium by the equity beta. The Commission notes that Damodaran has allowed for the market volatility by multiplying the country risk premium by 1.5. So to use this Damodaran’s number in the Commission method would be allowing for market volatility twice. So we must remove the 1.5 adjustment. Working backwards, for our purposes Damodaran’s Country Risk Factor for PNG is 4.0%.

The Commission also note the work of Thomas Stenfeldt Batchelor in his paper “Excessive Risk Premiums when Valuing Companies in Emerging Markets.”(Copenhagen business school May 2010). Batchelor concludes as follows;

“"The main issue being that a country risk premium is largely unfounded in theory, due to the fact that the WACC should not be increased in an emerging market context with a reference to country risks which are predominantly uncorrelated to the global financial markets and thus should be disregarded as unsystematic by a globally diversified investor. Even to the extent that a certain form of risk premium should be applied, the analysis shows that such a premium should not be equal to the sovereign bond spreads related to the country in which the company is based, but rather to a company specific risk premium, which may be based on the spread but which should take into account the risk exposures of the specific company in question and the (often limited) correlation to the risk of sovereign debt default. Finally, a company specific risk premium should be ensured not to double count risks, e.g. if a risk factor has been taken into account in a scenario upon which the DCF-valuation is based, then the risk premium should be reduced accordingly."

More specifically, Batchelor concludes;

- “the application of country risk premium often ignores the fact that most of such risk is unsystematic and can thus be disregarded for valuation purposes by a globally diversified investor;
- the methods for defining country risk premium by way of using sovereign bond spreads as a proxy ignores the fact that corporate risk is far from perfectly correlated to the risk of sovereign debt default; and
- a country-specific risk premium ignores the fact that the risk exposure of a company in an emerging market varies greatly depending on the industry in which it acts and on the potentially international nature of its business.

Looking at the DCF-valuation methodology and the underlying corporate finance theories such as the CAPM a key conclusion is thus that practitioners’ use of a rudimentary country risk premium has very little theoretical justification”

From this, the Commission concludes that the commonly used method for assessing country risk premiums is less than perfect and that there is a tendency to overstate the risk. Rather, the focus should be on the specific risk of the company in question.

6.4.8.3 The impact of the GFC

PPL also argued that the effect of the GFC has been to increase the country risk premium.
“Since the GFC, there has been a flight to safety in the international financial markets and a repricing of risk both at a corporate level and at a country level…… As yields on the risk free benchmark used by the ICCC (US Treasuries) have declined, either:
  • The risk free rate for PNG has declined; or
  • The PNG Country Risk Premium has increased.

It is illogical to suggest that, despite the increased risk premiums demanded by the international financial markets in the recent period, the PNG CRP has remained the same and the risk free rate for PNG has declined in line with the US bond yields. Put another way, when the spread for BBB bonds over AAA rated bonds has increased, it is illogical to suggest that the spread (CRP) for B+ rated PNG has remained the same.”

The Commission does not agree with this argument for the following reasons:

- While the rest of the world may now be considered to be more risky, this does not mean that PNG has become more risky. The credit rating for PNG has increased from a B to a B+. While the credit rating for the United States has declined from AAA to AA+ with a negative outlook. Based upon this, one could argue that PNG country risk premium should have declined.
- The flight to safety by American investors is not necessarily country specific. When market shocks cause flights to safety, the investment crowd often reacts irrationally and exits all foreign investments regardless of where they are.
- While the Commission accepts that the sum of Risk Free Rates plus Market Risk Premiums tend to remain the same over time, this does not necessarily apply also to International Risk Free Rate and Country Risk Premiums.
- The change in Market Risk Premium and Risk Free Rates is specifically allowed for in our WACC calculation, and to build this into the country risk premium also, would be double counting.

6.4.8.4 Country Risk Premium Determination

The Commission places significant weight upon being consistent in its determinations and so has determined to continue to use a Country Risk Premium of 3%. The Commission is not convinced by the evidence before it that the country risk premium for PNG has changed.

6.4.9 Debt Margin

The Debt Margin is the margin above the Risk Free Rate that is associated with debt. For regulatory purposes, it is an estimate of the cost that an efficient business would expect to incur through financing capital investment through debt. It is also related to the current interest rate on corporate bonds, the maturity of the debt on issue, the capital structure and the credit rating.

In their 2011 submission, PPL stated;

“The average margin for corporate bonds issued by Australian companies with a credit rating of BBB is approximately 300 basis points”.

On the basis of this and PPL’s credit rating, PPL submitted that the debt premium should be set at 3.0%.

However, in its 2012 submission, PPL argued the following points:

- Standard & Poor’s use BBB+ companies to assess WACC parameters.
- The Government of PNG is rated B+ and Bank of South Pacific was recently downgraded from B+ to B. PPL’s rating is likely to be lower than the PNG Government.
• The MRP (market risk premium) has increased and there is a relationship between MRP and Debt Premium.
• A submission to the AER (Australian Energy Regulator) by Aurora Energy provided a list of debt margins on corporate bonds. The average was 3.68%. Aurora also submitted that the extrapolated Bloomberg Fair value curve provided a better estimate of 4.11%.
• 10 year debt margin for BBB+ bonds is now 3.92% to 3.98% (compared to PPL’s March submission of 3.68%).
• The Australian Competition Tribunal granted an appeal by United Energy to set the debt margin at 4.34%.
• Corporate bond spreads have increased (i.e. the difference in debt margins between companies with different credit ratings).
• This increase in debt margin is consistent with standard finance theory that predicts that an increased debt margin of a firm will be associated with a heightened MRP for the firm.
• Debt margin for PPL is likely to have increased even more than this.
• PPL concluded that because market conditions had deteriorated and their credit rating was likely to be low, a debt margin of 4.5% would be appropriate.

For the 2009 Water & Sewerage Review, the Commission discussed debt premiums with PwC. PwC indicated at that time, that the global financial crisis had seen an increase in the Debt Margin being offered by financiers on debt funding, and suggested the Debt Margin available at that time was around 2.7%. Also in 2009, the PNG Ports determination used a debt margin of 4.0% based upon advice from PwC who identified a range from 3.1% to 5.2%. The Commission is of the view that debt margins have changed and notes the arguments of PPL.

The Commission also looked at PPL’s actual debt costs. Finance costs taken from PPL’s 2011 annual accounts indicate that PPL paid just over 9% interest on borrowed funds. The notes to the company accounts indicate that the major source of funds at that time was derived from an arrangement entered into in 2009 at a rate of 9.45% minus 1% per annum. Short term arrangements for insurance funding appear to have costed about 30% per annum. The high cost of short term funding is likely to explain why the current average rate is higher than the longer term rate would indicate it should be. PPL also supplied information about forward looking loan facilities. These had a weighted average of 11.5% per annum. If the current cost of funding is 11.5%, then with a risk free rate of 3.7%, a country risk factor of 3.0%, PNG inflation of 7% and US inflation of 2%, this would indicate PPL’s debt margin on current borrowing arrangements is negative according to our theoretical calculations. Either our theory is wrong or the providers of debt to PPL have a different view of the risk involved in making loans to PPL. The possibilities include:

• Their view of the risk free rate is lower;
• Their view of the country risk factor is lower; and / or
• Their view of inflation is lower.

Overall, the current funding costs do not appear to support an argument for a high debt margin.

The counter to this view is the various decisions made by the Australian Energy Regulator (AER) and the Reviews or their decisions by the Australian Competition Tribunal (ACT). The ACT have criticised the AER for not relying on the Bloomberg fair value curve to determine the debt margin. It appears that the AER are not comfortable with the results the methodology is producing and want to modify it in some way. However, the AER has not yet successfully found an alternative method which withstands robust analysis from the experts on the subject. However, the ACT ruled that the AER must continue to use accepted methods for determining Debt Premiums.

The Commission notes the Bloomberg fair value curve tends to provide a short term view of debt margin, and that early in 2012, results were providing debt margins in the range of 3.8 to 4.2%. The Commission would prefer to take a longer term view which will be representative of the likely cost of debt that PPL will face over the next five years.

The Commission had determined to use a debt margin of 4% on the basis of the weight of expert opinion from various Australian determinations. This is in line with previous determinations (i.e. PNG Ports Determination 2009)
and is countered by some of the higher results being derived in the immediate short term and the lower rate indicated by PPL’s actual costs.

6.4.10 Taxation

The Commission has determined to adopt the statutory tax rate of 30% in the WACC calculation. Given the relative cost and the level of intrusion associated with the calculation of an “effective” tax rate, the Commission is reluctant to alter its position from using the statutory tax rate.

6.4.11 Equity Beta

The equity beta represents the degree of riskiness of a business compared to the overall market. Equity beta is estimated by assessing the movement in a particular business’s share price relative to the average of the overall market.

In assessing the equity Beta for PPL, it is important to remember the nature of PPL. As already stated, PPL has the following characteristics. It is;

- a state owned enterprise;
- in a developing country;
- a monopoly;
- selling most of its load to price inelastic customers;
- subject to unpredictable changes in fuel prices.

6.4.11.1 The Impact of Fuel Prices

In both their submission’s, PPL focused upon the impact of fuel on their profitability. In 2008 PPL were majorly affected by the international increase in fuel prices. (See Figure 25: PNG Power Net Profit before Tax). In their 2012 submission, PPL argued that because of the unpredictable effect of fuel prices on their business, the business was extremely risky, and therefore, should have a high asset beta. The Commission has determined that the fluctuating fuel price will be specifically addressed by making quarterly adjustments to prices. Therefore, the risk of the unpredictable fuel prices impacting upon PPL’s profitability is largely removed. Consequently, our estimate of the asset beta does not take fuel prices into account.

Figure 25: PNG Power Net Profit before Tax

6.4.11.2 Estimating the Equity Beta
In its 2011 submission, PPL identified the asset betas of a list of comparable integrated power companies in Australia and the UK. They chose these countries because of the similar regulatory environment in those jurisdictions.

- The average asset beta for the UK companies was 0.42 with a range from 0.34 to .49; and
- The average asset beta for the Australian companies was 0.35 with a range from 0.14 to 0.71.

PPL argued that the main difference between PPL and the companies on the list was that PPL had a higher proportion of their business focused on generation rather than transmission and distribution, and that generation businesses are generally more risky than businesses that focus on transmission and distribution. Therefore, they argued the beta should be towards the higher end of the range and suggested that it should be between 0.5 and 0.6.

In the preliminary draft report, the Commission considered beta values for publically listed vertically integrated power companies in a range of other countries. See Table 27 (sourced from Bloomberg and Damodaran).

**Table 27: Asset Beta for vertically integrated power companies**

<table>
<thead>
<tr>
<th>Company</th>
<th>Country</th>
<th>Asset Beta (Unleveraged)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Contact Energy Ltd</td>
<td>New Zealand</td>
<td>0.826</td>
</tr>
<tr>
<td>Enersis sa</td>
<td>Chile</td>
<td>0.675</td>
</tr>
<tr>
<td>Irkutskenergo</td>
<td>Russia</td>
<td>0.656</td>
</tr>
<tr>
<td>Tenaga Nasional Bhd</td>
<td>Malaysia</td>
<td>0.604</td>
</tr>
<tr>
<td>Eletropaulo Metropoli-pref</td>
<td>Brazil</td>
<td>0.602</td>
</tr>
<tr>
<td>Dpl Inc</td>
<td>United States</td>
<td>0.600</td>
</tr>
<tr>
<td>Allete Inc</td>
<td>United States</td>
<td>0.546</td>
</tr>
<tr>
<td>Centrais Eletricas Bras-pr b</td>
<td>Brazil</td>
<td>0.526</td>
</tr>
<tr>
<td>Firstenergy Corp</td>
<td>United States</td>
<td>0.504</td>
</tr>
<tr>
<td>Black Hills Corp</td>
<td>United States</td>
<td>0.495</td>
</tr>
<tr>
<td>Nextera Energy Inc</td>
<td>United States</td>
<td>0.454</td>
</tr>
<tr>
<td>Duke Energy Corp</td>
<td>United States</td>
<td>0.447</td>
</tr>
<tr>
<td>Avista Corp</td>
<td>United States</td>
<td>0.413</td>
</tr>
<tr>
<td>Scottish &amp; Southern Energy</td>
<td>Britain</td>
<td>0.360</td>
</tr>
<tr>
<td>Cia General de Electricidad</td>
<td>Chile</td>
<td>0.337</td>
</tr>
<tr>
<td>Hokuriku Electric Power Co</td>
<td>Japan</td>
<td>0.251</td>
</tr>
<tr>
<td>Chubu Electric Power Co Inc</td>
<td>Japan</td>
<td>0.180</td>
</tr>
</tbody>
</table>

**Average**                      |                          | **0.499**                

Based upon this analysis, the Commission proposed to use an asset beta of 0.499.

PPL responded to this in its 2012 submission with a critique of the Commission’s list of companies as follows.

“PPL submits that most of these companies are very large, stable utilities and do not provide an accurate representation of companies that face the same systematic risks as PPL. Additionally, the shareholding in a number of companies is tightly held and trading volume is small.”

The Commission has reviewed the list of companies used based upon PPL’s comments. Any company which was considered to be thinly traded or had material portions of their business related to activities which were not directly
related to energy distribution or generation (e.g. coal mining) was removed from the list. The result was that the average beta changed from 0.499 to 0.466.

PPL also argued that their business was riskier than PNG Ports, and therefore, should have a higher asset beta than PNG Ports.

The Commission is of the view that if the risk of fluctuations in fuel prices is removed, then PPL is less risky than PNG Ports. PNG Ports is exposed to potential changes in demand as the exports and import volumes change with economic activity. In contrast, PPL sell a generally price inelastic product with very low demand fluctuation. The Commission is of the view that PPL should have a lower asset beta than PNG Ports.

PPL also presented the following arguments.

- The US Market is more volatile and, as utilities are relatively stable, their betas may tend to be underestimated.
- Many US utilities have major shareholders and generally have small equity turnover in the market. Thin trading of individual stocks can lead to estimates of beta that are biased downwards.
- US Utilities are subject to regulatory regimes with substantially lower risk and thus US betas will underestimate the betas of Australian and PNG firms regulated under a different regime.

The Commission notes that the beta presented by PPL in their first submission for UK and Australian companies had lower average betas than the US companies on Commission’s list. Thus, PPL’s argument in their second submission does not appear to be supported by their first submission.

PPL also referred to the work of Professor Martin Lally, who provided advice to the Queensland Competition Authority. Lally argued that companies which are subject to price cap regulation (like PPL), are likely to have higher betas than similar companies with revenue capping or rate of return regulation. The rationale is that companies with revenue caps or rate of return regulation can increase prices to ensure that their costs are covered in circumstances where demand falls unexpectedly.

The Commission notes that PPL is not exposed to the same risk of demand shock that both Australian and US companies are, because their customers are far less likely to drastically change demand due to weather events. In both the US and Australia, cold summers or warm winters can cause customers to use significantly less electricity for air conditioning and heating. This is not a common occurrence in PNG and so the Commission does not think this argument is particularly relevant.

PPL also presented a list of 82 American electric and or gas distributors. They had an average 3 year asset beta of 0.599.

In response to the second draft report, PPL agreed that addressing the effect of fuel separately did reduce the riskiness of PPL. However they did not agree with the Commission on several other points. In their submission, under the heading of “Climate Risk” PPL wrote;

"It is true that PNG does not have the same weather related within year seasonal demand shocks as the USA or Australia. However, the between year climate variability has a significant impact on demand and the business impact of demand changes are more severe for PPL due to its small size and restricted generation options.

For example, in 2010, the weather was a major contributor to the 9.9% demand increase in Port Moresby and the much lower than expected demand increase of 4.0% in 2011.

2009 was a cool year while 2010 was an exceptionally ‘hot’ year. Only 2004 was cooler than 2009 in the last ten year period and only 2005 was warmer than 2010.

