Final Report - Technical & Economical Study
for the Development of Small Scale Grid
Connected Renewable Energy in Kenya
# Contents

## Tables

<table>
<thead>
<tr>
<th>Tables</th>
<th>v</th>
</tr>
</thead>
</table>

## Figures

<table>
<thead>
<tr>
<th>Figures</th>
<th>v</th>
</tr>
</thead>
</table>

## Abbreviations and acronyms

<table>
<thead>
<tr>
<th>Abbreviations and acronyms</th>
<th>vii</th>
</tr>
</thead>
</table>

## Acknowledgments

<table>
<thead>
<tr>
<th>Acknowledgments</th>
<th>ix</th>
</tr>
</thead>
</table>

## 1 Introduction and Overview

1.1 Conduct of the Study | 1

1.2 Overview of the Small-Scale Renewables sector | 2

1.3 Overview of the approach | 5

1.4 Overview of the report and the deliverables | 6

## 2 Categories for promoting small-scale grid connected renewables

2.1 Study objectives and principles adopted | 8

2.2 Category 1- Electricity Banking | 9

2.3 Category 2 - Net Metering | 10

2.4 Recommendations and procedures for Categories 1& 2 | 10

2.5 Category 3 - Standardised non-negotiable PPA | 11

2.6 Larger renewable projects (>10 MW) | 12

## 3 Report on TOR tasks

3.1 Task 1 - Standardised PPAs | 16

3.1.1 Standardised Non-negotiable PPA (Category 3) | 16

3.1.2 Standardised Negotiable PPA (Category 4) | 17

3.1.3 Task 1 Recommendations | 17

3.2 Task 2 - Feed-in Tariffs | 17

3.2.1 Key elements of Feed-in Tariff Policy | 17

3.2.2 Revised FiT Model and the data assumptions made | 19

3.2.3 Proposed FiT values | 25
3.2.4 Comparison with international FiT values
3.2.5 Task 2 Recommendations
3.3 Task 3 - Engineering standards
3.3.1 Guidelines for Grid Connection of Small Renewable Generators
3.3.2 Guidelines content
3.3.3 Task 3 Recommendations
3.4 Task 4 - Grid integration – operations
3.4.1 Operational integration of small renewables
3.4.2 Task 4 Recommendations
3.5 Task 5 - Isolated grids
3.5.1 The load characteristics of isolated grids
3.5.2 Task 5 Recommendations
3.6 Task 6 – Monitoring and Planning Tool
3.6.1 Relationship between monitoring and planning
3.6.2 Task 6 Recommendations
3.7 Task 7 - Management of FiT Approval Process
3.7.1 Task 7 Deliverables
3.7.2 Task 7 Recommendations
3.8 Additional elements of the TOR and other topics covered
3.8.1 Items identified at start of Section 3 of TOR
3.8.2 Wheeling

4 Conclusion

A1 International experience of SPP regulatory regimes
A1.1 Small Power Producers in Thailand
A1.2 Community financing for wind power in Denmark
A1.3 Small Renewable Energy Program in Sri Lanka
A1.4 Small Power Project Development in Tanzania

A2 Electricity Banking/Net Metering Application Form
<table>
<thead>
<tr>
<th>Section</th>
<th>Title</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>A3</td>
<td>FiT Model user manual</td>
<td>72</td>
</tr>
<tr>
<td>A3.1</td>
<td>Model structure</td>
<td>72</td>
</tr>
<tr>
<td>A3.2</td>
<td>Model worksheets</td>
<td>73</td>
</tr>
<tr>
<td>A3.3</td>
<td>Instructions for updating FiTs</td>
<td>73</td>
</tr>
<tr>
<td>A3.4</td>
<td>Simplified FiT Model</td>
<td>74</td>
</tr>
<tr>
<td>A4</td>
<td>Planning and Monitoring Tool user manual</td>
<td>75</td>
</tr>
<tr>
<td>A4.1</td>
<td>Applications of the tool</td>
<td>75</td>
</tr>
<tr>
<td>A4.2</td>
<td>Structure of the tool</td>
<td>75</td>
</tr>
<tr>
<td>A4.3</td>
<td>Instructions for using the tool</td>
<td>76</td>
</tr>
</tbody>
</table>
Tables

Table 1  Pipeline projects 2012-2018 (up to 10 MW) 3
Table 2  RTAP project pipeline as of mid May 2012 4
Table 3  Main elements of FiT policy for on-grid projects 18
Table 4  FiT Model assumptions, not technology specific 20
Table 6  Summary of FiT values 29
Table 7  Standard FiT by capacity increment 30
Table 8  Front Loaded FiT by capacity increment 30
Table 9  Indexed Component by capacity increment 31
Table 10  VSPP tariffs by fuel type 56

Figures

Figure 1  Projected contribution of renewables (up to 30 MW) to generation 3
Figure 2  Overview of FiT Model structure 19
Figure 3  Load factors by technology 22
Figure 4  Investment costs (construction + transmission costs, before interest during construction) by technology 23
Figure 5  Fixed operating costs by technology 24
Figure 6  Variable operating costs by technology 24
Figure 7  Standard FiTs 25
Figure 8 Front Loaded FiT - wind 26
Figure 9  Linear tariffs - hydro 1-10 MW 27
Figure 10 Indexed component as a percentage of Standard FiT 28
Figure 11 Comparison with FiTs internationally - wind 32
Figure 12 Comparison with FiTs internationally - biomass 32
Figure 13 Comparison with FiTs internationally - hydro 33
Figure 14 Typical daily load profile of an isolated centre 39
Figure 15 Thai electricity sector institutional arrangement 53
Figure 16 Status of VSPP in March 2010
Figure 17 Feed-in tariffs and subsidies
Figure 18 Sri Lanka’s electricity sector institutional arrangement
Figure 19 Annual season SPP tariff
Figure 20 Energy permit application process
Figure 21 Overview of Tanzania’s electricity sector
Figure 22 Sequence of SPP implementation
Figure 23 Number of concluded SPPAs in November 2010
Figure 24 SPP types for tariff calculations
Figure 25 Overview of FiT Model structure
Figure 26 Overview of Planning and Monitoring Tool structure
## Abbreviations and acronyms

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Full Form</th>
</tr>
</thead>
<tbody>
<tr>
<td>CEB</td>
<td>Ceylon Electricity Board</td>
</tr>
<tr>
<td>CPI</td>
<td>Consumer Price Index</td>
</tr>
<tr>
<td>DNI</td>
<td>Direct Normal Irradiation</td>
</tr>
<tr>
<td>DNO</td>
<td>Distribution Network Operator</td>
</tr>
<tr>
<td>EGAT</td>
<td>Thai state-owned power company</td>
</tr>
<tr>
<td>EOI</td>
<td>Expression of Interest</td>
</tr>
<tr>
<td>ERC</td>
<td>Energy Regulatory Commission</td>
</tr>
<tr>
<td>ESDP</td>
<td>Energy Services Delivery Project (Sri Lanka)</td>
</tr>
<tr>
<td>ESIA</td>
<td>Environment and Social Impact Assessment</td>
</tr>
<tr>
<td>EWURA</td>
<td>Energy and Water Utilities Regulatory Authority (Tanzania)</td>
</tr>
<tr>
<td>FiT</td>
<td>feed-in tariff</td>
</tr>
<tr>
<td>GDC</td>
<td>Geothermal Development Company</td>
</tr>
<tr>
<td>GoK</td>
<td>Government of Kenya</td>
</tr>
<tr>
<td>IPP</td>
<td>independent power producer</td>
</tr>
<tr>
<td>kWh</td>
<td>kilowatt hour (unit of electrical energy)</td>
</tr>
<tr>
<td>kWp</td>
<td>peak capacity in kW</td>
</tr>
<tr>
<td>KPLC</td>
<td>Stock market and familiar name of Kenya Power</td>
</tr>
<tr>
<td>LCPDP</td>
<td>Least Cost Power Development Plan</td>
</tr>
<tr>
<td>LOI</td>
<td>Letter of Intent</td>
</tr>
<tr>
<td>LRMC</td>
<td>long run marginal cost</td>
</tr>
<tr>
<td>MWe</td>
<td>megawatts applying to electrical capacity</td>
</tr>
<tr>
<td>MWh</td>
<td>megawatt hour (unit of electrical energy)</td>
</tr>
<tr>
<td>PPA</td>
<td>Power Purchase Agreement</td>
</tr>
<tr>
<td>PUCL</td>
<td>Public Utilities Commission of Sri Lanka</td>
</tr>
<tr>
<td>PV</td>
<td>(Solar) photo voltaic</td>
</tr>
<tr>
<td>RE</td>
<td>renewable energy</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Description</td>
</tr>
<tr>
<td>--------------</td>
<td>-------------</td>
</tr>
<tr>
<td>RES</td>
<td>renewable energy sources</td>
</tr>
<tr>
<td>REA</td>
<td>Rural Electrification Authority</td>
</tr>
<tr>
<td>RERED</td>
<td>Renewable Energy for Rural Economic Development</td>
</tr>
<tr>
<td>RPS</td>
<td>renewable portfolio standards</td>
</tr>
<tr>
<td>SEA</td>
<td>Sustainable Energy Authority (Sri Lanka)</td>
</tr>
<tr>
<td>SPP</td>
<td>Small Power Producer</td>
</tr>
<tr>
<td>SPPA</td>
<td>Standard/Small Power Purchase Agreement</td>
</tr>
<tr>
<td>SPPT</td>
<td>Small Power Purchase Tariff</td>
</tr>
<tr>
<td>SREP</td>
<td>Scaling-up Renewable Energy Programme</td>
</tr>
<tr>
<td>STM</td>
<td>Standardised Tariff Methodology (Tanzania)</td>
</tr>
<tr>
<td>T&amp;D</td>
<td>transmission and distribution</td>
</tr>
<tr>
<td>TANESCO</td>
<td>Tanzanian state-owned power company</td>
</tr>
<tr>
<td>TGC</td>
<td>tradable green certificates</td>
</tr>
<tr>
<td>TOR</td>
<td>Terms of Reference</td>
</tr>
</tbody>
</table>
| VSPP         | Very Small Power Producers  
               (as defined in Thailand’s support programme) |
The Consultant Team, led by Economic Consulting Associates, would like to express its appreciation to the client organisations and all the Kenya stakeholders involved in the study. The study was commissioned by the Ministry of Energy, under World Bank financing, and coordinated by the Energy Regulatory Commission. The Steering Committee, in addition to the Ministry and ERC, had members from Kenya Power, Kengen, KETRACO, the Geothermal Development Company and the Rural Electrification Authority. More than a dozen private sector organisations involved in the renewables sector took part in the discussions and provided data for the FiT model, notably in this regard the RTA Programme for Financing Renewable Energy & Energy Efficiency, hosted by the Kenya Association of Manufacturers.

This final report contains improvements from the draft report stage that have resulted from the discussions at the final workshop held on 19 July 2012 and the training sessions on 20 July 2012, together with submissions from a large number of individuals.

London, 2 August 2012
1 Introduction and Overview

1.1 Conduct of the Study

The Government of Kenya has placed considerable importance on the Technical and Economic Study for Development of Small Scale Grid Connected Renewable Energy in Kenya. Since 2008, feed-in tariffs (FiTs) have been on offer to encourage investment in renewable energy (RE) generation projects, but there has to date been a rather limited response as measured by numbers of projects implemented under the FiT mechanism.

The Government seeks now, with the assistance of the World Bank, to create a framework which will encourage greater RE investment, thereby relieving the capacity constraint and allowing more Kenyans to connect to the grid, but at the same time avoiding high tariff increases being imposed on existing electricity consumers.

The study commenced in February 2012. The project schedule has been adhered to and the milestones have been:

- Project Kick-off Meeting – 16 February
- Inception Report - 16 March
- Inception Workshop – 30 March
- Mini Workshop on Technical Issues – 13 April
- Mini Workshop on Feed in Tariffs – 18 April
- Mid-Term Report – 14 May
- Mid-Term Workshop – 7 June
- Draft Final Report – 22 June
- Final Workshop – Thursday 19 July, with associated discussion/training sessions on engineering aspects and use of the FiT Model
- Final Report – 2 August
- An additional presentation and FiT model training session is to be provided in mid-August.

One of the immediate achievements of the study has been the degree of active participation in researching topics, debating options and forging a consensus around recommendations which are appropriate for Kenya. Fruitful discussions and exchanges have taken place with Steering Committee members and also with colleagues from their institutions. The exchanges have been through one-on-one
meetings, email and telephone exchanges, as well as via the mini and main workshops. These interactions have all had a training element, the consultant team keeping constantly in mind the training requirements of the study.

In addition to exchanges with people in public sector institutions with responsibility for renewables, the study has also drawn in private sector players, and this has served to further sharpen the debates and raise the level of recommendations being made. The main workshops have been attended by project promoters, bankers and technical experts. We have also had extensive exchanges via email with private companies and support organisations (such as RTAP - the Renewable Energy and Energy Efficiency Financing Programme, and Greening the Tea Industry in East Africa).

### 1.2 Overview of the Small-Scale Renewables sector

The electricity sector in Kenya is in many respects performing well. In the generation segment, there are independent power producers (IPPs) providing around 27% of the generated energy. The listed companies – Kenya Power and KenGen – are well run and financially sound, able to raise money through share and bond issues. Investment resources are also provided by government and donors, these being channelled in part through the Rural Electrification Authority.

The main problems in the sector are that existing capacity is barely able to meet demand, especially when hydrological conditions dip, and the electrification rate is only about 23%. Installed capacity in 2011 was only 1,590 MW, which is very low for a country of 40 million people (40 W per capita – South Africa’s figures are roughly 40,000 MW for 50 million people or 800 W per capita). Kenya’s Vision 2030 ambition is to be a middle income country in 18 years’ time: this will require system capacity to grow to 15,000 MW by 2030. Rapid growth in capacity is required both to underpin the GDP growth targets and to allow universal access to electricity to be achieved.

The overwhelming priority right now is to expand capacity in pace with economic growth, maintaining an adequate reserve margin so that security of supply can be assured. There is a well-established least cost power development plan (LCPDP) process in place. Two of the major upcoming developments identified in the LCPDP will be in renewables – large-scale geothermal generation to provide base load, and a high capacity (2,000 MW) direct current regional interconnector which will make it possible for Kenya to import low cost hydropower from Ethiopia.

Small-scale renewables also have a role to play. A study of Kenya’s renewable energy resource potential was undertaken during the inception phase, and an updated version is being released as a separate deliverable with this Final Report. Kenya’s renewable energy resource potential is substantial, and it is also evident that the impression of a lack of up-take of the FiTs is belied by the existence of a

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1 Kenya Power is the trading name of the company. The listed name on the Nairobi Stock Exchange is Kenya Power & Lighting Co. Limited. The company is often referred to as KPLC.
significant pipeline of projects. Taking ‘small-scale’ as being less than 10 MW, it is noted that small-scale renewables presently contribute only 3% of installed capacity, but this proportion has grown rapidly from around 1% in 2005.

<table>
<thead>
<tr>
<th>Type (&lt;30 MW)</th>
<th>Total MW</th>
<th>No. of sites</th>
<th>By when</th>
</tr>
</thead>
<tbody>
<tr>
<td>Small hydro</td>
<td>93</td>
<td>30+</td>
<td>2020</td>
</tr>
<tr>
<td>Biomass</td>
<td>36</td>
<td>6</td>
<td>2016</td>
</tr>
<tr>
<td>Small wind</td>
<td>0</td>
<td>0</td>
<td>n/a</td>
</tr>
<tr>
<td>Small geothermal</td>
<td>11.5</td>
<td>3</td>
<td>2017</td>
</tr>
<tr>
<td>Biogas</td>
<td>19.5</td>
<td>4</td>
<td>2018</td>
</tr>
<tr>
<td>Solar PV</td>
<td>10</td>
<td>1</td>
<td>2015</td>
</tr>
</tbody>
</table>


Our analysis of the pipeline of projects indicates that installed small-scale capacity will grow from the current level of under 50 MW to around 200 MW in 2018, with renewable projects of up to 30 MW (notably wind and biomass projects) bringing the total to 350 MW, which is expected to constitute at that stage around 6% of total system capacity. The less than 10 MW pipeline projects are dominated by small...
Introduction and Overview

hydro and biomass, followed by biogas and small geothermal – see Table 1. The evolution of the contribution of all renewables up to 30 MW is illustrated in Figure 1 above.

The number of projects of up to 30 MW would be about 12 per annum, with an average size of 3.6 MW, which sounds manageable from the viewpoint of the administrators of the FiT system, particularly when the bulk of these will be small projects (less than 10 MW) which will have streamlined procedures and agreements. The underlying assumption for the overall electricity system growth is the LCPDP forecasts based on reaching the ambitious Vision 2030 targets. The required growth rate for the system capacity is an annual average of 22% per annum, or in absolute terms an average increment of 660 MW each year.

The existence of a significant pipeline of projects is confirmed by other sources. The Regional Technical Assistance Project that is based in the Kenya Association of Manufacturers as of 18 May 2012 had a pipeline of 79 projects, of which 66 had been reviewed. Of these, 26 are classified as predominantly energy efficiency projects (including cogeneration, fuel and electricity cost abatement). Details of the remaining 40 renewable energy generation projects are given in Table 2. These projects are all targeted for implementation by as soon as 2014. One bottleneck is likely to be funding: the $155 million debt finance requirement for the 66 projects is nearly four times the financing capacity of the subsidised AFD credit line for Kenya. Other concessional loan financing is being sought.