2011 temperature was ‘normal’, as the average temperature also is the median for the last 10 years."
With the large proportion of air-conditioning load in Port Moresby and other demand centres, these shifts in average temperature have a noticeable impact on electricity demand.”

In response to this the Commission examined PPL’s demand curve (See Figure 27: Electricity Demand). The demand figures did not appear to show that weather had a material impact upon electricity consumption during the years concerned. While it is possible that the weather effect may be hidden by growth in the market, the Commission is of the view that PPL will continue to experience growth and that this will outweigh any short term weather impacts.

Generally the Commission was not convinced that weather was important enough to change its view on the asset beta. Clearly many of the companies to which the Commission is comparing PPL have more significant impacts due to weather and their average asset beta is 0.499.

Under the heading of “Volume Risk” PPL wrote;

“The ICCC states that they consider PNG ports to be more subject to change in demand from fluctuations in economic activity. As PNG Ports is one of PPL’s larger customers, the economic strife of said company also has a direct impact on electricity as a response to their own economic situation.

It is true that PPL’s market is largely price inelastic. However as PPL is regulated under a price cap regime, PPL cannot use the price inelasticity to adjust prices (and revenue) to reduce earnings volatility induced by demand slumps.”
The Commission agrees that PPL is not able to adjust prices to capture any price inelasticity benefits, and therefore agrees with PPL that price elasticity is largely irrelevant to determining asset beta.

PPL went on to say that demand forecasting has a low level of confidence. They presented the following figure as evidence of this.

“The graph below is for Port Moresby and the confidence intervals clearly show the massive forecast uncertainty and hence the significant volume risk PPL carries.”

Figure 28: PPL Demand Forecasting Model

The Commission accepts that demand forecasts in a growing economy are difficult and have a high level of uncertainty. However, in the Commission’s view the investment required by PPL to support growth in the market has a relatively low risk of being “stranded”, given the current state of PPL’s network and its struggle to meet existing demand.

Under the heading of “International Evidence” PPL wrote;

“The ICCC proposes to apply an Asset Beta of 0.499, the average of a list (Table 27) the Commission considers a relevant sample of publically listed companies in a range of countries.

PPL strongly contest the applicability and representativeness of the list. For example, the ICCC makes a point that being a developing country is one of the factors that needs to be considered when estimating the Asset Beta. By removing the companies from developed countries (Japan, USA, Great Britain and New Zealand) the average Asset Beta is 0.567 and the median 0.603. The median is more appropriate measure in small non-normal datasets.

It could also be argued that the Asset Beta of utilities should be higher in smaller (Island) markets as is evident from the Asset Beta of the New Zealand company on the list.

A larger sample of US companies supplied by PPL in the March 2012 submission, had an average Asset Beta of around 0.6. There is no theoretical or practical support that small price cap regulated utility in a developing country would have a lower Asset Beta than the average US utility.”

PPL Concluded with

“All things considered, PPL is of the opinion that an Asset Beta below 0.6 is unrealistic and not supported by evidence or theory.”
The Commission notes that PPL picked up upon the observation that PPL was in a developing country. The point was made as context for the overall decision about setting an appropriate WACC for PPL and as well as considering how risky it might be. However the WACC does specifically take into account the riskiness of PNG with the Country Risk Premium. Therefore any further consideration as to which country PPL operates in, would be double counting country risk. Therefore the Commission is of the view, that size of PNG and its geography have already been considered and taken into account and should not be further considered when determining the asset beta.

The Commission has sought to use the evidence before it to determine an Asset Beta. The Commission also notes that the range of asset beta’s identified for consideration by PPL in the course of its submissions ranged from 0.14 to 1.18. However PPL has then argued that companies with higher Asset Betas should be selected. The Commission has tried to select companies which operate in a comparable business, rather than being just any utility. In its first submission, part of PPL’s argument was that distribution companies were less risky than generation companies and that this should be a consideration in setting PPL’s Asset Beta. The Commission has chosen vertically integrated electricity companies as its benchmark.

The Commission selected an Asset Beta of 0.5 in its previous determination. PPL believe that 0.6 is the minimum. In the Commission’s view 0.5 and 0.6 are very close given the large range of possible Asset Betas for Utilities. However the evidence for vertically integrated electricity companies indicates that these types of companies have a median and average beta of closer to 0.5.

### 6.4.11.3 Beta Determination

In determining the asset beta, the ICCC, has considered the various arguments put by PPL. The evidence derived by both PPL and the ICCC points to the asset beta being in the range of 0.35 to 0.6. The ICCC has determined to use an asset beta of 0.5 being the average asset beta from data available for vertically integrated power companies. Using the Monkhouse formula this produces an Equity Beta of 0.67.

### 6.4.12 Gearing ratio

In its 2011 submission, PPL proposed a debt to debt plus equity ratio of 40% based upon an analysis of a group of companies which they considered were comparable to PPL. For the group of companies;

- The average debt to debt plus equity ratio of Australian utilities was 51%; and
- The average debt to debt plus equity ratio of all comparable companies was 49%.

The Commission considered a group of 24 vertically integrated power companies as shown in Table 28 (Source: Bloomberg and Damodaran). The average debt to debt plus equity ratio for these companies was 39.8% and the upper quartile was 59.13%.

In the first draft report the Commission proposed a gearing ratio of 50% and in its 2012 submission, PPL supported the Commission’s position. However following on from this PPL changed its position and again proposed a gearing ratio of 40%.

In support of a lower gearing ratio PPL made the following comments;

“PPL’s gearing ratio was below 30% in 2011 and an updated financial forecast indicates that the gearing ratio will stay below 40% throughout the 2013 -2017 regulatory period.

It is PPL’s opinion that it is highly unlikely that the gearing ratio will be above 40% in the 2013-2017 regulatory period, particularly in a policy environment where commercial generation projects that can attract significant debt funding are likely to be developed in off balance sheet arrangements (IPP’s).”
The Commission had previously thought that PPL’s debt levels would increase significantly. However with the release of the EIP, it is likely that major generation projects will be developed off PPL’s balance sheet. Also because the benchmark companies the Commission has used have an average gearing ratio of 40%, using 40% is more consistent with other parts of the Commission WACC determination.

The Commission has determined to use a gearing ratio of 40%.

Table 28: Debt ratios for vertically integrated power companies

<table>
<thead>
<tr>
<th>Company</th>
<th>Country</th>
<th>Debt / (debt + equity)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Centrais eletricas bras-pr b</td>
<td>Brazil</td>
<td>41.31%</td>
</tr>
<tr>
<td>Cia energetica de per-pref a</td>
<td>Brazil</td>
<td>26.10%</td>
</tr>
<tr>
<td>Eletropaulo metropoli-pref</td>
<td>Brazil</td>
<td>27.62%</td>
</tr>
<tr>
<td>International power plc</td>
<td>Britain</td>
<td>22.12%</td>
</tr>
<tr>
<td>Scottish &amp; southern energy</td>
<td>Britain</td>
<td>28.42%</td>
</tr>
<tr>
<td>Cia general de electricidad</td>
<td>Chile</td>
<td>61.14%</td>
</tr>
<tr>
<td>Enerisis sa</td>
<td>Chile</td>
<td>30.38%</td>
</tr>
<tr>
<td>Empresa electrica antofagast</td>
<td>Chile</td>
<td>22.74%</td>
</tr>
<tr>
<td>Clp holdings ltd</td>
<td>Hong Kong</td>
<td>31.95%</td>
</tr>
<tr>
<td>Iren spa</td>
<td>Italy</td>
<td>55.33%</td>
</tr>
<tr>
<td>Chubu electric power co inc</td>
<td>Japan</td>
<td>59.30%</td>
</tr>
<tr>
<td>Hokuriku electric power co</td>
<td>Japan</td>
<td>62.16%</td>
</tr>
<tr>
<td>Tenaga nasional bhd</td>
<td>Malaysia</td>
<td>25.95%</td>
</tr>
<tr>
<td>Contact energy ltd</td>
<td>New Zealand</td>
<td>25.42%</td>
</tr>
<tr>
<td>Karachi electric supply</td>
<td>Pakistan</td>
<td>57.41%</td>
</tr>
<tr>
<td>Irkutskenergo</td>
<td>Russia</td>
<td>15.80%</td>
</tr>
<tr>
<td>Korea electric power corp.</td>
<td>South Korea</td>
<td>59.63%</td>
</tr>
<tr>
<td>Allete inc</td>
<td>United States</td>
<td>35.37%</td>
</tr>
<tr>
<td>Avista corp.</td>
<td>United States</td>
<td>51.43%</td>
</tr>
<tr>
<td>Black hills corp.</td>
<td>United States</td>
<td>53.78%</td>
</tr>
<tr>
<td>Dpl inc</td>
<td>United States</td>
<td>28.29%</td>
</tr>
<tr>
<td>Duke energy corp.</td>
<td>United States</td>
<td>41.20%</td>
</tr>
<tr>
<td>Firstenergy corp.</td>
<td>United States</td>
<td>46.18%</td>
</tr>
<tr>
<td>Nextera energy inc</td>
<td>United States</td>
<td>46.92%</td>
</tr>
<tr>
<td>Average</td>
<td></td>
<td>39.83%</td>
</tr>
</tbody>
</table>

6.4.13 Summary of WACC Parameters

Having considered all of the above, the Commission has adopted a draft pre-tax real WACC of 13.2%. Table 29 gives a summary of the WACC inputs and outputs used.
Table 29: Summary of WACC Inputs and Outputs

<table>
<thead>
<tr>
<th>Summary of Inputs</th>
</tr>
</thead>
<tbody>
<tr>
<td>US Risk Free Rate</td>
</tr>
<tr>
<td>CRP</td>
</tr>
<tr>
<td>PNG Inflation</td>
</tr>
<tr>
<td>US Inflation</td>
</tr>
<tr>
<td>Debt Margin</td>
</tr>
<tr>
<td>MRP</td>
</tr>
<tr>
<td>Effective Tax Rate For Equity</td>
</tr>
<tr>
<td>Effective Tax Rate For Debt</td>
</tr>
<tr>
<td>Debt %</td>
</tr>
<tr>
<td>Asset Beta</td>
</tr>
<tr>
<td>Equity Beta</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Outputs</th>
</tr>
</thead>
<tbody>
<tr>
<td>International Risk Free Rate</td>
</tr>
<tr>
<td>Post Tax Nominal Return on Equity</td>
</tr>
<tr>
<td>Post Tax Real Return on Equity</td>
</tr>
<tr>
<td>Pre Tax Nominal Cost of Debt</td>
</tr>
<tr>
<td>Pre Tax Real Cost of Debt</td>
</tr>
<tr>
<td>Post Tax Nominal WACC</td>
</tr>
<tr>
<td>Post Tax Real WACC</td>
</tr>
<tr>
<td>Pre Tax Nominal WACC</td>
</tr>
<tr>
<td>Pre Tax Real WACC</td>
</tr>
</tbody>
</table>

6.5 Roll Forward of the Forecast RAB

The estimated value of the Regulatory Asset Base (RAB) has been rolled forward over the contract period using the same method as was used to update it from 2002 numbers. That is;

- The 2012 RAB closing balance was used as the opening balance for 2013 after inflating it by 7% to reflect current inflation rates;
- This balance was depreciated using rates that reflect the expected economic life of each asset;
- The forecast capex for the 2013 year was added to each asset class, to arrive at a closing balance for 2013;
- This closing balance was then used as the opening balance for 2014; and
- This was repeated for each year to establish how the RAB would change over the contract period.

Table 30 shows the resultant values. The Commission is proposing to use these values to estimate the depreciation or recovery of capital for the building blocks.

Table 30: Opening Balances of the RAB

<table>
<thead>
<tr>
<th>Kina (millions)</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Distribution</td>
<td>151</td>
<td>152</td>
<td>153</td>
<td>154</td>
<td>155</td>
</tr>
</tbody>
</table>
6.6 Depreciation

Each asset class was depreciated each year, using straight line depreciation, based upon the expected economic life of each asset class. Table 31 gives the depreciation rates the Commission is proposing to use. The Commission notes that some of these asset classes will include a variety of types of assets which have different economic lives. The Commission has tried to use rates that will approximately reflect the likely useful life of these different assets types.

Table 31: Depreciation Rates

<table>
<thead>
<tr>
<th>Asset Class</th>
<th>Economic Life</th>
<th>SL Depreciation Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capitalised overheads</td>
<td>20.0</td>
<td>7.1%</td>
</tr>
<tr>
<td>Distribution</td>
<td>30.0</td>
<td>3.3%</td>
</tr>
<tr>
<td>Generation - Hydro</td>
<td>50.0</td>
<td>2.0%</td>
</tr>
<tr>
<td>Generation - Diesel</td>
<td>10.0</td>
<td>10.0%</td>
</tr>
<tr>
<td>Land</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>20.0</td>
<td>5.0%</td>
</tr>
<tr>
<td>Motor Vehicles</td>
<td>8.0</td>
<td>12.5%</td>
</tr>
<tr>
<td>Office &amp; Residential</td>
<td>40.0</td>
<td>2.5%</td>
</tr>
<tr>
<td>Plant, Tools &amp; Equipment</td>
<td>30.0</td>
<td>3.3%</td>
</tr>
<tr>
<td>Transmission</td>
<td>50.0</td>
<td>2.0%</td>
</tr>
</tbody>
</table>

Applying the depreciation rates shown in Table 31, it produced the annual depreciation amounts shown in Table 32. The Commission is proposing, subject to any further information provided by PPL, that these amounts be used as part of the building block calculation to estimate the recovery of capital.

Table 32: Annual Depreciation used in building block calculation

<table>
<thead>
<tr>
<th>Kina (millions)</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Distribution</td>
<td>13</td>
<td>14</td>
<td>14</td>
<td>15</td>
<td>15</td>
</tr>
<tr>
<td>Generation - Hydro</td>
<td>10</td>
<td>16</td>
<td>18</td>
<td>19</td>
<td>23</td>
</tr>
<tr>
<td>Generation - Thermal</td>
<td>24</td>
<td>32</td>
<td>40</td>
<td>45</td>
<td>46</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>3</td>
<td>4</td>
<td>5</td>
<td>6</td>
<td>7</td>
</tr>
<tr>
<td>Motor Vehicles</td>
<td>9</td>
<td>8</td>
<td>6</td>
<td>5</td>
<td>4</td>
</tr>
<tr>
<td>Office &amp; Residential</td>
<td>10</td>
<td>10</td>
<td>10</td>
<td>11</td>
<td>11</td>
</tr>
</tbody>
</table>
6.7 Total Revenue Requirements

Each building block is added together to establish the total revenue requirement. That is the amount of revenue required to cover all of PPL’s operating and capital costs. The Commission has estimated the revenue requirement to be the amounts shown in Table 33. It is important to note that the total revenue requirement incorporates the total revenues required from regulated and non-regulated sales.

Table 33: Building Blocks

<table>
<thead>
<tr>
<th>Building Block</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel Costs</td>
<td>290</td>
<td>293</td>
<td>303</td>
<td>314</td>
<td>329</td>
</tr>
<tr>
<td>Non Fuel Operating Expenditure</td>
<td>318</td>
<td>310</td>
<td>316</td>
<td>324</td>
<td>331</td>
</tr>
<tr>
<td>Return of capital (Km)</td>
<td>80</td>
<td>96</td>
<td>106</td>
<td>115</td>
<td>122</td>
</tr>
<tr>
<td>Regulatory Asset Base (Km)</td>
<td>1,277</td>
<td>1,656</td>
<td>1,830</td>
<td>2,008</td>
<td>2,289</td>
</tr>
<tr>
<td>Working Capital (Km)</td>
<td>-4</td>
<td>5</td>
<td>9</td>
<td>13</td>
<td>20</td>
</tr>
<tr>
<td>Return on Capital (Km)</td>
<td>191</td>
<td>228</td>
<td>252</td>
<td>282</td>
<td>315</td>
</tr>
<tr>
<td>Non Fuel Revenue Requirement (Km)</td>
<td>589</td>
<td>634</td>
<td>674</td>
<td>721</td>
<td>768</td>
</tr>
<tr>
<td>Total Revenue Requirement</td>
<td>879</td>
<td>928</td>
<td>978</td>
<td>1,035</td>
<td>1,097</td>
</tr>
<tr>
<td>Delivered Power (MWh)</td>
<td>881,389</td>
<td>920,514</td>
<td>962,543</td>
<td>1,004,571</td>
<td>1,043,696</td>
</tr>
<tr>
<td>MWAP (Kina / MWh)</td>
<td>916.42</td>
<td>944.06</td>
<td>981.13</td>
<td>1021.11</td>
<td>1068.24</td>
</tr>
<tr>
<td>% Change in MAP</td>
<td>3.27%</td>
<td>3.02%</td>
<td>3.93%</td>
<td>4.08%</td>
<td>4.62%</td>
</tr>
</tbody>
</table>

The Commission is interested to note that the revenue requirement will fall in 2014 even though the delivered energy will increase. This is a combination of several factors built into the inputs. Fuel consumption is expected to fall, presumably because of new hydro-generation coming on stream. The capital recovery portion of the Kanudi contract also comes to an end in 2014.

6.8 Price Path Assessment

6.8.1 Discussion

The use of the MWAP, expressed in terms of Kina per MWh, means that as volumes of delivered power change, PPL’s revenues will also change in direct proportion to the change in volume.

However, as volumes change, PPL’s cost of delivery may change in ways that are not directly proportional to volume. This might be due to:

- Changes in input prices;
- Change in the relative mix of volumes between high cost and low cost service areas;
- Change in the relative mix of volumes between high cost and low cost generation;
- Change in the relative mix between high cost and low cost customers;
• Changes in the level of service and network reliability provided by PPL;

Changes in input prices are allowed for via the annual or quarterly adjustment process which reflects inflation, exchange rates and fuel price changes. However, changes in mix and changes in the network reliability and service levels are not provided for in the annual adjustment process.

Some of the changes can be directly managed by PPL. This includes changes in the mix of high cost and low cost sources of power generation (excluding the impacts of drought) and changes in the level of service and network reliability.

However, some of the possible changes are beyond PPL’s control. This includes changes in the mix of high cost and low cost customers and changes in the volume of power consumed in high cost or low cost areas.

Those factors that can be directly managed by PPL can be built into opex and capex budgets. But those factors which cannot be directly managed by PPL must be forecast. If the actual mix is materially different from the forecast, then PPL may over or under recover its cost of delivery. This is a particularly relevant issue for PPL because of the high growth rate of demand and the pressure to connect new customers in high cost areas.

The Commission is proposing to allow PPL to price differentiate between different service areas. But this will not affect the MWAP. And therefore, does not address the issue of changes in mix between high cost and low cost customers, affecting the total forecast revenue requirement.

To adequately address this issue, the Commission is of the view that the single MWAP currently used would need to be replaced by multiple MWAPs which each reflect the cost to provide service in different areas. With this approach, each service area would be classified according to its relative level of cost. Those service areas which had similar cost levels would be grouped together. For each grouping a separate MWAP would be established. Using the current price setting Methodology, this would require that RABs be established for each service area, and that separate operating costs also be established for each area. The Commission is of the view that this not likely to be practical given the current information constraints imposed by PPL’s information systems. Furthermore, the Commission is of the view that while allowing price differentiation between service areas will not address the issue of changes between forecast mix and actual mix, it will assist PPL in managing the overall risks associated with high cost areas.

When this issue was discussed with PPL, they did not consider it to be a material issue for them.

The Commission has determined to continue to use a single MWAP to cover all of PPL’s regulated prices. However, the new ERC also requires that PPL start collecting information by different service areas to support more tailored pricing in future.

6.8.2 Methods of setting the price path

The revenue requirement calculations shown in Table 33 show that over the course of the contract the MWAP will need to rise and fall by varying amounts each year. It is normal practice to smooth out prices over time. There are three approaches the Commission could choose to smooth prices.

• Method 1: Set an initial MWAP and identify an X factor for each year of the contract which would allow for different changes each year over the duration of the contract;
• Method 2: Estimate the MWAP that if used over the five year period would ensure that the NPV (Net Present Value) of the revenue was equal to the NPV of the revenue requirement over the contract period; and
• Method 3: Estimate an initial MWAP and the average annual percentage change required so that the NPV of the regulated revenue equals the NPV of the regulated revenue requirement over the contract period.

The Commission notes that PPL used this third method in their submission. The Commission also notes that;
Any of these methods can be used to produce a result whereby the forecast revenue received by PPL covers the forecast revenue requirement;

- Method 2 will result in a set of prices that do not change over the contract period, while method 1 and method 3 are likely to produce results where prices start lower and increase over the contract. However, once adjustments are made for inflation, exchange rates and fuel price changes, method 2 will still not produce a constant set of prices; and

- Method 3 will tend to smooth the changes out over time.

PPL commented in its 2012 submission that they would like to see method 1 adopted because of the flexibility it provides.

The Commission does not perceive that Method one provides additional flexibility over method 3, as the X factor or X factors will be predefined in the contract in either case.

On balance the Commission has determined to use method 3 because this is the method it has used in the past and will be simpler to apply.

### 6.8.3 Price Path

The Commission has determined that the Non Fuel WAP of 587.56 Kina per MWh be used in 2013 with an X Factor adjustment of 6.57% each year. Using the forecast demand and current fuel prices this will result in the Fuel WAP and hence MWAP shown in Table 34 (see section 5.7.4). If these MWAP’s are applied to existing prices, this will result in the prices shown in Table 35.

**Table 34: Proposed MWAP over the contract period**

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>MWAP (Kina / MWh)</td>
<td>916.42</td>
<td>944.06</td>
<td>981.13</td>
<td>1021.11</td>
<td>1068.24</td>
</tr>
<tr>
<td>Fuel WAP (Kina / MWh)</td>
<td>328.86</td>
<td>318.51</td>
<td>315.28</td>
<td>312.30</td>
<td>315.16</td>
</tr>
<tr>
<td>Non Fuel WAP (Kina / MWh)</td>
<td>587.56</td>
<td>625.55</td>
<td>665.85</td>
<td>708.82</td>
<td>753.08</td>
</tr>
<tr>
<td>% Change in MWAP</td>
<td>3.27%</td>
<td>3.02%</td>
<td>3.93%</td>
<td>4.08%</td>
<td>4.62%</td>
</tr>
<tr>
<td>% Change in Non-Fuel WAP</td>
<td>3.32%</td>
<td>6.47%</td>
<td>6.44%</td>
<td>6.45%</td>
<td>6.24%</td>
</tr>
</tbody>
</table>

**Table 35: Price path if X factor applied to existing prices**

<table>
<thead>
<tr>
<th>Prices (K/kWh)</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Domestic - credit</td>
<td>0.5285</td>
<td>0.5632</td>
<td>0.6002</td>
<td>0.6396</td>
<td>0.6816</td>
</tr>
<tr>
<td>General Supply - credit</td>
<td>0.6716</td>
<td>0.7156</td>
<td>0.7626</td>
<td>0.8127</td>
<td>0.8661</td>
</tr>
<tr>
<td>Industrial - credit</td>
<td>0.3089</td>
<td>0.3292</td>
<td>0.3508</td>
<td>0.3738</td>
<td>0.3984</td>
</tr>
<tr>
<td>Public Lighting - (average)</td>
<td>0.6716</td>
<td>0.7156</td>
<td>0.7626</td>
<td>0.8127</td>
<td>0.8661</td>
</tr>
<tr>
<td>Easipay Domestic</td>
<td>0.3742</td>
<td>0.3988</td>
<td>0.4250</td>
<td>0.4529</td>
<td>0.4826</td>
</tr>
<tr>
<td>Easipay Gen Supply</td>
<td>0.6466</td>
<td>0.6891</td>
<td>0.7343</td>
<td>0.7825</td>
<td>0.8339</td>
</tr>
<tr>
<td>Industrial Demand Price (K/kVA/month)</td>
<td>79.0080</td>
<td>84.1956</td>
<td>89.7239</td>
<td>95.6151</td>
<td>101.8932</td>
</tr>
<tr>
<td>Domestic Credit first block of 30kWh</td>
<td>0.1712</td>
<td>0.1825</td>
<td>0.1944</td>
<td>0.2072</td>
<td>0.2208</td>
</tr>
</tbody>
</table>

The Commission notes that if PPL chooses to price differentiate between service areas, prices will be different from those shown here.
Figure 29 shows the effect of price smoothing. The forecast revenue is the revenue which will result using PPL’s forecast sales and the prices in Table 35.

Figure 29: Price Smoothing

6.8.4 The Effect of the Mid-Term Adjustment

In section 5.7.10, a method of adjusting the X factor at the Mid-term review was proposed. In order to illustrate the adjustment, we have estimated the impact of this adjustment at varying levels of capital expenditure. Table 36 shows how the MWAP and X factor would be reset for 2016 and 2017 if actual prudent capex was at 80% of the planned capex.

Table 36: MWAP adjustment at Mid Term Review

<table>
<thead>
<tr>
<th>MWAP Metrics if Capex reduced by 20%</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>MWAP (Kina / MWh)</td>
<td>916.42</td>
<td>944.06</td>
<td>981.13</td>
<td>1021.11</td>
<td>1068.24</td>
</tr>
<tr>
<td>Fuel WAP (Kina / MWh)</td>
<td>328.86</td>
<td>318.51</td>
<td>315.28</td>
<td>312.30</td>
<td>315.16</td>
</tr>
<tr>
<td>Non Fuel WAP (Kina / MWh)</td>
<td>587.56</td>
<td>625.55</td>
<td>665.85</td>
<td>708.82</td>
<td>753.08</td>
</tr>
<tr>
<td>% Change in MWAP</td>
<td>3.270%</td>
<td>3.016%</td>
<td>3.926%</td>
<td>4.075%</td>
<td>4.615%</td>
</tr>
<tr>
<td>% Change in Non-Fuel WAP</td>
<td>3.321%</td>
<td>6.466%</td>
<td>6.443%</td>
<td>6.453%</td>
<td>6.244%</td>
</tr>
</tbody>
</table>
7 COST PASS-THROUGH ARRANGEMENTS

Cost pass-through events and processes are sometimes included in price control arrangements to allow the regulator to factor in the effects of unanticipated events which either raise or lower costs for the regulated business in a substantial manner. This is necessary to ensure that the regulated power entities are not severely disadvantaged by changes in circumstances which have not been accommodated for appropriately in the regulated price path.

The pass-through events allowed for in the current regulatory contract include:

- a change in taxes;
- an act of terrorism or major natural disasters; or
- a change in water access charges;

The Commission believes these pass-through events are still relevant and has determined that these be included for the next regulatory period.

In all cases, PPL must apply to the commission to have the pass-through costs approved.

7.1 Force Majeure Events

Force Majeure events are defined in the contract and are taken to mean:

a) a cyclone, storm, flood, drought that continues for more than two years, earthquake, tidal wave or landslide; or
b) an act of public enemy, war (declared or undeclared), sabotage, blockade, revolution, riot, insurrection, civil commotion or any violent or threatening actions,

which results in or is likely to result in an increase in the costs incurred by PPL.

7.2 Tax Change Events

Tax change events are defined in the contract. They include;

a) a change in application or official interpretation of a Relevant Tax or the way in which a Relevant Tax is calculated;
b) the removal of a Relevant Tax; or
c) the imposition of a Relevant Tax,

which results in PPL incurring materially higher or lower costs than it would have incurred but for that event.

7.3 Water Access Charges

If unforeseen circumstances arise where PPL incurs costs gaining access to water for the purpose of power generation, and these costs have not been allowed for in the regulatory price path, then PPL can apply to the Commission to pass these costs through to customers.
8 SERVICE STANDARD REQUIREMENTS

In determining the efficient costs and forecasting revenues, the Commission is required to take into account the standard of service that will be provided. The service standard variables are used to assess and measure PPL’s overall delivery performance. In particular, whether, or not, PPL is achieving its reliability targets while efficiently supplying electricity throughout Papua New Guinea.

The Commission is generally concerned that the current service measures may not be providing reliable and helpful indicators of the actual performance of PPL’s network. The Commission is also concerned that current rebate structures may not be providing the right incentives to PPL to improve its performance and the performance of its network. Care must therefore be taken to ensure any decisions are based upon facts rather than other factors such as public perception.

The Commission has noted and supports PPL’s proposal to introduce new measures and has chosen a structured approach to the introduction of new measures during this Regulatory Period. However, because these will take some time to introduce, the Commission has modified the current performance measure process as an interim step.

PPL is currently required, on a quarterly basis, to report to the Commission on the following service standard variables:

- Total Planned Outages
- Total Undelivered Energy
- Total Energy Delivered
- Unserved Energy Ratio
- For each Planned Outage, whether any Required Notice of that Planned Outage was given
- New Connections made
- New Connections not made by the required date
- Connection times

There is currently a rebate provision set in place which provides PPL the incentives to meet some of the targets in the above mentioned areas.

8.1 Interruptions (Generation, Transmission & Distribution)

Outages experienced throughout the country can be attributed to Generation, Transmission or Distribution infrastructure. Interruptions are generally classified as being either Planned or Unplanned.

- **Unplanned interruptions** are interruptions caused by failure of equipment, human error or natural causes (any interruptions not planned).
- **Planned interruptions** are interruptions required to service power facilities as part of a normal or scheduled maintenance program.

The following section is a summary of information provided by PPL addressing the number of Planned and Unplanned Interruptions in the three respective service zones over the regulatory period. PPL supplies electricity to a number of different service areas. Each of these service areas is currently categorised into one of three zones.

**Zone 1 (Port Moresby, Ramu and Gazelle systems).**

The Zone 1 system has been experiencing a high level of both planned and unplanned interruptions over the period. In response to the initially relatively high level of outages in Zone 1, PPL has undertaken significant capital expenditure to improve reliability, including:
• An upgrade to the Rouna 2 hydro power station in 2010 (K133.4 million);
• An upgrade to the Ramu 1 hydro power station in 2009 (K3.3 million);
• The construction of six 1,400 kW diesel generation sets in Lae in 2010 (K33.1m);
• An extension to the Lae Power station (diesel) in 2008 (K4.2m); and
• Rehabilitation of the Gazelle transmission lines in 2009 (K3.2m).

Zone 2 (Wewak, Kimbe system)

In Zone 2, planned and unplanned interruptions have been fairly steady, with the exception of unplanned interruptions in 2008, which experienced a spike in Kimbe due to a disruption to the main generation unit. Key capital improvements over the current period include:

• In Wewak, a new diesel generator in 2010 (K330,700), and additional distribution line in 2009 (K108,000); and
• In Kimbe, a diesel generator in 2009 (K458,000), a diesel generation engine in 2006 (K426,400), and urban distribution lines in Kimbe in 2006 (K39,000).

Zone 3 (Alotau, Buka, Finschaffen, Kavieng, Kerema, Lorengau/Lombrum, Maprik, Popondetta, Samarai, Vanimo and Bialla systems)

In Zone 3, both planned and unplanned interruptions have been high. However, this has been steadily decreasing since 2007. In response to the high unplanned interruptions typically caused by mechanical faults, PPL has taken a number of capital improvements, including:

• In Alotau, a 1,400 kW diesel generator (K4.4 million) and transformer (K266,800) in 2008;
• In Buka, a 6,000 kWh diesel generator (K135,000) in 2009 and automatic circuit recloser in 2008 (K54,500);
• In Popondetta, a diesel generator (K161,100) in 2009, distribution circuit recloser (K77,300) and other upgrades to distribution lines (K30,400) in 2006; and
• Bialla, being a small isolated system, an upgrade to the distribution network is planned for 2011.