<table>
<thead>
<tr>
<th>RE Technology</th>
<th>No. sites</th>
<th>Total MW</th>
<th>Investment US$ m</th>
<th>Unit cost US$/kW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydro</td>
<td>27</td>
<td>59</td>
<td>158</td>
<td>2,678</td>
</tr>
<tr>
<td>Biomass</td>
<td>2</td>
<td>6</td>
<td>6</td>
<td>1,000</td>
</tr>
<tr>
<td>Wind</td>
<td>3</td>
<td>10</td>
<td>25</td>
<td>2,500</td>
</tr>
<tr>
<td>Geothermal</td>
<td>2</td>
<td>5</td>
<td>19</td>
<td>3,800</td>
</tr>
<tr>
<td>Biogas</td>
<td>3</td>
<td>5</td>
<td>7</td>
<td>1,400</td>
</tr>
<tr>
<td>Solar PV</td>
<td>3</td>
<td>3</td>
<td>11</td>
<td>3,667</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td><strong>40</strong></td>
<td><strong>88</strong></td>
<td><strong>226</strong></td>
<td><strong>2,568</strong></td>
</tr>
</tbody>
</table>

*Source: RTAP project database*

Another potential bottleneck is the administrative procedures required for project approval and implementation. To ensure that the pipeline of projects actually move into implementation in the timescale envisaged, it is imperative that means be found to speed up and streamline the procedures for project approval and financing. The structures and procedures currently in place will not be able to cope with the large increase in demand for approvals that is expected to be coming through shortly.
1.3 Overview of the approach

The main objective of this study is precisely to reduce the transactions costs involved in project start-up and in the operational phase of small power producers (SPPs). The first few projects to have been introduced under the FiT mechanism have involved significant transactions costs, particularly for the project promoters and for KPLC in the phase of negotiating a power purchase agreement (PPA). The most important element of the approach adopted in this study to the minimisation of transactions costs has been to introduce the idea of a Standardised Non-Negotiable PPA which would be based on a fixed, non-negotiable FiT for each technology. Cutting out negotiation altogether is clearly a major step forward, and the standardisation of the PPA also implies that there is no monitoring to be done during the PPA implementation; so on-going as well as up-front transactions costs are being dramatically reduced.

However, a standardised non-negotiable PPA can only be applied in certain circumstances and there are certain costs and limitations which result:

- There is no bidding for renewable sites and resources – a first come, first served system applies.
- The plants are ‘embedded’, that is not despatchable by the National Control Centre.
- They are connected at distribution voltages of up to 33 kV and operate on a ‘must run, must take’ basis at a feed-in tariff which is fixed for each technology type and capacity level.
- Given the physical limitations of distribution systems and the implications of non-despatchability, the plant capacity for the embedded plants is to be limited to a maximum of 10 MW.

These limitations are to be traded off against the simplicity and efficiency of the standardised non-negotiable PPA, and the direct economic gains (to sponsors and the electricity sector as a whole) of projects being implemented and generating returns much sooner than would be the case if each and every PPA had to be separately negotiated. The factors listed above do not preclude small-scale renewables playing a significant role in national electricity supplies, as well as offering local advantages (notably voltage support when the generators are located at the end of long distribution lines).

A country such as Sri Lanka provides an important example of successfully implementing the standardised non-negotiable approach. The scheme was introduced in 1996 and has grown since that time. Embedded small-scale renewable generators presently have a combined capacity equivalent to 10% of Sri Lanka’s national maximum demand. The plants have operated without technical problems arising, despite their being non-despatchable.

The standardised non-negotiable PPA for embedded generators of less than 10 MW is not the only support framework that is presented in this report. After considering
all the combinations of aspects of (project scale, technologies, support instruments, transmission interconnection costs, feed-in tariffs), various different packages or ‘Categories’ of support for small scale renewables are proposed. The recommended categories are:

- **Category 1** - Electricity Banking
- **Category 2** - Net Metering
- **Category 3** - Standardised Non-negotiable PPA

These are discussed further in Section 2. At an earlier point in the study, support frameworks for renewable projects larger than 10 MW but still relatively ‘small’ were presented, but after thorough discussion this category has been replaced by a set of guidelines for larger projects, rather than a specific incentive framework. This is discussed further in Section 2 below.

### 1.4 Overview of the report and the deliverables

The main part of this report (Section 3) examines key aspects of the implementation of these categories, relating these to the seven main tasks laid out in the Terms of Reference (TOR) for the study:

- Task 1: Regulatory instruments for SPPs connected to the national grid
- Task 2: Tariffs for SPP sales into the interconnected system
- Task 3: Grid Integration - Connections
- Task 4: Grid Integration - Operations
- Task 5: Regulatory instruments for SPPs supplying isolated grids
- Task 6: Planning potential for SPPs in Kenya and private sector participation
- Task 7: Management of FiT approval process

This Final Report is a relatively brief and succinct document, the objective of which is to lay out the main arguments to back the recommendations. It includes various annexes, the first of which provides details of international experience of SPP regulatory regimes (focussing on Thailand, Denmark, Sri Lanka and Tanzania).

The substantive deliverables are associated documents:

- **Separate Deliverable 1**: Draft Revised FiT Policy
- **Separate Deliverable 2**: Standardised Non-Negotiable Power Purchase Agreement
Introduction and Overview

- **Separate Deliverable 3**: Connection Guidelines for Small-Scale Renewables
- **Separate Deliverable 4**: FiT Model
- **Separate Deliverable 5**: Application and Implementation Guidelines
- **Separable Deliverable 6**: Monitoring & Planning Tool
- **Separate Deliverable 7**: PPA Template for Projects larger than 10 MW
- **Separate Deliverable 8**: Renewable Energy Resource Potential in Kenya
2 Categories for promoting small-scale grid connected renewables

2.1 Study objectives and principles adopted

As the number of small renewable generation project applications grows and subsequently the number of small generators on the grid grows, it will become imperative to have procedures and operational practices which are as simple and as easy to manage as possible.

The primary objective of the study, as laid out in the TOR, is to minimise the transaction costs for the utility and the small power producers. The principles adopted to achieve the primary objective relate both to the start-up and the implementation phases of a small renewable project:

- **Start-up transactions costs**: The transactions costs associated with submitting a proposal for a small renewable project, having it approved, obtaining all the necessary agreements and permits, should be as simple and as streamlined as possible.

- **On-going transactions costs**: The transaction costs during the implementation phase should also be minimised. As far as possible, arrangements which require data to be collected and processed about the operation of small generating plants are to be avoided.

This immediate objective is cast in the context of objectives of the Electricity Expansion Project of which it is a part:

- Improve the quality and availability of power in Kenya
- Make power available to all Kenyans.

The broad national goal is to increase the supply of renewable energy into the interconnected and isolated grids.

Making these principles operational involves standardisation of procedures and automation in operation, for example, having a standardised PPAs and making small generators non-despatchable and not having penalties either for non-performance of the generator or non-availability of the transmission lines needed to evacuate the power.

These examples of standardisation and automation are intended as a preview of the discussion in this report: the framework this study is to recommend has to cater for a wide variety of situations and technologies. The main aspects which have been considered during the study are:

- Project scale – different capacity limits for standardised arrangements
Categories for promoting small-scale grid connected renewables

- Technologies – wind, biomass (grown and waste considered separately), small hydro, geothermal, biogas and solar

- Support instruments – different forms of net metering, standardised approaches for first come, first served approaches, solicited competitive bidding.

- Transmission interconnection costs – whether these should be paid by the developer or the offtaker, or some sharing mechanism

- Feed-in tariffs (FiTs) – whether technology-specific and cost reflective, or avoided cost based, and what capacity of project should be eligible.

From these issues, a number of ‘categories’ of support have been distilled and refined during the course of the study. These have been briefly previewed in Section 1.3 and are described in turn in more detail in the remainder of this section.

2.2 Category 1 - Electricity Banking

Category 1 is a variant of net metering, but one which does not involve any payment being made by KPLC for surplus electricity that may be supplied into the grid. Essentially, this model is limited to customers of KPLC signing up to be generators as well as consumers of electricity. The customers continue to pay monthly fixed charges, although a derogation could be allowed at times of national reserve margin shortfall (this is explained in more detail in the next section). In months when electricity bankers consume more than they generate, they are charged for the net amount. In months when they generate more than they consume, they are allowed a free banking facility. By this is meant that the surplus electricity fed into the grid is recorded and this ‘saved’ balance can be drawn down and used in subsequent months. To keep things simple and minimise administrative costs, there is no charge for this banking service.

The size of the generator is limited by the fact that the existing customer connection is used for the interconnection. All types of customer should be eligible – commercial and industrial customers as well as domestic customers. The non-domestic customers could invest in relatively large generators, but given that no customer will ever be paid for any surplus, the size of a generator will tend to be scaled so that an electricity banking customer, whether domestic, commercial or industrial, will be roughly in balance over the longer run.

A single reversible meter is adequate for Electricity Banking, but in order to maintain comprehensive records of the grid-connected renewable energy generation, we recommend that Electricity Banking customers be required to install a separate meter to record the electricity generated. Again, the advantages of two meters are elaborated further in the next section.
2.3 Category 2 - Net Metering

Category 2 is similar to Category 1, except that the customer is paid for the net electrical energy supplied to the grid. In the simplest form of Net Metering, the customer has a reversible meter and is paid at the retail tariff for any surplus that is produced. This arrangement is generous to the customer, because the utility continues to have to provide capacity backup and network services to evacuate the electricity that is produced, and these services are not paid for when the net surplus is bought at the retail tariff. This arrangement is offered in some countries as an incentive to encourage net metering, but is not acceptable in Kenya, where an additional concern is the loss of contribution of the net metering customers to the ‘pot’ that is used for cross-subsidising poor households.

The on-going Cost of Service (COSS) study will determine the capacity and the energy costs incurred at each voltage level and for each customer category. We recommend that the payment for net metering should be the energy charge for that customer category. Customers would still have to pay the fixed charges, though consideration should be given to this charge being waived during periods when the national reserve margin is inadequate. The idea behind this is that the net meter customer should be rewarded for contributing to reducing the reserve shortfall, which would have to be monitored by ERC.

It is further recommended that net metering from the start be established on a two meter system, that is separate meters for the energy that the customer draws from the grid and for the energy that is supplied to the grid. A single meter would be more in keeping with the ‘simplicity first’ mantra of this study, but in this case separate meters would have several advantages for KPLC:

- Separate meters would allow for a precise estimate to be made of the renewable energy being produced by net meter customers: a single reversible meter would give net balances only.
- Separate meters would allow the customer to be charged at a full rate for the energy consumed, including incorporating the rising block tariff structure. The contribution to the cross-subsidy ‘pot’ would thereby be preserved.
- Separate meters would also make it possible to introduce tradable green certificates, if this was ever thought desirable for Kenya.

2.4 Recommendations and procedures for Categories 1 & 2

We recommend that Electricity Banking (Category 1) be implemented immediately and Net Metering (Category 2) introduced as soon as the COSS study has generated the necessary information to set the net metering tariff for each category of consumer at the level of the energy costs of supplying that category, and has established the rules for indexation.
Electricity Banking (no payments) and Net Metering (payments for surpluses) can be facilitated in a very simple and straightforward manner:

- **Agreement**: a simple form of agreement between the customer and the utility, which is executed at the local KPLC office, will be adequate. Allowable capacity is to be up to the existing capacity customer has with the utility. A pro forma version of the agreement is provided as Annex A2.

- **Light handed regulation**: no formal license is to be required from ERC, but ERC is to be provided with a register of Electricity Banking and Net Metering customers and is to have powers (through a regulation) with regard to safety and access to data.

- **Electricity banking credits**: there should be full ownership of credits by electricity banking customers (i.e., they can carry forward credits indefinitely, and can take their credits with them when moving house or property provided they remain customers of KPLC).

- **Net metering surplus energy**: Net Metering customers are to have separate meters for their purchases from the grid and for the electricity they supply into the grid. They are to be paid on a quarterly basis for surplus energy, at the agreed tariff (equivalent to the level of the energy costs of supplying that category of consumer).

### 2.5 Category 3 - Standardised non-negotiable PPA

Category 3 is the main focus of this study. As already explained in Section 1.3, to minimise up-front and on-going transactions costs for projects of up to 10 MW, there is to be a standardised, non-negotiable PPA, based on fixed FiT values. The projects are to be non-despatchable and will operate on a ‘best endeavours’ basis with the minimum of requirements for penalties to cater for the risk that either the small renewable or the offtaker (KPLC) will fail to perform as planned.

The detailed implications and requirements for Category 3 projects are covered under the task headings in Section 3. Most of the separate deliverables are also fundamentally oriented to providing what is needed to implement renewable projects of less than 10 MW via the standardised non-negotiable PPA mechanism.

**Recommendation**: We recommend that the changes in FiT policy that are captured in the revised August 2012 draft be accepted. These entail the introduction of the Standardised Non-Negotiable PPA, new values for the FiTs from an updated FiT Model, Connection Guidelines for connection and operation of the generators, new application and acceptance Procedures, and the adoption of a Monitoring and Planning Tool by the FiT Committee.
2.6 Larger renewable projects (>10 MW)

Large renewable projects, which will involve the utilisation of unique natural resources, should be developed for the benefit of Kenya as a whole. An efficient way to ensure this outcome is for the Government of Kenya to identify and develop the projects up to some early point in the project cycle and then invite competitive bids from project developers. This principle has already been adopted in respect of large-scale geothermal resources, where GoK has established the Geothermal Development Company (GDC), which undertakes the upstream drilling to identify the resource and then sells on to developers, who have to bid for the sites. This is a useful way of government taking on the upstream development risks and of maximising the value of the national renewable resources that have been identified. Whenever possible, the same principle is to be adopted for other large-scale renewable resources. Careful design of the bidding process is needed in order to ensure that it is successful, an important measure of success being that the chosen project is actually implemented (unless there are adequate bid bonds in place, projects with low bids may be abandoned).

In some cases, a bidding process would not be possible. This applies in particular to some of the wind projects where the proving of the resource has involved substantial investments being made by project sponsors, even though the Ministry of Energy has also invested significantly in wind data collection. In the case of biomass or biogas, often the feedstock is already captive on site or already owned/controlled by a private company or parastatal and a bidding process would not be appropriate.

For such projects, the cut-off of 10 MW for Category 3 needs to be justified, given that it is to some extent arbitrary – it could be set at a somewhat higher or lower level. Taking into account the requirement that the embedded generators be connected to the distribution network, the figure of 10 MW has been chosen in part because this would be the limit for efficient transfer of power over a reasonable distance (such as 10 km). Beyond the 10 MW limit, bigger generators should be connected at higher voltage levels, and the National Control Centre really needs these bigger plants to be despatchable. Once the plants are despatchable, many of the ‘normal’ provisions of a PPA must be restored and there is no longer the basis for a standardised, non-negotiable PPA. In particular, there is need to make provision for compensation to be paid when the plant is not available, and conversely when KPLC lines are down and the electricity being generated cannot be bought.

The remaining element of standardisation is the FiT itself. Under the present FiT policy, solar and small hydro are limited to 10 MW, but a feed-in tariff is offered up to much higher limits for other technologies (40 MW for biogas, 70 MW for geothermal and 100 MW for wind and biomass). We have considered providing fixed FiTs for large projects, but after carefully reviewing the available data for each technology, have concluded that this would be an unnecessarily risky approach. The problem is that there are simply not enough projects to work from to have a reasonable level of confidence about the data that goes into the FiT Model. Offering a FiT that is based on data from a few projects which may or may not be representative would be most unsatisfactory. Once incorporated into a PPA, the FiT...
would be in place for a 20 year period. An inappropriately high tariff would impose a considerable burden on electricity consumers, while an inappropriately low tariff would result in a curtailment of investment at a time when new capacity relieving supply constraints on the system would have significant economic benefits.

The structure of the FiT for a large project might anyway need to be on the basis of a capital component and an energy component, rather than the simple energy only structure of FiTs for small projects. A fairer approach for larger projects is to require that the level and structure of the tariff be set on a project-specific basis. This will involve the use of the standard FiT Model, but with the data inputs that are specific to the project being considered. The US dollar-denominated tariff that is calculated through this approach will therefore be tailor-made to deliver the agreed 18% before tax rate of return on equity (ROE). The standardised FiT based on an ‘average’ project may or may not deliver 18% ROE in an actual project situation. Some projects will have exceptional resources or are located much closer to the grid so that the interconnection cost provision is overly large, and these should do better than 18% ROE. Other projects will be less fortunate, but their sponsors may still decide they are worth pursuing even though the ROE may be projected to be less than 18% even at the planning stage.

What is proposed for the larger projects is an assured 18% ROE before tax. This will reassure developers who have been responding to the existing framework and who may at first be disconcerted to find that a fixed FiT is in future going to be limited to 10 MW. On the KPLC side, there is need to develop the capability to carefully scrutinise and to the extent possible benchmark the proposals for larger projects. Under a system of project-specific FiTs, there is an incentive for proposers to ‘gold plate’ their projects (unnecessarily increase the capital base that forms the basis of the tariff calculation) and submit a longer construction period for the FiT calculation than is justified. The box below provides guidelines on identifying and dealing with the threat of gold plating.