8.2 Undelivered energy

The undelivered energy in respect of a service area for a specific period; currently refers to the amount of energy not delivered to the service area for that period as a result of outages other than uncontrollable outages. Most of the undelivered energy results from the generation and distribution networks within the three respective zones.

The Total Undelivered Energy for All the Zones within PPL’s Network System is discussed in detail below.

The overall trend for Zone 1 is further graphically illustrated in Figure 30. The results show that undelivered energy has generally declined.

Figure 30: Total Undelivered Energy for Zone 1 from 2005-2010
Zone 2 (Wewak, Kimbe systems)

For Zone 2 Kimbe and Wewak systems, it can be noted from Figure 31, that the total undelivered energy seems to be minimal over most of the regulatory years except for 2007. Most of this planned undelivered energy was as a result of mechanical faults in the generation systems. PPL with its capital works improvements has made improvements to the two diesel generating plants. PPL has been working to lower undelivered energy and ensure a consistent supply of electricity to its customers is maintained. However, there is a worsening trend observed gradually through the years.

Figure 31: Total Undelivered Energy for Zone 2 from 2005-2010

Zone 3 (Alotau, Buka, Daru, Finschaffen, Kavieng, Kerema, Lorengau/Lombrum, Maprik, Popondetta, Samarai, Vanimo and Bialla systems)

In zone 3, as depicted in Figure 32, the total undelivered energy was at a high in 2006 and gradually decreased towards the remaining years. This high undelivered energy attributed mainly from mechanical faults within the systems.

PPL in addressing these concerns, have invested in its capital works to ensure that the system networks are upgraded and improved to allow for continuation of delivered power supply throughout the service areas.
8.3 Delivered Energy

The total delivered energy refers to the amount of electricity that would normally be supplied during a specified period to a transmission or distribution network for delivery to premises or public lighting installations that are located in that service area.

From the current regulatory period, it can be noted from the graphs below that the total energy delivered for zones 1, 2 and 3 continued to increase throughout the years.

The following graphs below show the overall trend for the Total Energy Delivered for each of the three respective zones from Mar 2005 – Jun 2011.

Figure 33: Total Energy Delivered in Zone 1 Mar 2005- Jun 2011
8.4 Unserved Energy Ratio

8.4.1 Current Reliability Target and Measurement

Generally, improvements in reliability require additional investment in generation, transmission and distribution infrastructure, leading to increased prices for consumers.

Reliability standards and targets are used to provide signals to suppliers about the minimum expected level of reliability for customers. The current form of reliability measure used by the ERC is the Unserved Energy Ratio (USE).

There are targets specified under the current ERC that PPL must meet for reliability for each service areas in terms of the Unserved Energy Ratio (USE). The unserved energy ratio is the ratio of total undelivered energy to the total energy delivered:

\[ USE = \frac{Undelivered\ Energy}{Total\ Energy\ Delivered} \]

Where:
• **Undelivered Energy** means the energy not delivered to a Service Area as a result of Outages other than Uncontrollable Outages;

• **Total Energy Delivered** means the total energy that would normally be supplied to a transmission or distribution network in a Service Area; and

• **Uncontrollable Outages** means an Outage caused by an event the nature or extent of which could not reasonably have been foreseen or prevented by PPL.

In terms of the reliability targets, it is stipulated under the existing Electricity Code, Clause 4 that PPL must ensure that the unserved energy ratio must not be greater or above the reliability target set out in the Electricity Regulatory Contract. Reliability standards and targets are therefore used to provide signals to suppliers about the minimum expected level of reliability for customers.

The following table sets out the unserved energy ratio targets and actual results for each of the service zones for the current regulatory period:

### Table 37: Reliability targets for current regulatory period (%USE)

<table>
<thead>
<tr>
<th>Regulatory Year</th>
<th>Service Zone 1</th>
<th></th>
<th>Service Zone 2</th>
<th></th>
<th>Service Zone 3</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Target</td>
<td>Actual</td>
<td>Target</td>
<td>Actual</td>
<td>Target</td>
<td>Actual</td>
</tr>
<tr>
<td>2003</td>
<td>1.1</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>2004</td>
<td>0.8</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>2006</td>
<td>0.5</td>
<td>1.02</td>
<td>1.0</td>
<td>0.10</td>
<td>1.5</td>
<td>1.91</td>
</tr>
<tr>
<td>2007</td>
<td>0.4</td>
<td>0.58</td>
<td>1.0</td>
<td>1.38</td>
<td>1.5</td>
<td>0.89</td>
</tr>
<tr>
<td>2008</td>
<td>0.3</td>
<td>0.30</td>
<td>1.0</td>
<td>0.00</td>
<td>1.5</td>
<td>0.18</td>
</tr>
<tr>
<td>2009</td>
<td>0.22</td>
<td>0.14</td>
<td>1.0</td>
<td>0.08</td>
<td>1.5</td>
<td>0.24</td>
</tr>
<tr>
<td>2010</td>
<td>0.22</td>
<td>0.14</td>
<td>1.0</td>
<td>0.15</td>
<td>1.5</td>
<td>0.06</td>
</tr>
<tr>
<td>2011</td>
<td>0.22</td>
<td>0.09</td>
<td>0.4</td>
<td>0.00</td>
<td>0.8</td>
<td>0.05</td>
</tr>
</tbody>
</table>

If PPL exceeds the targeted %USE for one of the service areas, the current ERC requires it to provide a rebate to its customers, with the size of the rebate based on individual consumption. The ICCC has determined that the current measurement process is flawed and does not provide any value in reflecting performance, as it ignores unplanned outages. In the case of Zone 1 for 2011, the unplanned outages contributed a total of 2.3% undelivered energy whilst the planned outages account for 0.09%. A new approach is proposed in section 8.5.2.

### 8.4.2 Rebate Mechanism

The current reliability standards rebate is determined as the greater of zero, or the amount calculated via the following formula:

\[
R_z = \left[ IC_z \times \left( USE_{z,t} - \frac{RT_{z,t}}{100} \right) \right] \times [MAP_z \times 5] \times D_z
\]

Where:

- \(IC_z\) is the annual Individual Consumption at that premises (MWh);
\[ \text{USE}_{z,t} \] is the Unserved Energy Ratio at that premises for the year (Undelivered Energy/Total Energy Delivered).

\[ \text{RT}_{z,t} \] is the Reliability Target specified in Schedule 9 of the ERC; and

\[ D_z \] is a vector:
- Zero in the first regulatory year
- 1 in service Zone 1 after the first regulatory year
- 1 in Service Zone 2 and 3 from 2016 onwards.

The Commission believes that the current reliability measurement definitions and rebate structures are not providing an adequate incentive environment. During the next period the ERC will use a modified calculation of unserved energy, improvement targets and rebate regime. The new calculation is described in section 8.5.

### 8.5 Reliability Targets and Payments

The new ERC uses a modified version of % USE to measure performance. This provides a transition to the introduction of international measures in the 2018-2022 contract. The ERC also replaces the existing customer rebate with payments into a fund if PPL fail to achieve the performance targets.

The key attributes for the new measures are:

a. Current performance for each Generation System is the starting point for improvement.
b. Predefined targets for year on year improvement have been established to provide significant performance enhancement.
c. For the new regulatory period, Undelivered Energy Ratio (USE) will continue to be used but will have a new definition.
d. For the next regulatory period, from 2018 to 2022, measurement of performance will use international standard factors based on IEEE1366. Progress toward implementation of new measurements will be monitored by the Commission during the 2013 to 2017 contract period.
e. Failure to meet the reliability performance targets will require PPL to make rebate payments to a special fund. The fund will be used to address reliability performance issues, and any projects that access the fund must be approved by the Commission.

#### 8.5.1 General Principles

To provide the greatest benefit to the community, a balance is required between improved reliability performance targets and the additional cost to deliver improved reliability. The starting position for service reliability is based upon achievable targets related to the current average performance for each system. Over the term of the contract, service reliability levels should improve on an annual basis.

The 2013 to 2017 regulatory contract will be a transitional period to international standards of reliability performance measurement. The regulatory model for reliability assessments for the next five years will use the following principles:

a. Reliability will continue to be measured as Unserved Energy (USE %) ratio for this period.
b. USE will be measured and reported for each Generation System on a quarterly basis.
c. Performance targets will require significant year on year improvement in reliability for each Generation System.
d. Unserved Energy resulting from Force Majeure events and Planned Outages will be excluded from % USE calculations.
e. Penalties will be payable when reliability performance targets are not achieved and will be payable to a jointly controlled Reliability Improvement Fund (RIF). The RIF will be used, by mutual agreement between the Commission and PPL. It will be used to wholly or partly fund projects that are not part of the approved capital works or operational expenditure plan which was approved by the Commission at the start of the Contract term.

f. Improvements will be measured from the current average performance for each Generation System.

g. Quarterly measurement and reporting of USE to the Commission is to provide details of each unplanned event which must include date, time outage commenced, load impacted and duration. Excluded Events must also be reported.

h. Systems and data collection will be developed during the 2013-2017 period for the commencement of IEEE 1366 – 2003/2012 standard reliability measures from the commencement of the 2018-2022 regulatory period. Minimum standard reliability measurements for the 2018-2022 period are:
   i. System Average Interruption Frequency Index (SAIFI); and
   ii. System Average Interruption Duration Index (SAIDI).

8.5.2 Background to Reliability Performance Target Changes

In its original submission, PPL proposed:

“It to continue to measure reliability by way of the USE measure for the next 5-year period. However, PPL propose to have USE reliability targets for the sum of planned and unplanned outages (uncontrollable outages), excluding force majeure events such as non-annual extensive droughts, landowner unrest, etc.

It is PPL’s opinion that this will provide a better picture of the state and trend on power supply reliability in PNG and will provide clear guidance to PPL management and staff on the company’s ability to fulfil its contractual obligations.”

The Commission supported the position that USE would continue to be used as the reliability performance measure for the regulatory period, until new measures could be introduced and that the measure should include both planned and unplanned outages. However, the Commission thought that the targets proposed by PPL were unacceptably low and did not represent the sort of improvement that PNG as a nation is looking for. The Commission therefore proposed a far more challenging set of targets (see Table 38) and asked PPL to respond by estimating the additional capital and operating costs required to achieve them.

PPL responded that the cost would exceed the value of undelivered power. PPL referred to research carried out in Africa and Asia which surveyed customers to identify how much they would pay to avoid power outages. PPL also replied that

“It is PPL’s view that that these targets are unrealistic, fails to consider the nature of the electricity systems and the socio-economic realities of PNG and are economically inefficient.”

Table 38: % USE targets proposed in the initial draft report

<table>
<thead>
<tr>
<th>Location</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
</tr>
</thead>
<tbody>
<tr>
<td>Port Moresby</td>
<td>1.4%</td>
<td>1.2%</td>
<td>0.8%</td>
<td>0.4%</td>
<td>0.16%</td>
</tr>
<tr>
<td>Lae</td>
<td>1.4%</td>
<td>1.2%</td>
<td>0.8%</td>
<td>0.4%</td>
<td>0.16%</td>
</tr>
<tr>
<td>Madang</td>
<td>1.4%</td>
<td>1.2%</td>
<td>0.8%</td>
<td>0.4%</td>
<td>0.16%</td>
</tr>
<tr>
<td>Kokopo</td>
<td>1.4%</td>
<td>1.2%</td>
<td>0.8%</td>
<td>0.4%</td>
<td>0.16%</td>
</tr>
<tr>
<td>Mt Hagen</td>
<td>1.4%</td>
<td>1.2%</td>
<td>0.8%</td>
<td>0.4%</td>
<td>0.16%</td>
</tr>
</tbody>
</table>
The Commission is generally of a view that it is not PPL’s role to determine the level or reliability, but that this is an issue for government policy. The EIP lays down a minimum requirement for 98.5% availability.

The Commission accepts that the initial proposed targets may have been too aggressive and not accurately reflect the current performance of each Generation System.

PPL has also observed that the payment of rebates to customers have the effect of reducing PPL’s ability to invest in reliability improvements. The Commission acknowledges that the simple payment of rebates to customers has limited benefit and reduces the funds available to PPL for investment.

### 8.5.3 IEEE Beta vs. Force Majeure

PPL has proposed the exclusion of Major Event Day outages from the reliability performance calculations. They have also proposed the use of a modified IEEE Beta method as the definition of Major Event Days.

The Commission agrees with the concept of excluding major uncontrollable events from reliability performance measurement, but proposes the use of the Force Majeure event as the trigger for exclusion of an outage.

The total Undelivered Energy due to unplanned outages for each of the three major systems is attributed to a mix of generation, transmission and distribution causes. As shown in Table 39, the contribution to undelivered energy is spread across the three network components:

<table>
<thead>
<tr>
<th>Component</th>
<th>Port Moresby</th>
<th>Ramu</th>
<th>Gazelle</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generation</td>
<td>31.81%</td>
<td>40.68%</td>
<td>17.37%</td>
</tr>
<tr>
<td>Transmission</td>
<td>9.47%</td>
<td>20.98%</td>
<td>24.05%</td>
</tr>
<tr>
<td>Distribution</td>
<td>58.72%</td>
<td>38.34%</td>
<td>58.58%</td>
</tr>
</tbody>
</table>

The proposed PPL Major Event Day based on an IEEE Beta method may be a valid method for exclusion of abnormal results in the distribution network component, subsequent to the introduction of IEEE standard measurements by PPL in the next regulatory period. The Commission believes that the Major Event Day definition is not valid for USE measurements during the 2013-2018 regulatory period because:

a. IEEE 1366 recommends a process “Beta Method” to exclude Major Event Days from the normal measurement of performance and to analyse the Major Event Days separately. “Beta Method”—is used to identify Major Event Days (MED), provided that the natural log transformation of the data results closely resembles a Gaussian (normal) distribution. Its purpose is to allow major events to be studied separately from daily operation, and in the process, to better reveal trends in daily operation that would be hidden by the large statistical effect of major events”6.

b. IEEE 1366 is restricted to Distribution Networks only. USE measures Generation, Transmission and Distribution performance.

---

6 Section 3.5 of IEEE 1366
c. The IEEE Beta Method assumes that the system is stable, and daily SAIDI measures align with a Gaussian or Normal distribution. Without SAIDI measurement data, it is impossible to ascertain whether the PPL Distribution Network performance follows a normal distribution.
d. The IEEE Beta method is proposed as a uniform approach to normalise SAIDI results when comparing between different utilities and years. Until international standard measurements are established, comparison is not a requirement.
e. IEEE 1366 describes Major Event Days as when “the system experiences stresses beyond that normally expected" (such as during severe weather)” The definition of Force Majeure (within the ERC) also provides a description of an event beyond the normal that the Commission believes is a more appropriate definition for the identification of outage events to be excluded.
f. The intent of eliminating outages caused by major events is to ensure they do not make either operational or design stress on the system. The exclusion of Force Majeure triggered events will achieve the same outcome. IEEE 1366 suggests that data for outages caused by abnormal events is reported and analysed separately and the Commission will require reporting of all outages which are attributed to Force Majeure events.

Until IEEE 1366 measures are in use for the measurement of the PPL Distribution Network performance and alternative measures are agreed for Transmission and Generation reliability performance, the Commission has determined that Unserved Energy with exclusions for Planned Outages and uncontrollable events defined by Force Majeure is the process to be followed during this regulatory period.

8.5.4 Current USE performance

PPL has provided information about their current USE performance as shown in Table 40.

The Commission has determined to start USE % benchmark levels as the lower of the 3-year and 2-year average of the years immediately before the Contract period. The MIN column in Table 40 is to be used as the current USE performance.

### Table 40 - Current USE performance

<table>
<thead>
<tr>
<th>Generation System</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>3 year average</th>
<th>2 year average</th>
<th>MIN</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aitape</td>
<td>0.20%</td>
<td>0.66%</td>
<td>1.39%</td>
<td>0.75%</td>
<td>1.02%</td>
<td>0.75%</td>
</tr>
<tr>
<td>Alotau</td>
<td>0.54%</td>
<td>0.27%</td>
<td>0.88%</td>
<td>0.57%</td>
<td>0.58%</td>
<td>0.57%</td>
</tr>
<tr>
<td>Bialla</td>
<td>0.88%</td>
<td>1.24%</td>
<td>4.96%</td>
<td>2.36%</td>
<td>3.10%</td>
<td>2.36%</td>
</tr>
<tr>
<td>Buka</td>
<td>1.21%</td>
<td>2.75%</td>
<td>5.58%</td>
<td>3.18%</td>
<td>4.16%</td>
<td>3.18%</td>
</tr>
<tr>
<td>Daru</td>
<td>1.24%</td>
<td>1.12%</td>
<td>1.20%</td>
<td>1.19%</td>
<td>1.16%</td>
<td>1.16%</td>
</tr>
<tr>
<td>Finschaffen</td>
<td>0.67%</td>
<td>1.81%</td>
<td>4.58%</td>
<td>2.36%</td>
<td>3.20%</td>
<td>2.36%</td>
</tr>
<tr>
<td>Gazelle</td>
<td>3.20%</td>
<td>2.06%</td>
<td>1.82%</td>
<td>2.36%</td>
<td>1.94%</td>
<td>1.94%</td>
</tr>
<tr>
<td>Kavieng</td>
<td>0.54%</td>
<td>0.54%</td>
<td>1.47%</td>
<td>0.85%</td>
<td>1.00%</td>
<td>0.85%</td>
</tr>
<tr>
<td>Kerema</td>
<td>0.85%</td>
<td>0.43%</td>
<td>3.96%</td>
<td>1.75%</td>
<td>2.20%</td>
<td>1.75%</td>
</tr>
<tr>
<td>Kimbe</td>
<td>2.71%</td>
<td>10.06%</td>
<td>5.87%</td>
<td>6.21%</td>
<td>7.96%</td>
<td>6.21%</td>
</tr>
<tr>
<td>Lombrum</td>
<td>2.20%</td>
<td>2.77%</td>
<td>1.75%</td>
<td>2.24%</td>
<td>2.26%</td>
<td>2.24%</td>
</tr>
<tr>
<td>Maprik</td>
<td>0.13%</td>
<td>0.00%</td>
<td>10.83%</td>
<td>3.65%</td>
<td>5.41%</td>
<td>3.65%</td>
</tr>
</tbody>
</table>

---

7 Definitions IEEE 1366
8.5.5 Reliability Targets

The Commission has determined that reliability targets will be set as follows:

1. The initial performance target (2012) is to be calculated as the lower of the 3-year and 2-year average annual performance between 2009 and 2011. The Commission accepts that each Service Area is currently performing at different reliability levels and a single target is not appropriate, and that improvement from current Service Area performance is the aim.

2. Year on year % improvement of reliability:
   a. The reduction target will be higher for Service Areas with multi-generation source grid networks, Port Moresby, Ramu and Gazelle.
   b. Lower reduction targets are proposed for smaller systems (i.e. all Service Areas except Port Moresby, Ramu and Gazelle).

3. A minimum target floor value will apply to areas performing well. This will be a level of performance from which a common percentage reduction is no longer applicable.

The Commission has worked with PPL to establish the performance targets and these are shown in Table 41. In the second draft report the Commission proposed a performance target floor of 0.5% USE. In response to this PPL made the following comments.

- “For Port Moresby, a floor level of 0.5% is appropriate but for all other centres this target is over ambitious and uneconomic.

- For the Ramu system, with its dependency on a major generation source with a long single circuit transmission system, a complete local back-up facility with N-2 would be required for each major load centre (Lae, Hagen, Goroka and Madang). PPL is of the opinion that 0.75% would represent a very ambitious floor level for the next regulatory period.

- For Gazelle, annual drought condition in the run-of-river hydro scheme would also require a complete back-up facility with N-2. Again, PPL propose a floor level of 0.75%.

- For all other centres, PPL provided detailed information on Loss of Load reliability modelling that indicates that reliability close to 0.5% would require significant (uneconomic) investments in additional thermal gensets. PPL is of the opinion that 0.85% would represent an appropriate floor level for the next regulatory period.

The Commission has accepted these comments and has determined to use PPL’s proposed performance floors as shown in Table 41.

Table 41: Performance Improvement Target

<table>
<thead>
<tr>
<th>Generation System</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>3 year average</th>
<th>2 year average</th>
<th>MIN</th>
</tr>
</thead>
<tbody>
<tr>
<td>Popondetta</td>
<td>6.29%</td>
<td>1.82%</td>
<td>0.98%</td>
<td>3.03%</td>
<td>1.40%</td>
<td>1.40%</td>
</tr>
<tr>
<td>Port Moresby</td>
<td>1.01%</td>
<td>1.74%</td>
<td>1.87%</td>
<td>1.54%</td>
<td>1.80%</td>
<td>1.54%</td>
</tr>
<tr>
<td>Ramu</td>
<td>2.20%</td>
<td>2.21%</td>
<td>5.17%</td>
<td>3.19%</td>
<td>3.69%</td>
<td>3.19%</td>
</tr>
<tr>
<td>Samarai</td>
<td>2.85%</td>
<td>3.75%</td>
<td>2.11%</td>
<td>2.90%</td>
<td>2.93%</td>
<td>2.90%</td>
</tr>
<tr>
<td>Vanimo</td>
<td>0.72%</td>
<td>0.75%</td>
<td>14.33%</td>
<td>5.27%</td>
<td>7.54%</td>
<td>5.27%</td>
</tr>
<tr>
<td>Wewak</td>
<td>1.07%</td>
<td>0.64%</td>
<td>0.63%</td>
<td>0.78%</td>
<td>0.63%</td>
<td>0.63%</td>
</tr>
</tbody>
</table>
Based on the current MWAP price and proposed calculation methodology, if no change was made to reliability performance from the “Prior to ERC” level in any Service Area, the rebate payable for 2013 would be K1.29M rising to K7.9M in 2017.

Table 42 lists the % USE performance targets for each generation system.

### Table 42 – % USE Performance Targets

<table>
<thead>
<tr>
<th>Generation System</th>
<th>Prior to ERC</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aitape</td>
<td>0.75%</td>
<td>0.68%</td>
<td>0.61%</td>
<td>0.55%</td>
<td>0.50%</td>
<td>0.50%</td>
</tr>
<tr>
<td>Alotau</td>
<td>0.57%</td>
<td>0.51%</td>
<td>0.50%</td>
<td>0.50%</td>
<td>0.50%</td>
<td>0.50%</td>
</tr>
<tr>
<td>Bialla</td>
<td>2.36%</td>
<td>2.12%</td>
<td>1.91%</td>
<td>1.72%</td>
<td>1.55%</td>
<td>1.39%</td>
</tr>
<tr>
<td>Buka</td>
<td>3.18%</td>
<td>2.86%</td>
<td>2.58%</td>
<td>2.32%</td>
<td>2.09%</td>
<td>1.88%</td>
</tr>
<tr>
<td>Daru</td>
<td>1.16%</td>
<td>1.04%</td>
<td>0.94%</td>
<td>0.85%</td>
<td>0.76%</td>
<td>0.68%</td>
</tr>
<tr>
<td>Einschaffenen</td>
<td>2.36%</td>
<td>2.12%</td>
<td>1.91%</td>
<td>1.72%</td>
<td>1.55%</td>
<td>1.39%</td>
</tr>
<tr>
<td>Gazelle</td>
<td>1.94%</td>
<td>1.55%</td>
<td>1.24%</td>
<td>0.99%</td>
<td>0.79%</td>
<td>0.64%</td>
</tr>
<tr>
<td>Kavieng</td>
<td>0.85%</td>
<td>0.77%</td>
<td>0.69%</td>
<td>0.62%</td>
<td>0.56%</td>
<td>0.50%</td>
</tr>
<tr>
<td>Kerema</td>
<td>1.75%</td>
<td>1.58%</td>
<td>1.42%</td>
<td>1.28%</td>
<td>1.15%</td>
<td>1.03%</td>
</tr>
<tr>
<td>Kimbe</td>
<td>6.21%</td>
<td>5.59%</td>
<td>5.03%</td>
<td>4.53%</td>
<td>4.07%</td>
<td>3.67%</td>
</tr>
<tr>
<td>Lombrum</td>
<td>2.24%</td>
<td>2.02%</td>
<td>1.81%</td>
<td>1.63%</td>
<td>1.47%</td>
<td>1.32%</td>
</tr>
<tr>
<td>Maprik</td>
<td>3.65%</td>
<td>3.29%</td>
<td>2.96%</td>
<td>2.66%</td>
<td>2.39%</td>
<td>2.16%</td>
</tr>
<tr>
<td>Popondetta</td>
<td>1.40%</td>
<td>1.26%</td>
<td>1.13%</td>
<td>1.02%</td>
<td>0.92%</td>
<td>0.83%</td>
</tr>
<tr>
<td>Port Moresby</td>
<td>1.54%</td>
<td>1.23%</td>
<td>0.99%</td>
<td>0.79%</td>
<td>0.63%</td>
<td>0.50%</td>
</tr>
<tr>
<td>Ramu</td>
<td>3.19%</td>
<td>2.55%</td>
<td>2.04%</td>
<td>1.63%</td>
<td>1.31%</td>
<td>1.05%</td>
</tr>
<tr>
<td>Samarai</td>
<td>2.90%</td>
<td>2.61%</td>
<td>2.35%</td>
<td>2.11%</td>
<td>1.90%</td>
<td>1.71%</td>
</tr>
<tr>
<td>Vanimo</td>
<td>5.27%</td>
<td>4.74%</td>
<td>4.27%</td>
<td>3.84%</td>
<td>3.46%</td>
<td>3.11%</td>
</tr>
<tr>
<td>Wewak</td>
<td>0.63%</td>
<td>0.57%</td>
<td>0.51%</td>
<td>0.50%</td>
<td>0.50%</td>
<td>0.50%</td>
</tr>
</tbody>
</table>

The proposed 20% reduction target in major Service Areas is expected to produce significant improvement in electricity reliability. Over the five year regulatory period, an improvement of reliability of 66% from the current performance is required.

Table 43 shows the maximum number of hours of outage per month in the major systems if PPL achieve the targets.

### Table 43 – Maximum hours of outage with new targets (Notional Hours outage per month)

<table>
<thead>
<tr>
<th>Service Area</th>
<th>Prior to ERC</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Port Moresby</td>
<td>11.2</td>
<td>9.0</td>
<td>7.2</td>
<td>5.8</td>
<td>4.6</td>
<td>3.7</td>
</tr>
<tr>
<td>Ramu</td>
<td>23.3</td>
<td>18.6</td>
<td>14.9</td>
<td>11.9</td>
<td>9.5</td>
<td>7.6</td>
</tr>
<tr>
<td>Gazelle</td>
<td>14.2</td>
<td>11.3</td>
<td>9.1</td>
<td>7.3</td>
<td>5.8</td>
<td>4.6</td>
</tr>
</tbody>
</table>
8.5.6 Calculation

The Commission has determined that reliability performance is to be calculated as the proportion of the undelivered energy compared to delivered energy. Undelivered Energy is the energy which is not delivered due to unplanned outages. It should be noted that that this is the reverse of the current ERC, where undelivered energy is the energy not delivered due to “Planned Outages”.

The performance of each Service Area is to be calculated and reported quarterly. Clear differentiation is proposed between Planned and Unplanned interruptions acknowledging that maintenance work on the network may require brief interruptions to service in a planned and controlled manner.

- **Undelivered Energy (UE)**, for each Service Area for the specified period, means the amount of energy not delivered in that Service Area for that period as a result of Unplanned Interruptions, other than outages as a result of a Force Majeure Event. Energy which is undelivered due to a Force Majeure is excluded from the UE calculation. The calculation methodology must be in a form acceptable to the Commission. PPL will supply the Commission with a report showing how the UE data is calculated.

- **Unplanned Interruptions** are interruptions caused by failure of equipment, human error or natural causes (i.e. any interruptions which are not Planned Interruptions or the Required Notice was not issued).

- **Planned Interruptions** are interruptions required to service power facilities as part of a normal or scheduled maintenance program and where PPL has provided the Required Notice to effected customers. If an interruption occurs as part or normal or scheduled maintenance and the customer has not been supplied with the Required Notice it is classified as an Unplanned Interruption.

For each event the calculation of Undelivered Energy (UE) is to be:

- **UE (kWh) = (Duration of Unplanned Interruption in Hours) * (Hourly Delivered Energy for the same period of the previous week, provided there was no outage. If previous week not an uninterrupted period for the time or this outage the next suitable week is to be selected).**

- **Required Notice** – the agreed period and format of notice which must be given to all customers likely to be affected, prior to planned work as defined in the Contract.

- **Unserved Energy Ratio (USE) –** is the proportion of unserved energy compared to the total energy requirement of the Service Area for each period. The total energy requirement is the sum of the energy delivered in the period and the undelivered energy in the period. USE is expressed as a percentage for each Service Area.

Calculation for each Service Area per quarter is:

\[
USE\% = \frac{\sum UE}{(TED + \sum UE)}
\]

Where:

- **UE** is the undelivered energy for each event.

- **Total Energy Delivered (TED)** is the total energy metered and billed for the Service Area for the relevant period.

8.5.7 Reliability Standards Payments
The Commission is proposing that rebates will no longer be paid to customers, but instead payments will get paid into a special fund. The fund will be called the “Reliability improvement fund”, and will be used to support further improvements required to improve PPL’s network reliability. This is to address the issue identified by PPL that rebates paid to customers generally reduce the ability of PPL to pay for reliability improvements. PPL will make payments to the reliability improvement fund whenever the USE target (RT%) for each Service Area as described in Table 42 is not achieved.

The Commission is of the view that the reliability payments used in this way will still have the effect of an incentive to achieve the targets as well as helping to provide the resources to do so.

The reliability payment is dependent on the Service Area’s total demand and calculated as:

\[
\text{Reliability Payment} = (USE_{\text{Actual}} - RT_{\text{Target}}) \times MWh_{\text{Customer}} \times MWAPt \times 2
\]

Where:
- \(USE_{\text{Actual}}\) is the actual USE% achieved for the Service Area.
- \(RT_{\text{Target}}\) is the target USE% for the Service Area listed in Table 42.
- \(MWh_{\text{Customer}}\) is the actual consumption for the Service Area for the period.
- \(MWAPt\) is the Maximum Annual Price Cap for that Regulatory Year.

The rebate value is increased by a factor of 2 to reflect the cost of unserved energy to customers.

The Commission reserves the right at any time to audit the calculation of the reliability payments.

8.5.8 Reliability Improvement Fund

The Reliability Improvement Fund is to be managed by PPL as a separate fund unrelated to any other capital or operational activity in PPL. Quarterly reports of the value and transactions of the Reliability Improvement Fund are to be provided to the Commission.

Only network projects which are to improve the reliability performance of the network are to have access to the Reliability Improvement Fund. PPL proposed projects are to include the scope of work, estimate and the proposed impact on service level which will be provided.

The release of funds for identified and costed projects requires the approval of the Commission. The Commission reserves the right at any time to audit the operation of the Reliability Improvement Fund.

8.5.9 Minimum Service Standards versus Senior Management Remuneration

The Commission would like to see that senior management employees who have the responsibility to ensure that minimum service standards are met must be held accountable should PPL perform below expectations. The senior management has a duty to ensure that the people of PNG have access to quality and reliable electricity services from PPL. Failure to meet the minimum service standards would see senior management of PPL having their remuneration reduced if sufficient explanations are not provided to the Commission. The Commission would like to see these actions taken on an annual basis, based on objective criteria, as a measure to maintain and improve on the service standards requirements.

These are appropriate incentives provided to PPL to ensure that service standards requirements are met.