<table>
<thead>
<tr>
<th>Box – Guidelines on identifying and dealing with gold plating</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gold plating of project proposals by project promoters may be attempted through several different channels:</td>
</tr>
<tr>
<td>☐ Inflating expected capital and operating costs</td>
</tr>
<tr>
<td>☐ Inflating expected borrowing costs</td>
</tr>
<tr>
<td>☐ Underestimating the available project leverage, as decreased debt:equity ratios result in lower ultimate returns to equity</td>
</tr>
<tr>
<td>☐ Underestimating load factors</td>
</tr>
</tbody>
</table>

The cost factors vary for different renewables. All have in common that the costs are largely contained in the capital costs. Inflating expected costs can be accomplished through contracts with affiliates for installation and maintenance services: allocation of overhead.
costs and labor rates can make third-party services inflated for reporting purposes. At the construction stage, there can be discounts provided after-the-fact from the invoiced purchase price, in return for volume purchases or prompt payment. There can also be certain equipment vendor incentives above and beyond the base invoice or publicly reported cost. If there is a significant developer that does more than one project, or operates in more than one country, expenses can be allocated to certain projects and not others.

One way to limit this is to have equipment acquisition ranges that are acceptable for purposes of return calculations. Another way to do this is to ask to see pro forma invoices with a certification by the Seller that these are the correct and only pro formas. Although these documents are typically considered confidential, this is getting more common in countries that provide certain renewable energy certificates or other virtual incentives for renewable power. Here, it could be made a condition for eventual receipt of the FiT tariff. Penalties could be linked to receipt of the full FiT value, with reduction going forward in the FiT if there is not transparency up front.

Other than cost, the key variable to change revenue projections is decreasing expected kWh output, in other words decreasing the expected load factor. With PV units, if solar data is available, it is fairly straightforward to model and calculate irradiance and corresponding kWh output by hour for different regions of Kenya. Wind and hydro technologies are less exact. With biomass and biogas projects, the economics are less intermittent and more predictable for purposes of vetting actual output.

Before large unsolicited projects can be accepted, it will have to be confirmed that they can be absorbed into the national grid without technical problems arising – a full despatch and load flow analysis may be required. There are particular concerns about the level of wind capacity on the system, an issue which is being studied in detail as part of the preparations for the 300 MW Turkana wind project.

A further requirement for considering an unsolicited project proposal is that the project should contribute to minimising the overall costs of meeting Kenya’s demand for electricity over the life of the project. In conformity with established national LCPDP procedures, all plants of more than 30 MW (to be replaced by ‘more than 10 MW’) should be put forward as candidate projects, and accepted for investment if they form part of the least cost development sequence that emerges from the runs of the optimisation model. The LCPDP framework can also be used to optimise project design, for example to indicate whether a hydro project should be designed as a relatively low capacity energy project or as a higher capacity peak power project. An example of this is provided by the Karura Hydropower project being promoted by KenGen. The feasibility study identified two configurations, both of which are to be treated as candidates in the LCPDP – a 67 MW energy project or a 90 MW peaking project. The best option to choose cannot be decided in isolation through the feasibility study analysis, but has to be determined in the system-wide context via the LCPDP process.

**Recommendations:** For large projects involving utilisation of significant national renewable resources, we recommend that Government carry out preliminary identification studies and then initiates a solicitation process. For this, a model Request for Proposal (RFP), which includes a model PPA appropriate for the scale of such projects, should be prepared, early and clear information regarding Government intentions should be publicly communicated. A phased approach may
be required in sectors such as wind where many private developers in and outside of the FiT Policy have already invested significant resources. The objective would be to ensure not just a good outcome for electricity consumers but the best use of Kenya’s renewable energy resources. Projects in this category must form part of the national least cost development plan and meet loadflow/dispatch requirements and stability checks. If the Government wants the project to be developed as an IPP, interested developers have to competitively bid for the levelised price. With all the resource information given, and the bidding restricted to competent developers, the real competition will be for the lowest financing costs (best lender for the debt component and the lowest ROE).

Bidding is a solicited process over which Government has control. Care should always be exercised with unsolicited proposals for renewable projects larger than 10 MW. As for the competitive projects, these should only be considered if the projects form part of the national least cost development plan and meet loadflow/dispatch requirements and stability checks. In practical terms, the LCPDP checks will have to be made at a pre-feasibility stage and confirmed when the final costs have been confirmed in the feasibility study. Candidate renewable projects should not be made to wait for the next full iteration of the LCPDP, which has recently been put on a two year cycle. The optimisation models should be regularly run with updated lists of candidate projects (with costs measured in economic terms, that is free of any taxes), but other inputs held the same as in the previous model iteration. A project should be allowed to proceed to feasibility stage (and later to PPA negotiation) if the models show that it would contribute to a reduction in the overall national costs of meeting the current demand growth profile.

As regards tariffs, we recommend that there should be provision to offer fixed tariffs calculated to deliver 18% ROE before tax for unsolicited renewable generation projects greater than 10 MW that meet the LCPDP criterion. There is to be a standardised way of calculating these project-specific tariffs, which is the same as the method used for the FiT calculations for projects with capacities of less than 10 MW. We recommend that the excel model we have developed in this study be used for this purpose – a brief manual for its use is provided here as Annex A3.

The PPA for a despatchable generator has to be more complex that a Category 3 PPA, as there is need to have much more detailed provisions for risks and penalties. The objective is nonetheless to keep the PPA Template as standardised as possible, thereby limiting the time and the transactions costs of the negotiation process. Our team has adapted and modified the standard KPLC PPA template to make it suitable for renewable projects, limiting as far as possible the items which have to remain open for negotiation. This PPA template is submitted with this Final Report as Separate Deliverable 7.
3 Report on TOR tasks

The sections below present the results of work that has been carried out on the various tasks in the TOR. Each section is followed by recommendations, which have been discussed and endorsed at the Final Workshop held on Thursday 19 July.

3.1 Task 1 - Standardised PPAs

3.1.1 Standardised Non-negotiable PPA (Category 3)

A revised draft of the Standardised Non-negotiable PPA, which includes the purchase obligation of the offtaker, is presented as a separate deliverable attached to this report. It is based on a careful assessment our team of the following PPAs and a distillation of what is most suitable for each subject in the PPA:

- Tanzania Standard SPPA (Standardised Power Purchase Agreement for Purchase of Grid-connected Capacity and Associated Electrical Energy for the Republic of Tanzania);
- Sri Lanka SPPA (The standardised Small Power Purchase Agreement for the sale of Non-Conventional Renewable Energy-Based Power Plants for the Democratic Socialist Republic of Sri Lanka);
- Gura Power SPPA (A Power Purchase Agreement between a tea factory in Kenya (Gura Power Company Limited) and Kenya Power and Lighting Company Limited (KPLC) for a five megawatt small hydroelectric power generation plant under the Feed-in-Tariffs Policy);
- Stanbic Draft SPPA v.3 (A sample PPA from an infrastructure finance provider, Stanbic Bank).

The Standardised Non-negotiable PPA was presented at the Mid Term Workshop and again at the Final Workshop and the final version incorporates all the comments and concerns raised. It was drafted by the team’s lawyer, Catherine Kola. Comments have also been provided by Professor Steve Ferrey, an international expert in PPAs, who worked with Dr Tilak Siyambalapitiya on the standardised PPA in Tanzania.

In response to inputs from stakeholders, the Kenyan standardised non-negotiable PPA has some key provisions intended to give comfort to those financing renewable projects, which are not present in the Tanzanian and Sri Lankan standardised PPAs. These provisions, relating to payments for Deemed Energy in the event of a prolonged KPLC failure to receive supplies, and the Transfer Amount in event of premature project termination, deserve particular attention. (Paras 6.14, 6.16, 11.3 and Appendix F refer).

The final version of the PPA allows the PPA signatory to be a limited partnership incorporated under the Limited Partnerships Act, Chapter 30 of the Laws of Kenya.
Communal development of renewable projects, using the limited partnership framework, has immense potential in Kenya. Much of the early success of renewables in Denmark is attributed to the partnership approach – see box on the Middelgrunden Wind Turbine Partnership in Annex A1.2.

3.1.2 Standardised Negotiable PPA (Category 4)

For renewable projects larger than 10 MW, a more conventional PPA, with take-or-pay provisions, will be appropriate, but the size of the projects and the need to streamline procedures still dictates that the PPA should have as many standardised, non-negotiable clauses as possible. The negotiable clause mainly have to do with the dispatch arrangements and payments for either party (seller or buyer) failing to meet their obligations.

A draft of the Standardised Negotiable PPA was presented at the Final Workshop and is now included as Separate Deliverable 7. It is based on the previously developed ERC model PPA, examination of existing PPAs signed by KPLC, and reference to the Standardised Renewable Energy PPA for Jamaica. It has been further refined to include comments given at the workshop.

3.1.3 Task 1 Recommendations

It is recommended that the Standardised Non-Negotiable PPA, which is being made available with this report as the Separate Deliverable 1, be made available immediately for PPAs being signed for projects of less than 10 MW.

Similarly, it is recommended that the Standardised Negotiable PPA be adopted for projects where the capacity is larger than 10 MW. Although there will still be time and transactions costs involved in finalising the PPAs for larger projects, adoption of the template that has been provided will help to reduce these to a minimum.

3.2 Task 2 - Feed-in Tariffs

3.2.1 Key elements of Feed-in Tariff Policy

The starting point for the FiT concept is the idea of offering a standardised rate for the purchase of electricity which will be remunerative enough for developers to invest in a renewable energy generator which feeds into the grid. The FiT value is the result of a calculation made on the basis of assumed ‘average’ conditions which for those conditions would produce some agreed level of rate of return on equity. ‘Standardised’ implies that the tariff that is offered is not tailor-made to each project which is financed under the FiT. Projects which, relative to the assumed average conditions, have better resources, are closer to the grid, achieve lower capital and operating costs will achieve higher rates of return. Conversely, less favourably endowed projects will receive lower rates, but may still go ahead of the project promoters are willing to accept a lower rate of return than the benchmark set in the FiT calculation.
<table>
<thead>
<tr>
<th>#</th>
<th>Policy Element</th>
<th>Comment / Justification</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>FiT values are calculated on a <em>technology-specific basis</em></td>
<td>The alternative of avoided cost-based FiTs would give windfall profits to certain technologies.</td>
</tr>
<tr>
<td>2</td>
<td>Where the calculated value exceeds the generation LRMC, as calculated in the LCPD process, the FiT that is offered for that technology will be the LRMC (currently 11.86 USc/kWh).</td>
<td>The LRMC cap on FiT values means that electricity consumers will not be financially penalised through the introduction of small-scale renewables onto the grid. While the situation in the power sector at present is such that any new capacity that is brought on will help to reduce the power deficit, reserve margins will have been restored to reasonable levels by as early as 2014.</td>
</tr>
<tr>
<td>3</td>
<td>The FiT is denominated in <em>US dollars</em> or alternatively Euros or Kenya Shillings as agreed.</td>
<td>A hard currency denominated tariff reflects the normal capital and operational cost and financing structure of RE projects in Kenya. A pass-through charge neutralises any impact on the offtaker.</td>
</tr>
<tr>
<td>4</td>
<td>The FiT is calculated for certain specific capacities, with a <em>linear interpolation</em> being used to set the FiT based on the actual capacity of the project</td>
<td>Linear interpolation is appropriate where technologies exhibit large economies of scale. Linear interpolation rather than broad size categories avoids providing incentives for developers to opt for smaller capacities than they could, wasting national RE resources.</td>
</tr>
<tr>
<td>5</td>
<td>The project developer can choose a single FiT value to apply for the duration of the PPA <em>(the Standard FiT option)</em> or can choose to have a FiT which is higher in the early years and drops to a (fixed) lower value thereafter <em>(the Front Loaded FiT option)</em></td>
<td>The Front Loaded option is calculated to give approximately the same ROE to the investor, but permits higher cash flows in early years so that the DSCR requirements of the banks can be met. Banks may not lend under the Standard FiT if this means low DSCRs in early years. The choice is offered only at the start of the project and cannot be changed thereafter.</td>
</tr>
<tr>
<td>6</td>
<td>The FiT applicable at the time a PPA is signed is the <em>fixed value</em> which will apply over the 20 year life of the PPA, except for that the O&amp;M component of the FiT will be subject to <em>annual indexation</em> using the Consumer Price Index corresponding to the currency in which the tariff is denominated (<em>i.e. US CPI for a US denominated FiT)</em></td>
<td>Due to a current lack of local expertise and equipment for most project technologies, a large portion of O&amp;M costs will be tied to imported goods and services. The investor is offered indexation on the full O&amp;M component, denominated in US dollars, at the US CPI rate of inflation.</td>
</tr>
</tbody>
</table>

In many countries, the FiT calculations are made on the basis of the avoided costs of fossil fuel generation, and a single FiT applies for all renewable technologies. This
gives a big incentive for investment in the lower cost renewable technologies. In Kenya, it has become established practice that the FiT calculation is based on a technology-specific analysis, giving rise to a range of FiT values which are calculated to deliver the same agreed rate of return on equity. This study has endorsed and expanded upon the technology-specific, average-cost approach.

Following extensive discussions during the course of the study, the main high level elements of FiT policy in Kenya which have emerged are summarised in Table 3 above.

For off-grid projects, we argue in Section 3.5 (Task 5) that there may be (limited) scope for renewables, particular solar PV. In this case, the cap on the calculated FiT is not applied, given that the avoided cost of diesel generation is significantly higher (currently in excess of 30 USc/kWh) than the cost of renewables.

3.2.2 Revised FiT Model and the data assumptions made

Model structure

Building on the cash flow approach already adopted by the FiT Committee in the past, we have developed a refined model that has the following features:

- a single sheet for the data inputs;
- a calculation sheet with a drop-down menu to choose the technology;
- an outputs sheet where the full set of results for all technologies can be recorded by running some simple macros.

The structure of the model is illustrated in the Figure 2 below.

The calculation sheet provides a full cash flow analysis over the construction period (2 years, except 1 year for solar) and the PPA period (20 years as default, but this can be changed). The ‘bottom line’ is the return to the equity investor. The FiT is calculated as the value of the tariff needed to provide the required ROE. A similar calculation is required to calculate the two values for the Front Loaded FiT option,
except that it also ensures a minimum Debt Service Coverage Ratio (DSCR)\(^2\) is achieved.

**Generic assumptions**

The generic assumptions (those not associated with a particular technology) which are made in the final version of the model are summarised in Table 4.

<table>
<thead>
<tr>
<th>Item</th>
<th>Value</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>FiT duration</td>
<td>20 years</td>
<td>This is set in the PPA, but the model still has the flexibility to calculate FiTs of a duration up to 50 years.</td>
</tr>
<tr>
<td>Cost of debt</td>
<td>8.0%</td>
<td>This assumes some concessional financing (which will typically vary between 6 and 10%) on the basis that there is significant amounts currently available in Kenya and more potentially becoming available in the future. The estimate can be revised upwards towards commercial lending terms once concessional financing is no longer available in Kenya.</td>
</tr>
<tr>
<td>Loan period</td>
<td>10 years</td>
<td>Loan periods are likely to be between 8-12 years for most investments receiving concessional financing. Strictly commercial terms may be less and therefore (as above) this estimate should be revised once concessional financing is no longer available in Kenya.</td>
</tr>
<tr>
<td>Cost of equity</td>
<td>18% pre-tax</td>
<td>Investors have been calling for 18% post tax to be used in setting FiTs. Given current depreciation allowances and other tax breaks for energy investments and or renewables, we expect that the realised post-tax return of equity will be at least 18% for the first 10 years of the project.</td>
</tr>
<tr>
<td>Initial gearing</td>
<td>70%</td>
<td>The share of debt in investments is expected to be between 60% and 80%.</td>
</tr>
<tr>
<td>Residual value</td>
<td>-</td>
<td>No residual value is included. Most renewable technologies have an asset life of around 20 years and any revenues post-20 years are not especially significant once discounting is applied. Post PPA arrangements will take account of residual value.</td>
</tr>
</tbody>
</table>

\(^2\) The DSCR indicates the extent to which project cash flows cover debt servicing requirements. More specifically, it is calculated as net operating cash flows (after interest paid) divided by the principal to be paid on loan in that year. The DSCR provides only an approximate indication given that the model forecasts cash flows on a pre-tax basis – actual tax paid will vary significantly from year to year depending on the tax laws of the day.
Technology specific assumptions

To estimate load factors and the costs of different renewable technologies for different size categories we use data from prospective renewable energy investors in Kenya. In-country experts have reviewed and commented on our estimates, including staff at the RTAP project, housed in the Kenya Association of Manufacturers, who have reviewed over 66 prospective renewable projects in Kenya. We have also used studies where available, for example the GIZ study on biogas in Kenya. The reliability of our estimates varies somewhat by technology – we have data on over 30 different prospective hydro projects to rely on, but significantly fewer for the other technologies with around 5 for wind and only a handful for biomass, biogas, geothermal, and solar. The assumptions should be updated and refined based on data from actual investments in Kenya as it becomes available.

We further describe our technology-specific assumptions as follows:

- **Reference capacity size** – This is the size of the generator that we assume when estimating load factors and cost inputs. For wind, geothermal, and solar we use 5 MW because it is the midpoint of the 0-10 MW capacity range. Economies of scale in this size range is low for these technologies so the chosen reference capacity is not especially significant. For biogas, biomass, and hydro we use different reference capacities as there is strong economies of scale. For the 0-1 MW category we use a reference of 1 MW, given that we want to avoid encouraging costly micro-generators. For the 0-10 MW range we use a reference of 10 MW, as tariffs are calculated as linear interpolation between the FiTs at 1 MW and 10 MW.

- **Load factors** – The load factors we assume are shown in Figure 3 below, alongside approximate averages observed in Europe. It shows that most load factors are broadly in line with those in Europe, although wind and hydro load factors in Kenya are particularly high by international standards, reflecting the good wind flow and hydrology in Kenya.

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1 The high load factors in Kenya may also reflect that fact that many European hydro load factors are based on storage dams with lower capacity factors but higher energy output/ability to meet peaking demand.
Construction costs – The estimates we use vary between $2,500 and $6,000 per kW of installed capacity by technology. These estimates include the costs of feasibility studies, development of the site, and construction of the generating facility. Costs also include any applicable taxes and waivers (VAT, import duties etc.). We explicitly add interest during construction on to both construction and transmission costs in the model. Figure 4 below shows total costs (including transmission costs but excluding interest during construction) alongside approximate averages observed in Europe. One observation is that the construction costs of wind are significantly higher in Kenya than Europe owing primarily to the fact that specialized transport and installation equipment is not normally available in the country. Concrete and steel prices are also significantly higher in Kenya. By contrast biomass costs are much lower, likely due to the source of equipment used in biomass power plants in Kenya.

Transmission costs - Transmission line costs are based on an assumption of 10km of 33kv line for every technology at a cost of $50,000 per km. Substation costs are based on assumed costs of 0.5m for a 1 MVA substation, 1.0m for a 5 MVA substation, and 1.5m for a 10 MVA substation.
- **Outlay of investment costs** - All technologies are assumed to have a two year construction period (the percentage in the first year varies for each technology between 45% and 60%), with the exception of solar which is assumed to have a one year construction period.

- **Fixed operating costs** – We separate operating costs out into fixed and variable components in the model. Fixed operating costs are shown in Figure 5 below.
Variable operating costs – The majority of our assumed variable operating costs relate to repairs and maintenance rather than fuel costs. The only technology that we assume fuel costs for is grown biomass, at a cost of $41.3 per MWh. Waste biomass uses waste that is produced as a by-product and therefore has little or no value, for example bagasse from sugar plantations. Variable operating costs are shown in Figure 6 below.
3.2.3 Proposed FiT values

Standard FiTs

The Standard FiTs calculated by the model, using the data assumptions and approaches described in the previous section, are summarised in Figure 7 below. The policy that the offered FiTs must not exceed the LRMC implies that the standard FiTs for wind, geothermal, biogas, and solar will be capped at 11.86 c/kWh, alongside grown biomass and hydro which will be capped at certain sizes (depending on the linear interpolation between 1 and 10 MW).

![Figure 7 Standard FiTs]

Front Loaded FiTs

The Front Loaded tariff is calculated to improve debt service coverage while ensuring that the investor’s return on equity is the same as under the standard tariff – in other words, the initial increase in the tariff is offset by a commensurate decrease in the latter years.

To achieve a minimum debt service coverage ratio of approximately 1.5, the Front Loaded tariff is equal to the Standard Tariff multiplied by the following adjustments:

- **Years 1 to 10** = 110% (i.e. 10% above the standard tariff).
- **Years 11 to 20** = 50% (i.e. 50% below the standard tariff)
These adjustments ensure that a return of equity of approximately 18% is still achieved.¹

The Front Loaded FiT for wind is shown in Figure 8 below. Note that the Standard FiT is capped at 11.86 and the front load adjustments of 110% and 50% are applied to this capped figure.

![Figure 8 Front Loaded FiT - wind](image)

Based on the existing cost inputs and parameters, achieving a minimum DSCR of 1.7 or greater cannot be achieved through a Front Loaded tariff, as the tariff in years 11 to 20 would need to be negative to make up for the large initial increase. This is highly sensitive to assumptions about lending terms.

**Linear tariffs**

Linear tariffs are used for technologies which exhibit strong economies of scale and therefore the tariff should depend on the size of the installation, otherwise larger installations will make windfall profits. Linear tariffs are preferable to fixed size categories which distort investor incentives when sizing their generating plant.

The equations for linear FiTs (before the cap is applied) are as follows²:

- **Biomass – Grown**: \(15.17 - 0.372 \times \text{capacity}\)

¹ The exact adjustments required to achieve the minimum DSCR do differ somewhat by technology, but not significantly enough to warrant the complexity of varying adjustments by technology. At these standardised adjustments all technology categories are within 1 percentage point of the target return on equity and a minimum DSCR of 1.5 or greater is achieved in all cases.

² The slope of the line is calculated as the difference between the 10 MW FiT and the 1 MW FiT, divided by the difference in capacity sizes (i.e. 10 and 1 MW). The intercept is calculated as the FiT (either the 1MW or 10 MW FiT) less the calculated slope multiplied by its capacity size (1 or 10 MW).
Biomass - Waste: 10.88 - 0.37*capacity
Biogas: 16.78 - 0.424*capacity
Hydro: 14.05 - 0.438*capacity

FiTs are to be calculated using 1 MW increments of installed capacity. In other words, the calculated FiT for a 9.4 MW generator is based on 9 MW, whereas a 1.6 MW generator has a calculated FiT based on the 2 MW increment. An illustration of the linear tariff for hydro generators between 1 and 10 MW is shown in the figure below.

**Figure 9 Linear tariffs – hydro 1-10 MW**

**Indexed Component**

As discussed earlier in this section, a US dollar FiT will be subject to annual indexation using the US Consumer Price Index. Only the portion of the tariff that relates to operating costs is indexed. The Indexed Component as a percentage of the Standard FiT is shown in Figure 10 below.

---

1 The Indexed Component is calculated as the Standard FiT (after the cap is applied) multiplied by operating costs as a percentage of the calculated (uncapped) FiT.
Figure 10 Indexed component as a percentage of Standard FiT
Summary of FiT values

Our proposed FiTs are summarised in Table 5.

<table>
<thead>
<tr>
<th>Technology</th>
<th>Wind 0-10MW</th>
<th>Biomass - Grown 0-1MW</th>
<th>Biomass - Grown 1-10MW</th>
<th>Biomass - Waste 0-1MW</th>
<th>Biomass - Waste 1-10MW</th>
<th>Geo thermal 0-10MW</th>
<th>Biogas 0-1MW</th>
<th>Biogas 1-10MW</th>
<th>Solar 0-10MW</th>
<th>Hydro 0-1MW</th>
<th>Hydro 1-10MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Calculated Standard FiT (c/kWh)</td>
<td>18.21</td>
<td>14.80</td>
<td>15.17 - 0.372* capacity</td>
<td>10.51</td>
<td>10.88 - 0.37* capacity</td>
<td>12.31</td>
<td>16.36</td>
<td>16.78 - 0.424* capacity</td>
<td>26.61</td>
<td>13.61</td>
<td>14.05 - 0.438* capacity</td>
</tr>
<tr>
<td>LRMC cap on Standard FiT (c/kWh)</td>
<td>11.86</td>
<td>11.86</td>
<td>11.86</td>
<td>11.86</td>
<td>11.86</td>
<td>11.86</td>
<td>11.86</td>
<td>11.86</td>
<td>11.86</td>
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<td>11.86</td>
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<tr>
<td>Front Loaded adjustment, years 1-10</td>
<td>110%</td>
<td>110%</td>
<td>110%</td>
<td>110%</td>
<td>110%</td>
<td>110%</td>
<td>110%</td>
<td>110%</td>
<td>110%</td>
<td>110%</td>
<td>110%</td>
</tr>
<tr>
<td>Front Loaded adjustment, years 11-20</td>
<td>50%</td>
<td>50%</td>
<td>50%</td>
<td>50%</td>
<td>50%</td>
<td>50%</td>
<td>50%</td>
<td>50%</td>
<td>50%</td>
<td>50%</td>
<td>50%</td>
</tr>
<tr>
<td>Indexed Component as %</td>
<td>11%</td>
<td>51%</td>
<td>51%</td>
<td>22%</td>
<td>22%</td>
<td>32%</td>
<td>21%</td>
<td>21%</td>
<td>8%</td>
<td>14%</td>
<td>14%</td>
</tr>
</tbody>
</table>
The resulting FiT values in 1 MW capacity increments are summarised in the tables below.

### Table 6 Standard FiT by capacity increment

<table>
<thead>
<tr>
<th>Installed capacity (MW)</th>
<th>Wind</th>
<th>Biomass - Grown</th>
<th>Biomass - Waste</th>
<th>Geothermal</th>
<th>Biogas</th>
<th>Solar</th>
<th>Hydro</th>
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<tbody>
<tr>
<td>1</td>
<td>11.86</td>
<td>11.86</td>
<td>10.51</td>
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<tr>
<td>2</td>
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<td>11.86</td>
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<td>3</td>
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<td>11.86</td>
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<td>4</td>
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<td>11.86</td>
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<td>11.86</td>
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<td>11.86</td>
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<td>11.86</td>
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<td>7.18</td>
<td>11.86</td>
<td>11.86</td>
<td>11.86</td>
<td>11.42</td>
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</tbody>
</table>

### Table 7 Front Loaded FiT by capacity increment

<table>
<thead>
<tr>
<th>Installed capacity (MW)</th>
<th>Wind</th>
<th>Biomass - Grown</th>
<th>Biomass - Waste</th>
<th>Geothermal</th>
<th>Biogas</th>
<th>Solar</th>
<th>Hydro</th>
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<tr>
<td>1</td>
<td>13.05</td>
<td>13.05</td>
<td>11.56</td>
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<td>12.56</td>
<td>13.05</td>
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<tr>
<td>7</td>
<td>13.05</td>
<td>13.05</td>
<td>9.12</td>
<td>13.05</td>
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<td>12.08</td>
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<td>8</td>
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<td>13.05</td>
<td>8.71</td>
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<td>10</td>
<td>13.05</td>
<td>12.60</td>
<td>7.90</td>
<td>13.05</td>
<td>13.05</td>
<td>10.64</td>
<td>13.05</td>
</tr>
</tbody>
</table>
### Comparison with international FiT values

The figures below show our proposed Standard FiT values for Kenya (after caps are applied) in comparison with those used internationally. We do caution against direct comparison between FiTs in different countries as they will vary significantly depending on country-specific factors that affect load-factors, costs, and cost of capital. The FiT duration also has a significant effect. Furthermore, FiTs are sometimes set on the basis of policy reasons (rather than based on costs alone) and the amount of capacity eligible for FiTs may be capped at a very low level.

We have not included a comparison of solar FiTs internationally, given how quickly the costs are coming down (and therefore many FiTs around the world quickly become outdated) and the fact that many countries are now reviewing or removing solar eligibility.
Figure 11 Comparison with FiTs internationally - wind

Figure 12 Comparison with FiTs internationally - biomass
3.2.5 Task 2 Recommendations

Our recommendations on the key policy provisions that should be adopted are encapsulated in the Revised Draft FiT Policy which is attached to this report as Separate Deliverable 1. They include the following:

- Technology-specific FiT values are offered for all small-scale renewable projects (capacity up to 10 MW).
- FiT values (for grid-connected projects) are capped at the national LRMC as calculated as part of the Least Cost Power Development Plan process.
- Developer can choose a single FiT value to apply for the duration of the PPA (the Standard FiT option) or can choose to have a FiT which is higher in the early years and drops to a (fixed) lower value thereafter (the Front Loaded FiT option).
- The FiT value/s (applicable at the time a PPA is signed) is fixed for the life of the PPA, except for the O&M component (the Indexed Component) of the FiT which will be indexed to inflation.
- FiTs for small renewable projects (up to 10 MW) do not differentiate between firm and non-firm energy.
- FiT values vary depending on the capacity of the power plant for biomass, biogas, and hydro given that these technologies exhibit strong...
economies of scale. Linear interpolation of tariffs between 1 and 10 MW is used to prevent distorting developer’s decisions about the size of plant to install. FiTs apply to the closest 1 MW increment of installed capacity.

- Different FiTs are offered for two different types of biomass – waste and grown. This is because ‘Biomass - Waste’ plants using agricultural waste (including bagasse) or municipal waste have zero or low fuel cost, whereas ‘Biomass - Grown’ plants using agricultural products (grown specifically for the purpose of burning as fuel for power plants), bio-fuels and fuel wood do have significant fuel costs.

- The cost inputs and assumptions used to calculate FiT values are based on past and planned small renewable projects in Kenya, after review and comparison with costs internationally.

We also recommend that the new FiT Model be used to update and revise FiT values in the future. They should be updated on a semi-regular basis (every 2 to 3 years) to reflect:

- Changes in the underlying cost of technologies. For example solar PV investment costs have been decreasing rapidly in recent years, by as much as 20% per year, although the calculated FiT for solar is unlikely to fall below the LRMC cap any time soon.

- The availability of renewable resources in Kenya. For example, once all the very good hydro sites are developed the assumed load factor may need to be decreased.

- The availability of input data. As new renewable investments are made, data on the actual costs of investments and the amount of energy supplied will help refine the assumptions in the model.

- Changes in the LRMC of electricity. The cap (and therefore FiTs) should be adjusted each time it is updated as part of the LCPD process.

Policy makers should make clear that regular adjustments to FiTs will be based on the same methodology and model, thereby avoiding creating too much uncertainty for prospective investors. The FiT Policy itself need not be automatically reviewed on a regular basis.

The FiT Model and the methodology it applies should also be used to calculate FiTs for renewable investments larger than 10 MW and used for calculating tariffs for off-grid arrangements. This FiT Model has the functionality to do so.
3.3 Task 3 - Engineering standards

3.3.1 Guidelines for Grid Connection of Small Renewable Generators

Standalone Deliverable 2 is entitled *Guidelines for the Connection of Small Renewable Generating Plant to the Electrical Distribution Networks of Kenya*. The purpose of the Guidelines is to establish procedures and equipment to protect personnel, equipment, and network operator’s systems from any harmful effects arising from connection and operation of generators supplied and operated by others. They are intended to inform the owners of generators of the host network operator’s requirements for Generating Plant being connected to its System.

The main focus of the Guidelines is on the embedded Category 3 generators. An embedded generator is a single generator or a group of generating plant with a total export capacity below 10 MW, connected to a distribution network at 33 kV or below and not under the direct control of the systems operator. The Guidelines also, however, deal with requirements for Category 1 and 2 generators (Electricity Banking and Net Metering).

The Guidelines provide a comprehensive analysis of issues that may arise when connecting embedded generators to distribution networks in Kenya, dealing with types of interconnection, voltages, studies required, protection requirements, and the testing and certification procedure of embedded generators. These guidelines are for information only and are subsidiary to the mandatory requirements governing the connection of Generators set out in the Kenyan Grid Code (once this is formally adopted).

3.3.2 Guidelines content

The introductory sections of the Guidelines deal with the scope, definitions of technical terms and legal aspects. The substantive sections are as follows:

- **Capacity limits and connection voltage**
  
  This short section sets out the limits on generator capacity which can normally be accommodated at each system voltage.

- **Connection application**
  
  This section sets out the information exchange between the prospective generator and the host network operator.

- **Connection arrangements**
  
  This section describes the different operational modes of generating plant at each connection, focussing primarily on long-term parallel operation i.e. operation principally for exporting energy to the grid.
Generating plant connection, design and operation

This section explains the quality of supply parameters within which the network operator controls his system. Generators must support the safe and secure operation of the network.

Protection

This section gives details of the protection systems which must be in place and tested prior to energisation such that generators can assist in the management of disturbances on the network. This section forms a major part of the Guidelines.

Earthing

Appropriate earthing is a critical safety issue. The different earthing arrangements for HV and LV connected generators is discussed.

Installation, operation and control interface

The installation is largely covered by local legislation and international standards. It is important that both the equipment and its installation are compliant. Use of a Site Responsibility Schedule agreed between the network operator and the generator is recommended.

Testing and commissioning

There are significant differences in the testing and commissioning processes between very small generating plant, where type testing and approval applies, and larger systems where site-specific testing is required.

Reference standards (provided as an Appendix)

These are provided as a guide to UK/European approved standards.

The Guidelines are based on internationally recognised standards which have been adapted to the specific circumstances of Kenya and includes a reference table for UK and European standards. They also include example line diagrams.

Task 3 Recommendations

The Guidelines were discussed at the Final Workshop and at the Technical Training Session held the next day, and some further modifications have been introduced to respond to issues raised. The Connection Guidelines are now ready to be immediately adopted.
3.4 Task 4 - Grid integration – operations

3.4.1 Operational integration of small renewables

When considering a generator from an operational information perspective there are three factors to consider:

- How big is it?
- How predictable is it?
- Can it be controlled?
  - Is this an accurate control of its output; or
  - Just the ability to shut it down in an emergency?