Whilst the Commission intends to maintain all the current service standards, enhancements are proposed:
Firstly, the Commission considers PPL should continue to maintain the service standards requirements set out in the current Regulatory Contract. It considers that the revenues set out in this final decision are sufficient for PPL to not only maintain its current performance against the requirements set out in the Regulatory Contract but to improve performance to beat the performance reliability targets set as a result of new capital expenditure.

Secondly, the Commission proposes that PPL continue to monitor its compliance with the specified service standard requirements and report to the Commission on all service standards. The Commission will undertake its own independent investigation to verify this compliance report.

Thirdly, the Commission also proposes that PPL communicate any changes to the electricity network.

Fourthly, the Commission proposes to establishment of a formal link between tariffs and service standards during this regulatory period. It will require PPL to publish details of its performance in its Annual Report, and to provide the Commission with annual updates and performance against the designated standards.

Finally, but not the least, the Commission proposes to request the board of directors of both PPL and the IPBC to penalise the senior management of PPL during annual adjustment of tariffs period should PPL perform below expectations without satisfactory explanation to the Commission. This might also include recommending to the IPBC and PPL boards that they publish remuneration penalties for the top management where the two boards accept the Commission’s recommendations.

Should PPL prudently make the necessary capital investments for efficiently delivering its services, the Commission will allow PPL to retain the difference between its forecast capital expenditure and the actual cumulative expenditure as at 30 June 2015.

In terms of applying penalties, the Commission if deemed necessary, shall send a letter to the Chairman of the Independent Public Business Corporation (IPBC) as shareholder of PPL, or representative of the shareholders, copied to the Minister responsible for Public Enterprises, and each member of the Board of PPL suggesting that they consider reducing the Chief Executive Officer’s, and the Senior Management Team’s annual remuneration packages by as much as 10%, within one month of receiving the report and recommendation from the Regulator, without indemnity from PPL; because the organisation’s regulatory performance was assessed as sub-standard, and not in compliance with the Regulatory Contract.

The Commission is of the view that such penalties will provide the necessary incentive for PPL and its executive management to ensure that its approved investment plan is executed in a timely manner for the benefit of PNG consumers. It has been noted in the past that certain regulated entities did not undertake their planned capital investments which was approved by the Commission. This is unfair to consumers because consumers actually pay for these capital investments to be undertaken through the approved price paths of regulated entities.

8.6 Replacement of Zones

The current contract defines three zones as being made up of particular service areas. The new ERC replaces these zones for reporting purposes with a list of service areas, which are covered by the contract. Table 44 shows the current list of service areas which are covered by the ERC. Submissions received by PPL have aligned with the Service Area proposed definition.

Table 44: List of Service Areas

<table>
<thead>
<tr>
<th></th>
<th>Aitape</th>
<th>12</th>
<th>Kavieng</th>
<th>23</th>
<th>Mumeng</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>Alotau</td>
<td>13</td>
<td>Kerema</td>
<td>24</td>
<td>Mt Hagen</td>
</tr>
<tr>
<td>3</td>
<td>Bialla</td>
<td>14</td>
<td>Kimbe</td>
<td>25</td>
<td>Popondetta</td>
</tr>
<tr>
<td>4</td>
<td>Buka</td>
<td>15</td>
<td>Kokopo</td>
<td>26</td>
<td>Port Moresby</td>
</tr>
<tr>
<td>5</td>
<td>Central</td>
<td>16</td>
<td>Kundiawa</td>
<td>27</td>
<td>Samarai</td>
</tr>
<tr>
<td>6</td>
<td>Daru</td>
<td>17</td>
<td>Lae</td>
<td>28</td>
<td>Vanimo</td>
</tr>
</tbody>
</table>
8.7 Planned Outages Notices

As part of the regulatory requirements outlined in the current Contract, PPL is obliged to notify its customers by issuing a public notice through media of any planned outage that will affect premises located in a service area to which electricity is supplied by PPL.

An outage is any full or partial unavailability of a generating plant or a transmission or distribution network operated by PPL (or part thereof) which results in a disruption to the supply of electricity by PPL to a premises or a public lighting installation that is located in a service area.

If, the Required Notice is not provided to customers, the outage is to be regarded as an Unplanned Outage and included in the USE calculations irrespective of the reason for the outage.

If a customer in respect of that premises makes a complaint to PPL, either in person, by telephone or in writing about that power failure within 30 Business Days after the day on which that planned outage commences, a fee of K5.00 is paid to the customer in respect of that premises.

There are specific service standards requirements outlined in Clause 4 of the existing Electricity Code. The code specifies that PPL must try to use its best endeavours to ensure that the number of unplanned outages occurring in that year:

(a) that affect premises which are located in a service area and to which electricity is supplied by the licensee; and
(b) of which the required notice is not given.

must not be greater than 5% of the number of planned outages occurring in that year that affect premises which are located in that service area and to which electricity is supplied by the licensee.

In instances where the Commission finds that PPL exceeds the 5% of planned outages limit, a reduction will be made to the X factor of 2 percentage points.

Over the course of 2008 to 2010 regulatory period, there were no formal complaints being registered with PPL by the respective customers who were affected by planned outages.

From PPL’s point of view, it is assumed that the current channel of communication whereby the customers are informed of planned outages through media and public notice boards is sufficient. As such, no planned outage rebates has been determined and given to customers.

The rebate of K5.00 to each customer in a service area whereby required notices not given exceeds 5% of total planned outage has also not been reviewed given that sufficient notices were given to the customers.

The Commission is not proposing to make any changes to the current requirements for planned outage notices.

8.8 New Connections

The required connection times are specified in the ERC and Revised Electricity Code for:
- Reactivation of service to premises in Service Zones 1, 2 & 3;
- New low voltage connection from existing mains or Service Zones 1, 2 & 3 respectively;
- New low voltage connection which requires erection of new mains in Service Zones 1, 2 & 3 respectively;
- New high voltage connection which requires new mains and pole mounted transformers in Service Zones 1, 2 & 3 respectively; and
- New high voltage connection which requires new mains and ground type substations in Service Zones 1, 2 & 3 respectively.

In terms of connecting new customers to the distribution networks within the required time, it is noted that PPL has not achieved the target level of performance over the reporting period.

The following tables’ best summarize PPL’s performance from the current regulatory period in terms of new connections per respective zones. Table 45 shows the total Connection made from the current period for Zone 1.

Table 45: Total Connections Made in Zone 1

<table>
<thead>
<tr>
<th>Regulatory Year</th>
<th>Total Connections</th>
<th>Connections not completed on time</th>
<th>Max</th>
<th>Actual (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2003</td>
<td>n/a</td>
<td>n/a</td>
<td>2%</td>
<td>n/a</td>
</tr>
<tr>
<td>2004</td>
<td>n/a</td>
<td>n/a</td>
<td>2%</td>
<td>n/a</td>
</tr>
<tr>
<td>2005</td>
<td>1311</td>
<td>106</td>
<td>2%</td>
<td>8%</td>
</tr>
<tr>
<td>2006</td>
<td>1245</td>
<td>74</td>
<td>2%</td>
<td>6%</td>
</tr>
<tr>
<td>2007</td>
<td>870</td>
<td>50</td>
<td>2%</td>
<td>6%</td>
</tr>
<tr>
<td>2008</td>
<td>1028</td>
<td>40</td>
<td>2%</td>
<td>4%</td>
</tr>
<tr>
<td>2009</td>
<td>1318</td>
<td>317</td>
<td>2%</td>
<td>24%</td>
</tr>
<tr>
<td>2010</td>
<td>1033</td>
<td>396</td>
<td>2%</td>
<td>38%</td>
</tr>
<tr>
<td>2011</td>
<td>1170</td>
<td>224</td>
<td>2%</td>
<td>19%</td>
</tr>
</tbody>
</table>

The Zone 1 areas remain those with the highest number of connections as well as those with the highest proportion not connected on time. The highest recorded was in 2010 with about 38% not connected on time with the majority coming from the Port Moresby system. However, as stipulated under clause 4.1 of the Electricity Code, the percentage of new connections that fail to meet the connection date must not be greater than 2%. PPL, therefore, while showing some improvement, have still exceeded the standard required.

Table 46 shows the total Connection made from the current period for Zone 2.

Table 46: Total Connections Made in Zone 2

<table>
<thead>
<tr>
<th>Regulatory Year</th>
<th>Total Connections</th>
<th>Connections not completed on time</th>
<th>Max</th>
<th>Actual %</th>
</tr>
</thead>
<tbody>
<tr>
<td>2003</td>
<td>n/a</td>
<td>n/a</td>
<td>2%</td>
<td>n/a</td>
</tr>
<tr>
<td>2004</td>
<td>n/a</td>
<td>n/a</td>
<td>2%</td>
<td>n/a</td>
</tr>
<tr>
<td>2005</td>
<td>82</td>
<td>3</td>
<td>2%</td>
<td>4%</td>
</tr>
<tr>
<td>2006</td>
<td>100</td>
<td>7</td>
<td>2%</td>
<td>7%</td>
</tr>
<tr>
<td>2007</td>
<td>64</td>
<td>6</td>
<td>2%</td>
<td>9%</td>
</tr>
<tr>
<td>2008</td>
<td>52</td>
<td>12</td>
<td>2%</td>
<td>23%</td>
</tr>
</tbody>
</table>
Zone 2 centres of Wewak and Kimbe have less customers connecting to the service. These are standalone systems operating independently from a national grid structure. With less people applying for connections, there is less delay in completing connections in absolute terms. Nevertheless, it can be seen that, except in 2009, the proportion of those not connected as a percentage of total connection was still above the maximum level set under the standard in a significant number of years.

Table 47: Total Connections Made in Zone 3

<table>
<thead>
<tr>
<th>Regulatory Year</th>
<th>Service Zone 3</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Total Connections</td>
<td>Connections not completed on time</td>
<td>Max</td>
<td>Actual %</td>
</tr>
<tr>
<td>2003</td>
<td>n/a</td>
<td>n/a</td>
<td>2%</td>
<td>n/a</td>
</tr>
<tr>
<td>2004</td>
<td>n/a</td>
<td>n/a</td>
<td>2%</td>
<td>n/a</td>
</tr>
<tr>
<td>2005</td>
<td>337</td>
<td>45</td>
<td>2%</td>
<td>13%</td>
</tr>
<tr>
<td>2006</td>
<td>259</td>
<td>12</td>
<td>2%</td>
<td>5%</td>
</tr>
<tr>
<td>2007</td>
<td>235</td>
<td>2</td>
<td>2%</td>
<td>1%</td>
</tr>
<tr>
<td>2008</td>
<td>350</td>
<td>10</td>
<td>2%</td>
<td>3%</td>
</tr>
<tr>
<td>2009</td>
<td>252</td>
<td>4</td>
<td>2%</td>
<td>2%</td>
</tr>
<tr>
<td>2010</td>
<td>410</td>
<td>7</td>
<td>2%</td>
<td>2%</td>
</tr>
<tr>
<td>2011</td>
<td>323</td>
<td>13</td>
<td>2%</td>
<td>4%</td>
</tr>
</tbody>
</table>

Zone 3 centres consists of the smaller areas of PNG which are not connected by bigger grids and which have fewer customers connected to individual standalone systems. On an annual basis, new connections are summed across the zone to provide the basis for calculating the proportion of people not connected on time albeit on different standalone systems. Hence, the summary of the statistics may distort the requirement for individual standalone service areas. The performance across this zone falls short of the standard set, although there have been significant improvements made.

8.8.1 Delays in Connection and Rebate Mechanism

The delays in new connections to PPL’s networks can be, as a result of:

- PPL being understaffed for undertaking the required inspection;
- PPL not having the required materials for the connection in stock;
- Delays in undertaking technical inspections;
- Incomplete applications for connections from customers; and
- Delays in work carried out by electrical contractors engaged by the customer to facilitate the connections.

Delays have also occurred due to events beyond the control of either PPL or its customers such as weather (rain), damage to or theft of infrastructure, civil unrest/land disputes and bad road conditions.
The current rebate mechanism in place specifies that PPL must provide a rebate to customers of K20 per day for each day a connection time exceeds the Required Connection Date, up to a maximum of K100.

There is no rebate mechanism in place concerning the target of 2% for delayed connections as a proportion of total connections. As part of enforcing penalties for PPL’s service standards requirements, the Commission will factor in a 2 percentage reduction in the X factor for failure to meet any service standards targets.

8.8.1.1 Proposed Amendments to connection time measurements

In its submission, PPL state:

“….the ERC is not sufficiently clear concerning the calculation of the time it takes to make a connection in cases where circumstances outside its control are the cause of the delay. For example;

- Delays in contractors engaged by customers providing the required infrastructure. On some occasions, having been requested by a customer to provide a connection, PPL inspectors will find that the infrastructure on the customer side is not ready for connection, and will require the customer to engage a contractor to undertake work.”

“PPL has typically measured connection times from the date upon which the customer requests the connection. This has led to some very long connection times as reported to the ICCC, particularly, in the case of delays in the work of contractors to ensure the customer’s premises is suitable for connection. PPL is proposing an amendment to the ERC that clarifies the grounds for rebates for late connections by specifying that the calculation of the time taken for the connection will not include:

1. The time taken for the third party contractors to complete any work required for the connection. This could be achieved by specifying that if a PPL inspector finds that the customer-side infrastructure is not ready for connection, the calculation of time to connect is suspended until PPL is advised by the customer or their contractor that PPL’s requirements for connection have been met. This amendment would be consistent with clause 7.3 of the Standard Customer Supply and Sale Contract
2. Any other delays due to events outside the control of PPL, including weather, difficulty in obtaining access to remote locations or civil unrest.

PPL is not proposing any amendments to the current rebate mechanism or required connection dates.

The Commission accepts the reasonableness of PPL’s argument, and has made changes to the ERC, to achieve the effect that PPL describes. The Commission is of the view that this will more accurately measure PPL’s performance.

8.8.2 Improving Performance

In order to improve its internal performance on connection times, PPL is proposing significant new expenditure on customer connections over the next regulatory period, particularly, for the Port Moresby and Ramu systems, where the most delays occur. Table 48 sets out PPL’s proposed capital expenditure for new connections over the next regulatory period.

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Zone 1</td>
<td>4746</td>
<td>4888</td>
<td>5035</td>
<td>5186</td>
<td>5342</td>
<td>5502</td>
</tr>
<tr>
<td>Zone 2</td>
<td>149</td>
<td>154</td>
<td>158</td>
<td>163</td>
<td>168</td>
<td>173</td>
</tr>
</tbody>
</table>
8.9 New Performance Metrics

PPL and the Commission agree that the long term measurement of reliability of the Distribution Network performance is to be aligned with the IEEE 1366 standard. The proposed measurements of SAIDI and SAIFI focus on the customer impact rather than the total energy not delivered. The two measures show the duration or the frequency of outage occurrence per customer. At present, PPL does not have the ability to measure SAIDI and SAIFI inputs on a per customer basis.

To move to the new measurement methodology, PPL will have to capture additional information on the existing network topology and customer locations, and then implement new systems to record, process and evaluate reliability data. This regulatory period is to be used to capture the information and implement systems required to allow the introduction of the new measurement methodology prior to the commencement of the next regulatory period.

To provide customer based service performance data, without the use of Smart Meters at each premise, the location of all network elements will be recorded along with the location of each customer connection on the network. PPL does not have a populated geospatial recording system for the network, although a project has commenced to start capturing network data in a geospatial information system (GIS).

To ensure that the new reliability performance measurement approach is ready for use immediately following this regulatory period, progress milestones have been set and progress is to be reported during the regulatory period.

8.9.1 SAIFI and SAIDI

SAIFI refers to the System Average Interruption Frequency Index. It is commonly used as a reliability indicator by power utilities. SAIFI is the average outage frequency for each customer served, and is calculated as:

\[
SAIFI = \frac{\text{Sum of all customer interruptions}}{\text{Total number of customer served}}
\]

SAIFI is measured in units of interruptions per customer. It is usually measured over the course of a year, and according to IEEE Standard 1366-2003 the median value for North American utilities is approximately 1.10 interruptions per customer.

SAIDI refers to the System Average Interruption Duration Index. It is commonly used as a reliability indicator by power utilities. SAIDI is the average outage duration for each customer served and is calculated as:

\[
SAIDI = \frac{\text{Sum of all customer interruption durations}}{\text{Total number of customers served}}
\]

Other measures which are described in IEEE1366 include:

- CAIDI is the Customer Average Interruption Duration index;
- CAIFI is the Customer Average Interruption Frequency Index;
- MAIFI is the Momentary Average Interruption frequency index.

SAIDI is measured in units of time, often minutes or hours. It is usually measured over the course of a year, and according to IEEE Standard 1366-2003 the median value for North American utilities is approximately 1.50 hours.
The proposed move to the adjusted USE measure and eventually SAIFI and SAIDI will also involve a division of the current aggregated measure into individual measures for generation, transmission and distribution. This fine-tuned approach will simplify international benchmarking and pinpoint areas of improvement.

8.9.2 New Metric Timetable

The ICCC supports PPL’s proposal to move to SAIFI and SAIDI, but want to ensure that this happens in a controlled and realistic timeframe. The ICCC has determined that PPL will follow the following schedule.

Table 49: Schedule for implementation of SAIFI and SAIDI

<table>
<thead>
<tr>
<th>Milestone</th>
<th>Delivery Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project plan for the implementation of reliability performance measurements of SAIDI and SAIFI. (Include data capture and systems)</td>
<td>31-Sep-13</td>
</tr>
<tr>
<td>Complete the GIS capture of Port Moresby network infrastructure.</td>
<td>31-Dec-13</td>
</tr>
<tr>
<td>Complete the GIS capture of Ramu network infrastructure.</td>
<td>31-Dec-14</td>
</tr>
<tr>
<td>Complete the GIS capture of Gazelle network infrastructure.</td>
<td>30-Jun-15</td>
</tr>
<tr>
<td>Complete the GIS capture of remaining Service Areas’ network infrastructure.</td>
<td>31-Dec-15</td>
</tr>
<tr>
<td>Establish processes to capture new network installations and customer connections.</td>
<td>30-Jun-13</td>
</tr>
<tr>
<td>Commence customer location capture project.</td>
<td>1-Jan-14</td>
</tr>
<tr>
<td>Complete customer location capture in Port Moresby.</td>
<td>31-Dec-14</td>
</tr>
<tr>
<td>Complete customer location project in Ramu.</td>
<td>31-Dec-15</td>
</tr>
<tr>
<td>Complete customer location capture project.</td>
<td>30-Jun-16</td>
</tr>
<tr>
<td>Select system to capture and track outages including information on duration and customers impacted.</td>
<td>31-Dec-15</td>
</tr>
<tr>
<td>Implement Reliability Performance monitoring system. Complete installation and setup of systems, process and equipment required to support accurate SAIFI and SAIDI reporting for all service areas served by PPL.</td>
<td>31-Dec-16</td>
</tr>
<tr>
<td>Commence parallel capture and reporting of SAIFI and SAIDI</td>
<td>1-Jul-17</td>
</tr>
<tr>
<td>Commence reporting of SAIFI and SAIDI as part of standard reporting cycle</td>
<td>1-Jan-18</td>
</tr>
</tbody>
</table>

The Commission notes that the measures proposed in IEEE 1366 only apply to distribution systems, substations, circuits, and defined regions and that additional measurements will need to be developed to capture performance information for the Generation and Transmission portions of the network.

8.9.3 Reporting Framework

A reporting framework has been included in the Final Regulatory Contract as Schedule 7 to monitor the financial information of PPL per annum.

It is imperative to monitor the revenues and expenses of PPL to ascertain exactly how much is generated each from the network systems in the designated areas/zones, what portion of the cost of operation is consumed by all different categories of consumers in each of the designated areas, monies are spent only on essential areas of their operation, amongst other things. Most importantly, through reports like this the Commission needs to know which designated areas or zones are making profits or losses. This information is required in terms of providing cross subsidies or to appropriately monitor the channelling of government funding/grants when and if they become available. Further, in doing this annually, the Commission will ensure that operational costs are at efficient levels so that unnecessary costs attributable to inefficiency of operation are not passed onto consumers. It will assist the Commission to apply a price path for regulated services such that it reflects the efficient cost of providing reliable electricity services by PPL.
It should be noted that what is being proposed here to be included into the Final Electricity Services Regulatory Contract is consistent with the other regulatory contracts the Commission also has with PNG Ports Corporation Ltd, as well as the other regulated entities currently under regulation by the Commission.

Where regulated entities provide both regulated and unregulated services, issues can arise regarding cost allocation – both in respect of capital costs and operational costs; as well as revenue allocation. Forensic examination of costs and revenues is resource-intensive.

9 OTHER ISSUES

9.1 Illegal Connections

In spite of the lifeline tariffs in place there is still electricity theft through illegal connections to PPL. One conclusion could be that electricity prices are too high for those consumers with unpaid for use and illegal connections. The issue of unpaid for use and illegal connections is one of concern to both the Commission and PPL.

Illegal connections have a very direct and damaging impact upon the operations of the business through the loss of sales revenue, which results in the inability of the electricity company to recover the costs associated with providing electricity services.

In addition, the loss from unpaid for, and theft of electricity result in higher prices for other users of the network as the fixed cost of supply, which are traditionally high in the electricity industry are spread over fewer billable units of consumption. The net effect is that returns to the electricity company are reduced and the scope for potential future investment in electricity infrastructure is limited as a result of weak cash flows arising from the rising costs of the service and lower demand for billable electricity. The difficult question of how to address the illegal connections and the theft of electricity is a concern. At the heart of the matter is the fact that PPL is unable to recover the costs associated with the electricity that has been illegally obtained unless these costs are spread across consumers who do pay for these services.

On average, there are 125 instances of illegal connection discovered each year. The commission has estimated that this equates to about 0.04% of PPL’s total sales. If the actual amount (i.e. both discovered and undiscovered illegal connections) was triple this number then this would mean customers were paying an additional 0.1 Toea for every kWh of power purchased due to theft.

The ICCC is concerned that theft is potentially pushing up prices and encourages PPL to adopt techniques and approaches to minimise illegal connections.

9.2 Criteria for Industrial Customers

PPL in its 2011 submission proposed that the definition of an industrial customer be changed.

"Industrial Customer’s pay a variable per kWh charge, plus a fixed charge based on their kVA demand per month. Basing electricity charges on kVA is intended to provide incentives for customers to improve their power factor, as those customers with a lower power factor will have a greater kVA demand for each kW used, and pay more for their useful power. Ideally, all industrial customers should have a power factor of 0.9. This would ensure that customers benefitting from the lower Industrial Customer tariff also provide benefits to the system as a whole by assisting PPL improve reliability of the network”.

PPL is concerned that:
• “The demand threshold of 200kVA is too low for the purposes of identifying Industrial Customers, with the result that customers who would not generally be considered ‘Industrial’ in other jurisdictions have access to the Industrial Customer tariff.
• Although the industrial customer tariff was introduced to improve efficiency of the distribution system, it has not had this effect.”

PPL was proposing two amendments to the ERC to address these issues:

• Increasing the kVA demand threshold; and
• Introducing a minimum power factor.

9.2.1 Power Factor

The Commission agrees with the PPL concept and potential benefit of improving the Power Factor on the network. It is accepted that improvement in Power Factor will require both investment in network infrastructure and modification of customer loads to comply with acceptable standards. Improvements in Power Factor will reduce system losses, improve voltage profiles and generally improve stability within the system.

The Commission has determined that PPL will target a minimum network Power Factor of 0.9, although it is accepted that this target may take many years to achieve. The Commission notes that the current PPL Capital Works program includes some investment projects (e.g. Capacitor Installations) to improve the network Power Factor.

The following mechanism has been adopted:

• The Regulatory Contract specifies that PPL is required to target a power factor of 0.9 for all systems.
• The Regulatory Contract specifies that all new customer contracts (>200 kVA) include a requirement to target minimum power factor of 0.9.
• The Regulatory Contract specifies that renewal of existing customer contracts (>200 kVA) should include a requirement for all connections to target a minimum power factor of 0.9.
• The Regulatory Contract includes a provision for PPL to apply cost reflective penalties to customers (>200 kVA) which do not maintain a power factor greater than 0.9 under its their customer contracts.

During the term of the Regulatory Contract, PPL should provide regular reporting of the average peak load power factor for the major generation systems, demonstrating the improvements made.

The definition of an industrial customer has not changed in the regulatory contract.

10.3 COMPETITIVE CAPITAL AND OPERATIONAL TENDERING PROCESS

PPL has been required to operate as a commercial entity and simultaneously deliver efficient service throughout the country.

Any PPL capital and operational works or refurbishment projects should be implemented through a competitive tender process and must be prudent and efficient at all times. Prudent in the sense that the capital or operational works if it required as a result of a legal obligation, new growth, renewal of existing infrastructure, or it achieves an increase in the reliability or quality of supply that is explicitly endorsed or desired by customers. Whereas for expenditure is efficient if:

• the scope of the works (which reflects the general characteristics of the capital item) is the best means of achieving the desired outcomes after having regard to the options available, including the substitution possibilities and non-network systems,
• the standard of the works conforms with technical, design and construction requirements in legislation, industry and other standards, codes and manuals. Compatibility with existing and adjacent infrastructure is relevant as is consideration of modern engineering equivalents and technologies; and
• the cost of the defined scope and standard of work is consistent with conditions prevailing in the markets for engineering, equipment supply and construction.

PPL must ensure at all times that its procurement is consistent with its general obligations; its functions and objectives and its other general Government obligations and its other general obligations prescribed under the Electricity Industry Act Ch. 78.

The Commission as part of assessing the prudency and efficiency of the procurement projects may on its own accord carry out physical inspections of the projects and in cases where the Commission finds that the projects do not meet the procurement tender principles stated in the Final Regulatory Contract (clause 8.2) will allocate a value to the asset in its judgement considers appropriate. In addition, a financial penalty on the entity or management can be considered by the Commission.

Capital expenditure (capex) projects or operational expenditure (opex) that have gone through the competitive tender process will be reviewed by the Commission during the mid-term review and at the expiry period (final re-set of the next regulatory period) of the PPL Electricity Regulatory Contract. PPL will provide all necessary capex tender documents to the Commission for purposes of substantiating the competitive bidding process, prudency and the sequencing by some objective prioritization hierarchy, agreed between the parties, of the capex program. Investment planning should be transparent with public consultation, including prioritisation and sequencing of investments, which should be subjected to a competitive tender process.

10.3.1 Administering Public-Private Partnership

Public-Private Partnerships (PPP) should comply with all criteria under any specific PPP policy that may be adopted by the Government and, at a minimum, be competitively tendered. All PPPs formed should be the outcome of a competitive bidding process, and vetted by the relevant regulator and the PPP Centre.

10.3.2 General Duties and Obligations of PPL

In terms of any procurements, PPL is required to provide to the Commission its Approved Annual Plans indicating its annual capital and operational plans which it intends to undertake at a value of which will be at or over K500,000.00. The Commission will also require documentation as evidences of any capital and operational expenditure procurements valued to be K500,000.00 or above during previous regulatory period, this contract period or the subsequent regulatory period as outlined in clause 8.4 of the Final Regulatory Contract.

The Commission if necessary, will appoint an appropriately qualified independent consultant to assess the prudency and efficiency of the capital or operational expenditure and the robustness of demand forecasts, included latent or unmet demand. The cost of the independent consultant will be met by PPL.

10.4 Mid Term Review of Competition in the Market

In instances where the Commission believes that an existing non-regulated service or a new non-regulated service has the potential to have a significant substantive degree of market power, it may require PPL to submit a written statement which makes an assessment of the need for and extent of regulation of the provision of PPL electricity services in PNG. The manner in which the statement must be provided or the processes in conducting a Mid Term Competition Review are outlined explicitly under clause 11.2 in the Electricity Regulatory Contract.
10 APPENDICES

10.1 Regulatory Principles from 2002 -2011 Regulatory Contract

1. There must be an examination of:
   (a) the value of capital stock at the end of the term of this Contract, which must be based on the 
depreciated value of the initial capital value used in this Contract (K294,069,000) and the 
depreciated value of the actual prudent capital expenditures undertaken during the term of this 
Contract. The depreciation method to be applied to these capital amounts must be the current cost 
accounting approach applying a depreciated optimised replacement cost (the DORC methodology). The actual capital expenditure made during the term of this Contract must be 
reviewed to ensure that it was prudent and should be included in the asset base going forward;
   (b) the continued suitability of the real weights, W1 to W5 set out in the table contained in paragraph 
A.1 of Schedule 3, given the movement of costs during the term of this Contract;
   (c) the appropriate rate of return to apply in setting the new price path;
   (d) the level of future capital expenditure and operating expenditure to maintain service levels, 
   including any efficiency factor to be applied to operating expenditure (other than to fuel and 
depreciation);
   (e) the allowance for the costs associated with the Kanudi Contract which is expressed to terminate in 
2014;
   (f) any arrangements that are to apply in relation to, and the timing for, the introduction of access 
regulation for transmission and distribution networks and the introduction of contestability for 
electricity consumers; and
   (g) an allowance for accelerated depreciation of any assets identified by PPL as being stranded or 
potentially being stranded by the introduction of retail competition.

2. PPL must be regulated under an incentive regulation approach.

3. A building block approach must be adopted, consisting of the following components:
   (a) initial capital stock;
   (b) return on capital (WACC);
   (c) new capital expenditure;
   (d) return of capital - economic depreciation; and
   (e) operating expenses.