For systems operators, the worst case is a large uncontrollable and unpredictable generator. A fully controllable generator is ideal, while a predictable generator is acceptable.

At the Mid Term report stage, we considered the above questions for generators of up to 100 MW and discussed the implications of a growing share of national demand being met from large-scale renewables, with particular attention to wind. This discussion was necessarily at a rather high level, because we have not had sight of the detailed load flow and stability studies which have been carried out in connection with the 350 MW Lake Turkana project.

Given that agreement emerged to limit the FiT mechanism to embedded generators of less than 10 MW, the room for manoeuvre of the system operators in relation to the questions in the first paragraph is sharply reduced. The embedded, non-despatchable generators are not controllable and not individually predictable but once experience is gained, become reasonably predictable in aggregate. However, some limit needs to be set on non-despatchable capacity, and a figure of 10% of maximum demand is proposed. This is discussed further in the next sub-section.

For a renewable energy project with a capacity of more than 10 MW, we are recommending (see Section 2.6) that it be permitted to go ahead with a tailor-made tariff only if it contributes to the least cost power development sequence and passes load flow and stability tests. There is thus no need to specify an overall cap on any particular technology type, because each project that is put forward will be examined in relation to the existing and upcoming generation mix. The approach recommended will instead allow the continuous reassessment of the ability of the grid to absorb increasing quantities of specific renewable resources, notably wind.

Besides the systems operator, concerns about the absorption of increasing numbers of small renewable generators have also been raised by existing electricity users, who fear that the embedded generators may exacerbate the already significant stability and voltage problems with which the KPLC distribution system is plagued. In addressing these concerns, it has to be noted that there may occasionally be
specific local circumstances where problems could occur, but in general it is likely that the embedded generators will improve conditions on the distribution lines rather than worsening them. In particular, generators located at the far end of long distribution lines will help to provide voltage support on those lines.

### 3.4.2 Task 4 Recommendations

For the embedded, non-despatchable Category 3 generators, we recommend that an aggregate capacity limit of 10% of system-wide maximum demand be set. Setting the limit in this way allows the absolute number of MW of embedded capacity to grow in tandem with overall system growth.

The figure of 10% is at this stage somewhat arbitrary, but is a level with which the National Control Centre feels comfortable and is the level achieved in Sri Lanka without any technical problems arising. As experience is gained, the 10% figure should be reviewed. The Monitoring and Planning Tool (see Task 6) will be used to monitor the growth in total installed capacity of the embedded generators. When this approaches the 10% limit, and if there is at that time a significant pipeline of small renewable projects which would take the total over 10%, we would recommend that a comprehensive study should then be carried out to examine whether a higher level of embedded capacity could be accommodated.

### 3.5 Task 5 - Isolated grids

#### 3.5.1 The load characteristics of isolated grids

To date, there is approximately 18 MW of installed off-grid capacity, which is operated mainly by KPLC. The basic generation is mostly small diesels at present, and hence the variable operating cost of these grids is high (reportedly between 35 USc/kWh and over 60 USc/kWh. However customers on these grids are charged at national tariffs, so there is a significant cross subsidy in place. The tariff mechanism is such that all grid-connected customers contribute to subsidising the off-grid customers.

The heavy subsidies provide a prima facia case for examining whether some of the diesel generation can be replaced by renewables. The immediate problems that are faced, however, are as follows:

- The scheme size is small, with an average of around less than 1,000 kW of installed capacity. Maximum demand is generally much lower than this, the average being 350 kW. Annual load factors are very low (around 15-20%), as are daily load factors (very low demand at night). While some of the isolated grids have fairly substantial population growth rates indicating increased future demand, the more important isolated grids will likely become main grid connected sooner rather than later. For example, the two largest isolated grids, Garissa and Lamu, with daily demand in the range of 2-4 MW, are planned to be connected to the main grid by 2015/16. Moyale is being connected to Ethiopia,
Marsabit is on the Kenya-Ethiopia 400 kV interconnector route and Wajir will likely be targeted after Garissa is reached by the main grid.

- The isolated grids are generally in very dry parts of the country, far away from the mini-hydro areas or areas where there are significant agricultural residues for biomass plants. Similarly, dedicated grown biomass for biodiesel would only be possible at two or three of the isolated grids. In areas with large pastoralist communities, livestock dung for biogas is not considered due to uncertainty over availability of feedstock supply. Geothermal resources may in theory be available for the isolated grids in the northern Rift Valley, but it is not considered viable to assess and exploit these on a small scale. Tidal, wave or ocean current energy could be a solution for the coastal isolated grids, but costs are not known and there are no serious plans to deploy such technologies in Kenya to date.

- The remaining options are wind, which will be expensive due to lack of economies of scale, and of uncertain value due to energy variability, and solar PV. Without expensive battery storage, solar PV is of limited value because the main demand period is at night.

To illustrate, see Figure 14, which is the daily load curve for the Marsabit isolated grid (one sample day in July 2008 as provided by Kenya Power for the Rural Electrification Master Plan update). On that day, the total demand was about 30% higher than the average demand in 2008. Nevertheless the curve is considered as typical and representative for Marsabit. It is compared with forecasted wind turbine generation. Since then, the wind turbines have been installed and commissioned, but it is not known how their actual performance compares with this forecast. The relevant aspect is the yellow line that indicates the daily demand curve at the Marsabit isolated grid.
In order to ensure security of supply, diesels will still be necessary, so the issue is whether hybrid systems, with renewables playing some role in reducing the diesel consumption, can be made viable. Through retrofitting wind and solar, the Government of Kenya has taken the initiative in developing pilot hybrid projects. In Marsabit, for example, which has maximum demand of 600 kW, 500 kW of wind has been installed alongside 4 diesel generators with a capacity range of 120 kW to 600 kW. In Hola, which has a maximum demand of 280 kW, 60 kW of solar PV has been installed alongside 2 diesel generators each with a capacity of 400 kW. Habaswein has 30 kW solar PV array to complement the 360 kW of diesel and in Merti a 10 kW solar system is integrated with the 128 kW of diesel.

The preferred approach to small scale renewables that has been developed in this study – of RE generators operating on a must run, must take basis – is possible in the national grid (at least up to some proportion of maximum demand, this initially being set at 10%), but is not tenable in a small system of less than 1 MW. If the renewable generator is designed to have a capacity larger than the daytime demand trough in the isolated system, there would be times when the renewable capacity would have to be shed. Conversely, generation may sometimes be unexpectedly inadequate, for example, in a solar system there may be problems of low afternoon generation due to overheating, although fortunately in many locations wind speeds also pick up in the afternoon, providing useful cooling. To date the Kenya Power off-grid stations department reports no issues with the newly integrated solar PV systems, although these were only commissioned recently. In a wind hybrid, diesel will have to be kept in operation to cover the risk of the wind generation tripping, in particular the case where the trip is due to too high a wind speed. When a wind trip occurs there is a significant shock to the diesels – the governors must be correctly designed to pick-up quickly (ie, electronic governors, not pneumatic ones).

The detailed management that is required to achieve reliable and least cost operation of a small isolated hybrid system does not preclude a role for renewable IPPs, but makes it impossible to supply a simple integration formula that would work in all circumstances. In the face of these realities, the approach that the Government has been advocating, of offering centres to private operators on a concession basis, with the expectation that these be run as hybrid systems, seems very relevant at this juncture. PPP or ESCO approach rather than IPP is the best way to go, being relevant to the small system size.

A PPP approach removes the need for government to micro-manage the penetration of renewables into isolated grid supply and we understand that the Ministry of Energy has commissioned a separate study to investigate this possibility. The operators are left to make both the investment and the despatch decisions. The bid could be designed in different ways to achieve efficiency and cost-effectiveness, an obvious approach being bids based on the lowest subsidy required to achieve certain levels of connection and performance standards in electricity supply, with penalties applying for failure to meet the targets. Hopefully the bids would be sufficiently competitive for the subsidy level to be significantly less than the level projected under the current KPLC/Kengen predominantly diesel operations. The targets should not be impossibly stringent, as achievable targets would give an incentive for the winning operator to outperform the targets and thereby increase profitability above the levels expected at the bid acceptance stage.
The very high costs of diesel in remote locations should be sufficient to ensure that the concessionaires will invest in renewables and run the facilities on a hybrid basis. Furthermore, the Ministry of Energy and Rural Electrification Authority have budgeted plans to incorporate solar PV in more of the existing and new isolated grids, so by the time a concessioning framework is in place more renewable assets will likely be operational. However, some sort of additional incentive for renewables could be added, such as a cash payment for the residual value of well-maintained renewable generators.

3.5.2 Task 5 Recommendations

Concessioning

We recommend that one or more centres which are not soon to be absorbed into the national grid be packaged as concessions and offered to private operators on a competitive basis. These would be pilot projects and one of the concession conditions should be that concessionaires provide data on the capital and operating costs of the different elements of the system, and document how the systems have actually been operated in practice to meet demand.

In planning for concessioning, important lessons can be learned from Kenyan and regional experience:

- Mpeketoni isolated grid in coastal Kenya, which was privately operated but later taken over by Kenya power due to poor economic viability, and where there were plans to use part biodiesel but the existing gensets only use diesel.

- Mtwara isolated grid and distribution network in southeastern Tanzania, where a private natural gas IPP was given a generation concession and built a 12 MW power plant but different expectations regarding licencing and grid extension resulted in delays and the IPP exiting and the Tanzanian government utility buying the project.

- West Nile Electrification Project in northwestern Uganda, where a private operator, owned by a Kenyan company, was given a 20-year generation, distribution and electricity sales concession for an isolated diesel grid. Hydro resources are available, but delays in implementing a small hydropower plant to reduce electricity costs means the operator has faced insolvency.

Renewable IPPs

While we believe that the concessioning approach is likely to be most productive for isolated minigrids, we do not want to preclude privately financed renewable generators playing a role in complementing diesel supplies in existing minigrids operated by KPLC. For these we recommend that the cap on the FiT should be lifted, so that FiTs would no longer be limited to the LRMC tariff. This would imply for solar PV FiT of at least 26.6 USc/kWh.
We would go beyond this, though, to recommend that the FiT, interconnection requirements and details of the PPA be negotiated on a case by case basis. In the case of the solar PV FiT, for example, the value of 26.6 USc/kWh is calculated on the basis of a 20% load factor being achieved. If the two parties agree that because of the load profile, the purchase of electricity will in effect reduce the load factor, the FiT model should be re-run with the lower load factor, resulting in a high FiT value. The model should still be used to ensure a coherent and consistent framework for the tariffs which will enter PPAs, but the actual value is to be determined by specific circumstances.

Allowing case-by-case negotiation is contrary to the overall approach we have adopted in this study. However, this is justified in this case by the variety of circumstances and the small number of projects that would be developed. While the main grid the project pipeline indicates more than 100 MW of small-scale renewable energy producers, our estimate is that for the isolated grids, this would be at most 3-4 MW in aggregate. The specificity to be considered in each case includes the scaling of the projects and the payment arrangements which would be acceptable to both sides in a situation where ‘must run, must take’ cannot apply.

Future grid connection

Where private sector participation in renewable energy projects in isolated grids is concerned, either under an IPP or concessioning approach, the likelihood and timing of such grids being connected to the main grid in the future needs to be considered. For example, at Garissa and Lamu, where the possibility of integrating a ~1 MW solar generator is technically viable due to the higher daily demand, and hence a small IPP could be attracted, the fact that these will in the next five years be connected to the main grid presents an uncertainty for investors. Thus a regulatory framework to account for the eventuality for main grid interconnection would be required.

3.6 Task 6 – Monitoring and Planning Tool

3.6.1 Relationship between monitoring and planning

Coherent planning of small-scale renewable investments requires that future investments build on the experience that has been gained to date. It therefore makes sense to have a single tool that provides a unified framework for monitoring and for planning.

It is assumed that the proposed tool would be held and managed by the secretariat of the FiT Committee, although a different institutional home could be chosen for this. The main features of the proposed tool are as follows:

- Geo-spatial database - the location of small-scale renewables is important and the basis of the tool should therefore be a GIS-based system which would show the location of existing and planned generators in relation to each other and to substations and grid
connections. When receiving new applications, planners will immediately be alerted to likely up-coming grid interconnection issues, depending on where the proposed project is to be located in relation to existing generators and what the loading and load flow implications would be in that part of the grid.

- **Project development/implementation status** – for the assessment and monitoring of FiT EOI applications, more information should be collected and recorded. This would need to be updated regularly with the specific status of each project to enable the FiT Committee to better understand how projects are progressing. It is useful, for example, to know how long it has in fact taken for projects to move from conceptualisation to commissioning. This will help the Committee to decide if and when an EOI approval for a site should be revoked. Data such as exact geographical coordinates is also important where the FiT Committee may have received more than one application for a certain area and needs to consider whether to issue an approval for one, both or neither project developer.

- **Performance data** – it is also important to track the actual performance of small scale renewable generators, compare this with predicted performance at the time of project acceptance, and therefore be in a position to make an informed judgment about the latest project applications in the various technologies.

The sources of information and models on which the above components can be built are as follows:

- **Transmission and distribution system GIS model** – the on-going Distribution Planning study includes a component which will result in an up-to-date, accessible GIS model of the Kenyan T&D network becoming available. This model can and should be used for related purposes, including the planning of small-scale renewables. However, there needs to be coordination between different uses. The FiT Committee can use a version of the model for its high level planning purposes, but when the project moves to implementation it needs to be integrated into the distribution planning process. Implemented projects need to be reflected accurately and candidate projects which have not gone to full implementation dropped.

- **Rural Electrification Master Plan update GIS model** – the 2008 update to the Rural Electrification Master Plan includes a GIS database with layers for power infrastructure (existing and planned grid, substations and distribution transformers), population, load centres, roads, other geographic data (protected areas, lakes) and basic renewable energy resource potential maps. While the distribution planning study results will be more recent, as the Rural Electrification GIS database already includes an overlay of the renewable resource potential and it should be investigated if this can form the basis for the planning tool.
- **Renewable resource potential maps** - the Ministry of Energy is currently undertaking wind resource studies from more than 40 wind measurement masts installed around the country. The Ministry has also recently tendered for the development of a small hydropower atlas for Kenya. Data from these and other exercises can be fed into the planning and monitoring tool against which the FiT Committee can assess new applications and track the performance of existing projects.

- **FiT Committee and project developer records** – records should be kept along the way by the FiT Committee of the time taken to reach the milestones for which it is responsible. When the project is commissioned, the FiT Committee milestone information should be confirmed with the project sponsors and additional information added (for example how long before the EOI application to the FiT Committee the project was identified). The time required for financial closure is of particular interest.

- **KPLC Energy Purchasing Department records** - Part of the transactions cost-minimising approach that is advocated in this study includes the idea that small scale generators will not be required to collect and provide data on an on-going basis. The main source of information for monitoring purposes will therefore be the KPLC accounting system. The records of the KPLC Energy Purchasing Department will provide data on the energy produced and paid for each month. Problems can be flagged in the data if there have been interruptions. Investigation of the causes of interruptions will further enrich the information available for future planning.

### 3.6.2 Task 6 Recommendations

We recommend that a Small-scale Renewable Monitoring and Planning Tool be established and maintained within KPLC, on behalf of and for the use of the FiT Committee. The information collected would be useful also to the Kenyan government in tracking greenhouse gas emission reductions from renewable electricity generation. The main features of the model would need to be developed in parallel:

- The geo-spatial database aspect will have to wait for work on the on-going Distribution Planning Study to be completed but the possibility of building on the existing Rural Electrification Master Plan database can already be investigated.

- The implementation time is already being monitored together with the number of EOI applications. This is to be brought in line with the steps being defined in the revised Procedures (see Task 7).

- On the performance monitoring side, although there are to date only two projects that have been brought into operation under the FiT mechanism, the data monitoring system should nonetheless be established. From the month of first operation of the plant, data should
be made available by the Energy Purchasing Department of the energy produced, the amount paid and any indications of interruptions or other problems.

### 3.7 Task 7 - Management of FiT Approval Process

A review and assessment of the existing FiT approval and implementation process has been conducted by the consultant with inputs from study counterparts and other stakeholders. The initial findings and questions were presented and discussed at the Mid-Term Workshop.

The general conclusion was that the existing FiT approval and implementation process is performing relatively well, and that delays in project development are due primarily to other factors: (a) land issues, (b) delays in obtaining project ancillary approvals, (c) lack of project developer expertise, (d) low tariff levels in some cases and (e) broader regulatory uncertainty.

Nevertheless, certain improvements may be considered to better facilitate and standardise the FiT approval and implementation procedures and provide more clarity to project applicants, which in turn will help to reduce transaction costs and regulatory uncertainty.

#### 3.7.1 Task 7 Deliverables

In this regard, the following documents have been provided as deliverables under Task 7. The documents focus mainly on small-scale renewable energy projects of up to 10 MW but for the sake of completeness provide guidance as well for larger renewable projects.

- **Feed-in-Tariff Policy Application and Implementation Guidelines.** These Guidelines have been developed based on the existing implementation procedures section of the FiT Policy, the FiT Policy Guide for Investors, the consultants’ own understanding of the actual process in Kenya and experience from other countries such as Sri Lanka, South Africa and Tanzania. The Guidelines are intended to replace the current “Guide for Investors” with a document that is of use to both Government and project developers to provide more clarity on FiT application and implementation procedures and guidelines.

- **EOI Feed-in-Tariff Policy Application Form.** As an appendix to the draft FiT Application and Implementation Guidelines, a standard Expression of Interest (EOI) application form has been prepared. The form requires more information to be provided by project applicants and makes it mandatory that all requested sections be completed before the EOI application is processed. This should help the FiT Committee to better assess the application.

- **Feed-in-Tariff Policy Project Progress Report Form.** As per the current EOI procedures, approved project applicants are required to provide
progress reports every 6 months during the two-year exclusivity period they have to assess and develop their proposed project under the FiT Policy. The Project Progress Report Form makes it clear the information that EOI approved applicants must provide in their reports and gives indicative milestones against which progress can be assessed.

- **Feed-in-Tariff Policy Project Progress Assessment Criteria.** In order to help the FiT Committee evaluate progress made and provide transparent criteria on how this is done, a progress assessment checklist with proposed scoring for achievement of different project development milestones has been prepared.

- **Procedures for unsolicited projects that are larger than 10 MW.** The procedures to be followed are initially the same as for the less than 10 MW projects. Differences arise in respect of the requirement that the larger projects have to be shown to contribute to meeting the country’s electricity demand in a least cost manner through being suited as candidate projects in the LCPDP process. An initial indication may be needed early on to justify detailed studies being undertaken, with the formal LCPDP endorsement being based later on when accurate feasibility study figures are available. Load flow and stability studies will also need to be undertaken, the level of detail depending on the size and location of the project. The other main difference is that the FiT for larger projects is to be project specific, so once the LCPDP and engineering studies are complete, the parameters required for the FiT model need to be agreed and the model used to generate the FiT (probably two part capacity-energy structure) to be included in the PPA for which the Standardised Negotiable PPA template is to be used.

### 3.7.2 Task 7 Recommendations

The Guidelines and procedural forms were discussed at the Final Workshop. It is recommended that the FiT Committee should do a thorough review of the Application and Implementation Guidelines, in tandem with finalising the Revised FiT Policy. To avoid confusion and possible ambiguity, the Policy document must take precedence over the Guidelines. In the previous iteration, policy elements were repeated in the Guidelines, sometimes in a way which could lead to different interpretations of the policy.

In view of the fact that there has not yet been an opportunity for this thorough review, certain sections of the draft Guidelines which are being provided as Separate Deliverable 5 have been left as square bracketed options. The FiT Committee can accept the text indicated by removing the square brackets, or members may prefer to modify or delete. The Application and Progress Report forms need similarly to be scrutinised. One important point is to decide on the initial exclusivity period for site full feasibility and project development, or rejection. At the draft Final Report stage, we had set this period at 2 years, but participants at the workshop felt this was too short, and suggested 4 years instead. In the current draft, we have settled on 3 years, with the option for extension if
properly defined progress is evident, or termination if insufficient progress has been made.

We recommend that the main thrust of the Guidelines - the formalisation of the EOI and Progress Report procedures - should be endorsed, albeit with possible changes to the detailed wording in the draft that has been provided. Some of the square bracketed text refers to more specific and complementary recommendations:

- **Information sharing.** It is recommended that for transparency and to reduce time spent by FiT Committee members on assessing EOI applications and explaining procedures to different project developers, that the following be posted and regularly updated on the Ministry of Energy and ERC websites:
  

  (b) A list of EOI approved projects including the information suggested in the draft FiT Application and Implementation Guidelines.

  (c) A list or map of “no go” areas that EOI applicants should avoid due to Ministry of Energy planning, such as a location of the Ministry wind masts in Kenya and a 50km exclusion zone around each

  (d) A list of all approvals and consents that a small renewable energy power producer will be required to obtain to meet legal and regulatory requirements to help applicants better plan their project development activities.

- **Requirements for EOI applications.** The proposed FiT EOI Application Form if completed in full should be sufficient to enable the FiT Committee to approve or reject an EOI application. It is not recommended at this time to require project applicants to submit a prefeasibility study since in many cases sufficient data is unavailable and a developer may delay the EOI applicant in order to assess the resource, only to find that another applicant was granted the EOI for the site. Furthermore, it is not recommended to include an application fee with the EOI request so as not to exclude project applicants with minimal resources or add an extra administrative step to the EOI procedures.

- **Automatic offer of Standardised Non-Negotiable PPA for projects up to 10 MW when pre-determined milestones are reached.** It is suggested that the FiT procedures clearly state that a PPA will be automatically offered to EOI approved applicants who (a) demonstrate project technical and economic viability, (b) obtain necessary consents and approvals (d) agree to a grid connection plan and (d) secure or show that they will secure the financing requirement for the project. This should provide certainty to developers and financiers that the
project will receive a PPA offer and also ensure that KPLC is not bombarded with requests for PPA signing until a project applicant has shown significant progress. Alternatively, in principle after a certain amount of progress is achieved/milestones met, KPLC could consider to offer a Letter of Intent for PPA signing or even initial (but not sign) the PPA offered. Alternatively, the milestones could be inserted as Conditions Precedent in the PPA and the parties could sign once the grid connection plan is agreed. In whichever case, clarity should be provide on (a) when an EOI approved applicant should request a PPA and (b) at what stage it should expect the PPA to be signed.

- **Grid connection study.** The grid interconnection arrangements are one of the critical aspects that determine project viability and grid system operator acceptance of the proposal project. Under the small-scale renewable energy power producer procedures, the grid connection aspect is really the only part of the standard PPA that requires discussion. Hence, it is suggested as part of the EOI application procedure that the project developer already provide a proposed grid connection point and power line routing clearly identified on a map. Then, as part of the FiT project planning and monitoring tool to address potential grid connection constraints and requirements at an early stage, it is recommended that when the FiT Committee approves an EOI applicant, KPLC provide a quick and preliminary Grid Connection Opinion. This can be a very basic letter of one page indicating KPLC’s brief opinion on the proposed connection point and any considerations that the project applicant should take into account, such as alternative routing or expected reinforcements, when developing the project. While this recommendation might add a burden to KPLC staff upfront and some time might be wasted on projects that will not achieve viability, overall such a procedure will be useful for the implementation of the FiT project planning and monitoring tool, and may also inform some applicants immediately that their proposed project is not viable, thus saving time in the long run. Later, once the project is conducting or has completed a full feasibility study (usually 6-18 months after EOI approval), the detailed grid connection arrangements can be studied, discussed, agreed and inserted into the standard PPA template.

- **Support for EOI project ancillary approvals.** It has been suggested by some stakeholders that an EOI-approved project either be subject to less stringent regulatory requirements, in particular regarding the Environmental Impact Assessment, or should have a streamlined process for obtaining all necessary ancillary approvals. While in principle a good proposal, this study does not recommend this approach for two main reasons. Firstly, changes to any legislation such as the EMCA Impact Assessment and Audit Regulations may be difficult to achieve for a “niche” sector (e.g. small renewable energy projects under 10 MW) unless the Government is very supportive. Secondly, steamlining the process for all related approvals will require much consultation and liaison with a large number of line agencies on behalf of a large number of projects, which may place undue additional
responsibility on the Ministry of Energy or ERC, and in any case the Kenya Investment Authority may be the appropriate body to facilitate such approvals. Instead, the study recommends that the Ministry of Energy project letters of support as reasonably requested to help EOI approved applicants obtain other consents.

- **Legal status of EOI approval.** The legal status and implications for revocation/transfer of an EOI approval should be considered if FiT Policy is to be gazetted.

- **Effect of changes to the FiT Policy on EOI approved projects.** Some suggestions have been provided in the draft FiT Application and Implementation Guidelines that require further discussion but are important in order to provide certainty for investors.

### 3.8 Additional elements of the TOR and other topics covered

#### 3.8.1 Items identified at start of Section 3 of TOR

The bulk of Section 3 of the TOR is taken up with describing the 7 tasks, but there are also some other items which are mentioned before the tasks. The way in which these have been met is described below:

- **Assessment of the renewable energy resource potential in Kenya** – a thorough piece of work was done on this, and presented as Separate Attachment 8.

- **Challenges and constraints to low implementation** – the Inception Report noted that the low implementation to date was not reflective of the strong response to the FiT policy, which had produced a significant pipeline of projects. The thrust of this study was therefore very relevant to streamline the acceptance and implementation procedures in advance of a large expected increased in projects coming forward. In addition to procedural matters, other key constraints which remain include access to finance: some figures were given on this in Section 1.2.

- **Recommend minimum system sizes/capacities** – the previous policy specified minimum sizes for each technology. This study concluded that there is no strong reason to automatically preclude very small generators. Project promoters would not find it economic to put forward very small projects which would have to be subject to the same procedures as projects up to 10 MW – in future, very small generators are likely to be catered for under Electricity Banking and Net Metering, where the procedures are extremely straightforward.

- **Recommend cap values for installed capacity** of various grid connected generation plants – for the reasons given in detail in Section 2, under the proposed arrangements it is more appropriate to have a cap on the overall capacity of embedded, non-despatchable small-scale (less than
10 MW) renewable generators. We have recommended that this be set at 10% of system installed capacity in the first instance and reviewed through a thorough study once the 10% level is close to being reached. Currently the limit would be around 160 MW, but the system is expected to grow rapidly in the next few years, and the cap will grow with it (350 MW by 2015).

- Renewable energy premium tariff scheme for isolated grids – after considering a number of options, the recommended approach for isolated grids does not depend on an energy premium tariff. It is to concession them out to operators who would make the decisions about the type and level of renewables in the hybrid generation mix, and how best these would be despatched. The bids for the concessions would be on the basis of minimising the subsidy requirements. See Section 3.5.

- Develop a monitoring plan – this has been combined with the GIS-based planning tool, as planning has to take account of what is already in place and where, and how previous cohorts of generators have performed in practice. See Section 3.6.

- Overview of international experience of small power producer regulatory systems – this appears in this report as Annex A1.

The final point, to “propose regulatory instruments and guidelines for integrating small-scale renewable energy systems into the interconnected and isolated grids, based on full technical and economic analysis and international best practice” leads directly into the 7 Tasks analysed in detail in Section 3.

### 3.8.2 Wheeling

The team was also asked to comment and give advice on other topics, wheeling being one which involved significant debate with stakeholders. Wheeling over the national network between a privately owned generator and an earmarked customer is permitted under the Energy Act. What is yet to be determined, however, is the applicable wheeling tariff and hence the viability of wheeling for the entities involved. The parties involved do not seek to isolate themselves from KPLC – the utility is to be relied upon to provide continuity of supply when there are problems in the upstream supply system. KPLC loses a customer, but in the current constrained situation, should be able to find a new customer and hence may not have a reduction in revenue.

There is currently strong interest from the tea industry to develop small hydro-power projects on certain estates and wheel the power to tea factories located elsewhere. GTIEA has prepared a specific proposal, proposing a methodology for wheeling charges which would have both capital and energy components.

Wheeling charges are to be examined in detail and recommendations made by the team currently carrying out the electricity cost of service / tariff study for ERC. Suffice it here for use to make a few observations on what should be included in the wheeling cost methodology:
Direct costs (operating and maintaining the transmission and/or distribution equipment and lines involved)

Careful assessment of losses (inversely proportional to the square of the voltage and hence important to wheel at as high a voltage as possible)

These costs should be assessed on a zonal basis so as to minimise prejudice to other consumers from congestion

Indirect costs for the utility – costs of maintaining back-up capacity, and payment to offset the probable loss in the contribution to the cross-subsidy pot through the loss of the earmarked customer.

**Recommendation:** The wheeling charge must await the outcome of the COSS study. The team performing that study will recommend a tariff that is consistent with the system-wide costs. The structure of the wheeling tariff is also to be decided as part of the COSS study, ranging from a simple ‘postage stamp’ formulation to a three component structure:

- A charge for supporting the load in the case that generation is not available - this can become more complicated when over the year generation is not equal to demand;

- A zonal charge for generation entering the system; and/or

- A zonal charge for demand exiting the system.
4 Conclusion

The study has provided the opportunity for an intensive period of research and debate on key issues pertaining to the development of renewable energy resources in Kenya. In response to the forward-looking FiT policy introduced in 2008, there is a significant pipeline of projects waiting to be approved and implemented. To ensure that there will be no unwarranted hold-ups, it is important that the Revised FiT Policy, incorporating the results of this study, be gazetted as soon as possible.

The implementation of the revised policy will require the separate deliverables that have been prepared be brought into use:

- Standardised Non-Negotiable Power Purchase Agreement
- Connection Guidelines for Small-Scale Renewables
- FiT Model
- Application and Implementation Guidelines
- Monitoring & Planning Tool
- Standardised Negotiable PPA for Projects larger than 10 MW
- Renewable Energy Resource Potential in Kenya

This Final Report provides the context and justification for the decisions which have been made the course of action which has been agreed. The report also includes the annexes which provide a draft Electricity Banking / Net Metering Application Form as well as Manuals for the FiT Model and the Monitoring and Planning Tool.

The Revised FiT Policy and the above items together constitute a package for immediate implementation. It is timely for the implementation of renewable projects to be accelerated: Kenya’s greatest need for development of small renewables is in the current period in which there is insufficient reserve margin in the national generation systems and the economy is being held back from achieving its growth and social development potential.
A1 International experience of SPP regulatory regimes

A1.1 Small Power Producers in Thailand

Thailand is one of the first countries in Asia to adopt a small power producer (SPP) programme. The Thai SPP program was established in 1992, and was modelled in element on the PURPA small power program in the United States.

The Electricity Generating Authority of Thailand (EGAT), the state-own power utility, defines SPPs as a private or a state enterprise that generates electricity either from:

- Non-conventional sources, such as wind, solar, mini-hydro, and other fuels such as waste, residues or biomass, or
- Conventional sources, such as natural gas, coal, oil, using cogeneration technologies.

SPPs generating between 1 MW and 90 MW may sell electricity to EGAT and to industrial customers within the vicinity of the power plant. Very small power producers (VSPP) generating under 1 MW may sell electricity directly to one of the two national distribution companies. The institutional arrangement of the Thai electricity sector is illustrated in Figure.

Figure 15 Thai electricity sector institutional arrangement

Source: Palang Thai, Feed-in tariffs and south-south policy/technology transfer: The evolution and implementation of Very Small Power Producer (VSPP/SPP) Regulations in Thailand and Tanzania, 2010
Small Power Producer (SPP) Regulation

Under the 1992 SPP program, EGAT requested 300 MW of SPP power through a competitive solicitation process, whereby SPPs bid for the lowest per kWh subsidy payment. The reason for the subsidy is to take into account the higher capital cost of renewable energy technologies as compared to the conventional fossil fuel power plants. It was also acknowledged that SPPs are generally policy driven rather than market driven, hence, the subsidies served as financial incentives for investments in renewable energy and SPPs.

The subsidies are provided for the first 5 years of operations, and require the eligible SPPs to meet these conditions:

- SPPs has to fulfil EGAT’s requirements on plant location, fuel source, production details and costs
- SPPs submit a plan at a public hearing and demonstrate the approval of at least 70% of the local residents.

The selected SPPs sign a power purchase agreement (PPA) for the sale of their electricity to EGAT. SPPs are also allowed to sell their electricity to industrial customers located in the vicinity of the power plants. EGAT may purchase up to 60 MW of electricity from an SPP; however, it is within EGAT’s discretion to accept up to 90 MW. EGAT does not contract with projects of less than 1 MW. No net-metering is yet implemented, although it has been discussed as an option.

The SPP PPAs are between 5 and 25 years with terms and specifications set by EGAT. Since EGAT is a single buyer of electricity from SPPs, the PPA allocates market risks to EGAT, leaving the SPPs to manage operating and fuel price risks.

EGAT has defined two types of purchasing rates for buying SPP power:

- **Firm power** – which indicates that the SPP can guarantee availability of electricity supply during the system peak months. All cogeneration SPPs provide firm power to EGAT. Payment to firm SPPs is determined by EGAT’s long-run avoided capacity and energy cost.

- **Non-firm power** – most renewable SPPs are non-firm power providers, with most use bagasse as fuel. The value of non-firm power is determined by EGAT’s short-run avoided energy cost.

SPPs receive two types of payments from EGAT, on top of the initial 5-year subsidy:

- **Capacity payment** – based on actual kW produced multiplied by a capacity charge covering investment costs plus foreign exchange fluctuations, and

- **Energy payment** – based on actual kWh delivered to customers and covers the variable production and maintenance costs.
The SPP program has provided needed fuel diversification for Thailand, and has increased investments in renewable energy technologies. The competitive bidding process was one of the key success factors, as it minimise the cost of the subsidies and bring forth the maximum number of MW of new private power resources.

However, SPP stakeholders have expressed concern about the standardised PPA, which was solely drafted by EGAT, and which was found to be too simplistic and not protective of SPP interests.

In spite of this concern, by 2005, 84 SPPs has signed a PPA with EGAT, and 71 of those were in operation. By 2010, EGAT reported a total purchase of 2,200 MW of electricity from SPPs.

**Very Small Power Producer (VSPP)**

The regulation for VSPP was approved in 2002. Under this regulation, VSPPs are allowed to export their electricity to distribution companies as long as they use renewable energy sources and they exported less than 1 MW. The tariffs were set to equal the bulk supply tariff (amount paid by distribution companies for electricity bought from EGAT).