4. There must be the establishment of a glide path adjustment with a sharing of efficiency gains between PPL 
and electricity consumers.
## 10.2 List of Planned Capex Projects

### Table 50: Planned Capex - Generation

#### Generation Plan

<table>
<thead>
<tr>
<th>ZONE 1</th>
<th>Timing</th>
</tr>
</thead>
<tbody>
<tr>
<td>(Port Moresby &amp; Ramu)</td>
<td></td>
</tr>
<tr>
<td>Rouna Upgrade</td>
<td>2012</td>
</tr>
<tr>
<td>Diesel Generation</td>
<td></td>
</tr>
<tr>
<td>Naoro Brown Hydro</td>
<td>2013-2015</td>
</tr>
<tr>
<td>Ramu</td>
<td></td>
</tr>
<tr>
<td>Ramu Upgrades -hydro</td>
<td>2011-2012</td>
</tr>
<tr>
<td>Diesel Generation</td>
<td></td>
</tr>
<tr>
<td>Ramu/Mongi/Kaugel</td>
<td>2016-2024</td>
</tr>
<tr>
<td>Gazelle</td>
<td></td>
</tr>
<tr>
<td>Mevelo hydro</td>
<td>2016-2024</td>
</tr>
<tr>
<td>Replace M4 &amp; 5 with 2 x 2.5MW</td>
<td>2013/2015</td>
</tr>
</tbody>
</table>

#### ZONE 2

<table>
<thead>
<tr>
<th>Timing</th>
</tr>
</thead>
<tbody>
<tr>
<td>(Wewak &amp; Kimbe)</td>
</tr>
<tr>
<td>Replace M6 with 1 x 2.5MW</td>
</tr>
<tr>
<td>Install 1 x 4MW</td>
</tr>
<tr>
<td>Install 1 x 4MW</td>
</tr>
<tr>
<td>Replace M8 with 1 x 4MW</td>
</tr>
<tr>
<td>Kimbe/Bialla</td>
</tr>
<tr>
<td>Refurbish Rue Creek</td>
</tr>
<tr>
<td>3 x 1.5MW high sp. Diesel</td>
</tr>
</tbody>
</table>

#### ZONE 3

<table>
<thead>
<tr>
<th>Timing</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aitape</td>
</tr>
<tr>
<td>Install 1 x 256kW</td>
</tr>
<tr>
<td>Replace M1 &amp; M4 (2x292kW)</td>
</tr>
<tr>
<td>Alotau</td>
</tr>
<tr>
<td>Gumini Hydro</td>
</tr>
<tr>
<td>Buka</td>
</tr>
<tr>
<td>Ramazon Hydro</td>
</tr>
<tr>
<td>Daru</td>
</tr>
<tr>
<td>Replace M2 with 1 x 520kW</td>
</tr>
<tr>
<td>Install 2 x 400kw</td>
</tr>
<tr>
<td>Install??</td>
</tr>
<tr>
<td>Finschaffen</td>
</tr>
<tr>
<td>Replace with 1 x 100kW</td>
</tr>
</tbody>
</table>
Replace M1 with 1 x 192kW 2016-2024
Replace M2 with 1 x 100kW 2013
Kavieng
Replace M1 & M4 (2x1.5MW) 2011/2013
Replace M2 with 1 x 1MW 2014
Replace M5 with 1 x 1MW 2016-2024
Karma
Replace M1 with 1 x 160kW 2012
Replace M5 with 1 x 160kW 2016-2024
Replace M4 with 1 x 160kW 2016-2025
Lorena
Replace M4 & M5 with 1 x 800kW 2011
Replace M1 with 1 x 800kW 2014
Replace M2 with 1 x 800kW 2016-2024
Popondetta
Divune hydro 2011-2013
Replace M5 with 1 x 750kW 2016-2024
Samarai
Replace M1 with 1 x 80kW 2011
Vanimo
Replace M6 with 1 x 500kW 2011
Replace M2 with 1 x 500kW 2014

<table>
<thead>
<tr>
<th>Project</th>
<th>Description</th>
<th>Timing</th>
</tr>
</thead>
<tbody>
<tr>
<td>ZONE 1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>PORT MORESBY</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Boroko Substation</td>
<td>Develop Boroko as a three transformer substation, 2x30MVA and 1x19MVA</td>
<td>2011</td>
</tr>
<tr>
<td>Konedobu substation</td>
<td>Install a third (external) 30MVA transformer</td>
<td>2011</td>
</tr>
<tr>
<td></td>
<td>Replace one old 20MVA transformer with a 30MVA transformer</td>
<td>2016</td>
</tr>
<tr>
<td>Kilakila substation</td>
<td>Build substation with 66kV supply from 535 line</td>
<td>2012</td>
</tr>
<tr>
<td>Waigani substation</td>
<td>Install a third 30MVA transformer</td>
<td>2012-2013</td>
</tr>
<tr>
<td>Waigani 2 substation</td>
<td>Secure easement for 66kV transmission line</td>
<td>2012</td>
</tr>
<tr>
<td>CBD GIS substation</td>
<td>Complete detailed study of CBD 11kV feeder arrangement options</td>
<td>2011</td>
</tr>
<tr>
<td></td>
<td>Lay underground 66kV line to CDB GIS Substation</td>
<td>2012</td>
</tr>
<tr>
<td></td>
<td>Install 11kV switchboard in CBD and implement preferred feeder arrangement</td>
<td>2013-2014</td>
</tr>
<tr>
<td></td>
<td>including upgrading of conductors, RMU’s, and switchgear</td>
<td></td>
</tr>
<tr>
<td>Bautama substation</td>
<td>Closely monitor expected developments and implement as required</td>
<td>2015</td>
</tr>
<tr>
<td>Underground cables</td>
<td>Identify and replace 400A u/ground cables to 630A</td>
<td>2011-2014</td>
</tr>
<tr>
<td>Power quality</td>
<td>Assess power quality on all feeders from Konedobu, Waigani, and Boroko substation</td>
<td>2011-2013</td>
</tr>
<tr>
<td></td>
<td>Upgrade conductors and reactive power support as required</td>
<td>2011-2013</td>
</tr>
</tbody>
</table>

Table 51 Planned CAPEX - Transmission and Distribution
| Protection | Carry out scoping and needs assessment. Priority loads like the hospital, major customers need to be identified |
| Protection | Grading to allow selectivity, differentiation, timely operation and affordable protection to avoid indiscriminate feeder tripping | 2011-2024 |
| GIS map | Complete GIS mapping of Port Moresby 66kV and 11kV network | 2011 |
| Distribution Load flow analysis (ETAP) | Extend load flow analysis to distribution/feeder levels |
| | Training of engineers to gain appropriate level of skills | 2011 |

### LAE

<table>
<thead>
<tr>
<th>Description</th>
<th>Timing</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substations</td>
<td></td>
</tr>
<tr>
<td>Build new Substation at Singawa</td>
<td>2011-2013</td>
</tr>
<tr>
<td>Complete detailed study of conversion to 22kV distribution voltage in Lae</td>
<td>2011/12</td>
</tr>
<tr>
<td>Build 132KV transmission line Taraka - Singawa</td>
<td>2012/13</td>
</tr>
<tr>
<td>Build 66kV transmission line Singawa - Milford</td>
<td>2014</td>
</tr>
<tr>
<td>Augment (and covert to 22kV) Taraka and Milford substations as required</td>
<td>2015-</td>
</tr>
<tr>
<td>Distribution feeders</td>
<td></td>
</tr>
<tr>
<td>Study to confirm feeder rearrangements and offload options. (Requires GIS survey to be completed)</td>
<td>2011</td>
</tr>
<tr>
<td>Milford feeder 1-Up-rate Cherry and Banana to Saturn (37/3.00, 776A) along Malekula St from main market to SS180.</td>
<td>2011</td>
</tr>
<tr>
<td>Milford feeder 2-uprate Banana to Saturn at Hillside Av, Mt Lunaman. Replace Banana HV line to Lae Inter Hotel. Up-rate to Saturn HV line to ABS 210 and Colgate palm olive factory. Up-rate ”T off” line to P/Office/Melo up to ABS109 and HV line ”T Off” to ABS104 Tern St</td>
<td>2011</td>
</tr>
<tr>
<td>Milford feeder 3- Replace HV T off” to flour mill. Banana to Saturn</td>
<td>2011</td>
</tr>
<tr>
<td>Milford feeder 4-T offs” to PNG Ports, along Erika St replacing Apple with Saturn. Banana ”T offs” to Honibrooks and Trukai factory to Saturn</td>
<td>2011</td>
</tr>
<tr>
<td>Milford feeder 5 - replace Banana with Saturn from T Off” to ABS58 to ABS103 (open point). Up-rate line to SS184</td>
<td>2011</td>
</tr>
<tr>
<td>Milford feeder 6- Replace Banana with Saturn for the T off” line to Prima &amp; Pelgen factories, Morobe Av</td>
<td>2011</td>
</tr>
<tr>
<td>Taraka 1- T off” to W/board pumps and Unitech Admin up-rated to Saturn</td>
<td>2011</td>
</tr>
<tr>
<td>Taraka feeder 2- up-rate from intersection before SS88 &amp; SS203 up to Igam, Bumayong and Telekom Coll. From Telekom College to IFC Malahang replace Cherry. Also up-rate intersection line to SS186 West Taraka.</td>
<td>2011</td>
</tr>
<tr>
<td>Taraka feeder 4-”T off” line to ABS36, ABS 20 to ABS 103 and also ”T off” line to Barlow Industries and Nestle Fact. Replaced with Saturn.</td>
<td>2011</td>
</tr>
<tr>
<td>Taraka feeder 5- replaces Banana from 6-11mile &amp; Nari Bubia Poultry (Wau Bulolo H/way) with Saturn</td>
<td>2011</td>
</tr>
<tr>
<td>ABS’ and Switch gears up-rated</td>
<td></td>
</tr>
<tr>
<td>ABS 123 (Milford 2 and 3), ABS52 (Milford 2 and Tka 4), ABS29 (Milford 2 and 5), ABS103 (Milford 2 and Tka 4), ABS21 (M5/Tka 3), ABS13 (M1/M4), ABS154 (Tka3-Tka5), ABS138 (Tka 3-Tka4), ABS115 (Tka 3-Tka 4) upgraded to 630Amps or more breaking capability</td>
<td>2011</td>
</tr>
<tr>
<td>Replace CBs at Taraka</td>
<td></td>
</tr>
<tr>
<td>Old Reroll CBs at Taraka (1973 installed) to be replaced-66KV Buss tie and 508 line CBs are Reroll</td>
<td>2011</td>
</tr>
<tr>
<td>RAMU</td>
<td>Description</td>
</tr>
<tr>
<td>------</td>
<td>------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>601</td>
<td>Ramu to Singsing - construct Sinsing switchyard 510 line - redundancy using 22kV Line from Paunda to Dobel 602 line - 132kV operating voltage from Gusap to Meiro</td>
</tr>
<tr>
<td></td>
<td>602 line - improved bypasses from Gusap to Meiro (Madang)</td>
</tr>
<tr>
<td></td>
<td>Taraka - install 10MVA STATCOM</td>
</tr>
<tr>
<td></td>
<td>Paunda - upgrade capacitor bank to 5MVA</td>
</tr>
<tr>
<td></td>
<td>Detailed option study to be completed in 2011</td>
</tr>
<tr>
<td></td>
<td>Arrangement and operating model to be assessed by networks business unit in 2011</td>
</tr>
<tr>
<td></td>
<td>Detailed option study to be completed in 2011</td>
</tr>
</tbody>
</table>

10.3 Definitions of new performance metrics

SAIFI refers to the System Average Interruption Frequency Index. It is commonly used as a reliability indicator by power electric utilities. SAIFI is the average outage frequency for each customer served, and is calculated as:

\[ SAIFI = \frac{\text{Sum of all customer interruptions}}{\text{Total number of customer served}} \]

SAIFI is measured in units of interruptions per customer. It is usually measured over the course of a year, and according to IEEE Standard 1366-2003, the median value for North American utilities is approximately 1.10 interruptions per customer.

SAIDI refers to the System Average Interruption Duration Index. It is commonly used as a reliability indicator by electric power utilities. SAIDI is the average outage duration for each customer served and is calculated as:

\[ SAIDI = \frac{\text{Sum of all customer interruption durations}}{\text{Total number of customer served}} \]

SAIDI is measured in units of time, often minutes or hours. It is usually measured over the course of a year, and according to IEEE Standard 1366-2003, the median value for North American utilities is approximately 1.50 hours.

CAIDI is the Customer Average Interruption Duration index

\[ CAIDI = \frac{\text{Sum of all customer interruption durations}}{\text{Total number of customer served}} \]

The ICCC notes that:

\[ SAIFI = SAIDI \]

Therefore, if, SAIDI and SAIFI have been measured then CADI can be calculated.

CAIFI is the Customer Average Interruption Frequency Index

\[ CAIFI = \frac{\text{Total number of customer interruptions}}{\text{Total number of customers who had at least one interruption}} \]
MAIFI is the Momentary Average Interruption frequency index. MAIFI is the average number of momentary interruptions that a customer would experience during a given period (typically a year). Electric power utilities may define momentary interruptions differently, with some considering a momentary interruption to be an outage of less than 1 minute in duration while others may consider a momentary interruption to be an outage of less than 5 minutes in duration. MAIFI is calculated as

\[
MAIFI = \frac{\text{Sum of all customer interruption durations}}{\text{Total number of customer served}}
\]

10.4 Extracts from the Electricity Industry Policy statement about pricing

The following excerpts are the portions of the EIP which refer to price setting by the ICCC. The numbered references and pages numbers refer to the numbered sections of the EIP.

2.2.3 Affordability

“Uneconomic areas, particularly rural areas, are naturally high cost areas for investments, and therefore power companies would naturally set high prices to recover costs. However this is suppressed by the Government’s regulation of maintaining uniform tariffs.” (Section 2.2.3 page 5)

“Incentives that make electricity undertakers seek efficiency measures to minimize their costs and an enforceable and suitable price mechanism should alleviate the situations that bring about unaffordable prices of electricity.” (Section 2.2.3 page 5)

“This may include funding CSO’s, ... but also requires the adoption of appropriate price mechanisms to attract investment and promote efficient delivery of electrification services.” (Section 2.2.3 page 5)

“This approach to price regulation is currently being implemented by the ICCC, and will be maintained under this Policy, whereby the ICCC has the flexibility to adjust prices to reflect the higher cost of delivery services in some areas. Such an approach has been adopted ...by PNG Sustainable Energy Limited.... Flexibility in price regulation encourages investments in remote areas, improving accessibility, but also ensures efficient operations, and consequentially more affordable operators are encouraged to invest in remote areas where the cost of service may be higher”. (Section 2.2.3 page 5)

Section 4.1 State provisions for CSO

“It is the aim of the Government to ensure that the cost of usage by consumers in terms of tariffs is affordable, and that the cost of new connections, as a result of network extensions is also affordable. This requires both the taking into account of higher cost areas of investments through suitable price regulation by the price regulator and the need for clear CSO framework.” (Section 4.1 page 8)

Section 4.1.1 Tariff regulation in delivery of CSO

“The current price regulation includes uniform tariff for customers within a particular category, regardless of location, and this is regarded as an elemental form of CSO ...... to achieve ...affordable prices ... in higher cost areas.

This regulation however, suppresses the growth of the electricity sector in PNG by foreclosing investments that seek to charge the true costs on electricity commercially. The higher cost areas...especially rural areas have been effectively neglected the provision of vital electricity service as a consequence. While the uniform tariff regulation of the Government may be to the benefit of the users of electricity services (in the form of avoided high prices) in commercially higher cost areas ... it does not give the incentive to service providers, let alone the State-owned utility – PPL, to take up commercial investments in these areas.
PPL has been delivering CSOs by internally cross-subsidising its operation in areas that are unprofitable. It is a rational policy consideration that such types of internal cross-subsidies would not constitute a commercial objective of power companies that operate purely on commercial interest.

Under this Policy, the ICCC ... will implement a commercial price regulation model that features price flexibilities reflecting on the costs of investments to ensure that incentives exist in both higher cost and lower cost areas of investments.

Where a CSO is identified, costed and delivered by the Government, through capital subsidies under the competitive tender process, the ICCC will enforce a form of price cap regulation on the service provider ...by precluding earning rents ... at the same time enabling it a healthy commercial operation.” (Section 4.1.1 page 9)

4.1.3 State Financing towards CSO through competitive tender

“PPL is required to operate in a commercially-orientated manner rather than simply delivering CSO’s. The arrangement of direct injections of state financing ....does not provide the incentive to PPL to seek efficiencies in its operations ...” (Section 4.1.3 page 10)

“A new CSO framework ... should incentivise the providers ... to take up investments in high cost areas ... to enable them to comfortably recover the costs of investments and make healthy profits in an electricity price regime of uniform tariffs.” (Section 4.1.3 page 10)

4.1.5 Rural Electrification under CSO

“There is an inherent inability to recover costs .... to rural areas in PNG. The difference between postage stamp price (which is a feature of the current regulatory framework) and the actual cost of service provision does not usually prove economic sense......” (Section 4.1.5 page 11)

“The current practices of allowing flexible price regulation by the ICCC to allow investment in higher cost areas to take place, addresses this issue in some way.” (Section 4.1.5 page 11)

4.2.2 Economic Regulation – Price Regulation

“The economic regulator will implement a robust price regulation to ensure that the industry is vibrant in all commercial ventures through profits earned, whilst ensuring that the objective affordability, hence accessibility, remains attainable.

It is its absolute responsibility for the economic regulator to adopt a specific kind of price regulation mechanism that will ensure that electricity service provision in both low-cost and high-cost areas of investments in the industry in PNG is sustainable. Considerations should be made on the situation of rural areas where prices applied in urban areas may turn out to be unaffordable. The economic regulator will consult the responsible Department or the body in charge of this policy when imposing tariffs in rural areas under a specific price mechanism it employs.” (Section 4.2.2 page 14)