In 2006 the utilities felt comfortable enough with the initial VSPP projects to allow an increase in project size to 10 MW export and efficient cogeneration was also allowed. The government also recognized that VSPP could play a larger role in meeting the nation’s commitment of 8% renewable energy by the year 2011 (recently raised to 20% by year 2022). The upgrade to the regulations also created a technology-specific feed-in tariff subsidy adder.

In 2009 the feed-in tariff was changed to provide additional payments for projects that offset diesel generation, which is still used in Thailand in some remote mountain and island areas. The table below shows the VSPP tariffs as of 2010.

Most VSPPs use biomass as fuel, such as rice husks and biogas from pig farms. Some VSPPs also use solar and mini-hydro system. Figure 16 shows the status of VSPP in Thailand as of March 2010.

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Table 9 VSPP tariffs by fuel type

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Adder</th>
<th>Additional for diesel offsetting areas</th>
<th>Additional for 3 southern provinces</th>
<th>Years effective</th>
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<td>$0.030</td>
<td>$0.030</td>
<td>7</td>
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<td>Capacity &gt; 1 MW</td>
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<td>7</td>
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<td>$0.009</td>
<td>$0.030</td>
<td>$0.030</td>
<td>7</td>
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<tr>
<td><strong>Waste (community waste, non-hazardous industrial and non organic matter)</strong></td>
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</tr>
<tr>
<td>50 kW - &lt;200 kW</td>
<td>$0.024</td>
<td>$0.030</td>
<td>$0.030</td>
<td>7</td>
</tr>
<tr>
<td>&lt;50 kW</td>
<td>$0.045</td>
<td>$0.030</td>
<td>$0.030</td>
<td>7</td>
</tr>
<tr>
<td>Solar</td>
<td>$0.238</td>
<td>$0.045</td>
<td>$0.045</td>
<td>10</td>
</tr>
</tbody>
</table>

Source: Palang Thai, *Feed-in tariffs and south-south policy/technology transfer: The evolution and implementation of Very Small Power Producer (VSPP/SPP) Regulations in Thailand and Tanzania*, 2010

Figure 16 Status of VSPP in March 2010

Source: Palang Thai, *Feed-in tariffs and south-south policy/technology transfer: The evolution and implementation of Very Small Power Producer (VSPP/SPP) Regulations in Thailand and Tanzania*, 2010
A1.2 Community financing for wind power in Denmark

Denmark is well known for its wind power development in the late 1990s, with its unique community ownership model. The first modern wind turbines installed in Denmark in the 1970s were developed and owned by private individuals without government support. By the mid-1990s, the amount of wind capacity owned by individuals and community partnerships grew significantly, fuelled by:

- Declining turbine costs
- Lower interest rates
- Government incentives and regulations encouraging wind development.

In the early years of the 21st century, over 175,000 households owned 80% of all wind turbines in Denmark9. In the year 2000, wind capacity, the bulk of which was from community owned schemes, was about 2,200 MW and this produced 14% of Denmark’s total electrical energy consumption. However, the change in government in 2001 brought about changes in the energy sector, in particular the renewable energy program, which provide incentives for small wind development, was abolished. The new renewable energy program favours large wind power plants, which are more suitable for development by large utilities rather than communities or private individuals.

Government support for wind development

The growth in wind power in Denmark was largely due to the government policy and renewable energy program, which was enacted in 1979. These included:

- **Capital support** – the renewable energy program included a capital investment subsidy of 30% of total project costs. This subsidy program, started in 1979, was gradually phased out in the subsequent years and was completely withdrawn in 1989.

- **Feed-in tariff law** – since 1993, local utilities have been required to purchase wind energy from independent generators at a rate that is 85% of their production and distribution costs, which amount to about 0.3 DKK/kWh. This feed-in tariff law was replaced with a renewable portfolio standard (RPS) with a system of tradable green certificates (TGDs) in 1999. A transitional program was designed to replace the 85% feed-in tariff with a fixed-price tariff of 0.33 DKK/kWh until a turbine is 10 years old.

- **Environmental subsidies** – initially, a portion of the energy tax and the entire CO2 tax on electricity consumption is refunded to independent

---

generators, amounting to a total subsidy of 0.27 DKK/kWh. In the RPS system, the subsidy is in the form of TGDs, which value is determined by the market, subject to a minimum price of 0.10 DKK/kWh and a maximum price of 0.27 DKK/kWh. In the transitional program, turbines purchased and permitted prior to 2000 are eligible for the full 0.27 DKK/kWh subsidies up to a certain production limit (as shown in Figure 17 and illustrated in Box 1).

- **Shared interconnection costs** – independent generators pay for the cost of connecting to the nearest technically suitable point on the grid, which include the line from the plant to the grid connection point, control and metering equipment. The local distribution utilities pay for any grid reinforcement necessary in order to interconnect with the generator, or any other interconnection needed at some more distant point.

<table>
<thead>
<tr>
<th>Turbine Vintage</th>
<th>Size (kW)</th>
<th>Fixed Price (0.33 DKK/kWh)</th>
<th>Fixed Subsidy (0.27 DKK/kWh)</th>
<th>TGC (0.10-0.27 DKK/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Existing*</td>
<td>&lt;= 200</td>
<td>Until the turbine is 10 years old (but at least until 2002)</td>
<td>For first 25,000 full-load hours</td>
<td>After full-load hour limit: 0.10 DKK/kWh</td>
</tr>
<tr>
<td></td>
<td>201 – 599</td>
<td></td>
<td>For first 15,000 full-load hours</td>
<td>Once TGC market opens and turbine is 10 years old, turbine gets TGCs instead</td>
</tr>
<tr>
<td></td>
<td>&gt;= 600</td>
<td></td>
<td>For first 12,000 full-load hours</td>
<td></td>
</tr>
<tr>
<td>New**</td>
<td>For 10 years</td>
<td>NONE</td>
<td>YES</td>
<td></td>
</tr>
</tbody>
</table>

* Purchased and permitted prior to 2000
** Purchased and permitted in 2000, 2001, and 2002


**Community Ownership Model – Wind Partnerships**

The Danish power law requires that wind turbines be directly owned by electricity consumers. A partnership, which is understood to be a contractual relationship between several entities (in this case electricity consumers) to pool certain resources in order to run a business, is the only joint form of ownership to qualify under the Danish power law.

Therefore, wind partnerships in Denmark are simply a partnership made up of individuals who pool together resources to invest in a wind turbine and sell their power to the local utilities. Investors in a wind partnership continues to pay their own electricity bill as normal, while the turbine’s output is sold wholesale to the utility rather than to the individual members of the partnership.

There were some restrictions on turbine ownership, which was relaxed over the years. In the early 1980s, investment in a wind partnership was limited to those living within 3 km of the turbine. This restriction was expanded to those living within 10 km in 1985, to those in neighbouring boroughs in 1992, those who work...
or own property in a borough but do not live there in 1996, to all of Denmark in 1999 and the entire European Union in 2000.

Individuals use their own resources, such as savings or commercial loans, to finance the wind turbines. And since the partnership is not a taxable entity, taxes are levied proportionally on each individual partner. Household income from wind turbines is tax-exempt up to a certain limit. In 1985, the limit is income of up to 135% of household power costs are tax free. The limit is increase to 150% in 1992. In 1996, the tax law was changed, and the new regime allows for the first 3,000 DKK of income to be tax free, while 60% of any income above this is taxed for investments made during or after 1996. For investments prior to 1996, the old method applies. In addition to tax exemption, for individuals who took commercial loans to finance the investment, the interest on a loan for a wind turbine is tax deductible.

Shares of a wind partnership can be traded, although it is not publicly listed. The partnership board usually assist with matching buyers and sellers, and the shares are usually traded at par, with no adjustment for depreciation.

Since the removal of the feed-in tariff and the start of the more market based renewable portfolio standards (RPS), community investments in wind power projects has stalled. This is due to the less reliable revenue stream under the RPS, and because the RPS creates pressure to increase project size in order to lower costs and thereby maximise the tradable green certificate (TGC) income.

Box 1 The Middelgrunden Wind Turbine Partnership

The 40 MW Middelgrunden wind partnership power project was completed in the early 2000s, and was able to benefit from the feed-in tariff regime during the transition period.

Located about 2 km off of Copenhagen’s harbour in the narrow sound between Denmark and Sweden, Middelgrunden is both the largest community-owned wind project ever, as well as the first sited offshore. The 40 MW project consists of twenty 2 MW Bonus wind turbines, ten of which are owned by the partnership, with the other half owned by the local municipal utility, Copenhagen Energy. With the annual output of its ten turbines guaranteed by Bonus at 40,500 MWh, the partnership consists of 40,500 shares (each share is 1,000 kWh/year) owned by nearly 9,000 members who invested DKK 4,250 per share for between four and five shares on average, reflecting the tax-free status of the first five shares.

Because receipt of planning permission and the turbine purchase order both took place in 1999, the Middelgrunden project will for six years receive the same attractive feed-in tariff that wind turbine owners in Denmark have enjoyed in the past. In years 7 through 10, income is still guaranteed, but at a lower level, and after 10 years the project must sell both its output and its “green certificates” on the open market, which is likely to lead to lower returns in years 11 through 20. Thus, through fortunate timing, Middelgrunden remains insulated from the full impact of market pricing for the first half of its projected life-span, meaning that the high degree of investor enthusiasm it has attracted may not be indicative of what lies ahead for future partnerships that are more exposed to the market. The following table shows the expected cash flows for one 1,000 kWh/year share in the
International experience of SPP regulatory regimes

Middelgrunden project. All cash flows are virtually locked in, with the exception of the feed-in tariff in years 11-20, which is highly uncertain.

<table>
<thead>
<tr>
<th></th>
<th>Years 1-6 (DKK/kWh)</th>
<th>Years 7-10 (DKK/kWh)</th>
<th>Years 11-20 (DKK/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Feed-In Tariff</td>
<td>0.33</td>
<td>0.33</td>
<td>0.33</td>
</tr>
<tr>
<td>Energy Tax Refund</td>
<td>0.17</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>CO₂ Tax Refund</td>
<td>0.10</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Tradable Green Certificate</td>
<td>0</td>
<td>0.10</td>
<td>0.10</td>
</tr>
<tr>
<td>O&amp;M</td>
<td>-0.07</td>
<td>-0.07</td>
<td>-0.07</td>
</tr>
<tr>
<td>Net Cash Flow</td>
<td>0.53</td>
<td>0.36</td>
<td>0.36</td>
</tr>
</tbody>
</table>

Assuming that the project can continue to sell its output for 0.33 DKK/kWh in years 11-20, and receives the minimum guaranteed TGC price of 0.10 DKK/kWh for all of its output, the project yields a 20-year IRR of 8.25%. In a worst-case scenario, where the project is simply unable to sell any of its output in years 11-20 (i.e., the 0.33 goes to zero), yet still receives the minimum guaranteed TGC price, the 20-year IRR falls to 4.44%. The first 3000 DKK of revenue (corresponding to the first 5 shares) is free from income tax, while 60% of all revenue beyond 3000 DKK is taxed, usually at a rate of 60%.

The completion of Middelgrunden brings the total amount of wind power capacity in Copenhagen to 47.8 MW, enough to supply about 35,000 homes with electricity, assuming a 25% capacity factor and average usage of 250 kWh/household/month. Wind partnerships own 27.8 MW of that total.

**The project has a simple payback of nine years.**

“**The tax exemption on 40% of revenue in excess of 3,000 DKK reflects the effect of a 20-year straight-line depreciation; writing off 5% of the investment each year reduces taxable income by about 40%.**

A1.3 Small Renewable Energy Program in Sri Lanka

As an island nation, Sri Lanka is faced with unique energy situation, in that it cannot import or export electricity. Increasing electricity demands fuelled by economic growth has put a strain on the generation and transmission capacity. In addition, ambitious Government electrification targets have led to the opening of the electricity sector to private investment.

The electricity sector in Sri Lanka is dominated by the state-owned utilities, Ceylon Electricity Board (CEB), who owns and operates major generation plants and transmission system, and Lanka Electricity Company, who owns and operates some of the distribution system. A number of Independent Power Producers (IPPs) and Small Power Producers (SPPs) exists and supplied power to the grid. There are also some off-grid village hydro generation and solar PV systems providing electricity to remote rural areas. Figure 18 illustrates the institutional arrangement in the electricity sector.

Figure 18 Sri Lanka’s electricity sector institutional arrangement

Adapted from various documents cited in this report.

In 2007, the Sustainable Energy Authority Act established the Sri Lanka Sustainable Energy Authority, which is defined as the custodian of all state’s renewable energy resources, and has the function of facilitating the development and implementation of projects using non-conventional renewable energy sources. The Public Utilities Commission of Sri Lanka (PUCL) is a utility regulator, which also responsible for the regulation of energy infrastructure.

Small Renewable Energy Program

A number of donor sponsored programs has fuelled and increased the number of small renewable energy projects. For example, the Energy Service Delivery Project
International experience of SPP regulatory regimes

(ESD) in 1997-2002 and the Renewable Energy for Rural Economic Development (RERED) Project in 2002-2007 has increased the number of community and private sector led renewable energy initiatives, such as mini-hydro systems and stand-alone or home solar PV systems. The projects have enabled communities and local private sector to access commercial loans from local financial institutions to finance renewable energy projects. ESD and RERED have also provided capacity building and technical assistance in both technical and financial aspects of renewable energy investments.

By March 2005, the ESD and RERED projects have installed 87 MW of mini-hydro and 1 MW of biomass (dendro) power capacity through 32 projects, while off-grid community-owned village hydro scheme and stand-alone solar home systems provided electricity to around 4,000 and 66,000 households respectively.

The need for increased generation capacity and the Government’s renewable energy targets continue to drive the development or small renewable energy projects. The National Energy Policy of Sri Lanka, adopted in 2006, sets a target of 10% electricity generated from non-conventional renewable energy sources by 2015. In 2011, this target is revised in the Development Framework of the Government of Sri Lanka to be 20% renewable energy generation in 2020, and the 10% target is aimed for 2016.

The standardisation of the Small Power Purchase Agreement (SPPA) and the Small Power Purchase Tariff (SPPT) has facilitated the development of SPPs. By the end of 2010, Sri Lanka has 84 new renewable energy power plants (each producing less than 10 MW) of a total capacity of 211 MW, owned and operated by private sector. This includes two wind power plants and a biomass power plant using rice husks.

Small Power Purchase Agreement (SPPA)

In 1999, as part of the ESD project, a standardised Small Power Purchase Agreement (SPPA) and Small Power Purchase Tariff (SPPT) mechanism for renewable resource based power producers, selling up to 10 MW of electricity to the state utility (CEB). These standardised documents form the backbone of the small power producer (SPP) procurement.

The SPPA is a contract between the state utility (CEB) and the SPP developer, and has these following main features:

- Term of SPPA may be up to 15 years
- CEB must accept all power at the delivery point as long as the SPP maintains its eligibility status by selling no more than 10 MW

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The SPP is designated as a “must run” facility, whereby CEB is obligated to take and pay for the energy tendered.

SPPs are not allowed to sell or divert power to other buyers.

CEB owns and maintains all metering equipment, however, a third party may be contracted to perform the measurements.

Net metering is now contemplated or allowed.

SPP must deliver power to the delivery point at its own cost, which include all interconnection and protective costs.

The SPPA also includes other general contract obligations, such as force majeure, dispute resolution, termination clauses, and risk allocation mechanism.

**Small Power Purchase Tariff (SPPT)**

A standardised tariff is designed for SPPs selling up to 10 MW to CEB. The tariff calculations are as follows:

- Tariff is based on CEB’s avoided costs, which is defined as the maximum value of additional generation that it avoids.

- CEB only pays for the energy value for the power, no capacity charge is included.

- The energy value is calculated based on the marginal cost of fuel and variable O&M, with marginal fuel cost defined as the cost of petroleum to CEB from the state Petroleum Corporation.

- Allowance of a total 7.7% are made for station and transmission losses and CEB overheads.

- The tariff is the average of:
  - The prospective energy avoided cost calculation, and
  - The calculation utilised during the prior two years.

- The price for energy is seasonally adjusted, with “dry season” comprises February to April, and “wet season” comprises May to January.

An example of the annual season SPP tariff is shown in Figure 19.
SPP Application Process

Initially, there was no competitive bidding process to select SPP developers for a particular source/location. Application for the development of a renewable energy generation was reviewed by CEB, who can issue a Letter of Intent (LOI) to the developer on an ad hoc basis.

In 2011, the Sustainable Energy Authority (SEA) published a guideline for on-grid renewable energy project approval process, in order to streamline and improve transparency of the SPP selection process. The guideline is based on the processes prescribed in the On-Grid Renewable Energy Project Development Regulation 2009, which requires all renewable energy projects being built or operational in any of the declared resource areas to obtain energy permit from SEA.

New SPP developers are required to apply through the Provisional Approval process, while projects with active SPPAs as of 1st October 2007 can apply for a permit without going through the Provisional Approval process. Figure 20 illustrates and explains the process of applying for a permit from SEA.

The Regulation identifies main categories of new renewable energy sources: mini-hydro, wind, biomass (dendro), biomass (agricultural and industrial waste), municipal solid waste, waste heat recovery, and other.

Each application submitted for Provisional Approval needs to be accompanied by a non-refundable application fee.
A1.4 Small Power Project Development in Tanzania

Tanzania has recently developed a comprehensive small power project (SPP) program, under the National Energy Policy 2003 and Electricity Act 2008. The Energy and Water Utilities Regulatory Authority (EWURA) is responsible for developing the rules and procedures for the SPP program, which include: a set of guidelines for SPPs, Standardised Power Purchase Agreements (SPPAs) and Standardised Tariff Methodology (STM).

SPPs are defined as power plants using renewable energy sources or waste heat, or cogeneration of heat and electricity, with an export capacity of up to 10 MW. SPPs may export their electricity to TANESCO, the state-owned vertically integrated utility, or directly to final customers. Figure 21 illustrates Tanzania’s electricity sector institutional arrangements.

Figure 21 Overview of Tanzania’s electricity sector


Small Power Project (SPP) Program

The objective of the SPP program is to facilitate development and interconnection of SPP projects to increase generation capacity and encourage the use of renewable energy sources. In order to streamline the development of SPPs, EWURA, as the energy regulator, is to exercise “light handed regulation” approach, which means:

- minimised amount of information required for SPP licencing,
- minimised number of regulatory requirements and decisions, and
The use of standardised documents, such as PPAs and tariff calculation methodology.

In addition, EWURA has published Guidelines for Developers of SPP and Guidelines of Grid Interconnections of SPP in Tanzania. The guideline for SPP development outlines the process for SPP development, which is illustrated in Figure 22.

**Figure 22 Sequence of SPP implementation**

1. Land title or lease
2. Resource Rights (e.g. water rights from River Basin Water Office)
3. Letter of Intent (LOI) with DNO (Tanesco)
4. Business license, tax registration, etc.
5. Building Permit
6. Environmental and Social Clearance (NEMC)
7. SPPA
8. EWURA license

Sequence is important to avoid competing claims on project sites.

Source: C. Greacen, Guidelines for Developers of Small Power Projects (SPP) in Tanzania, 2009

SPP developers are required to obtain a land title or lease for the land where the SPPs are to be developed, and any resource permits, such as water rights for hydro power. Then, the developer is to request a Letter of Intent (LOI) from TANESCO, which indicates TANESCO’s no objections, in principle, to interconnecting a power plant of the proposed type, size and power export capacity from the proposed location. Once the LOI is issued, the SPP developers will need to register as a business entity and obtain tax payer ID and VAT certificates, obtain a building permit requirements, and conduct an Environmental and Social Impact Assessment (ESIA). Depending on the size, some projects may not require an ESIA.

Once all the above requirements are met, the SPP developers will sign a Standard Power Purchase Agreement (SPPA) with TANESCO, and apply for a licence from EWURA. SPPs exporting less than 1 MW do not need to apply for a licence from EWURA, but are required to register their generation capacity to EWURA.

**Standard Power Purchase Agreement (SPPA)**

An SPPA is a standard contract between SPP developers and TANESCO (as the licenced Distribution Network Operator or DNO) for the sale and purchase of
electricity. For SPPs not connected to the main grid, the SPPA will be between the SPP developer (seller) and the customer (buyer).

The SPPA has the following major features:

- It is a ‘must-take’ contract. TANESCO is required to purchase all energy supplied by the SPP developer.
- The Standardised Power Purchase Tariff is announced annually, based on TANESCO’s avoided costs.
- The floor tariff over the term of the SPPA is set at 100% of the tariff in the year in which the SPPA is signed.
- The tariff is capped at 150% of the tariff in the year in which the SPPA is signed.
- The term of the SPPA is 15 years, starting from the commencement date of operation.

The SPPA also includes duties and obligations of both parties, including:

- The grid connection requirements, such as specific power quality standards, relay, and other technical requirements.
- Metering arrangements.
- Billing and payment.
- Force majeure.
- Limitation of liability, and
- Dispute resolution.

The number of concluded SPPAs in November 2010 is shown in Figure 23.
**Standardised Tariff Methodology (STM)**

The STM aims to protect both parties from future price fluctuations by including a price floor (at 100% of initial tariff in the year which the SPPA is signed) and a price cap (at 150% of initial tariff), which are locked in for the duration of the SPPA. The price cap is adjusted annually to account for changes in Consumer Price Index (CPI). The STM differentiate tariff calculation methods by SPP types, as shown in Figure 24.

### Table: Number of concluded SPPAs in November 2010

<table>
<thead>
<tr>
<th>SPP DEVELOPER</th>
<th>INSTALLED CAPACITY</th>
<th>MAXIMUM FOR SALE</th>
<th>DATE SIGNED</th>
<th>EXPECTED ONLINE DATE</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 TPC Moshi (co-generation)</td>
<td>17.487 MW</td>
<td>9.0 MW</td>
<td>6/10/2009</td>
<td>13/09/2010</td>
</tr>
<tr>
<td>2 TANWAT (Biomass)</td>
<td>2.5 MW</td>
<td>1.4 MW</td>
<td>17/09/2009</td>
<td>15/06/2010</td>
</tr>
<tr>
<td>3 Mwenga Hydro Ltd (Mini hydro)</td>
<td>4.0 MW</td>
<td>3.0 MW</td>
<td>19/01/2010</td>
<td>2012</td>
</tr>
<tr>
<td>4 Ngombeni Power Ltd (Biomass)</td>
<td>1.4 MW</td>
<td>1.0 MW</td>
<td>19/01/2010</td>
<td>2012</td>
</tr>
<tr>
<td>5 SAO Hill Energy Ltd (Biomass)</td>
<td>15.75 MW</td>
<td>10.0 MW</td>
<td>26/02/2010</td>
<td>2012</td>
</tr>
</tbody>
</table>


### Figure 24: SPP types for tariff calculations

<table>
<thead>
<tr>
<th>Selling wholesale (to DNO)</th>
<th>Connected to main grid</th>
<th>Connected to isolated mini-grid</th>
</tr>
</thead>
<tbody>
<tr>
<td>Selling retail (directly to final customers)</td>
<td>Case 1</td>
<td>Case 2</td>
</tr>
<tr>
<td>Case 3</td>
<td>Case 4</td>
<td></td>
</tr>
</tbody>
</table>


The tariffs are calculated for the different cases as follow:

- **Case 1 - Wholesale tariff for electricity sold to the main grid**: SPP tariff is based on TANESCO’s avoided costs, which are calculated as an average of its long run marginal cost (LRMC) and its short run marginal cost (SRMC). The LRMC is as defined by TANESCO’s long-term power plan, while the SRMC is the budgeted cost of thermal generation for the next year.

- **Case 2 – Wholesale tariff for electricity sold to isolated mini-grids**: Similar to Case 1, tariff is calculated as an average of LRMC and SRMC. The difference is that the calculation of SRMC uses the average incremental levelized cost of electricity from a new mini-grid diesel generator, including capital, fuel, and operational and maintenance costs.
Case 3 & 4 – Retail tariff for electricity sold to final customers: SPP developers selling directly to final customers must submit to EWURA an application for a cost-based tariff that is based on its own actual or projected total costs plus a reasonable profit. This retail tariff can be in the form of a conventional per kWh charge, a fixed monthly charge based on customers’ estimated usage, or another tariff mechanism approved by EWURA.

The revised SPP tariffs for the current year, announced by EWURA in March 2012, are (at the exchange rate used in the calculations) 10 USc/kWh (TSh 152.54/kWh). The dry and wet season levels are 12 c/kWh and 9 c/kWh respectively. The isolated grid rate is 31 c/kWh (TSh 489.5/kWh).
Electricity Banking /Net Metering Application Form

A2 Electricity Banking /Net Metering Application Form

Application for Electricity Banking or Net Metering of an On-Grid Small-Scale Renewable Energy Facility

The small-scale renewable energy facility shall be located at the premise served by the electricity account stated in Section 2. The installed capacity shall be up to the Contract Demand of the existing installation, subject to a maximum installed capacity of 42 kVA (3-phase, 60 Ampere)

1. Project Type: Please mark ✓ in the appropriate boxes below. Please select one or a combination of types.

<table>
<thead>
<tr>
<th>Wind</th>
<th>Biomass (grown)</th>
<th>Biomass (waste)</th>
<th>Geothermal</th>
<th>Biogas</th>
<th>Solar Photovoltaic</th>
<th>Hydro</th>
</tr>
</thead>
</table>

2. Information about the Applicant:

Electricity Consumer's Account No. ___________________________________________
Name ___________________________________________.
Address as specified in the Account No. ___________________________________________
Contract Demand of the Installation: single/three phase, _____ Ampere
Telephone numbers: ___________________________________________ Email. _______________

3. Facility Information – Please indicate whether application is for

Electricity Banking or for Net Metering..............................................................

Provide installed capacity and expected monthly kWh exports to the grid in the case of a Net Metering application...........................................................................................................

4. Certification

- I attach the receipt number ......................dated ............... for the payment of KSh............ as the review fee for this application, charged by Kenya Power.
- I certify that Net Metering Facility is required at the same premise where electricity account is already provided, and that the renewable energy resource is within the property served by the existing electricity supply.
- I have read the Agreement and the Interconnection Standards applicable for Electricity Banking or Net Metering Facility. I agree to install all the required equipment and to provide information whenever requested by Kenya Power.

Name of registered consumer signing this application ______________________

Signature __________________________ Date: ______ DD-MM-YYYY
A3 FiT Model user manual

In this brief user manual we describe the structure of the FiT model and provide instructions for updating FiTs or calculating new FiTs for negotiated or off-grid projects.

We will happily answer by email any questions that the FiT committee has on how to operate the model for six months following the completion of this assignment.

A3.1 Model structure

As described above, the FiT Model applies a similar approach to that applied by the FiT Committee in the past. The key differences are that this FiT Model groups all inputs on one page and does the cash flow calculations just once, rather than replicating them for each and every technology. Because they are run once (for the selected technology) a macro is used to cycle through each technology, run the calculations, and collect the outputs.

The structure of the model is illustrated in the Figure 25 below.

![Figure 25 Overview of FiT Model structure](image)

The calculation sheet provides a full cash flow analysis over the construction period (2 years) and the PPA period (20 years as default, but this can be changed). The ‘bottom line’ is the return to the equity investor. The FiT is calculated as the value of the tariff needed to provide the required ROE. A similar calculation is required to calculate the two values for the Front Loaded FiT option, except that it also ensures a minimum Debt Service Coverage Ratio (DSCR)\(^2\) is achieved.

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\(^2\) The DSCR indicates the extent to which project cash flows cover debt servicing requirements in a particular year. More specifically, it is calculated as net operating cash flows (after interest paid) divided by the principal paid on loan. The DSCR provides only an approximate indication given that the model forecasts cash flows on a pre-tax basis – actual tax paid will vary significantly from year to year depending on the tax laws of the day.
A3.2 Model worksheets

Each of the FiT Model’s worksheets are briefly described below:

- **Cover** – Provides a link to each of the subsequent worksheets and shows the model structure diagram.

- **Inputs** – Shows all cost and physical data inputs in the one sheet. Input cells are highlighted in grey, all other cells contain calculations based on formulae. These inputs are used in the subsequent sheet to calculate cash flows.

- **Calc (Selected tech)** – The user selects a technology category and the relevant inputs are pulled through from the Inputs worksheet. These inputs are used alongside the FiTs entered on the Outputs worksheet to calculate investor returns.

- **Outputs** – Shows FiTs which can be entered manually or calculated based on the target return on equity. The sheet also shows Front Loaded adjustments, linear tariffs, Indexed Components, and various graphs and tables to summarise the results.

A3.3 Instructions for updating FiTs

The user can follow the steps below to update a FiT for a given technology or technologies. The same instructions can be used to calculate a new FiT for a negotiated project.

- **Make sure macros are enabled.** In Excel 2010 Go to File > Options > Trust Centre > Trust Centre Settings > Macros > Enable Macros

- **Add or amend the inputs.** These are the grey cells on the "Inputs" worksheet. All other cells in this sheet (in white) are calculated based on formulae.

- **Calculate the Standard FiT.** To do this click the button "Calculate (to achieve target ROE)" on row 11 of the "Outputs" worksheet.

- **Check that the cash flow calculations and resulting IRR look correct.** These are on the "Calcs (Selected Tech)" worksheet. Select the relevant technology from the drop down box in row 9 and then review the cash flows, in particular the IRR on row 84.

- **Set the Front Loaded adjustments.** These are in rows 19 and 21 of the "Outputs" worksheet. The user can either input values manually or click the buttons in rows 20 and 22 to calculate them. The first adjustment is calculated based on achieving the minimum DSCR, while the second is calculated to achieve the target IRR.
Check that the actual ROE is equal to the target. The actual IRR and target IRR are compared in rows 39 and 40 of the "Outputs" worksheet. If they are not equal, then the Standard FiT needs to be recalculated (as per step number 3).

Calculate the linear equation if applicable. The user can choose whether to show the FiT as a linear equation on row 26 of the “Outputs” worksheet. This equation is an interpolation between the selected technology and that of the technology/category in the column immediately to its left.

The final Standard FiT, Front Loaded FiT, and Indexed Component are summarised in the table beginning on row 64 of the Outputs worksheet. Note that the model calculates Standard FiTs only. If separate capacity and energy charges are to be used for negotiated projects, then they have to be calculated separately, which can be done by setting the Indexed Component as the energy charge and converting the remainder into an annual capacity charge.

A3.4 Simplified FiT Model

We have also provided a simplified version of the FiT Model. This version applies the same approach as the main FiT Model, but only does the calculation for a single technology, uses no macros (the user can use the Excel “Goal Seek” function instead), and does not calculate Front Loaded adjustments, linear tariffs, or Indexed Components. This simplified version will be most useful if the user wishes to make a more intuitive check on the main FiT Model, or if the user wants to calculate a feed-in tariff for a single technology, as would be the case for the negotiated projects (ie on-grid projects larger than 10 MW or off-grid projects).
A4  Planning and Monitoring Tool user manual

The Planning and Monitoring Tool is in essence a database for entering information about applications and projects eligible for FiTs. It closely follows the content included in the Application Guidelines, so can be used alongside it to keep track of the potential pipeline of renewable projects. It can also be used for planning purposes.

By collecting the information in a pre-determined format, the user has a great deal of flexibility to analyse the results in any way he or she finds useful. We expect the model to be developed by users over time, particularly once the geo-spatial component has been developed and added.

A4.1  Applications of the tool

The objectives of the tool include allowing the user to:

- Track the number and type of applications and their progress.
- Record and report on key information about existing projects.
- Together with the geo-spatial database, use the tool for monitoring and planning.

Examples of practical uses of the tool include:

- Monitor the growth in total installed capacity of the embedded small generators (against the 10% limit).
- Use cost and performance data to update FiT values in the future.
- Keep track of the application status of individual projects and their associated eligibility.

A4.2  Structure of the tool

The structure of the Planning and Monitoring Tool is illustrated in the Figure 26 below.
A4.3 Instructions for using the tool

The instructions for using the different worksheets in the tool are as follows:

- **Input – Applications** – The user inputs relevant data into the worksheet, which each row representing a new project. The fields closely follow those in the application guidelines. Not all fields need to be filled in, but the more detail contained, the more accurate and useful any future analysis of applications will be. The information covered includes the following categories:
  - Project name, e.g. reference no, name of applicant
  - Description of project, e.g. technology type, installed capacity, electricity generation, connection point
  - Financing, e.g. construction cost, operating costs, debt/equity ratio
  - Applicant details, e.g. type of entity, address
  - Project location, e.g. gps coordinates, nearest centre
• Application status, e.g. date EOI submitted, progress score, date exclusivity granted

• Key milestones dates, e.g. signed land agreements, signed connection agreement, signed PPA, financial close achieved

• **Input - Projects** – This worksheet is to be used in a very similar way to the ‘Inputs – Applications sheet’. Once an application is approved and eventually becomes a project, much of the information can be copied across to projects, with only a few extra pieces of information added – including the applicable FiT values.

• **Input - Generation** – On this sheet the user simply enters the amount of energy generated by each project on a monthly basis. The project names and numbers are linked to the ‘Inputs – Projects’ sheet.

• **Report - Applications** – This sheet uses a Pivot Table to summarise and analyse data contained on the ‘Inputs – Applications’ sheet. The user therefore has full flexibility to display and filter information. For example, the user could calculate the percentage of applications that are approved, or the average investment cost per kW of installed capacity for hydro power plants. The sheet includes a macro to refresh the Pivot Table. Alternatively the user can refresh it manually (by right clicking on the Pivot Table and clicking ‘Refresh’).

• **Report - Projects** – This sheet uses a Pivot Table to summarise and analyse data contained on the ‘Inputs – Projects’ sheet. The user therefore has full flexibility to display and filter information. The sheet includes a macro to refresh the Pivot Table. Alternatively the user can refresh it manually (by right clicking on the Pivot Table and clicking ‘Refresh’).

• **Report - Generation** – This sheet uses a series of array formulae to sum up the monthly generation amounts and display them as annual figures. The user could use this data to compute average load factors for different technologies etc, perhaps by adding a new Pivot Table which references this report.